ISO new england

2004

Annual Markets Report

2004 Annual Markets Report

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1 Introduction and Executive Summary

Each year, ISO New England Inc. (the ISO) reports on the wholesale electricity markets that it administers. This report covers the period from January 1 to December 31, 2004, and contains the ISO's summaries and analyses of market operations.

1.1 Introduction

1.1.1 About ISO New England

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

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

On February 1, 2005, the ISO began operation as a Regional Transmission Organization (RTO), assuming broader authority over the day-to-day 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 continues to work closely with regulators and stakeholders, including participants in the marketplace.

1.1.2 About Market Monitoring and Mitigation

The ISO's responsibility in overseeing the region's wholesale electricity marketplace is to ensure that the markets are fair, transparent, efficient, and competitive. As part of this responsibility, the ISO's Internal Market Monitoring Unit (INTMMU) monitors the markets, publishes market results, analyzes market efficiency, and addresses any impediments to efficiency or competition. Where design flaws are identified, the ISO works with market participants, state regulators, the Federal Energy Regulatory Commission (FERC), and other agencies to correct those imperfections.

To assess the operation of the markets, provide transparency, and meet Federal reporting guidelines, the ISO issues periodic markets reports that describe the development and performance of New England's wholesale markets. The ISO seeks regular input from its Independent Market Monitoring Unit (IMMU), Dr. David B. Patton, to provide an additional, independent review of significant market developments.

This *2004 Annual Markets Report*, as required by Section 11.3 of Market Rule 1, Appendix A, *Market Monitoring, Reporting, and Market Power Mitigation*, is an assessment of New England's wholesale electricity marketplace during its most recent operating year. Based on market data, performance criteria, and independent studies, the report describes the development, operation, and performance of the markets, and provides a retrospective analysis of market outcomes observed by the ISO.

1.2 Executive Summary

In 2004, the New England wholesale electricity market completed the first full year of operation under Standard Market Design (SMD). SMD is an energy-market structure that incorporates the following features:

- Locational-marginal pricing that identifies where congestion occurs on the bulk power grid and assigns the cost of congestion to those locations
- Day-Ahead and Real-Time Energy Markets that produce separate financial settlements
- Risk-management tools to hedge, or protect, against the adverse impacts of having to pay higher locational-marginal prices (LMPs) when transmission congestion occurs

These features were incorporated into the New England market design on March 1, 2003, replacing the Interim Market structure of a single real-time market and regionwide energy price.[1] The report concludes that the new market design continued to operate effectively in 2004, with reliable operations and competitive market outcomes.

In 2004, the peak-demand summer months were cooler than normal, resulting in a peak electricity demand 2.3% below the 2003 peak. New England also continued to have a surplus of installed capacity (ICAP), evidenced by very low ICAP prices and robust reserve margins. These factors contributed to competitive market outcomes and estimated net revenues for new capacity that were insufficient to induce new entry. When adjusted for fuel costs, 2004 spot-market prices for electricity in the Day-Ahead and Real-Time Energy Markets were slightly lower than 2003 prices and also lower than those in previous years.

In addition to being the first full year of operation under SMD, 2004 was the fifth full year of operation for the wholesale electricity market. Changes in both the physical power system and the structure of the wholesale markets have brought about a more efficient New England system over the last five years:

[1] The New England wholesale market was implemented on May 1, 1999. The period of May 1999–February 2003 is referred to as the "Interim Market period" in this report.

- The addition of 9,450 MW of new generation capacity by competitive suppliers from 2000 to 2004 has led to cleaner power. The majority of the capacity additions were natural gas-fueled generating units that are more efficient to operate and produce fewer harmful emissions of SO_x, NO_x, and CO_2 than older oil-fueled plants, which now run less frequently.

- The addition of more efficient generating capacity has helped to reduce overall system production costs. The system MW-weighted average heat rate, which measures the efficiency with which liquid-fueled generators convert fuel to electricity, has declined by 5.6% since 2000.

- The percentage of time that generating units are available to the system, rather than out of service for maintenance, has increased from 81% in 2000 to 88% in 2004.[2] This suggests that market participants are responding to market signals to make their generators available.

- The addition of more efficient generating capacity to the system and competitive market operations have contributed to a reduction in fuel-adjusted wholesale electricity spot-market prices by 5.7% since 2000.

- The requirement for regulation service (i.e., the second-to-second response to dispatch signals for meeting instantaneous variations in demand) has decreased by 29% since 2001 due to improvement in the response time of generators providing this service to the ISO's regulation-control signals. Regulation costs are lower than they otherwise would have been due to this decrease.

In 2004, the ISO made many incremental market enhancements and corrections to minor operational and market problems. The ISO implemented an innovative Forward Reserve Market designed to improve incentives for installing and maintaining quick-start generating resources essential for reliability. The ISO also revised the rules for making operating-reserve payments. These payments compensate generators for operating *out of economic-merit order* (out-of-merit). That is, they have operated at the ISO's direction for reliability reasons or to meet their physical operating criteria, despite being more expensive than the marginal, or price-setting, supply offer. The rules were revised to ensure that these generators are compensated appropriately.

Other changes are as follows:

- Improved gathering and exchange of information with gas pipeline operators

- Procurement of additional reliability resources for Southwest Connecticut, or generators that support the transmission system in this area by providing operating reserves or another service

[2] Based on the Weighted Equivalent Availability Factor of New England generating units. Additional information on this topic is available in Section 4.3 of this report.

- Upgrades to the ISO Web site that provide easier data access

- Modifications to the Day-Ahead Energy Market clearing process that speeds the clearing and posting of results[3]

Incremental improvements will continue as new circumstances arise and problems are identified.

This year, the most severe test of the New England market occurred due to the cold snap on January 14–16, 2004 (the January 2004 Cold Snap), during which New England experienced extremely low temperatures and record winter peak demand. Overall, the New England electricity markets and infrastructure produced reliable operations and competitive outcomes. While installed capacity was more than adequate to meet demand, plant operational difficulties, caused by cold weather and inadequate firm natural gas contracting, rendered unavailable a significant portion of New England's generation supply. Although market prices were indicative of extreme conditions, they generally were below the underlying costs of natural gas generators. These generators had insufficient market incentive to procure spot-market gas and operate to meet peak loads (unusual demand for electricity).

The ISO's experience in responding to the January 2004 Cold Snap events helped to identify areas for improvements. During the nine months that succeeded these events, the ISO, the New England gas pipelines, and stakeholders developed a number of short-term responses to the issues identified as a result of that event, as follows:

- Improved communications from participants and market information from the ISO, to help increase understanding of system conditions and enable better risk management

- Increased coordination and information flow between the gas pipelines and the ISO, which should improve system reliability and efficient market operations

- Enhanced ability of dual-fueled generators to switch fuels during emergency conditions

- Development and implementation of plans for revised electricity market timing, to increase the use of the existing gas pipeline infrastructure in the most extreme circumstances

While these changes comprise only a first step, they should help improve system and market performance during similar events in the future. The North American Energy Standards Board is using these actions as a foundation to develop a set of nationwide recommendations for improving gas-electricity market coordination. In the longer term, it is critical that the electricity and natural gas markets are well coordinated, that LMPs consistently reflect the price of the

[3] The ISO-New England's Web site address is <http://www.iso-ne.com/>.

marginal resource, and that the market provides strong incentives to ensure the availability of capacity resources when needed.

A major challenge ahead will be to address the increases in out-of-market compensation (i.e., payments outside of energy market-clearing processes). These payments were primarily to generators in 2004 and took two forms—compensation for daily out-of-merit costs in the northeastern Massachusetts (NEMA)/Boston and Connecticut constrained areas and for Reliability Agreements, also concentrated in these constrained areas.

Daily out-of-merit costs in constrained areas were driven by reliability needs for transmission support, typically reactive power and second-contingency coverage. The biggest increase was the cost of Volt Ampere Reactive (VAR) payments, which rose from $12 million in 2003 to $78 million in 2004, driven by increases in the Boston area. These costs have a number of corrosive effects, including the reduction of LMPs below efficient levels; an increase in day-ahead/real-time price differences due to flawed cost allocation of real-time Operating Reserve Charges (i.e., charges made to participants whose real-time load deviates from the day-ahead schedule); and increased difficulty for participants to hedge transactions and serve load in constrained regions. The ISO and participants are pursuing infrastructure upgrades, operational changes, and market-rule changes designed to reduce the severity of these problems. The market-rule changes must provide appropriate incentives for flexible resources to locate in the correct places to reduce out-of-merit costs.

Reliability Agreements are contracts between the ISO and generators that ensure generators will stay in service to meet identified reliability needs. Reliability Agreements generally cover a generating unit's fixed costs, net of market revenues, and are approved by FERC. In 2004, Reliability Agreements covered approximately 2,342 megawatts (MW). In the first quarter of 2005, 2,707 MW were under such agreements, with generators seeking such treatment for an additional 4,625 MW. Together, approved and requested Reliability Agreements through the first quarter of 2005 cover approximately 20% of New England's installed capability. While the approved contracts are with units in historically constrained areas, many of the pending agreements are with units in unconstrained portions of New England.

The increased use of Reliability Agreements suggests that, while there is adequate systemwide capacity, the current capacity-payment mechanism does not adequately identify or compensate existing generators required for reliability. The existing market structure is not sending appropriate market signals regarding the need for new investment and the maintenance of existing investment in critical sub-areas of New England, such as Connecticut and Greater Boston. Reliability Agreements are not a long-term solution to problems in these areas, but rather a signal that improved markets are needed. Improving the market design, primarily through the proposed Locational Installed Capacity (LICAP) mechanism, which will appropriately value existing power supplies and incent investment in new capacity resources in needed locations, is critical for both reducing the need for Reliability Agreements and attracting the investment needed to meet electricity load growth.[4]

This *2004 Annual Markets Report* also includes information about load and demand levels, market-clearing prices, competitive market conditions, and other topics. The next section summarizes these results.

1.3 Summary of 2004 Results

- **Price levels and fuel costs—**Electric energy prices were consistent with those expected in a competitive market. The average load-weighted real-time system energy price was $53.57/MWh in 2004. Yearly average natural gas and fuel oil prices were higher than those of previous years, driving energy prices higher. When adjusted for fuel-price changes, electricity prices were lower than in previous years. Natural gas prices were especially high during January 2004 and moderately high in December 2004, contributing to increases in wholesale electricity prices during those months. The combination of high natural gas prices and high demand, driven by severely cold weather, caused the highest prices of 2004 to occur during the winter months of January and December. While peak electrical demand was higher in the summer of 2004 than in the winter months, it was below the highest range of forecast summer demand due to generally cool weather, and generation capacity was more than adequate to meet it. These conditions, combined with moderate fuel prices, led to a summer season without the systemwide price spikes seen during the winter months.

- **Day-ahead and real-time prices and relationship to demand—**Electric energy prices were positively correlated with the level of demand. As expected, off-peak prices were generally lower than on-peak prices.[5] At the Hub, day-ahead prices averaged 3% ($1.59/MWh) higher than real-time prices for the year. This is an increase from last year, when the premium was 1% ($0.38/MWh). Each load zone also demonstrated slight price premiums in the Day-Ahead Energy Market over the Real-Time Energy Market. The average day-ahead zonal prices ranged from $48.62/MWh in Maine to $54.62/MWh in Connecticut. Average real-time prices ranged from $47.79/MWh in Maine to $52.80/MWh in Connecticut. The increase in price differences between the Day-Ahead and Real-Time Energy Markets may be partly driven by relatively large Operating Reserve Charges that are applied to real-time deviations from day-ahead schedules.

- **Imports and Exports—**New England continued to be a net importer of power in 2004, with net imports equal to 3.7% of the total energy needed to serve demand, including losses within the New England Control Area, termed Net Energy for Load (NEL). Both imports and exports fell from 2003 levels, with New England a net importer from Canada

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[4] See <http://www.iso-ne.com/FERC/filings/Other_ISO/ER03-563-030%204-27-05.doc>.

[5] Bilateral contracts use the hours between 7:00 a.m. and 11:00 p.m. on nonholiday weekdays as on-peak hours in the New England Control Area. The weekday hours between 11:00 p.m. to 7:00 a.m., and all day on Saturdays, Sundays, and holidays, represent the off-peak period.

and net exporter to New York. As in the past, power flows over the New York interface have not reflected the relative prices in New York and New England. This important market inefficiency has been addressed, in part, through the December 2004 elimination of export fees, but requires additional improvements, such as the implementation of the ISO's Intra-hour Transaction Scheduling, which will simplify trading between New England and New York.

- **Day-Ahead and Real-Time Energy Market clearing—**Consistently high amounts of actual real-time load cleared in the Day-Ahead Energy Market. On average, 97% of eventual real-time load obligation (i.e., the sum of metered load, exports, and load-shifting contracts for which a lead participant is financially responsible) cleared in the Day-Ahead Energy Market during 2004. This indicates that market participants hedged market positions in advance of real-time operation, which results in less demand being exposed to real-time price volatility. The average cleared percentage for New England load zones ranged from a high of 100% in the southeastern Massachusetts (SEMA) load zone to a low of 92% in the Maine load zone. Low levels of day-ahead clearing seen in Connecticut last year disappeared, coincident with the expiration of certain load-serving contracts.

- **Forward Reserve Market—**The Forward Reserve Market (FRM) went into operation on January 1, 2004, following a December 2003 auction. The FRM compensates generating resources for providing nonsynchronized (nonspinning) 10-minute and 30-minute reserves. These generators can provide electricity to the system within 10 or 30 minutes in response to a contingency, even if they are not generating prior to the contingency. Payments to generators providing forward reserves totaled about $86 million (about $4/kW-Month), while penalties for nonperformance totaled $3 million. Most of the penalties were incurred during the January 2004 Cold Snap. Approximately 1,900 MW were cleared in each auction. There was adequate participation, and units with characteristics that appear to make them low-cost providers of the service provided the large majority of reserves. FRM providers appear to have taken steps to improve their reserve performance and avoid FRM penalties, which seems to have increased their ability to provide the forward-reserve products.

- **Capacity Market—**The portion of the capacity market settled through the ISO had relatively low prices in 2004, reflective of the systemwide surplus of installed capacity. Supply auction prices were significantly lower in 2004 than in 2003, while deficiency auction prices were greater than $0/MW-Month for the first time in November and December. On average during 2004, 6% of the system capacity requirement was met through the supply and deficiency auctions, with the rest being self-supplied (i.e., provided by participants from their own resources) or bilateral contracts. Delisting from the ICAP Market increased during the year and is most prevalent in NEMA and Connecticut, which does not correlate with the reliability needs in those areas. This highlights a deficiency of the current capacity market; it does not recognize the differing value of capacity in different locations.

- **The Regulation Market—**The Regulation Market clearing price averaged $28.92/MWh in 2004. Payments made to generators providing regulation service totaled $44 million including $4 million in real-time opportunity costs. A rule change implemented in

February 2004 has improved the market by including more providers in the price-setting process. There was ample regulation capacity in 2004.

- **Operating Reserve Credits (ORC)—**Payments to generators providing Economic or Reliability Must Run (RMR) operating reserves totaled approximately $91 million in 2004, an increase over the $84 million paid in 2003. These payments were in addition to energy-market revenues. RMR Operating Reserve Credits were made to generators that were needed to meet local reserve requirements in Connecticut and Boston. Economic ORC payments were made to generators needed for systemwide reserves or energy. RMR charges were increased by the Peak Unit Safe Harbor (PUSH) rules, designed to compensate generating resources providing reliability service, and by increased fuel costs. The ISO developed an action plan for 2005 to reduce the need to commit generators that create these costs.

- **Transmission Tariff Service Payments—**Payments to generators providing VAR and Special Constraint Resource (SCR) services under the transmission tariff totaled approximately $78 million in 2004. As with ORC, these payments were in addition to energy-market revenues. The majority of these payments was made to generators providing VAR control in the Boston area. These VAR and SCR charges increased from $21 million in 2003, driven by transmission system operating changes and participant behavior in NEMA. The Boston-area transmission owners have proposed system upgrades to reduce these costs and the ISO has identified market-rule changes that should also reduce these costs.[6]

- **Congestion Hedging through Financial Transmission Rights (FTRs)—**Market participants are able to buy financial instruments that help them hedge the price risk of day-ahead congestion caused by constraints on the transmission system. FTRs were offered to the marketplace in 12 ISO-administered monthly auctions and two six-month auctions during 2004. Participation in the auctions was strong, and market participants purchased FTRs generally consistent with expected patterns of congestion. The total auction revenues and congestion-cost offsets were similar. Winning auction bids generated $91.7 million in auction revenue, and the monthly and long-term FTRs awarded during the year provided $99.3 million of day-ahead congestion-cost offsets to their holders. In 2003, FTRs provided much greater congestion-cost offsets than they generated in auction revenue.

- **Demand Response—**Demand response, or when customers reduce their electricity consumption in response to price, can help address short-run reliability problems by reducing supply needs. It is an integral part of an efficient wholesale market because it can reduce market price spikes and volatility and provide a hedge against price risk. As of September 1, 2004, 486 assets were under contract under the ISO's demand-response programs; they represent over 356 MW of potential curtailment in any hour. During 2004, implementation of demand-response programs by the ISO resulted in over 13,000 MWh of decreased electricity usage in New England. Significantly increasing the amount of demand response is critical to improving the long-run performance of the New England

[6] The tariff is available on the ISO's Web site at <http://www.iso-ne.com/FERC/filings/tariff/>.

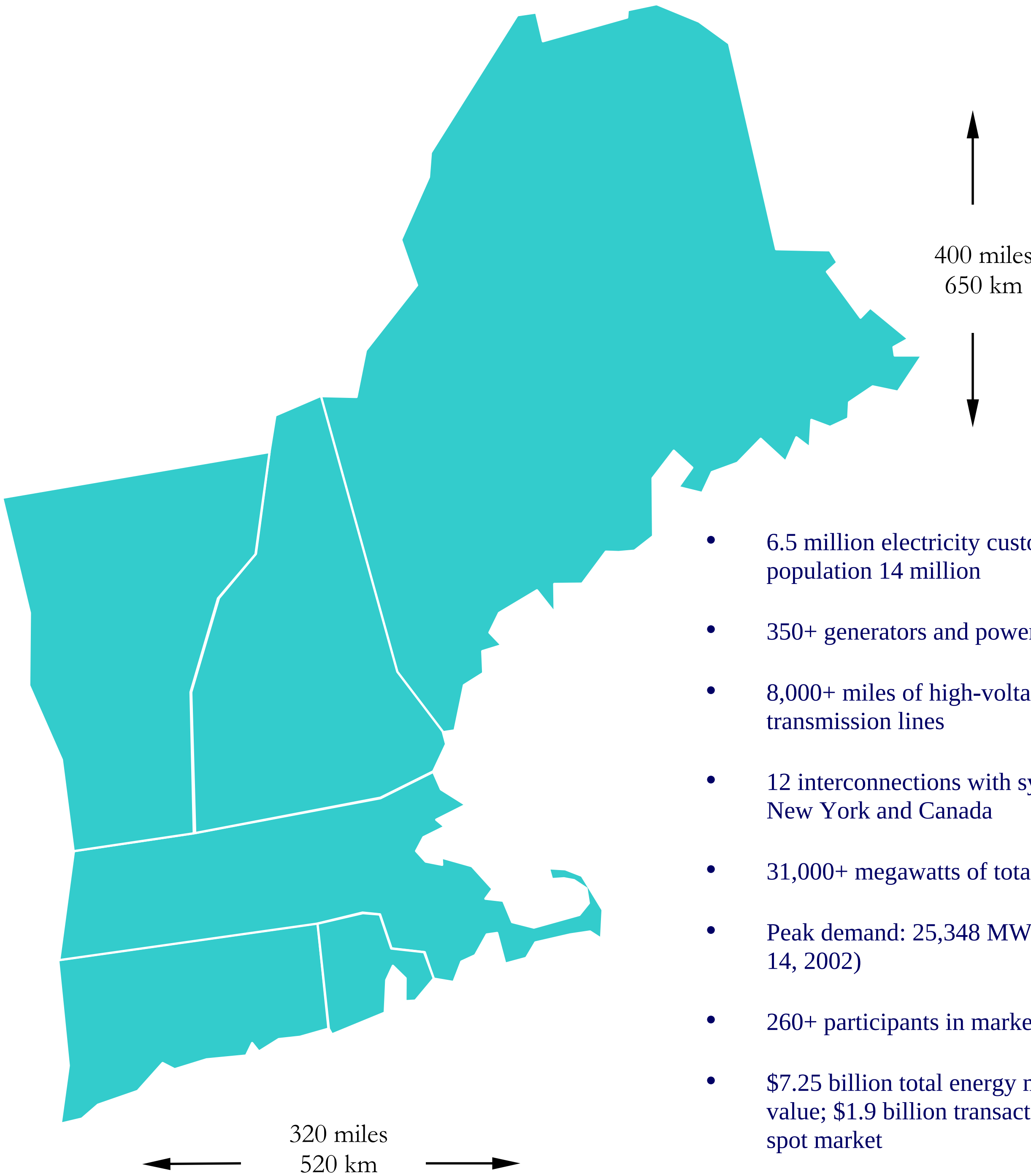
electricity markets. The number of enrolled megawatts has been roughly constant over the last 1.5 years, likely due to low capacity prices and retail-rate designs implemented at the state level.

- **Market Monitoring—**The ISO monitors the market to ensure efficient and competitive market results. In specific circumstances, the INTMMU, in consultation with the IMMU, may intervene in the market to mitigate behavior that exceeds clearly defined thresholds. The primary intervention is to substitute supply offers that exceed conduct and market-impact thresholds that the participant does not adequately explain with supply offers intended to represent a unit's marginal costs. During the year, congestion mitigation authority was triggered only twice. This shows participants' understanding of the relevant mitigation rules as well as the strong incentives to abide by those rules.

- **Audits—**The ISO participated in several market-related audits during 2004. The ISO successfully completed a Statement on Auditing Standards (SAS) 70 Type 2 Audit in December 2004. An audit conducted by the North American Electric Reliability Council (NERC), completed in May 2004, identified ISO practices that could serve as "best practices" for other control areas. The ISO also participated in a "management-assertion" review, which is an audit verifying that the organization was correctly calculating charges and complying with rules and tariffs; an operations review; and the re-certification of its market system software. The results of these audits and reviews are available on the ISO's Web site and are important for providing transparency and accountability to the ISO's stakeholders.

New England's electricity markets performed well over the last year, both during the high-load summer months and during a cold snap that tested much of the region's energy infrastructure. The ISO and stakeholders must address the issues of out-of-merit generation and reduce the use of Reliability Agreements through the implementation of LICAP to ensure both efficient markets and adequate levels of reliability in the future. Improved signals for flexible capacity are needed and should be provided by the proposed Ancillary Service Markets, which will add real-time products to the current markets and change the FRM to be locational. An improved capacity market should help to stimulate enrollment in the Demand Response Programs, but modification of retail-rate designs is also needed to remove any barriers to revealing efficient prices to retail consumers.

Key Facts: New England's Power System and Wholesale Electricity Market



- 6.5 million electricity customers; population 14 million
- 350+ generators and power plants
- 8,000+ miles of high-voltage transmission lines
- 12 interconnections with systems in New York and Canada
- 31,000+ megawatts of total supply
- Peak demand: 25,348 MW (August 14, 2002)
- 260+ participants in marketplace
- $7.25 billion total energy market value; $1.9 billion transacted in spot market

2 Markets

This section of the report contains information about the Electric Energy Markets, Forward Reserve Market, Capacity Market, and Regulation Market.

2.1 Electric Energy Markets

2.1.1 Overview of Electric Energy Markets

The Electric Energy Markets operated by the ISO consist of a Day-Ahead Energy Market and a Real-Time Energy Market for electricity, with each market producing a separate 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. The Real-Time Energy Market reconciles differences between the day-ahead scheduled amounts of electricity and the actual real-time load requirements. Changes to supply or demand can occur for a variety of reasons, including market participant re-offers, 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, including weather. Participants with load or generation megawatt-hour deviations from their day-ahead committed schedules either pay or are paid the real-time LMP for the energy amount that is sold or purchased from the Real-Time Energy Market.

The ISO calculates and publishes prices at five types of locations. These pricing locations are called Pnodes and include the external interfaces, load nodes, individual unit nodes, and the load zones and the Hub, which are collections of Pnodes. To settle markets at these locations, participants submit supply offers and demand bids, after which the ISO calculates the LMPs. A generator is paid the price at its Pnode, while participants serving demand in each zone pay a load-weighted average of the load Pnodes located in that zone.

New England is divided into the following zones: Maine, New Hampshire, Vermont, Rhode Island, Connecticut, Western/Central Massachusetts (WCMA), Northeastern Massachusetts and Boston (NEMA), and Southeastern Massachusetts (SEMA). These eight load zones reflect the historical operating characteristics of, and the major transmission constraints on, the transmission system.

Transmission systems experience electrical losses as electricity travels through the transmission lines. To compensate for the losses, generators must increase the production of electricity by a small percentage. Nodal prices are adjusted to account for the marginal cost of losses.

If the system was entirely unconstrained and there were no losses, all LMPs would be equal and reflect only the marginal energy offer. The generation with the lowest cost would be able to flow to all nodes over the transmission system. If the transmission network were congested, the next increment of electric energy in a constrained area could not be delivered from the least expensive unit on the system because it would violate transmission operating criteria, such as thermal or voltage limits. The congestion component of price is calculated at a Pnode as the difference between the unconstrained energy component of price and the cost of providing an additional, more expensive, increment of electric energy to that location.

2.1.2 Underlying Drivers of Electric Energy Market Prices

Key factors that influence the market price for electric energy are supply and demand, fuel prices, and transmission constraints. This section elaborates each of these factors.

2.1.2.1 Supply and Demand

Market clearing is accomplished by the interaction of supply and demand at each location on the system in both the Day-Ahead Energy Market and the Real-Time Energy Market.

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 the load zone, and they may bid virtual supply and demand at the Hub, load zone, or Pnode. Generating units offer their output at the Pnode specific to their location. The intersection of the supply and demand curves as offered and bid determines the Day-Ahead Energy Market price at each node, with zonal prices calculated as a load-weighted average of nodal prices within each zone. 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 generally driven by input fuel costs. Supply offers also incorporate the units' operating characteristics, operating costs, and bilateral contract requirements. Demand bids reflect participants' load-serving requirements and accompanying uncertainty, tolerance for risk, and expectations surrounding congestion.

After the Day-Ahead Energy Market clears, the supply at each location can be affected in two ways. First, as part of its Reserve Adequacy Analyses (RAA), the ISO may be required to commit additional generating resources to support local-area reliability or provide contingency coverage.[7] Second, generators that were not committed in the Day-Ahead Energy Market can request to self-schedule their units for real-time operation or, alternatively, units that were committed can request to be decommitted.

[7] After the Day-Ahead Energy Market clears, generators are able to re-offer uncommitted capacity to the market. The ISO performs the RAA after 6:00 p.m. on the day preceding dispatch to ensure that sufficient generation has been committed systemwide and in each sub-area for reliable operation during the upcoming dispatch day.

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 scheduled the 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 minute-to-minute, while ensuring sufficient reserves and safe transmission line loadings. 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, both systemwide and in constrained sub-areas.

2.1.2.2 Fuel Prices

For most electricity generators, the cost of fuel is the largest production-cost variable, and as fuel-costs increase, there is a corresponding increase in the prices at which generators submit offers in the marketplace. Over the last five years in New England, the increase in generating capacity has been almost entirely natural gas-fired capacity. Generating units burning primarily natural gas, or capable of burning natural gas and oil, constitute approximately 51% of electric generating capacity in the region, and these units are the marginal supply units over 85% of the time. New England electricity prices are highly sensitive to changes in natural gas prices. Natural gas and fuel oil prices in 2004 exceeded the prices of recent years. Natural gas prices have increased by 82% since 2002.

2.1.2.3 Transmission Constraints

In an unconstrained system, all LMPs would be the same at every location, except for marginal losses. However, the patterns of demand (physical and virtual); generator outages; and thermal, voltage, and stability limits on the transmission system all can lead to binding transmission constraints that the ISO must manage.

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

2.1.3 2004 Demand

Total yearly demand in 2004 exceeded that of previous years, while the peak hourly load during the year was lower than in 2002 and 2003. (See Section 7.2 in the statistical appendix for more information on hourly and monthly loads.) The Net Energy for Load supplied to the system in

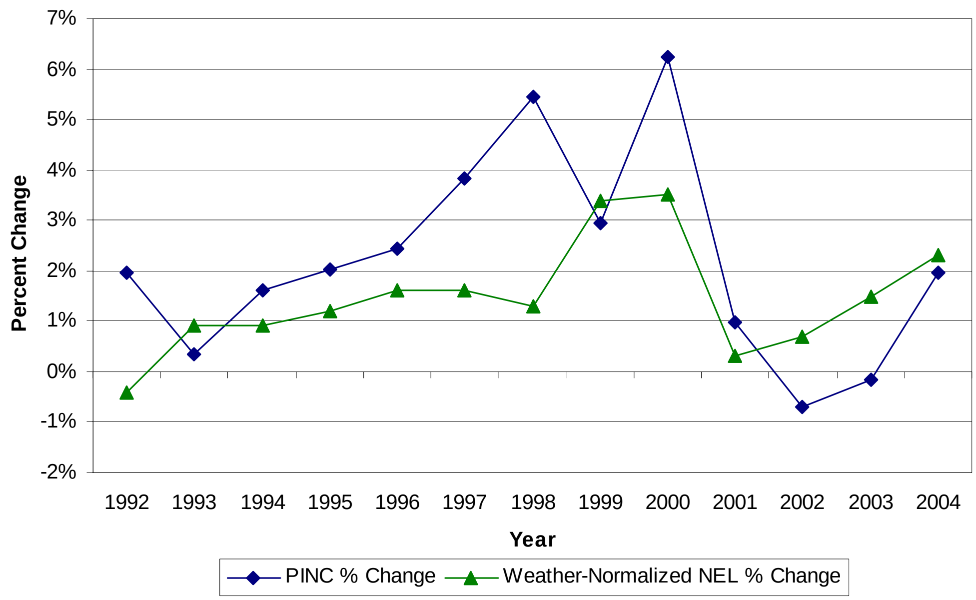
2004 was 132,522,000 MWh, an increase of 1.3% over the 2003 level.[8] Since NEL is modestly influenced by weather, to more accurately compare load growth across years, the ISO calculates the weather-normalized NEL, that is, the NEL that would have been observed if weather were normal. After weather normalization, the increase in the NEL from 2003 to 2004 was 2.3%, as shown in Table 1.[9] The higher weather-normalized demand in 2004 compared with 2003 is driven largely by economic growth. Figure 1 compares the year-to-year percentage change in weather-normalized NEL to the percentage change in personal income (PINC), an indicator of economic growth. NEL growth from 2003 to 2004 was about average, after low-to-average growth in the previous three years.

Table 1 - Annual Electric Energy and Peak Statistics

Energy Concept	2004	2003	Change	% Change
Annual NEL (MWh)	132,522,000	130,775,000	1,747,000	1.3%
Normalized NEL (MWh)	131,753,000	128,846,000	2,907,000	2.3%
Recorded Peak Load (MW)	24,116	24,685	-569	-2.3%
Normalized Peak Load (MW)	25,735	25,170	565	2.2%

Figure 1

Percent Change in Personal Income* vs. Weather-Normalized NEL, 1992-2004



*Federal Reserve Bank of Boston Real Personal Income.

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8 Net Energy for Load is calculated as total generation (not including generation used to support pumping at pumped-storage hydro generators) plus net imports and exports.

9 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. If temperatures are more severe than normal, consumption is adjusted downward; if milder than normal, an upward adjustment is made. Data for summer months also account for the effect of humidity on consumption levels.

The 2004 system peak hourly load of 24,116 MW occurred on August 30. This was 2.3% below the 2003 peak, which occurred during a period of hot summer weather. The temperature at the time of the peak in 2004 was 82 degrees, with a dew point of 70 degrees. The 2003 peak occurred on August 22, when the temperature was 90 degrees and the dew point was 71 degrees, after several days of above-normal temperatures. Both 2003 and 2004 peak loads were lower than the all-time peak load of 25,348 MW, which occurred in August 2002. After weather normalization, the 2004 summer seasonal peak increased by 2.2% over the 2003 weather-normalized peak. The ISO calculates a weather-normalized peak load for the summer and winter seasons.

Figure 2 shows total yearly electric energy demand for each of the eight New England load zones. Demand was highest in Connecticut, followed by NEMA.

Figure 2

2004 Demand by Load Zone

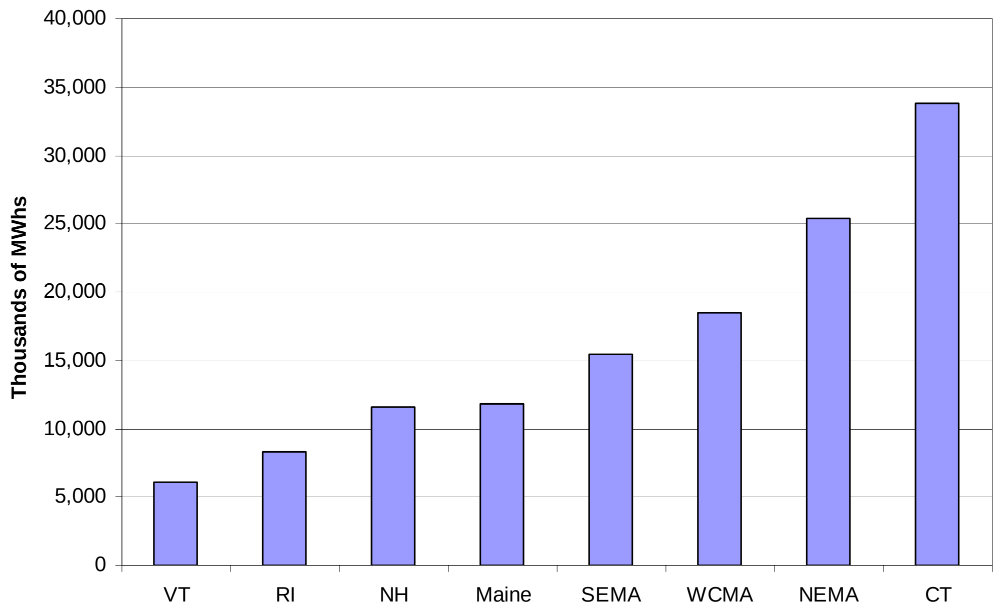


Figure 3 and Figure 4 show the actual system electrical load for New England over the last four years as load-duration curves, with load levels ordered from highest to lowest. The duration curve shows, for each year, the percentage of time that the hourly load was at or above the load levels shown on the vertical axis. Figure 3 shows that in 96% of the hours, the hourly loads in 2004 were above the levels for each of the previous three years. Figure 4, which includes only the highest 5% of hours, shows that the earlier years had higher peak loads. Low 2004 peak loads were largely the result of a relatively cool summer.

Figure 3

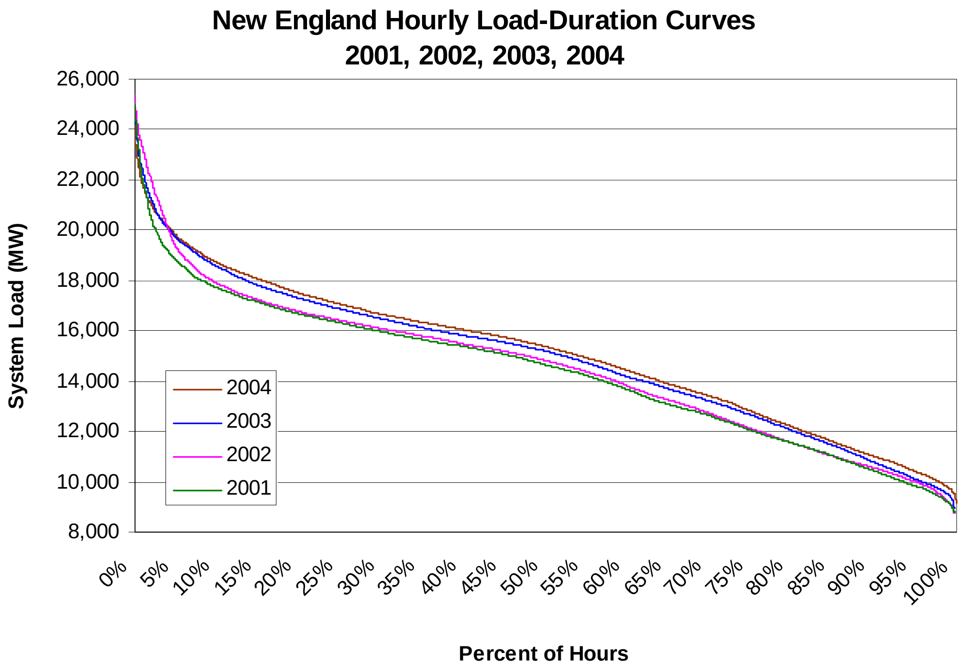
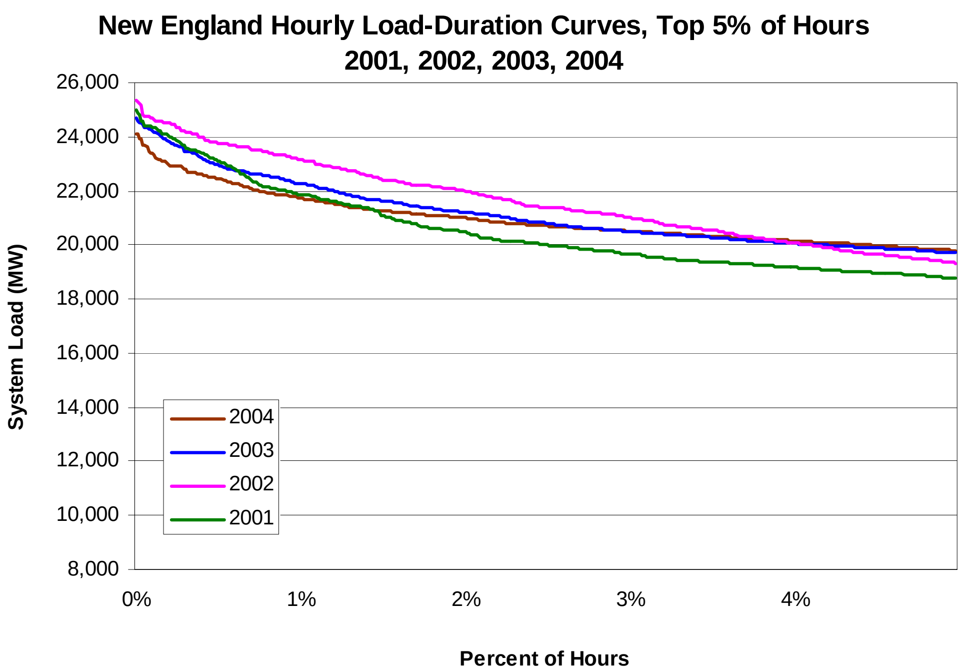


Figure 4



2.1.3.1 Load Obligation

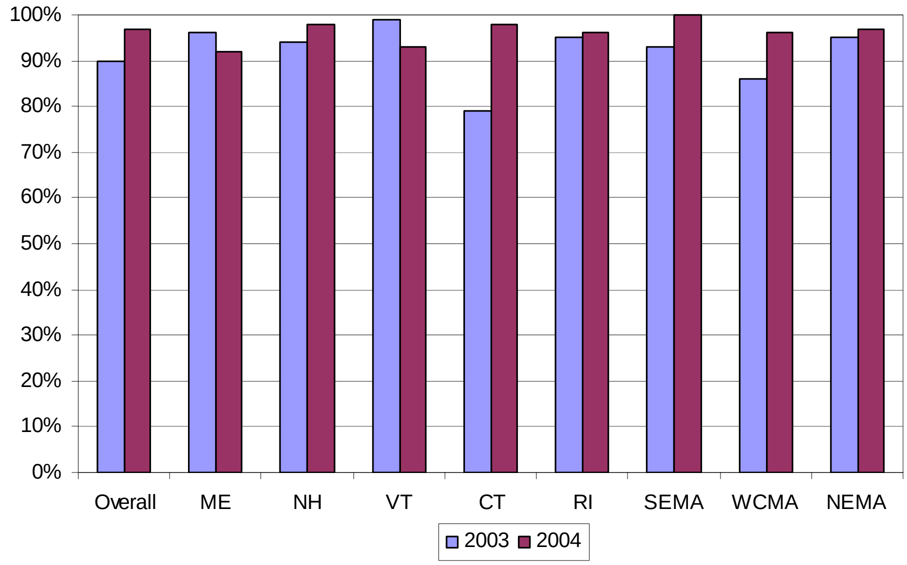
Figure 5 compares the percentage of real-time load obligation cleared in the Day-Ahead Energy Market in each load zone for 2003 and 2004. Table 2 presents statistics on the percentage of real-time load obligation cleared in the Day-Ahead Energy Market for 2004, by zone and overall. The average day-ahead load obligations in 2004 was 97% of the real-time load obligation, while in 2003 day-ahead load obligation averaged 90% of real-time load obligations. This increase was driven largely by changes in the Connecticut load zone, though many load zones showed an increase from 2003 to 2004. In 2003, only 79% of Connecticut real-time load obligation was cleared day-ahead, and that figure increased to 98% in 2004. This change coincided with the expiration of certain long-term contracts that served Connecticut load. The contracts, which did not specify that the delivery points be in Connecticut, often were settled in Maine, which experienced a drop in day-ahead cleared load in 2004.

Table 2 - Percentage of Day-Ahead vs. Real-Time Load Obligation

Zone	Average	Minimum	Maximum	Std. Dev.
Overall	97%	90%	106%	3%
Maine	92%	80%	112%	5%
New Hampshire	98%	21%	170%	7%
Vermont	93%	23%	113%	8%
Connecticut	98%	87%	108%	4%
Rhode Island	96%	67%	110%	6%
SEMA	100%	85%	112%	4%
WCMA	96%	85%	111%	4%
NEMA	97%	86%	106%	3%

Figure 5

Percentage of Real-Time Load Obligation Cleared in Day-Ahead Energy Market, 2003 vs 2004 by Load Zone and Overall



2.1.3.2 Day-Ahead Demand and Virtual Trading Trends

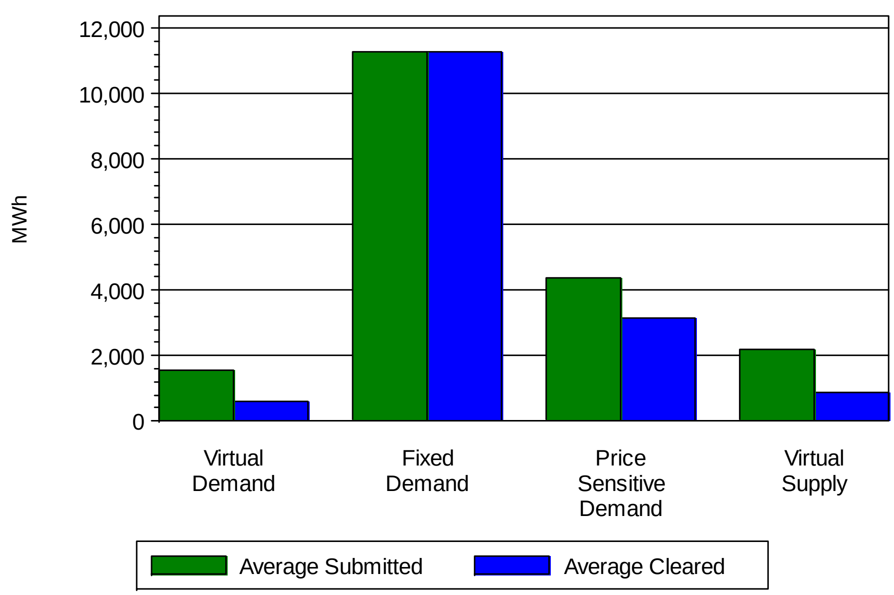
Market participants serving load can participate in the Day-Ahead Energy Market by bidding fixed and price-sensitive demand. All participants can bid virtual demand in the Day-Ahead Energy Market and sell virtual supply. Virtual demand bids are called decrement bids, or *decs*, while virtual supply sales are called incremental offers, or *incs*. All purchases or sales are at the Day-Ahead Energy Market clearing prices. Fixed and price-sensitive demand can be submitted at the load zones, while virtual demand and supply can be submitted at specific Pnodes. Demand bids that clear in the Day-Ahead Energy Market create price certainty for purchasers because price and quantity are locked in ahead of the Real-Time Energy Market. Virtual demand may represent expected real-time consumption at a Pnode, may be used to manage the financial obligations of generating resources, or may be used to arbitrage day-ahead and real-time prices.

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 and thereby helping to determine day-ahead LMPs. It also allows more participation in the day-ahead price-setting process, allows participants to manage risk in a multi-settlement environment, enables arbitrage that promotes price convergence, and mitigates market power in the Day-Ahead Energy Market by reducing net day-ahead purchases when prices would otherwise rise.

Increment offers that clear in the Day-Ahead Energy Markets create a financial obligation for the participant to purchase energy at a particular location in the Real-Time Energy Market, while decrement bids create a financial obligation for the participant to sell at a particular location in the Real-Time Energy Market. That is, an inc in the Day-Ahead Energy Market is "filled" by a purchase in the Real-Time Energy Market, and a dec in the Day-Ahead Energy Market is then sold in the Real-Time Energy Market. An exception to these obligations is a virtual demand bid that is mirrored by consumption at the Pnode in real-time. When a participant's real-time consumption occurs at the same location as a cleared virtual demand bid, the settlement rules applicable to fixed- and price-sensitive demand bids, with the operating-reserve allocation rules being the most important, are applied to the virtual demand bid (see Section 3.2). 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 any applicable Operating Reserve Charges. Figure 6 shows average hourly quantities of day-ahead demand and virtual supply for 2004.

Figure 6

Average Hourly Submitted and Cleared Demand, Virtual Demand, and Virtual Supply Day-Ahead Energy Market, 2004



The sum of the average hourly cleared fixed bids, price-sensitive bids, and decrement bids in the Day-Ahead Energy Market represents over 96% of average hourly system real-time load. Seventy-five percent of cleared demand bids during 2004 were fixed bids, insensitive to price, while 21% of the bids were price-sensitive. The remaining 4% of cleared day-ahead demand was composed of cleared decrement bids representing day-ahead locational purchases of electric energy. By comparison in 2003, 64% of cleared demand was fixed, 28% was price-sensitive, and 8% was virtual. Virtual supply made up 3% of day-ahead cleared supply in 2004 and 2% in 2003.

Figure 7 plots the fixed demand submitted in the Day-Ahead Energy Market as a percentage of total demand in the Day-Ahead Energy Market (price-sensitive demand plus fixed demand) against the actual real-time peak load each day. Participants increased their percentage of fixed demand submitted on days when load was high. Assuming that expected loads generally correspond well with actual loads, this behavior is consistent with participants seeking to avoid exposure to real-time prices when those prices might reasonably be expected to be high and more volatile than normal due to forecasts of high loads.

Figure 7

Daily Peak Actual Load vs. Bid Fixed Demand as Percentage of Total Bid Demand, 2004

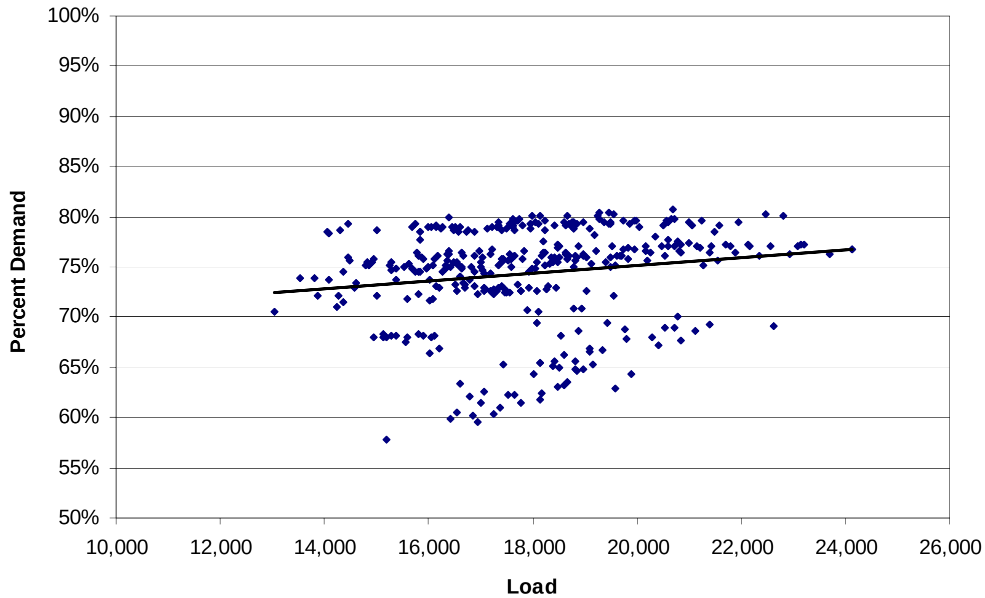


Figure 8 and Figure 9 show the total monthly submitted and cleared virtual demand and virtual supply from March 2003 through December 2004. The figures show that the volumes of both submitted and cleared virtual demand were much lower in 2004 than in 2003. The volume of submitted virtual supply declined modestly, while cleared virtual supply did not exhibit a clear pattern. Refer to Section 7.3 in the statistical appendix for more information on virtual supply and demand.

Many factors influenced these patterns, including tariff charges allocated to virtual transactions, expected Operating Reserve Charges, and expected day-ahead/real-time price patterns. Virtual trades are an important part of well-functioning day-ahead and real-time markets, as they arbitrage prices and fill-in for supply and demand in the Day-Ahead Energy Market when physical resources bid and offered into the market are insufficient or not priced well. While the volume of trades has not decreased to necessarily worrisome levels, further declines might signal problems. The ISO has identified a proposed change to the allocation of the real-time Reliability

Must Run Operating Reserve Credit that should reduce costs of virtual transactions. (See Section 3.2 for additional information on RMR-ORC payments.)

Figure 8

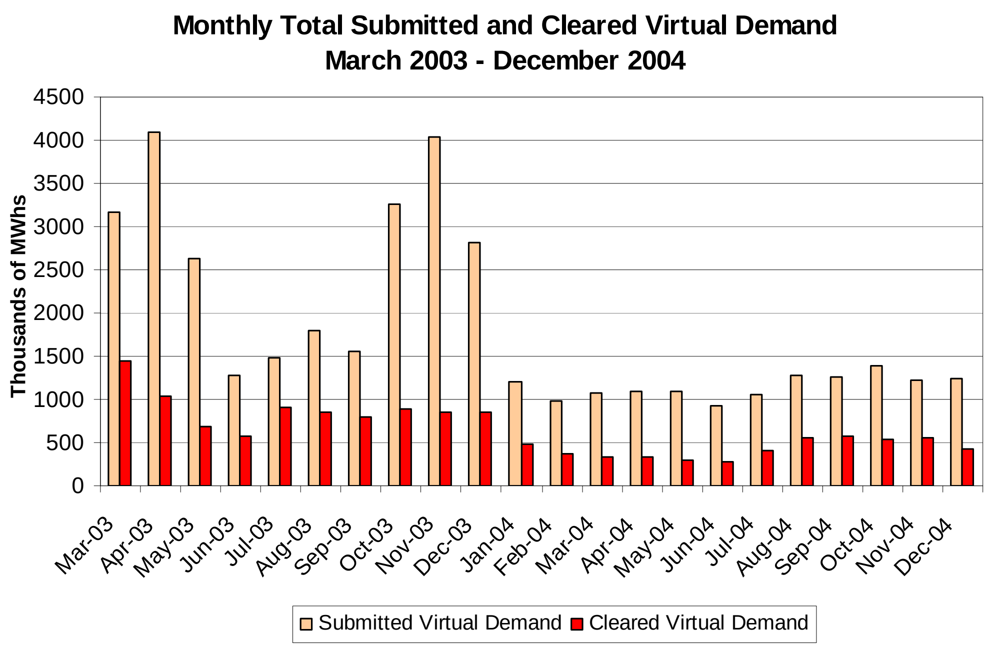
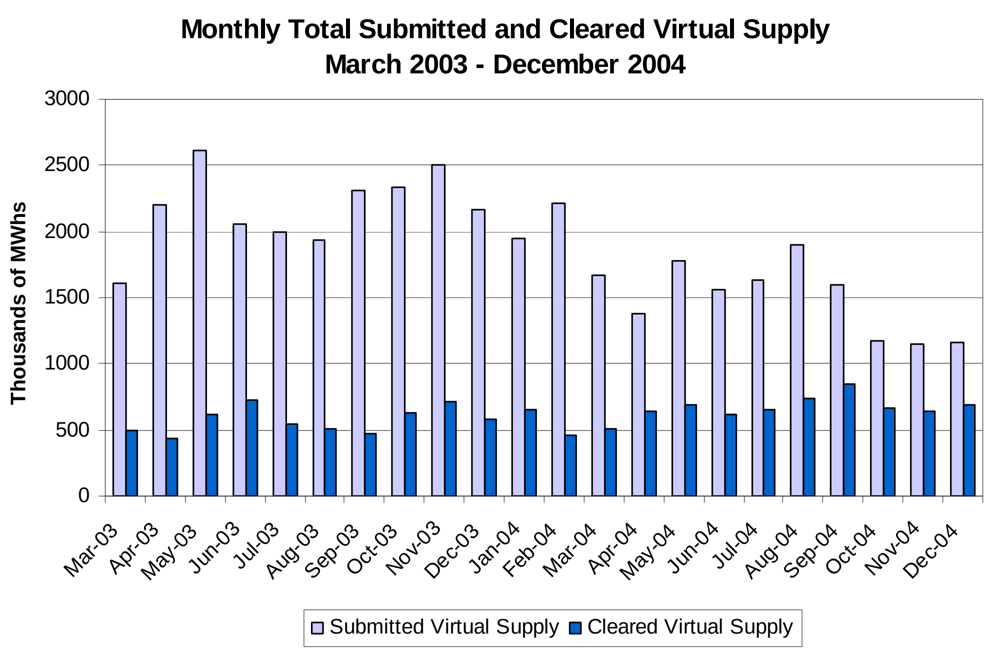


Figure 9



2.1.4 2004 Supply

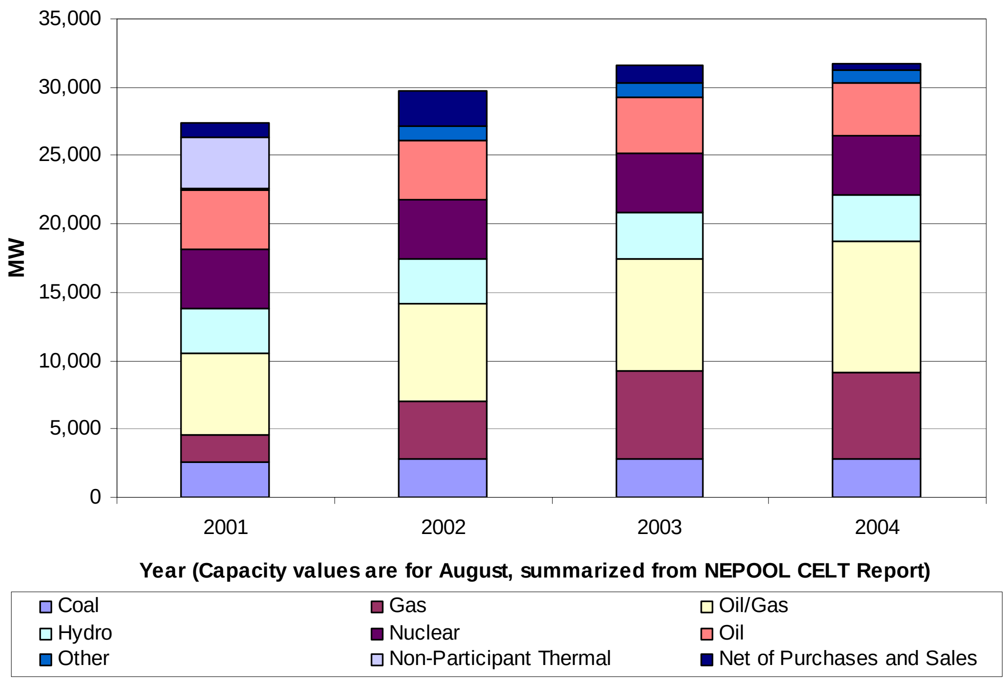
2.1.4.1 Generation Capacity

The total 2004 system capacity for summer was 31,299 MW, and the total for winter was 33,943 MW. Eight generating units at five power stations retired in 2004. The total summer claimed capability, or maximum production, for the units was 242 MW. Two additional generating units retired in October but reactivated three months later. New capacity with a summer capability of 588 MW was added to the system in 2004. This included two up-rate projects at existing generating units and three new generating units. By comparison, 2,949 MW of new generation was added in 2003, and 2,786 MW was added in 2002.

Figure 10 shows summer capacity in MW, by year and input fuel type, for the most recent four years. Capacity levels were similar in 2003 and 2004.[10] In 2004, dual-fueled generators, capable of burning both oil and natural gas, made up 28% of installed capacity, while natural gas-fired generators made up 19% of installed capacity. Of the new capacity added in 2004, 535 MW was dual-fueled oil/gas. Many dual-fueled generators capable of burning both oil and natural gas operate primarily on natural gas.

Figure 10

System Summer Capacity by Generator Type



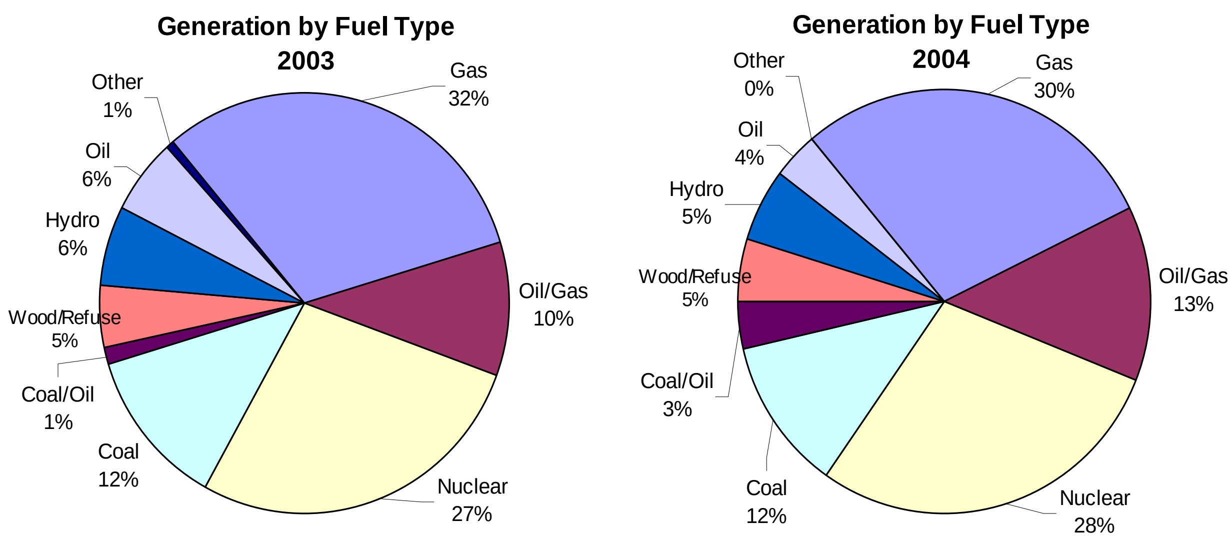
[10]Detailed information about generating capacity is available in the NEPOOL Forecast Report of Capacity, Energy, Loads, and Transmission (CELT). See <http://www.iso-ne.com/Historical_Data/CELT_Report/>.

2.1.4.2 Generation by Fuel Type

Figure 11 shows actual generation by fuel type for 2003 and 2004. The figures show the fuels used to actually generate electric power, which differs from the capacity fuel mix shown in Figure 10 and the marginal unit by fuel type shown later in Figure 19. The percentages of generation by fuel type are fairly constant from 2003 to 2004.

The shift in production from relatively inefficient oil-fired units to efficient gas-fired units has had large efficiency and environmental benefits. Estimated annual emissions of NO_x fell by 10,000 tons in 2004, relative to 2000 levels. SO_x emissions decreased by 40,956 tons and CO_2 decreased by 1.3 million tons. The average new gas-fired generator is about 15% more efficient than the most efficient existing oil-fired generators.

Figure 11



2.1.4.3 Renewable Portfolio Standards and Existing Generation by Fuel Type

Four New England states–Connecticut, Maine, Massachusetts, and Rhode Island–have established Renewable Portfolio Standards (RPSs) to encourage the development of renewable resources in the region. Vermont also is developing legislation to establish RPSs, and a number of other Northeastern states have implemented these standards.

RPSs typically require competitive retail energy suppliers to procure a certain percentage of their energy from renewable resources, such as small hydro, wind, solar, selected biomass, ocean thermal, and, in some states, fuel cells. To cover their renewable energy requirements, participants may buy renewable energy credits created at renewable facilities in the region, or they may own and operate such resources. Suppliers that do not meet their RPS requirements may be required to pay penalties or alternative compliance payments.

These RPSs generally require suppliers to obtain an increasing percentage of their energy from renewable resources over the next 10 or more years. The specific percentages vary by state and year, as do the types of resources included. These standards do not apply to municipal utilities. In 2004, RPS requirements were for 4.5% of statewide load in Connecticut, 1.5% in Massachusetts, and 30% in Maine. Rhode Island's requirements do not start until 2007. By 2013, the requirements will increase to 10% in Connecticut, 8% in Massachusetts, and 7.5% in Rhode Island. The requirement in Maine will remain at 30%.

In 2004, renewable resources generated about 8.5% of total New England electricity. These resources included refuse, biomass, and hydro generators. Much of this energy generation could meet the requirements of the RPSs of the various states. In the immediate term, significant new renewable capacity additions are not expected. However, as the requirements increase over time, new capacity additions may be required. This would be expected to increase retail costs.

The *2004 Regional Transmission Expansion Plan* contains additional information on RPSs, including a discussion of New England's renewable energy supply outlook.[11]

2.1.4.4 Self-Scheduled Generation

Figure 12 compares real-time self-scheduled generation and total real-time generation by month for 2004. Self-scheduling is of interest because self-scheduled generators are price-takers (i.e., generators willing to operate at any price and not eligible to set clearing prices). Participants may choose to self-schedule the output of their generators for a variety of reasons. For example, those with day-ahead generation obligations may self-schedule in real-time to ensure that they meet their day-ahead obligations. Participants with bilateral contracts to provide energy also may self-schedule. Self-scheduled megawatts were between 57% and 66% of total real-time generation during 2004.

[11] Contact ISO Customer Service for a copy of the 2004 RTEP report.

Figure 12

**Real Time Generation:
Self-Scheduled and Pool-Scheduled, Monthly Totals**

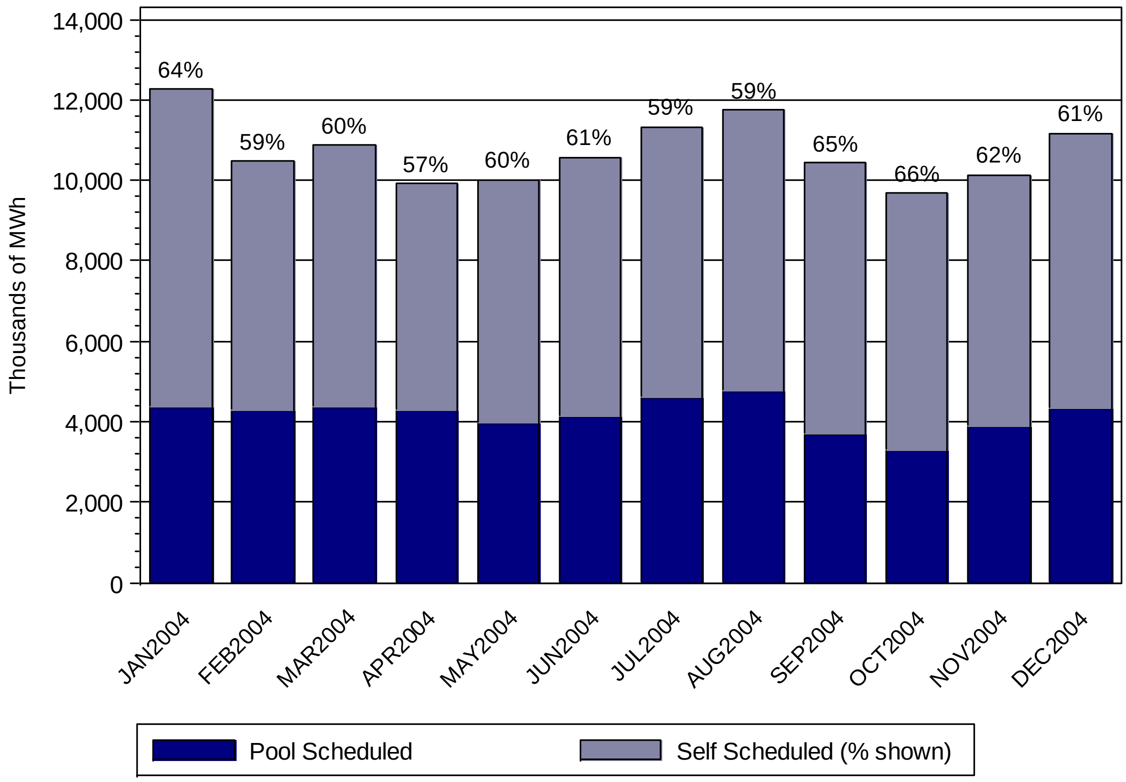


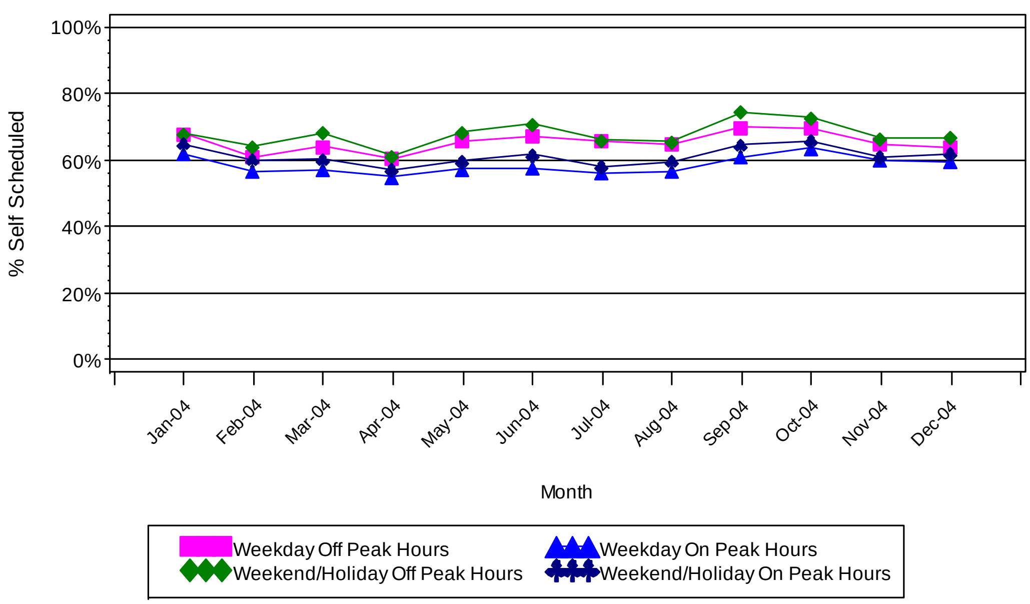
Table 3 shows the percentage of generation that was self-scheduled during 2004 by generator fuel type. Nuclear-fueled generators self-scheduled 99% of their generation, while diesel oil, oil, and jet fuel generators self-scheduled less than 20% of their generation. The percentage of generation self-scheduled is highest in off-peak hours and lowest in on-peak hours, as illustrated by Figure 13.

Table 3 - Percentage of Generation Self-Scheduled by Generator Fuel Type, 2004

Generator Type	Percent of Generation
Diesel Oil	14%
Oil	14%
Jet Fuel	16%
Coal / Oil	31%
Gas	31%
Oil / Gas	45%
Coal	69%
Wood / Refuse	82%
Hydro	82%
Nuclear	99%

Figure 13

Real Time On-Line MWh Self-Scheduled, Total Percentage by Month and Period
January 2004 - December 2004



2.1.4.5 Imports and Exports

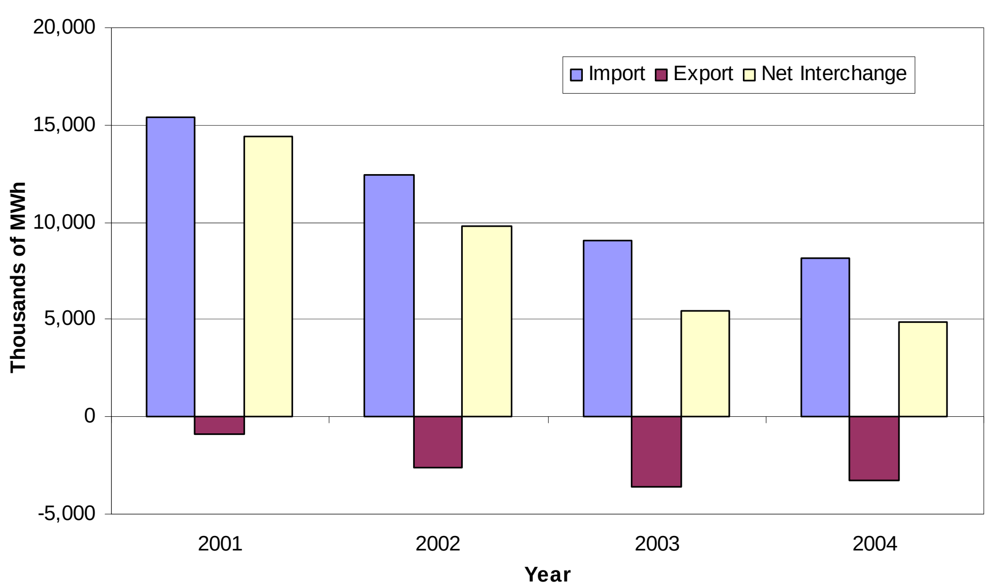
New England remained a net importer of power during 2004. Net imports from neighboring regions amounted to 4,907,000 MWh for the year, representing 3.7% of the annual NEL in New England during 2004. New England was a net importer from Canada and a net exporter to New York; however, import and export quantities both declined from 2003 to 2004. In 2003, New

England had 439,000 MWh of net exports to New York, compared with 112,000 MWh of net exports in 2004. Imports from Canada were 5,880,000 MWh in 2003, compared with 5,019,000 MWh in 2004.

Figure 14 shows net interregional power flows for 2001 through 2004. Figure 15 shows imports and exports by interface for 2004. The NY-AC interface is the collection of AC tie lines connected through Connecticut, Massachusetts, and Vermont. The NY-CSC interface is the recently constructed Cross-Sound Cable. Figure 16 shows the price difference between the ISO's New England Roseton bus, where exports to New York are priced, and the NYISO's NEPEX bus, where exports from New York to New England are priced.[12] Points on the figure that are above zero indicate hours when prices in New England were higher than prices in New York. The figure shows that there is no clear relationship between New England and New York price differences and net interchange with New York. If trading between the two markets functioned well, one would expect the data to be clustered in the upper-right and lower-left quadrants in the figure. This would reflect power flowing from low-priced to high-priced areas. The ISO and stakeholders are exploring ways to improve trade between the control areas. In December 2004, one trading barrier was removed with the elimination of export charges between New England and New York.

Figure 14

New England Annual Imports, Exports, and Net Interchange
All Interfaces: 2001, 2002, 2003, 2004 Totals



[12] A *bus* is a point of interconnection to the system.

Figure 15

New England Imports and Exports by Interface 2004

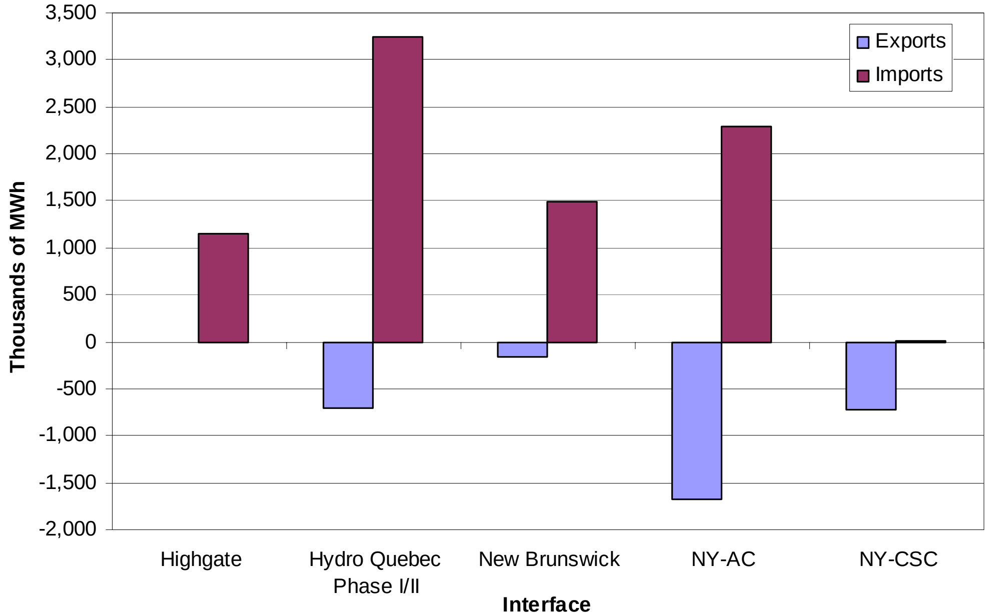
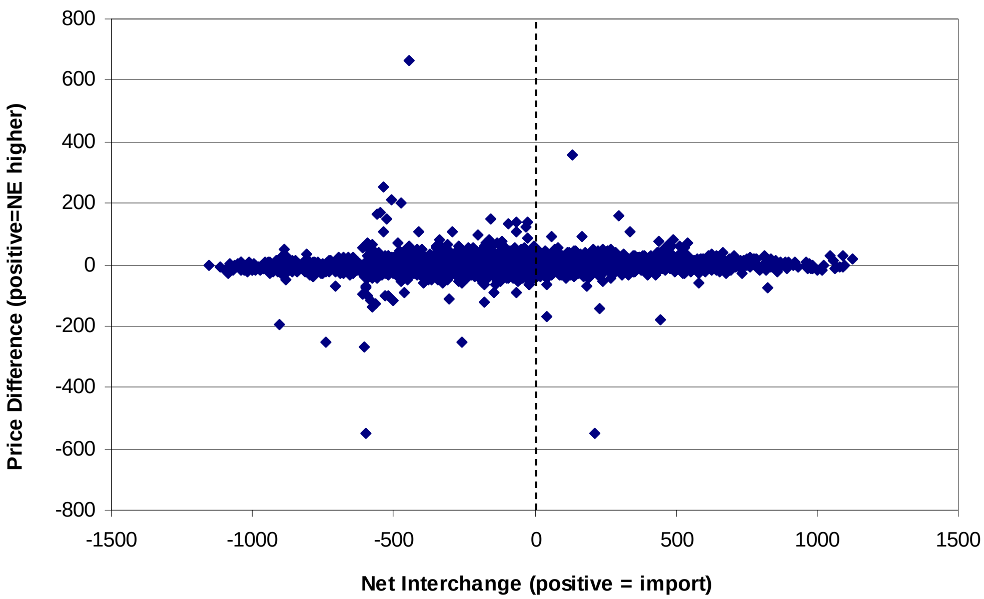


Figure 16

New England Roseton LMP minus New York NEPEX LBMP and Net Interchange with New York, 2004



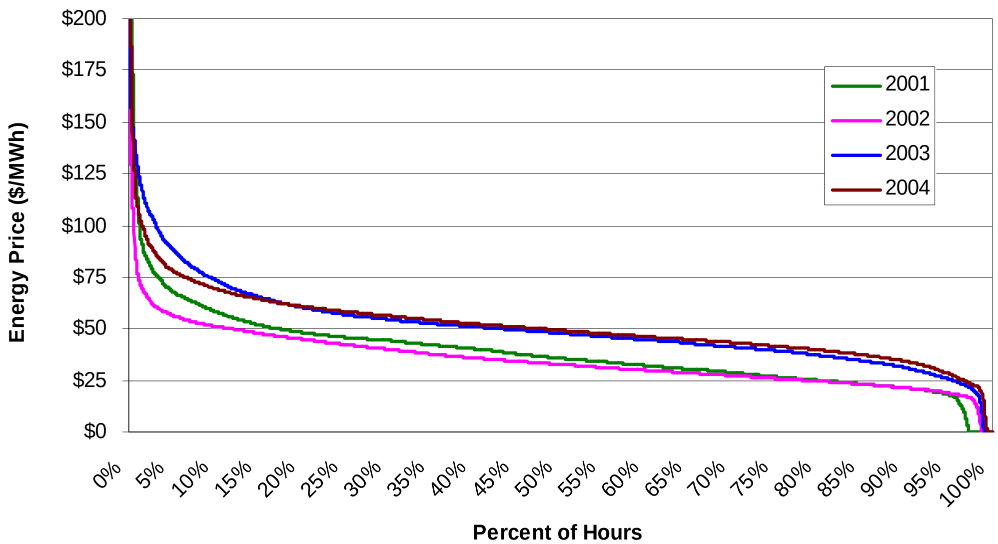
2.1.5 2004 Electric Energy Prices

2.1.5.1 Annual Real-Time Electric Energy Prices

Figure 17 and Figure 18 show the real-time system electric energy price for New England over the last four years as duration curves with prices ordered from highest to lowest. For the Interim Market period ending February 23, 2003, the system price is the single energy-clearing price (ECP). For March 2003 to December 2004, the system price is the load-weighted Real-Time Energy Market LMP. For each year, the duration curve shows the percentage of time that the system price was at or above the price levels shown on the vertical axis. The figures show that typical prices during 2004 were generally similar to prices in 2003, although 2003 had more prices over $75/MWh. The 2004 prices were higher than those in 2002 and 2001. This is due primarily to input fuel prices (as discussed in the next section). The peak prices shown in Figure 18 were lower in 2004 than in earlier years, with no hours reaching $1000/MWh, largely due to moderate summer weather. Some of the highest-priced hours in 2004 occurred during the January 2004 Cold Snap. (See Figure 63.)

Figure 17

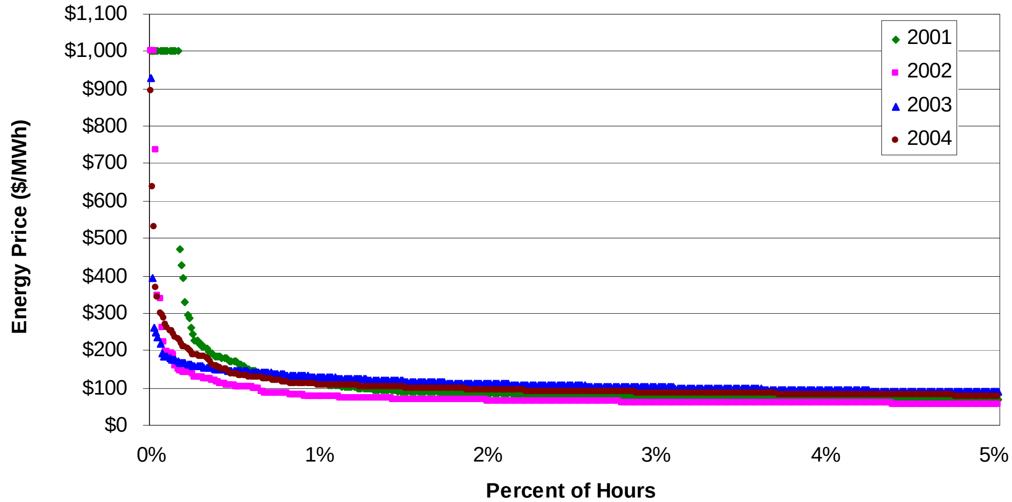
System Price Duration Curves, Prices < $200
2001-2004



System Price is single Energy-Clearing Price for Interim Market Period ending Feb. 28, 2003, and load-weighted Real-Time Energy Market LMPs for Mar. 2003 - Dec. 2004.

Figure 18

System Price Duration Curves, Prices in Most Expensive 5% of Hours 2001-2004



System Price is single Energy-Clearing Price for Interim Market Period ending Feb. 28, 2003, and load-weighted Real-Time Energy Market LMPs for Mar. 2003 - Dec. 2004.

2.1.5.2 Electric Energy Prices and Input Fuel Costs

Figure 19 shows the marginal, or price-setting, input fuels during 2004 as a percentage of pricing intervals in the year. Binding real-time transmission constraints produce instances when there is more than one marginal generating unit on the system because there is a marginal unit on each side of a constraint, one setting price for the constrained area and one setting price for the unconstrained area. Since each marginal unit is included in the analysis, the percentages in the figure total more than 100%. Some types of generating units, such as nuclear power stations, were never marginal during 2004 and are not included in the figure. The figure shows that units burning natural gas were marginal 55% of the time (approximately 4,830 hours out of 8,784 hours) during the period.[13] Oil/gas units, many of which burn gas as their primary fuel, were on the margin 31% of hours. These results show the extent to which the New England electricity prices depend on the offers of units capable of burning natural gas.

[13] The hourly calculations are the result of summing each five-minute interval in which the fuel type was marginal.

Figure 19

Marginal Input Fuels in Real-Time, 2004

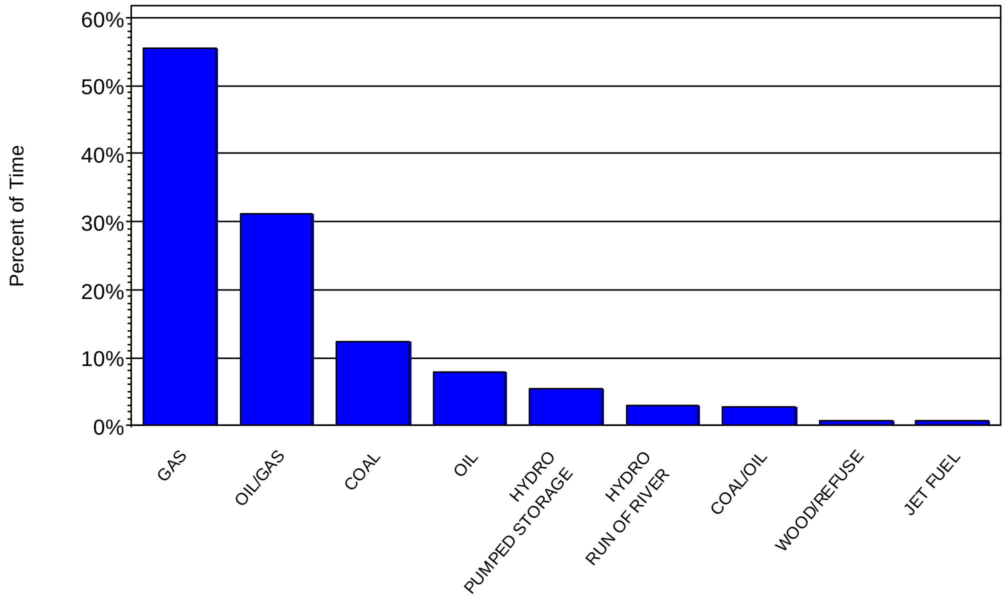
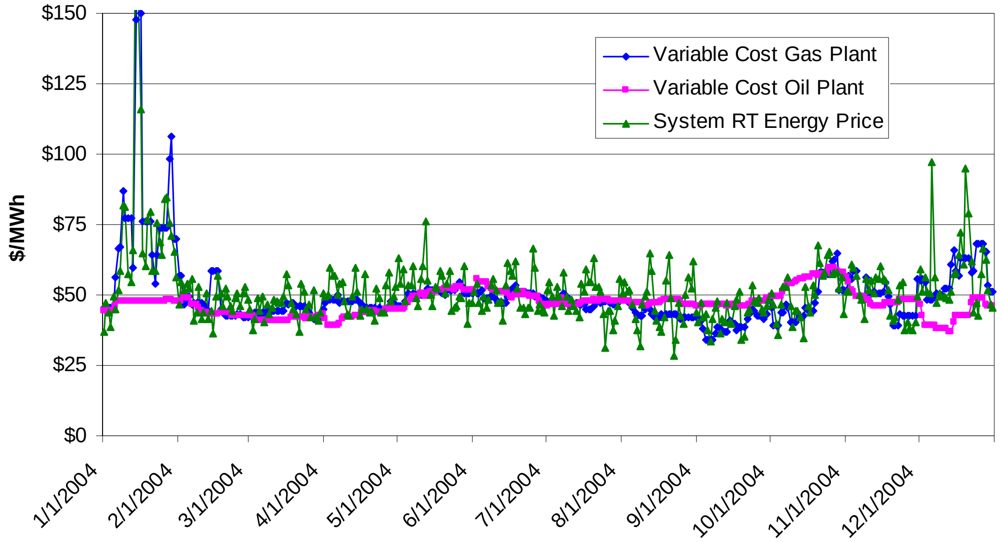


Figure 20 shows the daily average real-time system price plotted against the daily average variable production cost of hypothetical power plants burning either natural gas or oil. The gas plant production costs are based on a gas plant with a heat rate of approximately 7,000 Btu/kWh, while the oil plant production costs are based on a heat rate of approximately 10,500 Btu/kWh. 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, may cause energy-price spikes that are unrelated to fuel prices.

Figure 20

Daily Average Real-Time System Price of Energy vs. Variable Production Costs*



*System Energy Prices and Variable Cost of Gas Plant exceeded $150 on January 14 and 15.

Since fuel is the largest variable expense for most electrical generating plants, in a competitive market the energy offers made by generators, which are at marginal costs, are sensitive to variation in fuel prices. Hence, electric energy market-clearing prices rise and fall with changes in fuel prices. This relationship is shown in Figure 20, with gas plant costs and electricity prices highly correlated. This is consistent with the marginal fuels data shown in Figure 19. Because the fuels used by marginal generators vary, and because changing demand levels cause movements along the supply curve, electricity prices are not expected to perfectly track underlying fuel costs, but rather, more loosely correlate with fuel costs.

Table 4 shows average annual fuel prices for natural gas and No. 6 oil for each of the last five years, indexed to its value in the year 2000. These two fuels are shown because they are on the margin for a majority of the time in New England, as was shown in Figure 19. Natural gas prices during 2004 were 5% higher than those in 2003. Natural gas prices nearly doubled from 2002 to 2004. Oil prices were less volatile than gas prices, but still showed significant swings, including an increase of 35% from 2001 to 2004. These data suggest that electricity price changes shown in Figure 17 are due, at least in part, to the large change in input fuel costs.

Table 4 - Fuel Price Index, Year 2000 Basis

Fuel	2000	2001	2002	2003	2004
Natural Gas	1.00	0.88	0.75	1.30	1.37
No. 6 Oil (1%)	1.00	0.83	0.90	1.09	1.12

To help isolate electricity price differences due to input fuel-price changes, the ISO calculates an annual electricity price adjusted for fuel prices. The fuel-adjusted energy price normalizes the electricity market-clearing prices for the variation in the input fuel prices used by price-setting generating units. 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 its input fuel price compared with year 2000 fuel prices.

Fuel-adjusted electric energy prices for the Interim Markets period of January 2000 through February 2003 were derived by adjusting each five-minute RTMP by a monthly index of spot-market prices of the fuel used by the generator setting the RTMP. Fuel-adjusted energy prices for the SMD period of March 2003 through December 2004 were derived by adjusting five-minute Hub real-time LMPs in the same way as Interim Market prices were adjusted.

Five-minute prices set by hydro plants were adjusted by a monthly index of average electric energy prices to reflect changes in opportunity costs. Nuclear, wood, and other fuels without reliable prices were not adjusted. These unadjusted prices should not significantly affect the results because units using these fuels were seldom marginal.[14] The adjusted five-minute energy prices were then averaged to the hourly level and weighted by hourly load before the yearly averages were calculated.

Table 5 shows yearly average load-weighted actual and fuel-adjusted real-time electric energy prices for New England. The fuel-adjusted energy price is the electricity market-clearing price normalized to year 2000 fuel-price levels. Both actual and fuel-adjusted prices for 2003 and 2004 were very similar because fuel prices were similar. While 2004 had the highest actual real-time electricity prices, after adjusting for the price of fuels used to generate electricity, the electric energy price in 2004 was approximately the same as the electric energy price in 2003 and lower than prices in the previous years. This finding supports the hypothesis that the higher actual electric prices in 2004 were caused primarily by higher input fuel prices. See Section 7.4 in the statistical appendix for a graph of the information presented in Table 5. Compared with year 2000 prices, fuel-adjusted electricity prices have fallen by 5.7% in 2004.

[14] Generating units fueled with composite, nuclear, refuse, or wood were marginal less than 1% of the time during the five-year analysis period.

Table 5 - Actual and Fuel-Adjusted Average Real-Time Electric Energy Prices

$/MWh	2000	2001	2002	2003	2004
Load-Weighted Actual Electric Energy Price (ECP during Interim Markets; Hub LMP during SMD)	$45.95	$43.03	$37.52	$53.40	$54.44
Load-Weighted Electric Energy Price Normalized to Year 2000 Fuel Price Levels	$45.95	$48.60	$46.65	$43.51	$43.33

The variation among fuel-adjusted yearly average prices was less than among 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 and 2004, when gas prices were higher, were lower when adjusted.

This analysis has limitations. The most significant is that if the relative prices of alternative fuels differed, the marginal generating units might also change. This analysis, however, assumes that the marginal units remained the same, while their fuel prices varied. This is not likely to result in a large error because the hours for which fuel-price differences would alter the merit order of oil and gas-fired units are most likely limited in number. Second, the analysis does not make any adjustment for changes in offer rules or unit-commitment models over the five-year period, though it is not clear what, if any, systematic effects this might have.

2.1.5.3 Electric Energy Prices Throughout the Year

Table 6 shows the 2004 average LMP, as well as its minimum and maximum values, at the Hub and in the eight load zones in New England. Generally, day-ahead prices exhibited a slight premium over their real-time counterparts, with zonal prices varying from the Hub according to zonal supply/demand balance and the existence of congestion. During 2004, average day-ahead and real-time prices were similar both at the Hub and in each of the eight load zones except in Maine. Average LMPs in Maine were several dollars lower than those in other areas, primarily due to the effects of marginal losses on Maine LMPs. Average LMPs in Connecticut were slightly higher than those in other areas. During high-demand periods, Connecticut is frequently import-constrained, which results in congestion and higher prices. Connecticut also experiences relatively high losses, due to a combination of its distance from economic generation and weak transmission lines. For more details on hourly price statistics, see Section 7.4.

Table 6 - Summary LMP Statistics by Zone for 2004, All Hours

Location / Zone	LMP ($ / MWh)					
	Average		Minimum		Maximum	
	Day-Ahead	Real-Time	Day-Ahead	Real-Time	Day-Ahead	Real-Time
Internal Hub	$53.72	$52.13	$20.22	$0.00	$520.08	$920.29
Maine	$48.62	$47.79	$18.52	$0.00	$483.64	$850.83
New Hampshire	$52.09	$50.72	$19.82	$0.00	$508.19	$899.18
Vermont	$53.95	$52.32	$20.55	$0.00	$505.37	$880.25
Connecticut	$54.62	$52.80	$20.49	$0.00	$578.56	$893.00
Rhode Island	$52.82	$51.21	$19.97	$0.00	$510.75	$902.88
SEMA	$52.33	$50.72	$19.84	$0.00	$505.18	$908.94
WCMA	$53.86	$52.33	$20.32	$0.00	$518.42	$911.69
NEMA / Boston	$53.46	$51.46	$19.96	$0.00	$508.76	$903.10

The day-ahead Hub price averaged $53.72/MWh, while the corresponding real-time price averaged $52.13/MWh, a $1.59 or 3% difference.[15] In over 90% of hours during the year, both day-ahead and real-time Hub LMPs were below $75.00/MWh. Maximum hourly prices never reached $1000/MWh in either the Day-Ahead or Real-Time Energy Markets. Minimum generation conditions, when prices are set to $0/MWh during periods of excess supply, occurred in the Real-Time Energy Market but not the Day-Ahead Energy Market. Figure 21 shows daily average LMPs at the Hub. Prices were at the highest levels of the year during the January 2004 Cold Snap, driven largely by extremely high natural gas prices.

[15] These average prices are not load-weighted.

Figure 21

Daily Average Hub LMP
January - December 2004

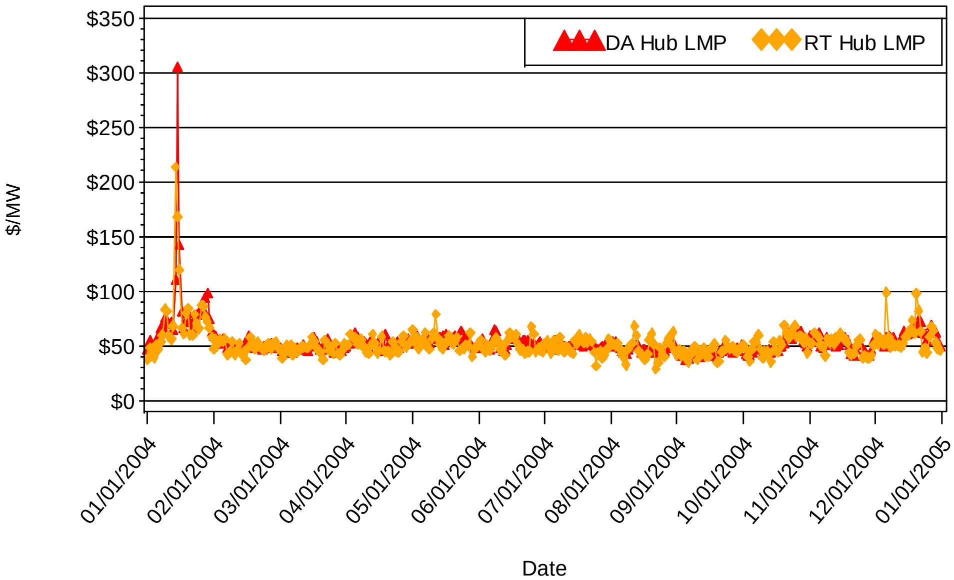
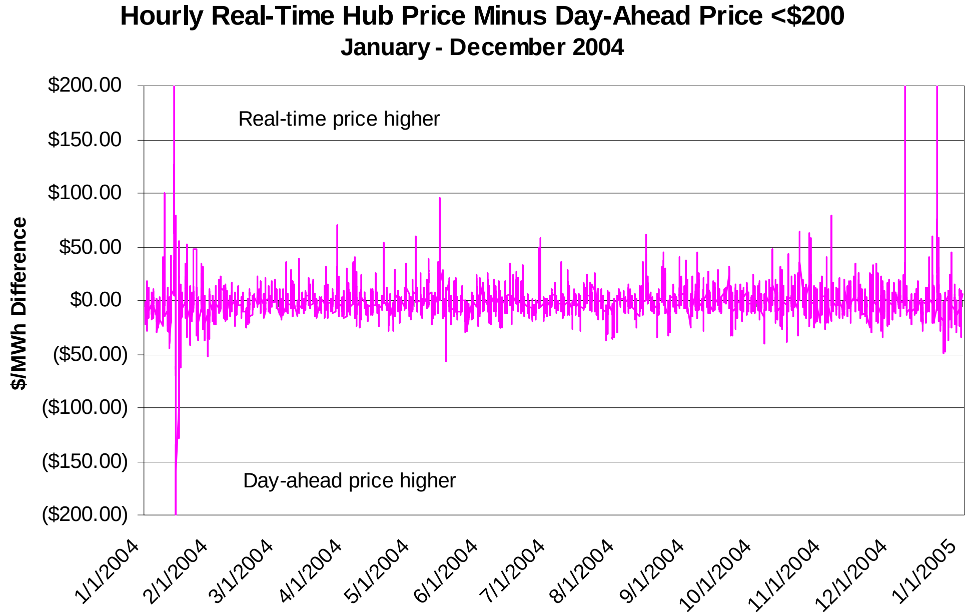


Figure 22 shows the difference between real-time and day-ahead Hub LMPs. At the Hub, day-ahead prices were higher than their real-time counterparts in 60% of the hours. Prices in the Real-Time Energy Market are more variable than prices in the Day-Ahead Energy Market due to unexpected events, such as generator and transmission contingencies or variations in the actual demand compared to the demand forecast. Large differences between day-ahead and real-time prices occurred in January. Real-time prices were higher on January 14, exceeding $800/MWh in hour ending 6:00 p.m., while day-ahead prices for the same hour were approximately $160/MWh.[16] On January 15, day-ahead prices were approximately $520/MWh during the evening peak, while real-time prices were about $260/MWh. On both days, capacity was tight due to unexpected cold weather and generator outages. On December 6 and December 20, cold weather and associated tight capacity conditions caused the real-time Hub price to reach $645/MWh and $308/MWh, respectively.

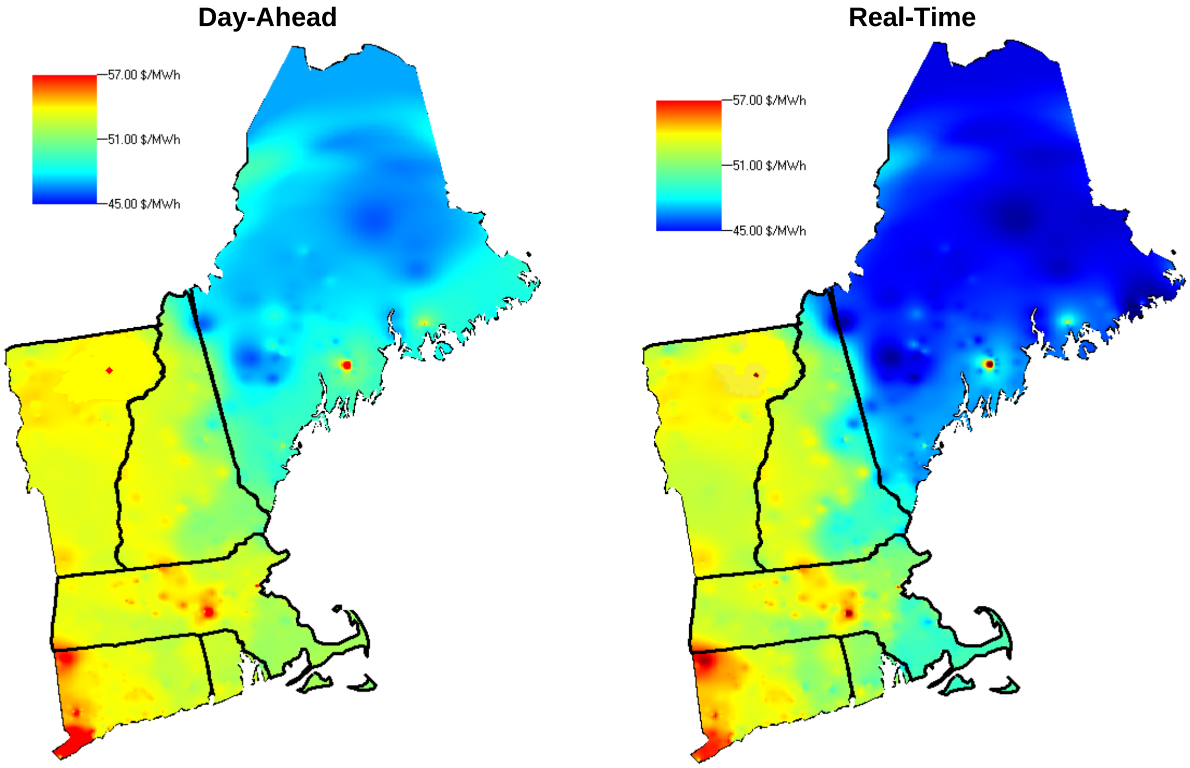
[16] Hour ending 6:00 p.m. is the time period from 5:01 p.m. to 6:00 p.m.

Figure 22



On the maps in Figure 23, average annual nodal LMPs are shown in color gradations from blue, representing $45/MWh, to red, representing prices of $57/MWh and higher. The area with the highest prices was Southwest Connecticut. Maine had the lowest prices. The area in Vermont with slightly higher than average prices is the location of small generation that had high prices during the January 2004 Cold Snap.

Figure 23
2004 Average Nodal Prices, $/MWh



2.1.5.4 Wholesale Prices in Other Northeastern Pools

Comparing price levels across interconnected power pools provides a context for evaluating price levels in New England. Table 7 shows yearly average system prices for the three northeast ISOs—ISO-NE, NYISO, and PJM. Hourly system prices for New England and New York were calculated based on locational prices and locational loads, while prices for PJM are PJM's published hourly system prices.[17] New York had the highest prices, while PJM had the lowest.

Table 7 - NE, PJM, and NY Average Electric Energy Prices, 2004

Control Area	Day-Ahead			Real-Time		
	All	On-Peak	Off-Peak	All	On-Peak	Off-Peak
NE	**$53.12**	$60.39	$46.86	**$51.53**	$58.81	$45.27
NY	**$55.64**	$65.51	$47.15	**$55.73**	$65.63	$47.20
PJM	**$42.91**	$52.97	$34.27	**$43.78**	$53.10	$35.77

[17] PJM's Web site is available at <http://www.pjm.com>. NYISO's Web site is available at <http://www.nyiso.com>. Yearly average system prices are not load-weighted.

Variation in average prices among the power pools is affected by a variety of factors, such as transmission congestion, daily and seasonal load 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.[18] The average yearly day-ahead prices were higher than the average yearly real-time prices in New England, but not in New York and PJM. The price difference between New England day-ahead and real-time prices was $1.59/MWh, a price difference greater than in 2003. These differences are likely due to a number of factors, such as uplift in the Day-Ahead and Real-Time Energy Markets, commitment practices, and real-time reliability needs.[19] The proposed 2005 revisions to the real-time allocation of RMR Operating Reserve Charges should decrease price differences by reducing barriers to price arbitrage between the day-ahead and real-time markets.

2.1.5.5 Price Separation: Congestion and Losses

In addition to energy production costs, LMPs reflect the costs of congestion and losses. The inclusion of these costs in the energy price and the resulting price separation between locations are key elements of efficient pricing. Losses are caused by resistance in the transmission system and are inherent in the existing transmission infrastructure. Congestion is caused by transmission constraints that limit the flow of otherwise economic power.

Figure 24 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. The results for day-ahead and real-time are similar for 2004. There are negative differences (compared with the Hub) in the LMP for the Maine, New Hampshire, Rhode Island, SEMA, and NEMA load zones and positive differences (compared with the Hub) in the Connecticut, Vermont, and WCMA load zones. These differences 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 the same in the Day-Ahead and Real-Time Energy Markets. Since the price differences are reasonably indicative of actual real-time price differences, the data in Figure 24 indicate that the Day-Ahead Energy Market is functioning well.

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[18] See <http://www.pjm.com/services/system-performance/operations-analysis.html>.

[19] Uplift consists of payments to resources operated out-of-merit.

Figure 24

Average Hourly LMP Difference from Hub
2004

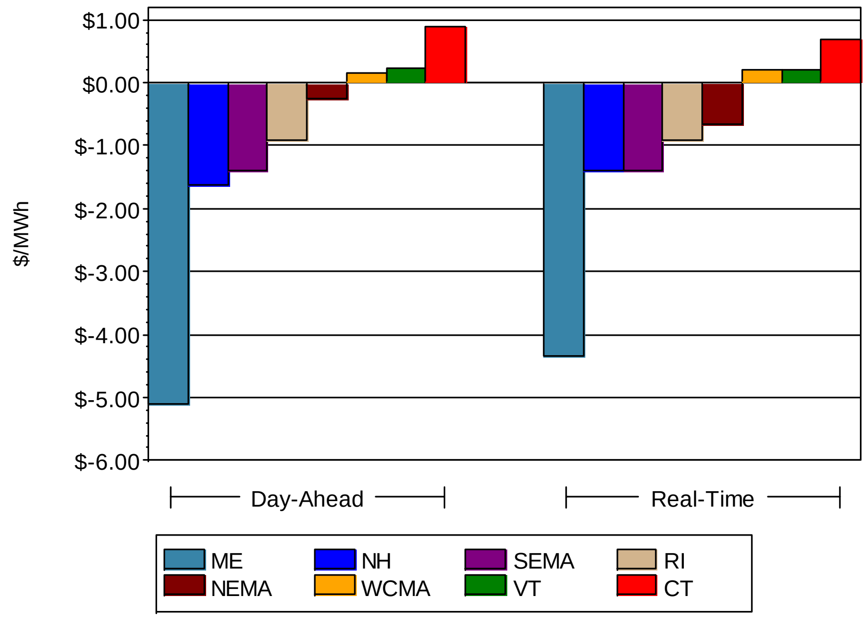


Table 8 and Table 9 show the 2004 averages of the congestion component, marginal loss component, and the sum of the two components for the Internal Hub and each load zone for the Day-Ahead and Real-Time Energy Markets. These values are indicative of the relative impact of congestion and marginal losses among the load zones. The proportions of the energy, congestion, and loss components on 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, it is more useful to compare trends in the differences between LMPs over time, rather than trends in the values of the congestion and marginal loss components. The variation in each component will be affected by the reference bus calculation, but the change in LMPs will reliably show the net impact of the components.

Because the relative values of the three LMP components depend of the definition of the distributed reference bus, the dollar value of the congestion component should not be used directly to measure the underlying cost of congestion in a location. Rather, differences in the congestion components between locations indicate relative congestion costs. The Hub and most load zones (ME, NH, VT, RI, SEMA, WCMA) experienced negative real-time congestion on average. 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 and NEMA/Boston experienced positive real-time congestion. These results are consistent with historical experience that shows NEMA/Boston and Connecticut to be transmission-constrained.

The marginal loss component of the LMP reflects the change in transmission losses for the entire system if one additional megawatt of power were injected at that location. System losses are related to transmission voltage and the distance between generation and load. If system losses are estimated to decrease by an additional injection of electricity at a location, the loss component for that location will be positive, increasing the LMP. Energy at that location has additional value because it results in smaller losses. If system losses increased by an additional injection at a location, the loss component for that location will be negative, lowering the LMP.

Real-time loss components are positive in the Connecticut, Vermont, and Western Massachusetts load zones and at the Hub. They are negative in NEMA/Boston, Rhode Island, Southeastern Massachusetts, New Hampshire, and Maine. The exporting zones generally have negative losses, and, with the exception of NEMA/Boston, the importing zones generally have positive losses. This makes sense intuitively. Losses would be reduced by an injection in an importing zone, which would reduce the need for power to travel long distances, and losses would be increased by an additional injection in an exporting zone, which would increase the amount of power shipped long distances. Maine, for example, has the most negative loss component, indicative of its large distance from the major load centers in New England.

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

Location	Congestion Component	Marginal Loss Component	Congestion Component plus Marginal Loss Component
Internal Hub	$-0.16	$0.80	$0.65
Connecticut Load Zone	$0.68	$0.87	$1.54
Maine Load Zone	$-1.66	$-2.79	$-4.46
NEMA/Boston Load Zone	$0.36	$0.02	$0.38
New Hampshire Load Zone	$-0.67	$-0.31	$-0.98
Rhode Island Load Zone	$-0.20	$-0.06	$-0.26
SEMASS Load Zone	$-0.20	$-0.55	$-0.74
Vermont Load Zone	$-0.25	$1.13	$0.87
WCMASS Load Zone	$-0.13	$0.92	$0.79

Table 9 - Average Real-Time Congestion Component, Loss Component, and Combined

Location	Congestion Component	Marginal Loss Component	Congestion Component plus Marginal Loss Component
Internal Hub	$-0.07	$0.72	$0.64
Connecticut Load Zone	$0.49	$0.83	$1.32
Maine Load Zone	$-0.82	$-2.88	$-3.70
NEMA / Boston Load Zone	$0.02	$-0.04	$-0.02
New Hampshire Load Zone	$-0.40	$-0.36	$-0.76
Rhode Island Load Zone	$-0.13	$-0.14	$-0.27
SEMASS Load Zone	$-0.17	$-0.59	$-0.77
Vermont Load Zone	$-0.14	$0.98	$0.83
WCMASS Load Zone	$0.01	$0.83	$0.84

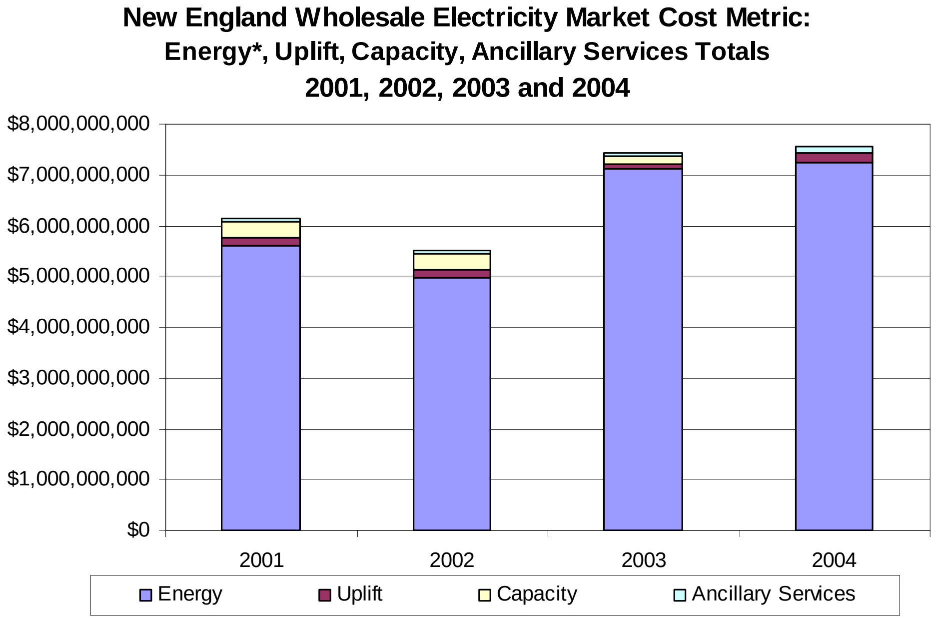
The methods for calculating the marginal loss component and accounting for losses can cause more revenue to be collected from load than is required to pay generators. The marginal loss component is based on the most expensive marginal loss MW, as opposed to the average cost of losses, which leads to the collection of more revenues than required to compensate generators. However, day-ahead scheduled load and most real-time submitted metered load are not adjusted upward for losses, leading to generation amounts and metered load amounts that are not equal. The imbalance between generation and metered load is due to transmission losses, but it is reflected in both the energy and loss components of the LMP. Costs associated with these imbalances affect the amount of money available in the Marginal Loss Revenue Fund.

Excess energy and marginal loss revenue is collected in the Marginal Loss Revenue Fund and returned to load serving-entities, according to each participant's monthly share of the real-time load obligation, net of bilateral trades. In 2004, a total of $87.5 million was returned to load-serving entities from the Marginal Loss Revenue Fund.

2.1.5.5 All-In Wholesale Electricity Market Cost Metric

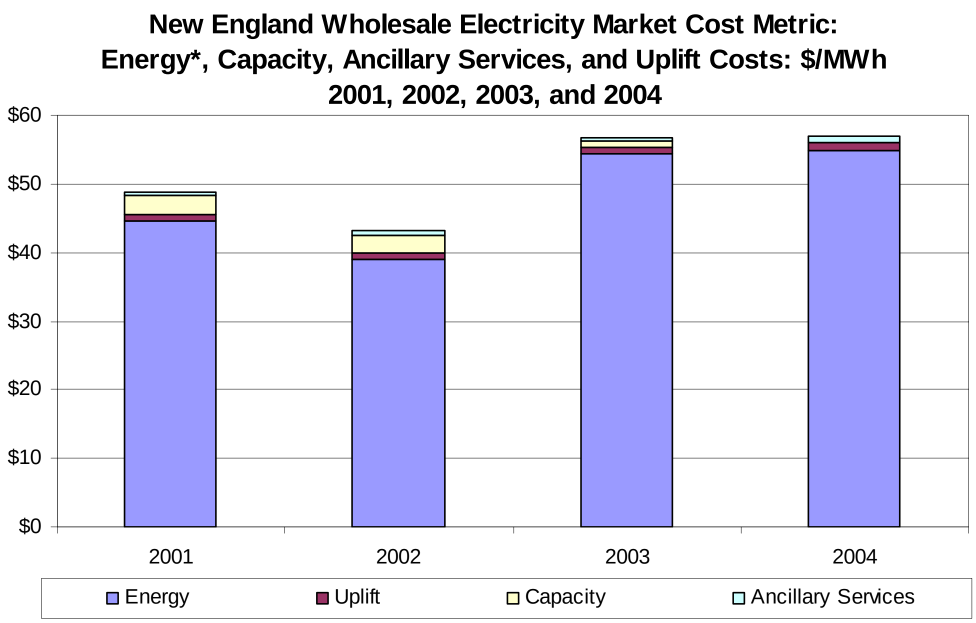
The *all-in* wholesale electricity price is the annual total of the energy, uplift, capacity, and ancillary service components. Figure 25 shows the all-in wholesale electricity price in New England over the last four years. Figure 26 shows the same information on a $/MWh basis. The figure illustrates that energy costs are by far the largest component of wholesale costs, accounting for 96% of wholesale charges to load in 2004. Total energy costs were very similar in 2003 and 2004, while uplift and ancillary services costs were higher in 2004. The Forward Reserve Market, introduced in January 2004, contributed to higher ancillary service costs in 2004, while an increase in VAR tariff-reliability payments contributed to the increase in uplift. Capacity costs in 2004, as reflected in the ISO-administered auctions, were very small and are not discernible in the figures.

Figure 25



*Energy: Interim Markets period = Energy Clearing Price * System Load, SMD period = Real-Time Load Oblig * Real-Time LMP.

Figure 26



*Energy: Interim Markets period = Energy Clearing Price * System Load, SMD period = Real-Time Load Oblig * Real-Time LMP.

Table 10 provides the same data as Figure 27 for the 2003 and 2004 all-in wholesale electricity prices, in $/MWh, along with the percentage of the total accounted for by each component. Shares of energy costs are similar across years. Capacity costs decreased from 1.8% of total costs to 0.1% of total costs. Ancillary service costs increased, driven primarily by the introduction of the Forward Reserve Market. Uplift also increased, due to the increased need to operate units out of economic-merit order to support the transmission system.

Table 10 – New England Wholesale Market Cost Metric

Component	2003 ($/MWh)	% of Total	2004 ($/MWh)	% of Total
Energy	$53.08	95.9%	$54.75	96.0%
Uplift	$0.71	1.3%	$1.27	2.2%
Capacity	$0.97	1.8%	$0.06	0.1%
Ancillary Services	$0.60	1.1%	$0.96	1.7%
Total	$55.36	100.0%	$57.05	100.0%

2.1.6 Energy Market Volumes

Table 11and Table 12 present information about the quantity of energy transacted in the Day-Ahead and Real-Time Energy Markets. Participant transactions to buy and sell energy 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 upon prices. Some of these contracts are submitted for scheduling in either the Day-Ahead or Real-Time Energy Market. They may enter into internal contracts, under which 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.

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 always considered to be willing to pay congestion charges. *Wheel-through* contracts, in which both generation and delivery occur outside New England, also are submitted into the market system for scheduling.

In New England, more MWhs are traded than there are MWhs of actual load. Day-ahead load-obligation MWh quantities settled at the day-ahead LMP are very close to actual load, and 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. The bulk of import contracts generally are without-price contracts, which are equivalent to self-scheduled import. This may be related to the observation that net imports from New York are not well correlated to differences in New York and New England prices.

Table 11

MWh Quantities Traded in the Day-Ahead and Real-Time Energy Markets by Transaction Type January - June 2004

Transaction Type by Market	Jan.	Feb.	Mar.	Apr.	May.	Jun.
Day Ahead						
Load Obligation – Day-Ahead LMP*	12,431,707	10,916,087	11,169,611	10,103,312	10,152,550	10,634,168
*Bilateral – Export With Price***	*9,312*	*10,846*	*132,273*	*151,829*	*39,239*	*77,625*
Bilateral – Export Without Price	*67,915*	*79,590*	*115,508*	*82,918*	*132,677*	*65,727*
Bilateral – Export Up-To Congestion	*28,973*	*35,090*	*53,361*	*11,557*	*18,379*	*11,811*
Bilateral – Internal for Market Day Ahead (IBM)	9,373,913	8,746,408	8,724,552	7,426,054	7,588,974	8,092,781
Bilateral – Import With Price	23,085	138,438	92,468	45,100	82,605	55,294
Bilateral – Import Without Price	359,843	338,222	230,675	162,001	160,944	244,539
Bilateral – Import Up-To Congestion	249	8,245	1,386	3,185	8,265	920
Total Day-Ahead MWh	**22,294,995**	**20,150,401**	**20,218,691**	**17,739,652**	**17,993,338**	**19,027,703**
Real Time						
Adjusted Load-Obligation Deviation – Real-Time LMP[#]	375,331	40,558	9,822	79,495	280,819	432,110
Adjusted Load-Obligation Deviation – lower than Day Ahead	*-1,387,277*	*-1,234,302*	*-1,082,765*	*-1,046,595*	*-994,136*	*-931,721*
Adjusted Load-Obligation Deviation – higher than Day Ahead	*1,762,607*	*1,274,860*	*1,092,588*	*1,126,090*	*1,274,955*	*1,363,831*
Bilateral – Export With Price	*65*	*125,405*	*0*	*16,795*	*61,675*	*49,349*
Bilateral – Export Without Price	*155,852*	*634,095*	*280,785*	*296,466*	*252,322*	*230,977*
Bilateral – Internal for Market – Additional to Day-Ahead IBMs	695,175	148,886	570,247	555,370	565,198	593,702
Bilateral – Internal for Load Real Time	171,573	27,540	141,667	129,497	127,918	139,278
Bilateral – Import With Price	7,746	551,906	1,285	40,978	118,150	132,449
Bilateral – Import Without Price	615,422	824	361,970	261,616	339,598	419,031
Bilateral – Through	0	0	0	0	0	0
Total Real-Time MWh	**2,021,163**	**1,403,809**	**1,084,991**	**1,066,957**	**1,431,683**	**1,716,570**
Net Energy for Load (MWh)[‡]	*12,629,000*	*10,863,000*	*10,898,000*	*9,875,000*	*10,106,000*	*10,774,000*

*The day-ahead load obligation for energy is equal to the MWhs of demand bids, decrement bids, and external transaction sales accepted by the ISO in the Day-Ahead Energy Market. It is settled at the day-ahead LMP. The figure reported here is the pool total of participants' locational load obligations. It is reported in this table as a positive number; however, it is calculated as a negative number on an individual participant level.

** Exports are included in load obligation.

[#]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 pool total of participants' locational adjusted load-obligation deviations. Adjusted load-obligation deviation may be negative (indicating that there is a lower load obligation than cleared day ahead) or positive (indicating that there is a higher load obligation than 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 the day-ahead load obligations at the participant level net to zero when the pool 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.

[‡]Net Energy for Load is shown here for reference.

Table 12

MWh Quantities Traded in the Day-Ahead and Real-Time Energy Markets by Transaction Type

July - December 2004

Transaction Type by Market	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Day Ahead						
Load Obligation – Day-Ahead LMP*	12,019,470	12,404,241	11,174,982	10,520,505	10,663,390	11,691,412
*Bilateral – Export With Price***	*7,522*	*4,002*	*18,771*	*5,975*	*72,110*	*26,580*
Bilateral – Export Without Price	*138,990*	*183,872*	*221,047*	*71,743*	*41,998*	*22,662*
Bilateral – Export Up-To Congestion	*16,255*	*2,760*	*4,980*	*16,340*	*11,355*	*4,502*
Bilateral – Internal for Market Day Ahead	9,527,582	9,508,256	8,370,498	8,191,785	7,874,172	7,957,059
Bilateral – Import With Price	474,711	554,909	458,189	324,769	188,921	123,128
Bilateral – Import Without Price	283,991	250,373	163,133	521,616	449,108	579,439
Bilateral – Import Up-To Congestion	5,420	286	2,166	9,961	9,647	2,810
Total Day-Ahead MWh	**22,311,175**	**22,718,066**	**20,168,967**	**19,568,636**	**19,185,238**	**20,353,848**
Real Time						
Adjusted Load Obligation Deviation – Real-Time LMP#	65,677	147,427	-103,763	-6,034	38,823	207,806
Adjusted Load Obligation Deviation – lower than Day Ahead	*-1,233,490*	*-1,356,279*	*-1,223,914*	*-1,162,597*	*-1,204,602*	*-1,042,661*
Adjusted Load Obligation Deviation – higher than Day Ahead	*1,299,167*	*1,503,705*	*1,120,152*	*1,156,563*	*1,243,424*	*1,250,468*
Bilateral – Export With Price	*0*	*7,649*	*1,796*	*4,975*	*4,675*	*417*
Bilateral – Export Without Price	*196,850*	*257,006*	*371,992*	*153,886*	*277,874*	*122,527*
Bilateral – Internal for Market – Additional to Day-Ahead IBMs	621,836	664,389	583,035	633,280	583,246	565,095
Bilateral – Internal for Load Real Time	156,198	166,720	135,512	128,835	131,094	149,202
Bilateral – Import With Price	164,371	185,606	156,073	82,157	76,372	110,270
Bilateral – Import Without Price	705,231	752,357	572,582	815,709	563,466	693,670
Bilateral – Through	0	1,402	1,400	3,028	15,260	1,684
Total Real-Time MWh	**1,713,314**	**1,917,900**	**1,344,839**	**1,656,975**	**1,408,260**	**1,727,727**
Net Energy for Load (MWh)‡	*11,913,000*	*12,311,000*	*10,687,000*	*10,317,000*	*38,823,000*	207,806,000

Note: Refer to the notes for Table 11.

2.1.7 Abnormal-Condition Events during 2004

High demand for electricity along with other events required the ISO to declare Operating Procedure No. 4, *Action During a Capacity Deficiency* (OP 4), on three occasions in 2004.[20] Because prices during each event were higher than in surrounding periods, each event is briefly discussed in this report.

[20] NEPOOL operating procedures are posted on the ISO's Web site at <http://www.iso-ne.com/smd/operating_procedures/>.

2.1.7.1 The January 2004 Cold Snap

During January 2004, New England, as well as the greater northeastern region of the United States and eastern Canada, experienced some of the most extreme winter weather in recent history. January 2004 was the coldest January on record in the Boston area since 1888. During a cold snap that took place between January 14 and 16, 2004, both the electric and natural gas systems experienced record demand that tested the capability of the regional energy delivery systems. The electric system also experienced an unusual number of unit outages, due to a combination of forced outages (i.e., the unplanned inoperability of a generator), many of which were related to weather and fuel unavailability. The ISO implemented Actions 1 and 6 of OP 4 from 5:00 p.m. to 7:00 p.m. on January 14.[21] Real-time LMPs at the Hub and load zones reached the \$850 to \$910 range. Although operating conditions were difficult, both the regional bulk electric power system and natural gas system reliably served the regional peak demands during the January 2004 Cold Snap. The event highlighted the growing interdependence of the two energy systems within New England.

On May 10, 2004, the ISO published the report entitled *Interim Report on Electricity Supply Conditions in New England during the January 14–16, 2004 "Cold Snap"* (Interim Report). The Interim Report documented the ISO Market Monitoring Department's detailed investigation into both the market and operational performance of the bulk electric power grid during those extreme weather conditions. Market Monitoring released its final version of the Interim Report (*Final Cold Snap Report*) on October 12, 2004.[22] Modifications to the market rules and procedures that took place as a result of that report are discussed later in this report.

2.1.7.2 August 20, 2004, System Disturbance

A system disturbance occurred on August 20, 2004. Temperatures and humidity were higher than normal, and the day's peak of 23,209 MW was significantly above the morning report forecast load of 21,075 MW. At approximately 3:25 p.m., lightning in the Boston area caused a phase-to-phase fault on the Tewksbury-Woburn 345 kV line (the 338 line), which resulted in that circuit tripping out of service. Several area generators automatically shut down for reasons related to the loss of the 338 line. As a result of the heavier-than-expected loads and the 1,200 MW generation loss, Master/Satellite Procedure No. 2, *Abnormal Conditions Alert*, was implemented throughout New England for a systemwide capacity shortage at 3:35 p.m. OP 4, Actions 1 and 13, were also

[21] OP 4, Action 1, requires the ISO to notify generators that a capacity shortage exists and for generators to notify the ISO about the availability of additional capacity. OP 4, Action 6 requires the ISO to begin to allow the depletion of the 30-minute reserve. For more details, see <http://www.iso-ne.com/smd/operating_procedures/OP4_RTO_FIN.doc>.

[22] See <http://www.iso-ne.com/special_studies/January_14_-_16_2004_Cold_Snap_Reports/>.

implemented for the Boston area.[23] Real-time LMPs reached $292 in the Connecticut load zone, and were in the $90 to $100 range at the other load zones and the Hub. System conditions returned to normal at approximately 11:30 p.m. that evening.

2.1.7.3 December 6, 2004, Cold Weather

The first cold weather of the 2004/05 winter occurred on Monday, December 6, 2004. Temperatures in New England were 14ºF lower than expected, resulting in an evening peak load that was 650 MW over the original forecast. Imports were below forecasts by approximately 550 MW. Generation outages and reductions were approximately 200 MW higher than expected. A negative capacity margin over the peak hour necessitated the implementation of OP 4, Actions 1 and 6, from 5:06 p.m. until 7:10 p.m. Real-time LMPs reached the $590 to $650 range at the Hub and load zones.

2.1.8 Energy Market Conclusions

The energy markets functioned well in 2004, with good day-ahead/real-time price convergence and prices similar to those in previous years after adjusting for input fuel costs. Yearly total energy demand of 132,522,000 MWh exceeded the 2003 total by 769,000 MWh, and supply was adequate. Total system summer capacity was approximately 31,000 MW, compared to an hourly peak of 24,116 MW. Natural gas and nuclear-fueled power plants were the largest source of generation, and natural gas plants were the most frequent setters of the energy price. Average yearly prices were highest in the Connecticut load zone and lowest in the Maine load zone. Average day-ahead prices were $1.59/MWh higher than average real-time prices, but real-time prices were more volatile.

Large quantities of real-time demand cleared in the Day-Ahead Energy Market, and the percentage of real-time load obligation cleared in the Day-Ahead Energy Market increased from 90% in 2003 to 97% 2004. This increase was driven by an increase in the Connecticut load zone.

New England was a net importer of power in 2004, as it has been in past years, but net imports were lower in 2004. Increased volumes of exports over the Cross Sound Cable to New York contributed to this trend.

[23] OP 4, Action 13, requires local control centers to reduce their normal operating voltages and make certain energy-emergency alerts if not previously made. For more details, see <http://www.iso-ne.com/smd/operating_procedures/OP4_RTO_FIN.doc>.

2.2 Forward Reserve Market

2.2.1 Overview of the Forward Reserve Market

The Forward Reserve Market (FRM), which was implemented in December 2003, is a market-based method for acquiring generating resources to satisfy the 10- and 30-minute nonsynchronized reserve requirements for New England. FRM auctions are held twice a year, one month in advance of each of the semi-annual service periods of June 1 through September 30 and October 1 through May 31. Generating units with 10- and 30-minute nonsynchronized reserve capacity may offer it into the auctions. Generating units selected in each auction must offer energy into the Day-Ahead Energy Market at or above the forward-reserve strike price for the service period, that is, the price at which the FRM auction entitles generating units to purchase energy. The strike price is set each month and is determined by a heat rate multiplied by a fuel-price index. The monthly strike prices are not known at the time of the auction. All costs related to compensating generating resources in the FRM are allocated to load based on real-time load obligations.

Forward-reserve generating units selected in the auctions are paid the auction-clearing price and may be required to provide energy when the real-time LMP reaches or exceeds the strike price. Generating units must respond to the ISO's dispatch signal within either 10 minutes (for 10-minute nonspinning reserves) or 30 minutes (for 30-minute operating reserves). If a forward-reserve generating unit were not able to supply energy or reserves when needed, it would be required to pay a penalty.

2.2.2 Forward Reserve Market Auction Results

The results of the first three FRM auctions are shown in Table 13; Figure 27 shows the offer curves for the auctions. Prices for 10-minute and 30-minute products were the same in each of the three auctions. This occurred because many 10-minute forward-reserve offers were lower than 30-minute forward-reserve offers, and thus 10-minute forward-reserve resources were substituted for most 30-minute forward-reserve resources. Note that the first auction implemented was for a shorter period than future winter auctions will be, and that two auctions will be implemented per year in the future, one in the spring and one in the fall.

Table 13 - Results for First Three Forward Reserve Auctions

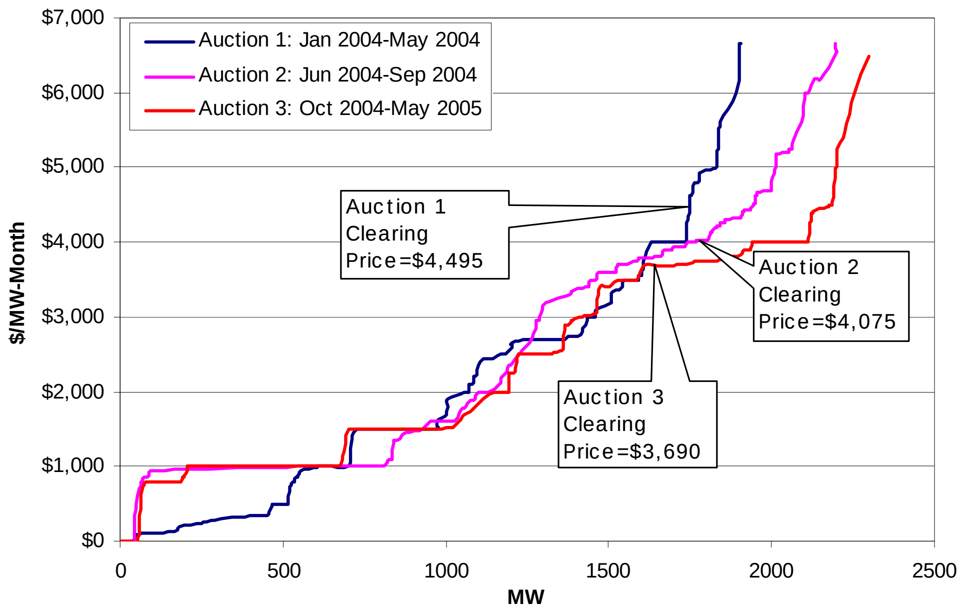
Auction Period	10-Minute Forward Reserve			30-Minute Forward Reserve		
	Total Supply Offers (MW)	Cleared MW	Clearing Price ($/MW-Month)	Total Supply Offers (MW)	Cleared MW	Clearing Price ($/MW-Month)
January 1–May 30, 2004	1,908	1,624	$4,495	1,566	252	$4,495
June 1–September 30, 2004	2,196	1,678	$4,075	1,782	285	$4,075
October 1, 2004–May 30, 2005	2,298	1,514	$3,690	1,568	349	$3,690

Prices have steadily fallen from $4,495/MW-Month to $3,690/MW-Month. Figure 27 shows that supply has increased in each successive auction consistent with the falling prices. This entry of supply occurred at the upper end of the supply stacks, with the remainder of the supply stack remaining fairly stable.[24] Because the 30-minute requirement was met with 10-minute offers, the 30-minute supply stack is not shown.

The increase in supply to date has been primarily based on modifications made to the configuration of existing facilities to allow the generators to qualify for the market. Given the novelty of this market design, such adaptation is to be expected.

Figure 27

Supply Stacks: 10-Minute Forward Reserve Auctions



[24] A supply stack shows generator offers ordered by ascending price.

Hydro- and jet fuel-powered generators cleared the largest amounts of generation in the forward-reserve auctions. Only one natural gas unit cleared the auctions. That unit had contracts for firm gas supply allowing it to reliably provide reserves even during periods of tight gas pipeline capacity. Another generator added dual-fuel capability to improve its ability to provide the forward-reserve product, while a less-efficient combined-cycle unit chose to operate as two combustion-turbine units to be able to participate in the Forward Reserve Market. Table 14 shows the cleared generation in the forward-reserve auctions by fuel type.

Table 14 - Generation Cleared In Forward Reserve Auctions by Fuel Type, MW

Generator Fuel Type	Auction 1: Jan. 2004–May 2004	Auction 2: Jun. 2004-Sep. 2004	Auction 3: Oct. 2004-May 2005
Coal	63	63	63
Diesel Oil	9	34	28
Gas	150	119	69
Hydro	640	815	711
Jet Fuel	611	471	485
Oil	198	192	234
Oil / Gas	204	269	268
Wood / Refuse	0	0	6
Total	1,876	1,963	1,863

2.2.3 Forward Reserve Market Operating Results

Table 15 summarizes total payments, penalties, and net dollars for all forward-reserve resources by month. Payments are determined by prorating the $/MW-Month clearing price over all on-peak hours in the month. Generators that fail to provide energy when given dispatch instructions by the ISO incur penalties based on the cost of replacement energy. Significant penalties were imposed in January during the January 2004 Cold Snap, with only small penalty amounts imposed in other months. The penalties in January were incurred largely by one unit that failed to start when called to dispatch. Repairs were made to the unit allowing it to operate the next day.

Table 15 - 2004 Forward-Reserve Payments and Penalties

Month	Total Payments	Total Penalties	Net Dollars
January	$7,017,895	$-2,875,435	$4,142,460
February	$7,352,539	$-726	$7,351,813
March	$7,500,393	$-4,272	$7,496,121
April	$7,691,614	$-81	$7,691,533
May	$7,757,998	$-2,844	$7,755,154
June	$7,700,098	$-911	$7,699,187
July	$7,663,014	$-7,679	$7,655,335
August	$7,690,926	$-4,192	$7,686,733
September	$7,369,678	$-364	$7,369,314
October	$5,765,089	$-619	$5,764,470
November	$6,184,584	$-1,311	$6,183,273
December	$6,236,593	$-104,846	$6,131,747
Total	$85,930,422	$-3,003,280	$82,927,141

FRM resources are subject to dispatch for energy when the real-time LMP reaches the monthly FRM strike price. As Table 16 shows, in most months, there were few or no hours with real-time LMPs greater than the strike price. As a result, FRM resources were dispatched for energy in their reserve ranges on only a few occasions during 2004.

Table 16 - 2004 Percentage of On-Peak Hours with Real-Time LMPs Greater than Monthly FRM Strike Price

Month	Strike Price	Real-Time LMPs > Strike Price
January	$96.90	24%
February	$109.35	0%
March	$85.65	1%
April	$87.00	1%
May	$95.40	3%
June	$108.92	0%
July	$100.56	0%
August	$94.83	2%
September	$82.77	0%
October	$85.65	5%
November	$125.39	0%
December	$108.20	3%

2.2.4 Forward Reserve Market Conclusions

The level of participation in the auctions was adequate. Internal combustion units' (ICUs) participation was nearly universal. Hydro units participated, but only when they had significant water-storage capability. The level of participation by thermal units with available peaking capacity was modest. The FRM is intended to provide a price signal to maintain existing peaking resources, attract new entry into the marketplace, and aid generator-owner decisions to modify or retire units. The strike-price feature targets flexible resources with high variable costs, that is, the units that can provide reserves most economically.

2.3 Capacity Market

2.3.1 Overview of the Capacity Market

In the Installed Capacity, or ICAP, Market, generators receive compensation for their investment in generating capacity in New England. Load-serving entities, the market participants with load obligations, make ICAP payments to generators across New England to ensure the availability of sufficient generation capacity for the reliable operation of the bulk power grid.

New England's installed capacity requirements are calculated each year based on the Northeast Power Coordinating Council (NPCC) resource adequacy standard.[25] With input from participants, the ISO converts the capacity requirements into reliability requirements for the New England Control Area. A generating unit's installed capability rating is adjusted to reflect the probability that a resource will be unavailable to serve load due to forced outages. This adjusted value of a resource is referred to as unforced capacity, or UCAP. Two resources may have the same installed capacity rating, but the resource with a lower forced-outage rate will have more of the UCAP commodity to sell. UCAP requirements are allocated to participants responsible for serving load based on their share of the prior year's system peak demand. Participants can meet their UCAP obligations through bilateral transactions, self-supply, resource-backed external transactions, Hydro Quebec Interconnection Capability Credits, or the purchase of UCAP in either the supply or deficiency auctions administered by the ISO.

The ISO conducts a supply auction at the middle of each month for the following month as one method for participants to transact UCAP. After a supply auction, the ISO conducts a deficiency auction to allow any load-serving participant that has not procured sufficient UCAP to cover its monthly UCAP requirement. Participants are required to offer in the deficiency auction any UCAP in excess of their UCAP requirement. Market Rule 1 requires market participants that are still deficient after the completion of a deficiency auction to pay a monthly deficiency charge of

[25] See <http://www.npcc.org>.

$6.66/kW-Month. Generators delisted as qualified ICAP resources are not required to participate in these auctions. In March 2004, the ISO filed a plan for a Locational Installed Capacity market to be implemented June 1, 2004.[26] On June 2, 2004, FERC issued an order delaying implementation of a LICAP market.[27] In the June 2 order, FERC established hearing procedures to determine certain parameters of the LICAP market and delayed the implementation of the market until January 2006.

2.3.2 Capacity Market Results

Most load-serving entities meet their ICAP Market requirements through self-supply or bilateral contracts with ICAP suppliers; relatively small amounts are traded through the supply and deficiency auctions, as shown in Figure 28. Over the January through December obligation months, approximately 93% of the pool requirement (MW-Month) was met by participants that either owned entitlement to capacity or procured it bilaterally. Over the period, about 2% of the pool requirement transacted in the supply auction; the remaining 5% was obtained in the deficiency auction. The percentage of capacity requirements met through the deficiency auction increased steadily during 2004, from less than 2% in January to almost 9% in December. This increase in purchase activity reflects the zero-dollar clearing prices that had been observed in the deficiency auction prior to November.

[26] See <http://www.iso-ne.com/FERC/filings/Other_ISO/LICAP_Filing.pdf>.

[27] See <http://www.iso-ne.com/FERC/orders/ER03-563-030_6-2-04.pdf>.

Figure 28

Sources of Capacity (MW) in SMD ICAP Market

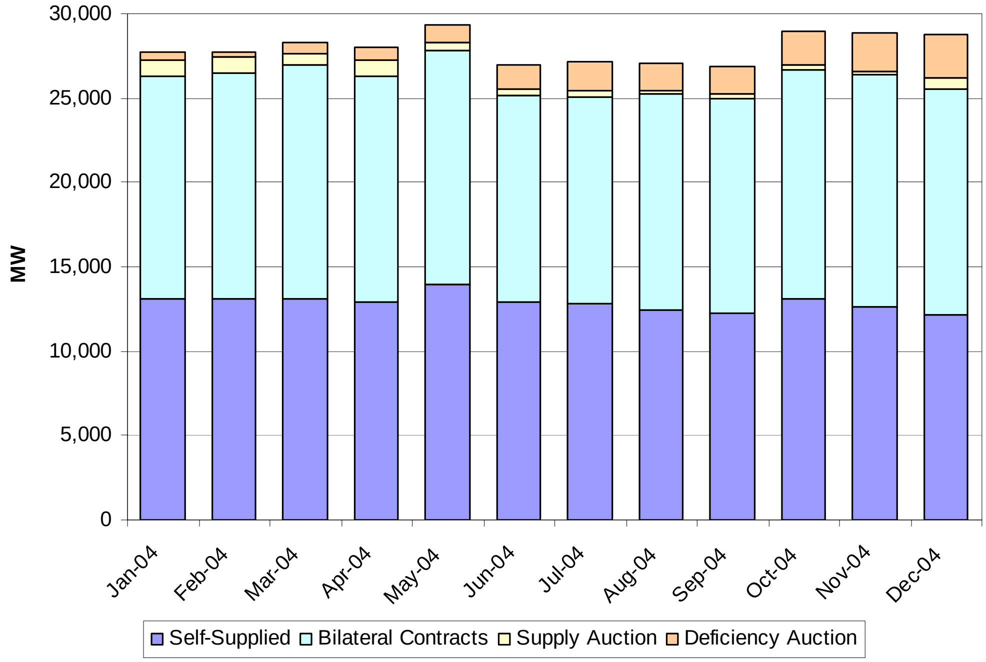


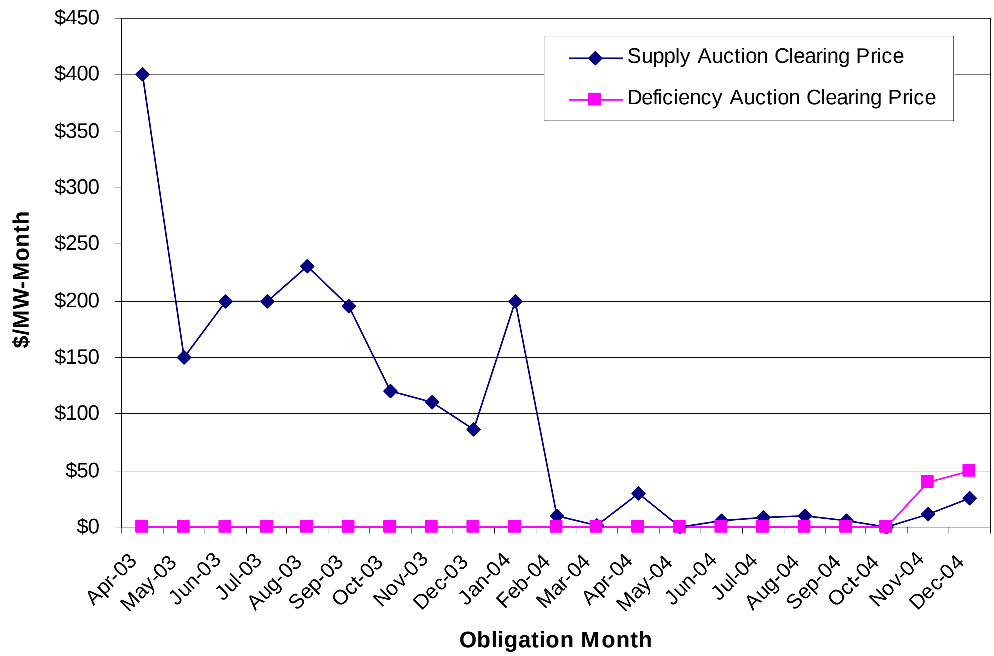
Table 17 provides the clearing prices and cleared quantities for the ICAP Market auctions during 2004. Figure 29 shows clearing prices in the supply and deficiency auctions since April 2003. Deficiency auction prices were $0.00/MW-Month from April 2003 through October 2004 before increasing to $40–$50/MW-Month in November and December 2004. This increase was consistent with the increase in purchases in the deficiency auction, as well as the increase in the capacity of delisted resources. Supply auction prices exhibited more variation over the 21-month period, and were much lower in 2004 than in 2003.

Table 17 - ICAP Market Summary for 2004

Obligation Month	Supply Auction Cleared (MW)	Supply Auction Clearing Price ($/MW-Month)	Deficiency Auction Cleared (MW)	Deficiency Auction Clearing Price ($/MW-Month)
January	1,327	$200.00	519	$0.00
February	1,102	$10.00	287	$0.00
March	916	$2.00	670	$0.00
April	1,273	$30.00	802	$0.00
May	1,164	$0.01	1,046	$0.00
June	1,270	$6.00	1,444	$0.00
July	1,432	$9.00	1,720	$0.00
August	741	$10.00	1,631	$0.00
September	884	$6.00	1,639	$0.00
October	648	$0.02	1,931	$0.00
November	1,183	$12.00	2,286	$40.00
December	1,474	$25.00	2,570	$50.00

Figure 29

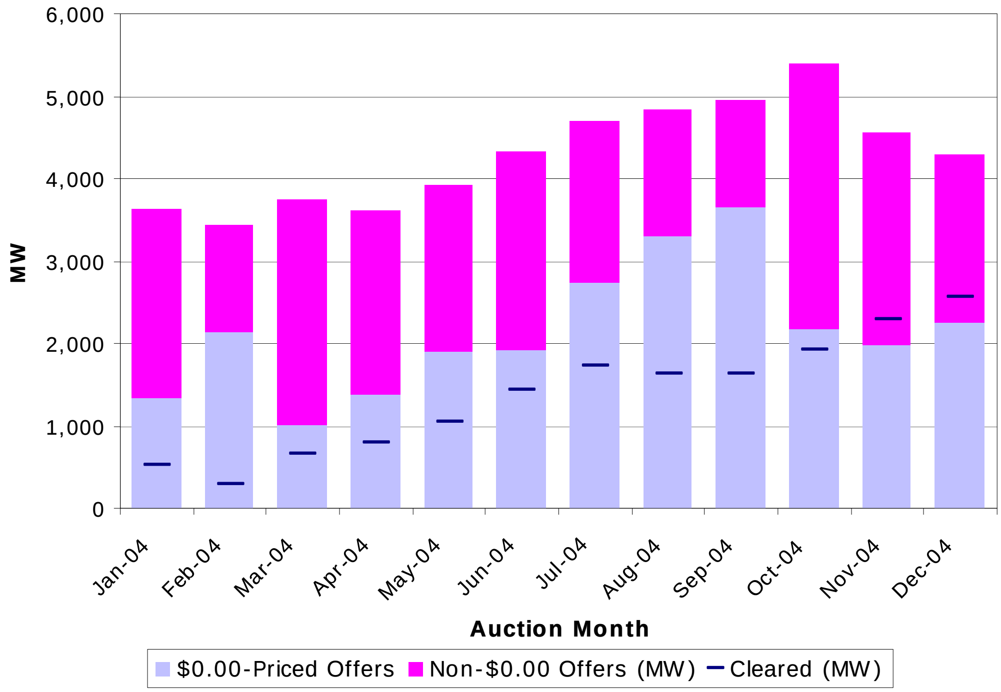
Capacity Auction Clearing Prices
April 2003 - December 2004



Deficiency auction quantities that were submitted and cleared are shown in Figure 30. The capacity offered into the deficiency auctions, and the relative quantities offered at zero and nonzero prices, varied widely over the year. The megawatts cleared in the deficiency auction increased over the course of the year, from 519 MW in January, to 2,570 MW in December.

Figure 30

ICAP Deficiency Auction Quantities, 2004



2.3.3 Delisted Capacity

Market participants with lead-participant responsibility for a generating unit may delist the unit as a qualified ICAP resource. The lead participant of the delisted unit may then sell the unit's capacity as unforced capacity in an external control area or simply avoid the obligations associated with an ICAP resource. Delisted units are exempt from the requirement to offer generation into the Day-Ahead Energy Market but may continue to do so.

Manual M-20 explains the steps that a participant must take to delist a unit.[28] At present, only entire units may be delisted and delistings remain in effect until a relisting request is made. Figure 31 shows delisted capacity by month, and Table 18 shows delisted capacity by month and load zone. Delisted MW in the historically constrained areas of NEMA/Boston and Connecticut are of concern. While an overall increase in delisting is reflective of current ICAP prices, the delisting of the units most needed for reliability, those located in NEMA/Boston and Connecticut, confirms the flawed nature of the current ICAP market, which treats all capacity as equal. Capacity in a constrained area generally has greater value to the system than capacity outside such areas.

[28]This manual can be accessed at the following Web site: <http://www.iso-ne.com/smd/market_rule_1_and_ISO_new_england_manuals/ISO%20New%20England_Manuals/M-20_Installed_Capacity/>.

Figure 31

Total Delisted Capacity, April 2003 to December 2004

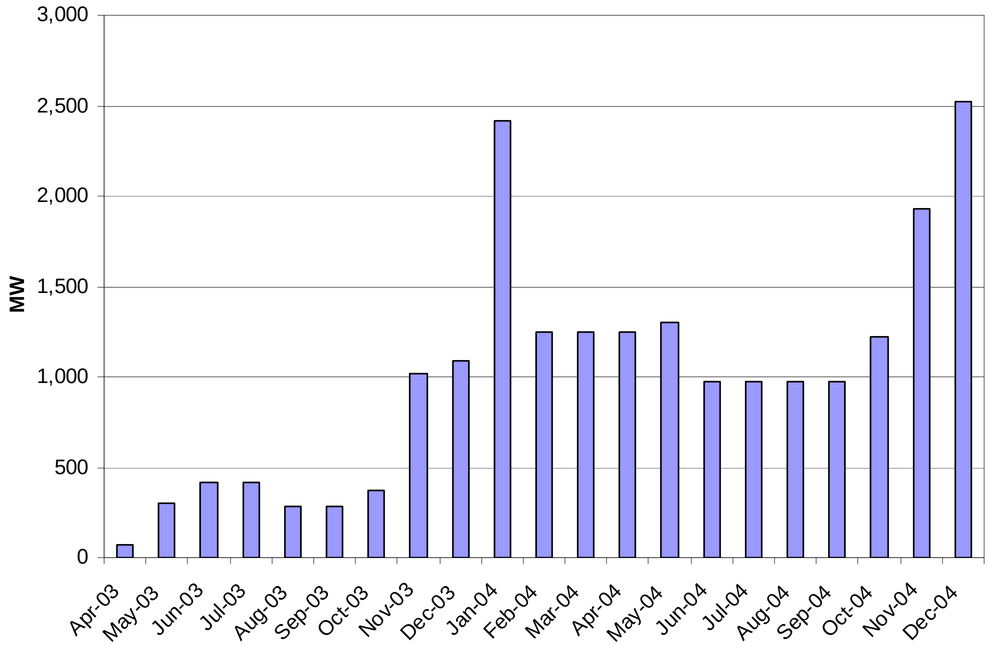


Table 18 - Delisted Capacity by Load Zone, April 2003 to December 2004

	Load Zone								
Month	**Maine**	**NH**	**Vermont**	**CT**	**RI**	**NEMA**	**SEMA**	**WCMA**	**Total**
April-03	0	0	0	69	0	0	0	0	69
May-03	0	0	0	132	0	0	0	0	296
June-03	0	0	0	204	0	0	0	0	416
July-03	0	0	0	204	0	0	0	0	416
August-03	0	0	0	72	0	0	0	0	284
September-03	0	0	0	72	0	0	0	0	284
October-03	0	0	0	49	0	0	109	0	369
November-03	0	0	0	403	0	291	109	0	1,019
December-03	0	0	0	536	0	231	109	0	1,091
January-04	0	535	0	1,551	0	225	109	0	2,419
February-04	0	535	0	484	0	225	0	0	1,244
March-04	0	535	0	484	0	225	0	0	1,244
April-04	0	535	0	484	0	225	0	0	1,244
May-04	0	535	0	445	0	225	0	0	1,305
June-04	0	535	0	336	0	0	0	0	971
July-04	0	535	0	336	0	0	0	0	971
August-04	0	535	0	336	0	0	0	0	971
September-04	0	535	0	336	0	0	0	0	971
October-04	0	522	0	465	0	0	132	0	1,219
November-04	0	522	0	613	0	560	132	0	1,926
December-04	0	522	0	706	0	560	632	0	2,521

2.3.4 Capacity Market Conclusions

Capacity Market activity during 2004 was normal. Participants met most of their UCAP requirements through self-supply or bilateral transactions, and small amounts of capacity cleared in the ISO-administered auctions at low prices. Increased purchases through the deficiency auction, coupled with increases in delisted capacity, raised prices in the deficiency auction. Delisting increased during the year—dramatically in the last three months. Of concern is the fact that many of these delistings occurred in historically constrained areas. The incorporation of a locational component in the proposed LICAP design should address this problem.

2.4 Regulation Market

2.4.1 Overview of the Regulation Market

Regulation is the capability of specially equipped generators to increase or decrease their generation output every four seconds in response to signals it receives 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. This system balancing maintains proper power flows into and out of the New England Control Area.

The Regulation Market clearing process selects a set of generators to provide regulation service and sets hourly clearing prices based on day-ahead offers submitted by generators willing to supply this service. The regulation price is set by the generating unit that has the highest combined regulation offer and ISO-estimated unit-specific opportunity costs based upon the Day-Ahead Energy Market clearing prices.[29] In the Real-Time Energy Market, the ISO issues appropriate dispatch instructions to generators, which are compensated for any real-time lost opportunity costs incurred while providing the service. Load-serving entities then pay for regulation service based on real-time load obligations. Market participants may satisfy regulation requirements by providing the service from their own resources, through internal bilateral transactions for regulation, or by purchasing regulation from the market.

2.4.2 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 the NERC Control Area Control Performance

[29] Unit opportunity cost is the estimated cost each generating unit would incur if it adjusted its output as necessary to provide its full amount of regulation. It is computed roughly as follows: [absolute difference between the day-ahead LMP at the generator's bus and the generator's energy offer associated with the regulation setpoint (in MW) the unit would have to maintain to provide its full amount of regulation] x [the deviation between economic dispatch and the regulation setpoint in MW].

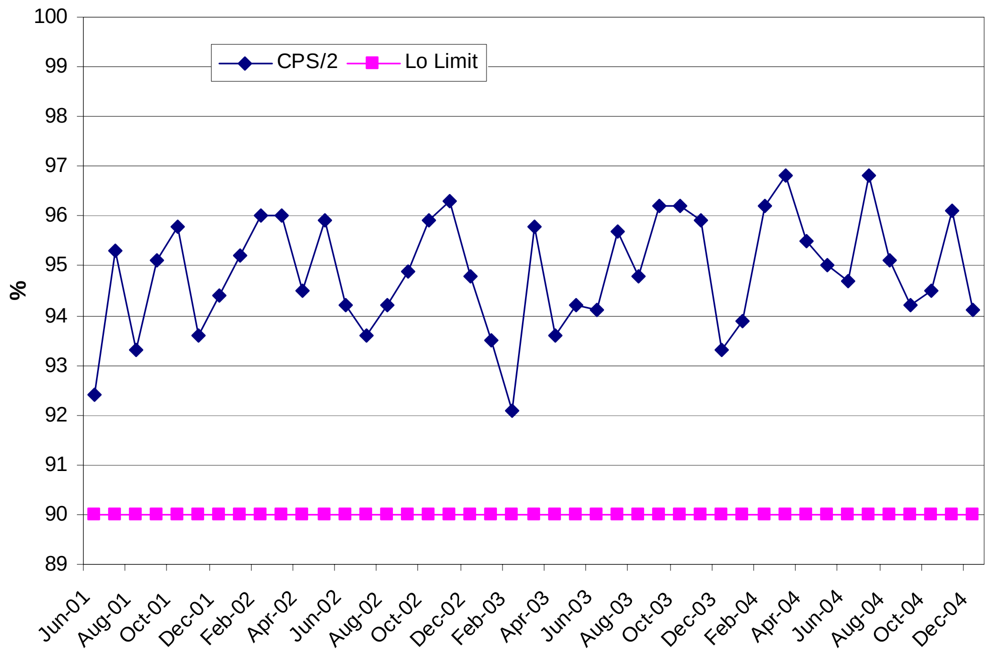
Criteria specified in NERC Policy 1. The primary measure of the Control Performance Criteria is specified as the Control Performance Statistic 2 (CPS/2):[30]

> *The average Area Control Error (ACE) for at least 90% of the clock ten-minute periods (6 nonoverlapping periods per hour) during a calendar month must be within a specific limit, referred to as L_{10}.*[31]

For the New England Control Area, the CPS/2 annual average compliance target is 92% to 97%. Figure 32 shows the CPS/2 compliance each month from June 2001 to December 2004, and the 90% lower monthly limit. The ISO has continually met its CPS/2 targets.

Figure 32

CPS2 Compliance



The ISO periodically evaluates the regulation requirements necessary to maintain CPS/2 compliance. The regulation requirements (as posted on the ISO's Web site) are determined by hour and vary by time of day, day of week, and month. Figure 33 shows a time-weighted monthly average of the regulation requirements. In the figure, the requirements for June 2001 through

[30] Control Performance Statistic 1 and Control Performance Statistic 2 compliance reports are on the NERC Web site at: <http://www.nerc.com/~filez/cpc.html>.

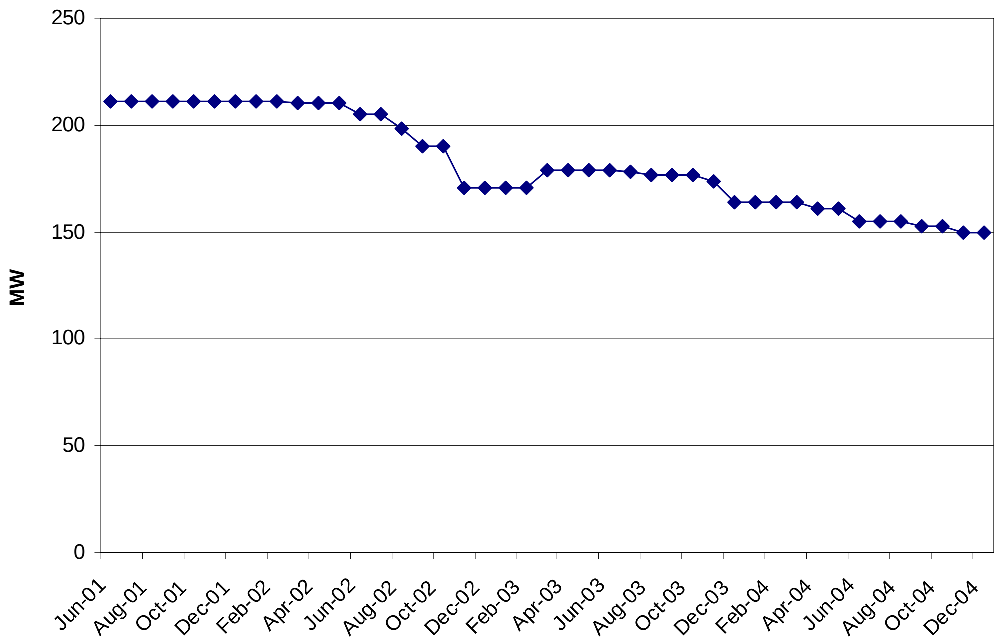
[31] The Area Control Error of the New England Control Area is the actual net interchange minus the biased scheduled net interchange.

February 2003 have been converted from REGS (the regulation requirement of the Interim Market) to MW of regulation to be consistent with present market requirements.

Figure 33 shows a gradual downward trend of the average monthly requirements over the period. The average requirements have decreased by 29%, from 211 MW in June 2001 to 150 MW in December 2004. The ISO has been able to reduce the requirements, in part, due to the overall improvement in the response of the regulation resources to the regulation-control signals.

Figure 33

Regulation Requirements (MW)



To compare recent historical regulation offers with regulation requirements, the ISO used the regulation offer data available to the daily 10:00 p.m. Reserve Adequacy Analysis and regulation-scheduling (REGO) process and averaged the totals of the regulation-offer regulating capacity (in MW) across all hours of the operating day. The hourly regulation requirements for each operating day were averaged across all hours to produce a daily average regulation requirement. The average regulation requirement was then compared with the average available regulating capacity. This comparison indicates that, on average, the regulation capacity offered into the market exceeds the regulation requirements by a factor of 7.5.

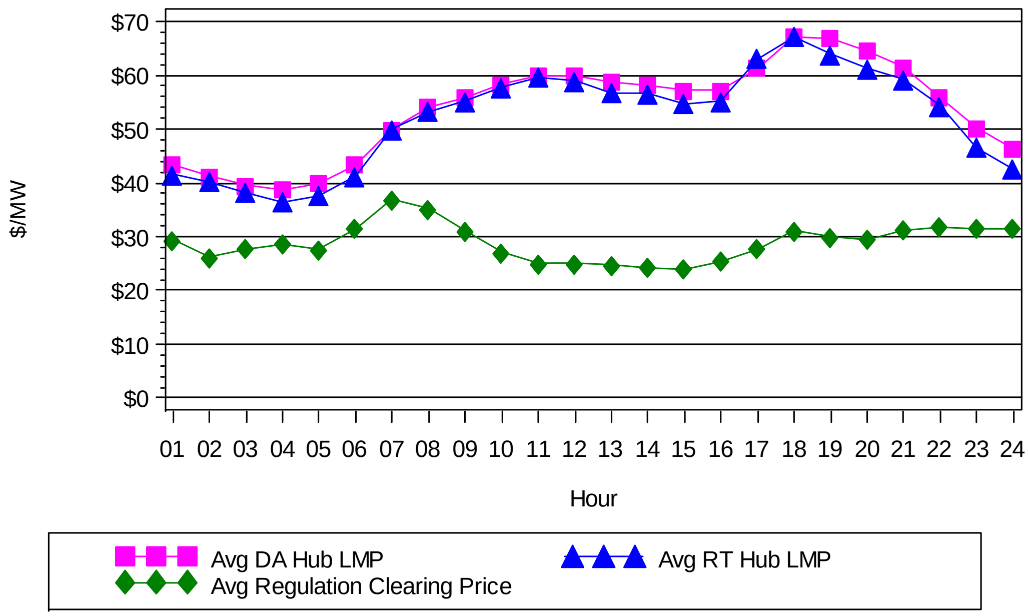
2.4.3 Regulation Market Results

The hourly Regulation Market clearing price averaged $28.92/MWh (unweighted) over the year. Payments to generators for providing regulation totaled $44 million, including $4.4 million in real-time opportunity cost payments.

As Figure 34 illustrates, average regulation prices were highest during the morning peak hours. The prices declined during the mid-day and the 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, with supply becoming tighter as units are decommitted overnight. The Regulation Market clearing process minimizes the total daily cost of procuring regulation service.

Figure 34

Average Hourly Regulation Clearing Prices and Hub Day-Ahead & Real-Time LMPs, 2004



The table below shows summary information about clearing prices in the Regulation Market during the year.

Table 19 - 2004 Regulation Market Clearing Prices

Summary Statistics, $/MWh

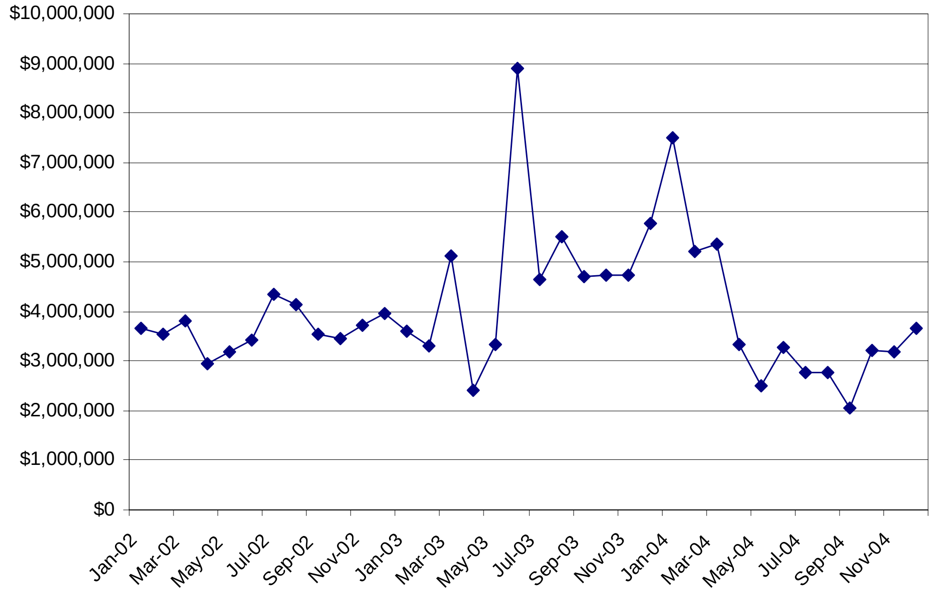
Month	($/MWh)			
	Average	Median	Minimum	Maximum
January	$54.54	$50.25	$15.00	$344.17
February	$43.84	$45.21	$0.00	$87.61
March	$41.31	$41.61	$0.00	$103.16
April	$28.71	$27.18	$0.00	$165.60
May	$19.93	$19.82	$0.00	$56.83
June	$25.16	$24.85	$0.00	$56.94
July	$20.08	$19.93	$0.00	$102.35
August	$19.79	$18.41	$0.00	$52.30
September	$18.25	$17.51	$0.00	$41.11
October	$27.11	$24.69	$0.00	$232.64
November	$23.92	$22.22	$13.48	$65.31
December	$24.73	$23.30	$7.23	$59.84
2004 Total	**$28.92**	**$25.00**	**$0.00**	**$344.17**

2.4.4 Regulation Market Improvements during 2004

After the implementation of the new Regulation Market as part of SMD in March 2003, the ISO's Internal Market Monitoring Unit and its Independent Market Monitoring Unit identified a problem arising from the ability of participants to self-schedule their units in real-time without affecting the regulation price, which had been set as part of the REGO process. This situation decreased the incentive for certain participants to offer the service in advance, and resulted in potentially inefficient selection of generating resources and higher regulation prices. On February 20, 2004, operating procedures governing the Regulation Market were revised to limit the ability of participants to self-schedule after the close of the Regulation Market and the determination of regulation-clearing prices. The implementation of the procedural changes was improved in late October 2004. Figure 35 shows that Regulation Market clearing prices were lower from April 2004 through December 2004, perhaps due, in part, to the implementation of the rule change.

Figure 35

Total Regulation Payments, 2002 - 2004



2.4.5 Regulation Market Conclusions

The Regulation Market has performed effectively to provide sufficient amounts of regulation. During the year, there were ample units available to supply regulation to the New England markets, and the New England Control Area's compliance with NERC reliability requirements for regulation was excellent.[32] The procedural change implemented in February increased the number of regulation-providing resources available to the day-ahead price-setting process and resulted in lower regulation prices.

[32] Control Performance Statistic 1 and Control Performance Statistic 2 compliance reports are on the NERC Web site at <http://www.nerc.com/~filez/cpc.html>.

3 Reliability Costs, Congestion Management, and Demand Response

This section of the report covers supplemental commitment of generation, Operating Reserve Credits, tariff payments, Peaking Unit Safe Harbor activity, FTRs, and demand-response programs.

3.1 Supplemental Commitment of Generation

The requirements for the reliability of New England's bulk power system reflect standards developed by NERC and NPCC. These requirements are codified in the system operating procedures.[33] The ISO commits some generation outside of the market-clearing process to maintain power system reliability and meet these requirements.

Supplemental commitment for the reliable operation of the power system begins with evaluating the set of generator schedules produced by the Day-Ahead Energy Market solution. If the Day-Ahead Energy Market solution does not meet the requirements for real-time operation, the ISO will commit additional capacity following the seven-step commitment plan outlined as follows:

1. Special Constraint Resource generators are committed to meet a requirement on the low-voltage network that is not visible to the ISO. These commitments are made at the request of the local transmission owner.

2. Generators are committed to provide reactive power to control voltage during light-load periods when voltage on the 345 kV network can increase to unacceptable levels.

3. Generators are committed to meet first transmission-line contingency requirements for local or import-congested areas.

4. Reliability Must Run generating units are committed specifically to meet the second transmission-line or second generator contingency in import-congested areas.

5. Generators are committed to meet the systemwide spinning reserve requirement when the Day-Ahead Energy Market and supplemental real-time commitment do not provide sufficient spinning capability to meet the real-time requirement.

6. Generators are committed to meet the systemwide regulation requirement when the Day-Ahead Energy Market and supplemental real-time commitment do not provide sufficient regulating capability to meet the real-time requirement.

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[33] The system operating procedures are available on the ISO's Web site at <http://www.iso-ne.com/smd/system_operating_procedures/>.

7. Generators are committed to meet the systemwide operating-reserve requirement when the Day-Ahead Energy Market and supplemental real-time commitment do not provide sufficient capacity to meet the real-time requirement.

The day-ahead and Reserve Adequacy Analysis supplemental commitment are performed in this order to effectively minimize real-time supplemental commitment. The constraint that can be met by the fewest number of generators is solved first. The generation committed to solve the first constraint can offset the need to commit additional supplemental generation for meeting the local, regional, and systemwide requirements. This process helps to meet system reliability requirements while also minimizing the capacity committed.

Figure 36 shows the quantities of these supplemental commitments in the Day-Ahead Energy Market and RAA process. The increase in day-ahead reliability commitments in late 2004 was driven by a reduction in self-scheduling by generators in load pockets, which necessitated additional commitments by the ISO.

Figure 36

Total Monthly Reliability Committments (MW)
Day-Ahead and RAA

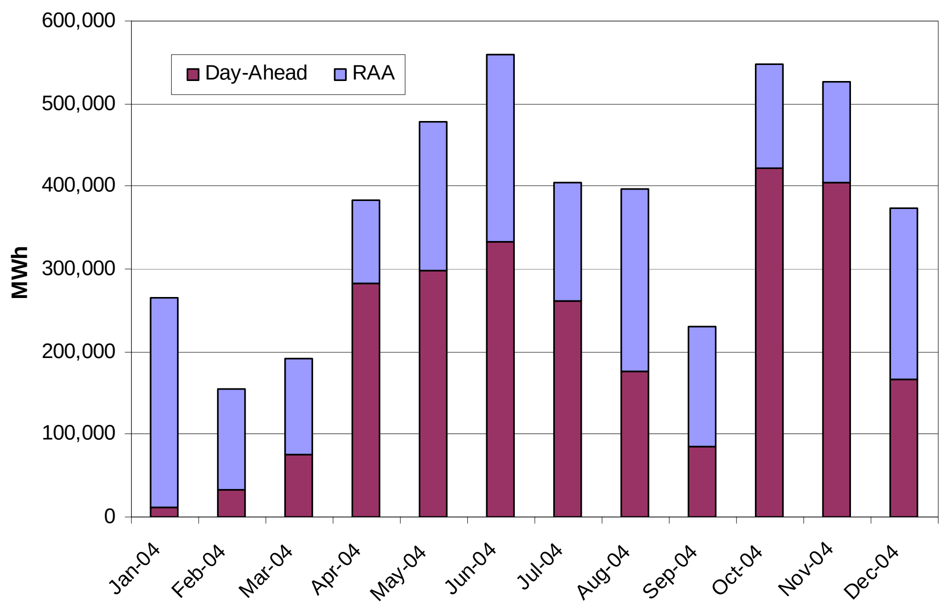


Figure 37 shows total supplemental commitments made to supply local second-contingency (Reliability Must Run) reserves by month, while Table 20 shows the same information by load zone. RMR commitments follow a seasonal pattern, with higher commitments in high-load summer and winter months. All RMR commitments were made in the Connecticut and NEMA/Boston zones because only the Boston area, Southwest Connecticut, Norwalk-Stamford Connecticut, and the rest of Connecticut have local second-contingency reserve requirements. RMR commitments are a function of local reserve requirements and the availability of quick-start units to meet these requirements. Areas with local reserve requirements that are greater than available quick-start generation, and without sufficient in-merit generation, require RMR commitments. Local reserve requirements are determined by local contingencies, including the possibility of a transmission line or generator failure, and load-shedding assumptions for the area, which are supplied to the ISO by transmission owners. Limited transmission capacity into an area reduces the amount of reserves that can be supplied from outside the area, and this lack of supply increases local reserve requirements.

Figure 37

Supplemental Commitments for Local Reserves (RMR)
2004 Monthly System Totals

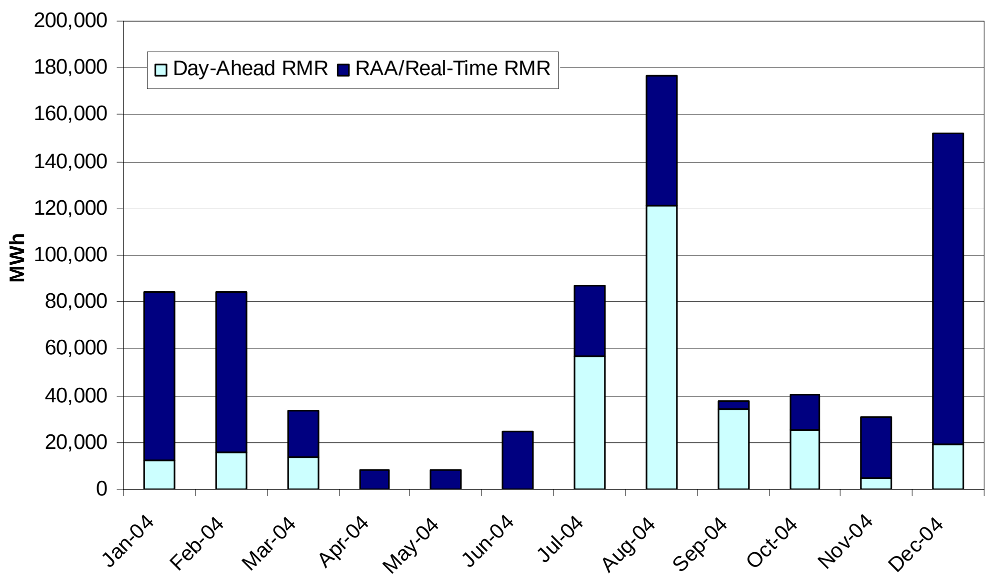


Table 20 - 2004 RMR Commitments by Load Zone, MWh

	Connecticut		NEMA / Boston	
Month	Day-Ahead RMR	RAA / Real-Time RMR	Day-Ahead RMR	RAA / Real-Time RMR
January	12,342	50,227	0	21,989
February	12,200	46,588	3,840	21,910
March	13,611	19,908	0	0
April	0	8,447	0	0
May	0	8,054	0	0
June	0	21,557	0	2,790
July	1,650	28,221	55,170	1,975
August	119,248	30,404	2,160	23,152
September	34,216	1,606	0	1,840
October	9,868	1,767	15,640	12,810
November	0	4,409	4,500	21,850
December	640	11,162	18,491	121,651
Total MWh	203,775	232,351	99,801	229,968

Figure 38 shows total commitments made in 2004 to provide reactive power to control voltage by month, and Table 21 shows the same information by load zone. VAR commitments are generally driven by hours when load levels are low. In 2004, the majority of VAR commitments were made in the NEMA/Boston load zone.

In the Boston area, underground cables produce approximately 1,000 MVAR of charging. During light-load conditions, reactive transmission losses are low, and reactors and generators are required to absorb charging and reduce voltage. VAR commitments increased in 2004 for a number of reasons, including the addition of two new 345 kV lines in the Boston area, which increased charging in low-load hours; changes in cable-switching practices, which decreased the assistance available from this source; and the replacement of four existing 345/115 kV transformers, which had load-tap changers (LTCs), with new transformers that do not have LTCs. While new reactors were added in the Boston area to provide VAR control, overall, VAR control capacity from nongenerator resources declined during 2004. Therefore, generators had to operate more frequently in 2004 than in past years to provide VAR control, with the associated costs paid through tariff-reliability service credits (see Section 3.3). The ISO worked with the local control center for Rhode Island, Eastern Massachusetts, and Vermont (REMVEC) and Boston area generation and transmission owners in 2004 to reduce VAR uplift by repairing a reactor and a LTC and making plans to install a new 150 MVAR reactor in the spring of 2005.

Figure 38

Supplemental Commitments for Reactive Power (VAR)
2004 Monthly System Totals

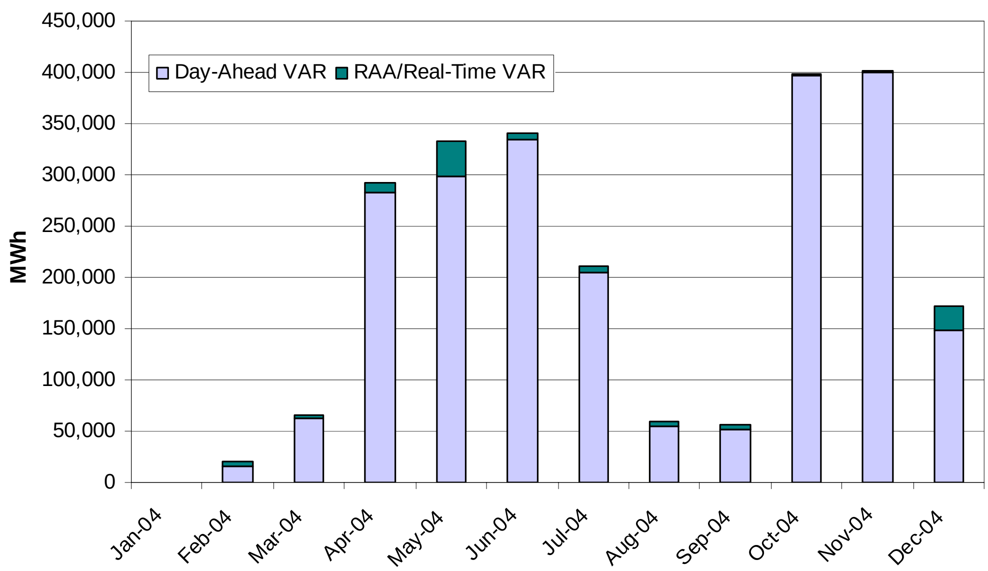


Table 21 - 2004 VAR Commitments by Load Zone, MWh

Month	NEMA / Boston		SEMA	
	Day-Ahead VAR	RAA / Real -Time VAR	Day-Ahead VAR	RAA / Real -Time VAR
January	0	0	0	0
February	16,110	3,653	0	0
March	62,640	2,250	0	0
April	282,832	9,268	0	0
May	297,900	29,213	0	5,285
June	333,850	7,050	0	0
July	204,800	6,796	0	0
August	54,670	5,400	0	0
September	51,570	5,040	0	0
October	345,980	2,880	50,200	0
November	320,220	450	80,160	0
December	67,835	24,645	80,160	0
Total MWh	2,038,407	96,644	210,520	5,285

Supplemental commitment costs that are not covered by energy-market revenues are paid through Economic and RMR Operating Reserve Credits (see Section 3.2) and VAR and Special Constraint Resource transmission tariff payments (see Section 3.3). Economic and RMR ORCs are assigned to clearing load in the Day-Ahead Energy Market or to deviations in the Real-Time Energy Market. VAR and SCR costs are assigned outside the market directly to transmission owners. Table 22 illustrates the relationship between operating requirements and financial settlements. These compensation arrangements are discussed in greater detail below. The ISO developed an action plan for 2005 to reduce the need to commit resources that create these costs.

Table 22 - Relationship between Supplemental Physical Commitments and ORC and Tariff Payments

Physical Commitments	Financial Settlement			
	Economic ORC	RMR ORC	VAR Tariff Payments	SCR Tariff Payments
Pool-wide first and second contingency (voltage, stability, transmission)	X			
Pool-wide out-of-merit energy (on to satisfy minimum run time)	X			
Regional first and second contingency in Boston, SW CT, NRST CT (voltage, transmission)		X		
Reactive power for voltage control			X	
Local transmission support				X

3.2 Operating Reserve Credits

3.2.1 Overview of Operating Reserves

Operating reserves can be viewed as the bulk power system's insurance policy. They provide a margin of additional supply above what is otherwise needed to meet real-time system demand. Operating reserves allow the ISO to respond to significant, unexpected imbalances between supply and demand without interrupting load. Providers of these reserves are paid through Operating Reserve Credits.

The Interim Market had separate, auction-based markets for procuring and compensating operating reserves (10-minute spinning reserve, 10-minute nonspinning reserve, 30-minute operating reserve). SMD compensates participants providing these reliability services in a different way.

The ISO schedules adequate resources in the Day-Ahead Energy Market to meet the cleared demand plus forecasted regional reserve requirements. After the Day-Ahead Energy Market closes, the ISO conducts a Reserve Adequacy Analysis to ensure that operating-reserve requirements are met based on the forecast demand for the following operating day. Additional resources are then scheduled as necessary.

Generators eligible for compensation are those whose output the ISO has constrained above or below the economic level, as determined by the LMP and in relation to their offers. This compensation is based on the generator's submitted costs for providing energy, including start-up and no-load costs. This compensation approach ensures that generators that provide reserves and experience lost opportunity costs or overall revenue shortfalls (insufficient revenue) are paid for any expenses not recovered through their daily energy payments. These payments are called Operating Reserve Credits.

Operating Reserve Charges 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 who do not follow real-time dispatch instructions, are charged in proportion to these deviations.

3.2.2 Types of Operating Reserve Credits

ORCs are calculated in both the Day-Ahead Energy Market and Real-Time Energy Market. There are two types of ORCs:

- Economic ORCs are paid to eligible units that provide operating reserves and that are not flagged, or designated, for another type of ORC. The ISO makes these payments to generating units it has committed to ensure pool reliability (e.g., to supply replacement reserves) and whose decommitment would pose a threat to that reliability. Most Economic ORC payments are made to generators committed to supply systemwide energy in peak hours that must stay on during later hours to satisfy minimum runtime requirements. While these generators may have been in-merit during peak hours, they become out-of-merit in later hours and receive ORC payments. Costs associated with Economic ORCs are not incurred as part of the economic dispatch of the power system.

- Reliability Must Run ORCs are paid to generating units that are required for reliability within a particular reliability region on that particular day. In 2004, NEMA/Boston and Connecticut were the only regions in which RMR ORCs were made because these regions are the only ones that have local second-contingency coverage requirements.

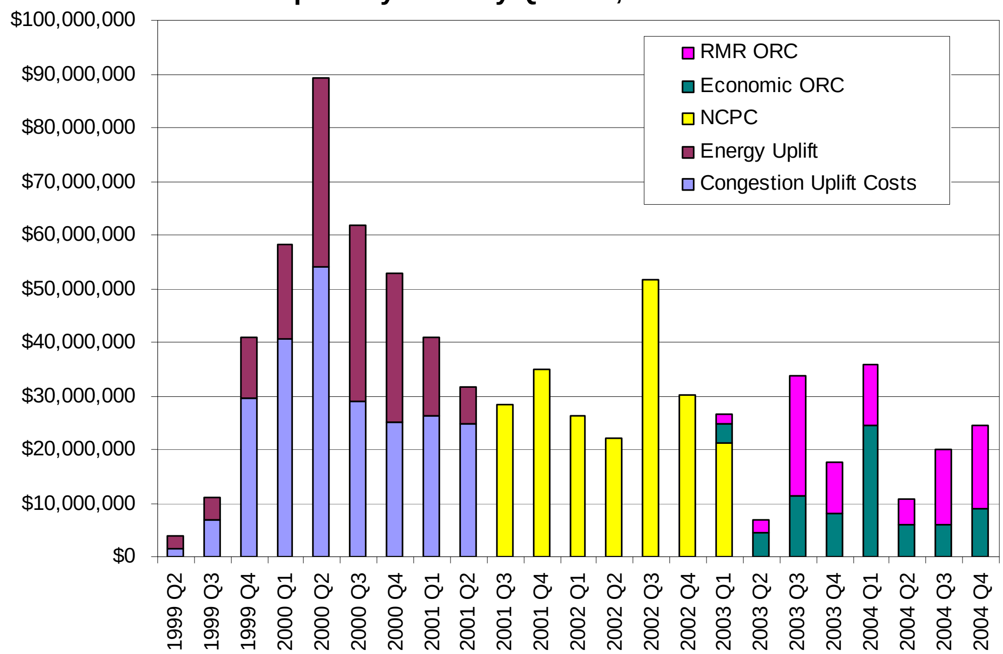
VAR and SCR transmission-reliability service payments, which are calculated in the same way as ORC payments, are discussed in Section 3.3.

ORC payments are made to eligible pool-scheduled generators and participants with external dispatchable transactions that have a shortfall between their revenue (based on clearing prices in the energy markets and Regulation Market) and their offer price (based on their energy offer, start-up fee, and no-load fee). If a generator operates in economic-merit order, most of its compensation will be from the energy market, unless the energy revenues are insufficient to cover its daily costs. Owners of eligible resources may receive ORC payments on a daily basis, if the ISO commits them for economic or daily RMR.

From the beginning of the Interim Market in May 1999 through June 2001, participants were eligible to receive uplift payments for hourly shortfalls between energy costs, represented by their bids, and electric energy-market compensation. Uplift payments were made to generating units that needed to operate to maintain system reliability, when transmission congestion occurred, and for nontransmission reasons, such as to maintain proper voltage limits. During the Interim Markets period of July 2001 through February 2003, participants received Net Commitment Period Compensation (NCPC) payments. NCPC was calculated on a daily basis in a manner similar to the ORC calculation. Although the eligibility criteria and calculation methods for uplift payments, NCPC payments, and ORC payments differ, all three represent payments for generation outside of those based on the energy-clearing price. Figure 39 compares quarterly totals for uplift, NCPC, and ORC payments since the markets began. Payments for VAR control, which are not included in ORCs, were included in transmission uplift and NCPC.

Figure 39

Uplift Payments by Quarter, 1999 - 2004



3.2.3 Operating Reserve Credit Results

In 2004, Economic and RMR ORCs totaled approximately $91 million. In 2003, total uplift was approximately $84.1 million. Table 23 shows Economic and RMR-ORC payments for 2004. (See Section 7.5.)

Table 23 - Total ORC Payments, 2004

Payment Type	Day-Ahead	Real-Time	Total
Economic	$11,389,394	$34,146,984	$45,536,378
RMR	$13,592,986	$31,824,918	$45,417,904
Total	$24,982,380	$65,971,902	$90,954,282

Generating units in the Connecticut load zone received the largest amount of RMR ORCs, $29.3 million, with units in the NEMA/Boston region receiving $16.0 million. Table 24 shows RMR-ORC payments for the Norwalk-Stamford area of Connecticut, Southwest Connecticut excluding Norwalk-Stamford, and the rest of Connecticut excluding Southwest Connecticut. About 50% of all ORC payments were made to generators in the Norwalk-Stamford area. Generators committed for RMR payments in Norwalk-Stamford satisfied local-area reserve requirements for all of Connecticut. However, due to import constraints into the Norwalk-Stamford area, generators committed in the rest of Connecticut cannot satisfy all of Norwalk-Stamford's reserve requirements. The charges were increased by the Peaking Unit Safe Harbor offer rules (see Section 3.5), designed to compensate resources providing reliability service, and by increased fuel prices.

Table 24 - Connecticut RMR-ORC Payments by Sub-Area

Sub-Area	Day-Ahead	Real-Time	Total
Norwalk-Stamford	$5,955,780	$16,591,505	$22,547,285
Southwest Connecticut	$322,735	$1,315,412	$1,638,147
Rest of Connecticut	$0	$5,147,579	$5,147,579

Table 25 shows the average allocation of Operating Reserve Charges by month for 2004. These averages are calculated based on days with charges. The daily real-time RMR charges per MWh of deviations in Boston and Connecticut are very large. Average charges for days with charges were as high as $47/MWh in the NEMA/Boston area. These charges are likely to have a strong effect on participants' willingness to transact in the Real-Time Energy Market and their incentives to arbitrage price differences between the Day-Ahead and Real-Time Energy Markets. These charges likely account for part of the growing day-ahead price premium noted above in Section 2. The ISO has proposed changing how these charges are allocated to better reflect the operating-reserve requirements that drive the need to commit the resources that generate these charges and to decrease impediments to arbitrage.

Table 25 – 2004 Operating-Reserve Charge Allocations for Days with Charges, $/MWh

Month	Day-Ahead Economic	Real-Time Economic	CT Day-Ahead RMR	CT Real-Time RMR	NEMA Day-Ahead RMR	NEMA Real-Time RMR
January	$0.51	$6.53	$0.00	$10.62	$0.00	$0.79
February	$0.33	$0.45	$1.12	$17.44	$6.29	$17.11
March	$0.01	$0.86	$0.00	$16.09	$0.00	$0.00
April	$0.18	$0.45	$0.00	$20.47	$0.00	$0.00
May	$0.05	$0.72	$0.00	$12.75	$0.00	$0.00
June	$0.04	$0.94	$0.00	$16.94	$0.00	$7.92
July	$0.01	$0.64	$0.00	$15.28	$2.80	$5.54
August	$0.04	$0.88	$1.37	$16.20	$1.13	$10.07
September	$0.01	$0.82	$1.34	$20.91	$0.00	$15.80
October	$0.07	$0.86	$1.45	$12.16	$2.78	$47.32
November	$0.12	$1.12	$0.00	$16.49	$2.96	$20.02
December	$0.16	$1.62	$0.73	$18.25	$1.24	$13.98
2004 Average	**$0.13**	**$1.32**	**$0.50**	**$16.13**	**$1.43**	**$11.55**

3.2.4 Operating Reserve Credit Conclusions

ORCs reflect out-of-market expenses that participants cannot hedge. These payments are assigned to load-serving entities in the Day-Ahead and Real-Time Energy Markets. The payments reflect out-of-merit operation that dampens price signals emanating from constrained areas on the system and decreases the incentive for flexible, quick-start capacity to locate and operate in those areas. The ISO will continue to refine the market rules to ensure that generating units following dispatch instructions are fairly compensated and to send appropriate price signals to local resources. This will provide proper incentives to maintain reliability and promote economic efficiency.

3.3 ISO Tariff and NEPOOL Tariff Payments

3.3.1 Voltage Ampere Reactive and Special Constraint Resource Tariff Charges

Generators providing VAR or SCR service are compensated for shortfalls between their energy revenues and energy offers in the same way as generators receiving Economic or RMR ORCs. Figure 40 shows VAR and SCR payments for 2003 and 2004, and Table 26 shows 2004 SCR and VAR payments broken out by Day-Ahead or Real-Time Energy Market. Almost all VAR payments in 2004 ($64.3million) were made to generation that was required to control high-voltage levels during low-load periods in the Boston area. In 2003, VAR payments totaled $14.3 million. The reasons for the increase in VAR commitments from 2003 to 2004 and the actions being taken to reduce these charges are discussed in Section 3.1. VAR payments are shared by all New England transmission owners based upon network load, while SCR payments are assigned directly to the transmission owner requesting that the generator be committed. (See Section 7.5.)

Figure 40

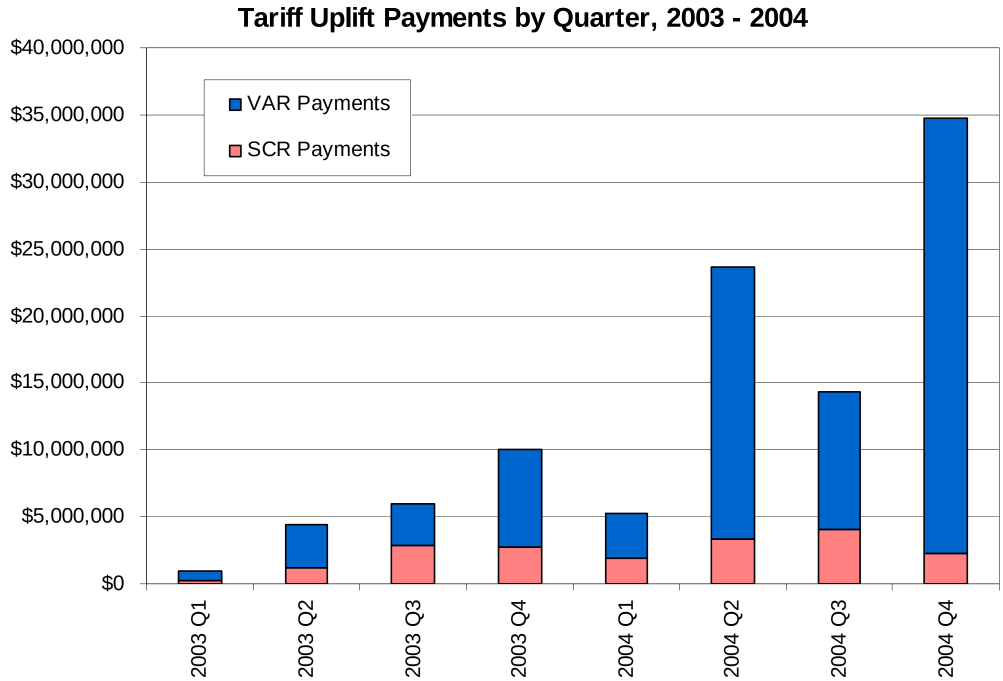


Table 26 - Transmission Tariff Payments, 2004

Payment Type	Day-Ahead	Real-Time	Total
SCR	$0	$11,520,095	$11,520,095
VAR	$60,608,247	$5,841,674	$66,449,921
Total	$60,608,247	$17,361,769	$77,970,016

3.3.2 Other Tariff Charges

In 2004, participants paid for administrative and transmission services under the ISO and NEPOOL tariffs.

The ISO Self-Funding Tariff contains rates, charges, terms, and conditions for the functions carried out by the ISO.[34] These services are:

- **Schedule 1: Scheduling, System Control, and Dispatch Service—**scheduling and administering the movement of power through, out of, or within the control area

[34] The tariff is available on the ISO's Web site at <http://www.iso-ne.com/FERC/filings/tariff/>.

- **Schedule 2: Energy Administration Service (EAS)—**charges for services provided by the ISO to administer the Energy Market

- **Schedule 3: Reliability Administration Service (RAS)—**charges for services provided by the ISO to administer the Reliability Markets

Total payments under each ISO schedule are shown in Table 27.

Table 27 - ISO Tariff Charges

Date	Schedule 1: Scheduling, System Control, and Dispatch Service	Schedule 2: Energy Administration Service	Schedule 3: Reliability Administration Service
2004 Total	$18,437,879	$76,947,970	$26,818,184

Transmission services were paid for under the NEPOOL tariff.[35] These services are:

- **Schedule 1: Scheduling, System Control, and Dispatch Service—**scheduling and administering the movement of power through, out of, or within the NEPOOL Control Area.

- **Schedule 2: Reactive Supply and Voltage Control (VAR)—**providing 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)—**point-to-point transmission service with respect to a transaction that goes through the NEPOOL Control Area or originates on a Pool Transmission Facility (PTF) and flows over the PTF prior to passing out of the NEPOOL Control Area. This charge was eliminated in December 2004.

- **Schedule 9: Regional Network Service (RNS)—**The ISO provides accounting services for Regional Network Services. RNSs allow network customers to efficiently and economically utilize their resources, internal bilateral transactions, and external transactions to serve their network load that is located in the New England area.

- **Schedule 16: System Restoration and Planning Service (Black Start)—**planning and maintaining adequate capability for restoration of the NEPOOL Control Area following a blackout.

- **Schedule 19: Special Constraint Resource Service of the Open Access Transmission Tariff—**the payments and charges for operating reserves flagged as Special Constraint Resources.

Total payments under each NEPOOL schedule are shown in Table 28.

[35] The transmission tariff is available on the ISO's Web site at <http://www.iso-ne.com/FERC/filings/tariff/>.

Table 28 - NEPOOL Tariff Charges

	Date Schedule 1	Schedule 2: CC	Schedule 2: VAR	Schedule 8: TOUT	Schedule 9: RNS	Schedule 16: Black Start	Schedule 19: SCR
2004 Total	$17,637,024	$12,377,683	$66,449,921	$5,418,848	$337,528,379	$7,707,269	$11,520,095

3.4 Reliability Agreements

3.4.1 Overview of Reliability Agreements

Reliability Agreements provide eligible generators with monthly fixed-cost payments for providing reliability service. The agreements reflect a determination by the ISO that the system needs certain generating units to maintain reliability because of transmission constraints or for voltage support, operational reserves, or other reliability reasons. These contractual arrangements, which are subject to FERC approval, provide financial support to ensure that such units will continue to be available. Reliability Agreements are paid for by network load in the zone in which the generating units are located, with the exception of one agreement in the Boston area that is paid for by a specific participant. The need for these agreements suggests that the current market structure does not signal the need for new infrastructure or adequately compensate generators providing reliability service.

Most Reliability Agreements are for cost of service—the generator recovers its fixed costs in a monthly payment and its variable costs through energy offers made at short-run marginal cost. All revenues received in excess of variable cost, including capacity-market revenues, serve to reduce the monthly fixed-cost payment. Thus, the generator recovers no more than its fixed and variable costs. Other agreements, known as reliability trackers, provide for payment of actual costs for minor and major maintenance materials and services. A single generating station may be covered by both types of agreements. Most of the agreements currently in effect will terminate when the proposed locational capacity market is implemented.

During 2004, rulings by FERC clarified eligibility for cost-of-service Reliability Agreements. Generators that meet the eligibility criteria in Market Rule 1 and are needed for reliability are entitled to recover their cost of service and do not need to apply for retirement to qualify for a Reliability Agreement. Following these rulings, applications for cost-of-service agreements increased. Requests for agreements were received from generators outside of the import-constrained areas of Southwest Connecticut and Boston and from new, efficient generators.

3.4.2 Reliability Agreement Results

In 2004, Reliability Agreements were in effect for six generating stations, with a total of 21 units and 2,342 MW. Agreements covered the Devon, Norwalk Harbor, Middletown, and Montville stations in Connecticut, and the New Boston and Kendall Stations in the NEMA/Boston area.[36] The annual fixed costs of Reliability Agreements for 2003 and 2004 are presented in Table 29. Total net costs for 2004, which reflect offsets for net energy market and capacity revenues, were approximately $159.4 million.

Table 29 – Annual Fixed Costs of Reliability Agreements

Date	NEMA	CT	Total
As of Dec 31, 2003	$30,000,000	$52,171,789	$82,171,789
As of Dec 31, 2004	$43,661,118	$121,779,276	$165,440,394

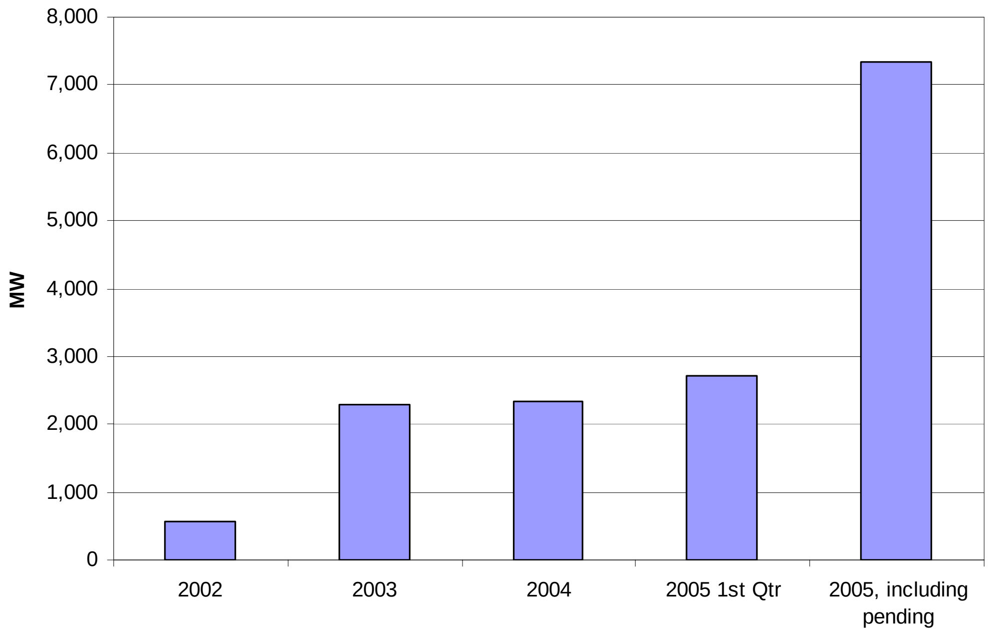
Figure 41 shows the total megawatts covered by cost-of-service and reliability-tracker agreements from 2002 through 2005. The last bar includes agreements that are either pending at FERC or under review by the ISO (in the first quarter of 2005) to determine if the generator meets the requirements for entering into Reliability Agreements. During 2004, 2,342 MW were under agreement. In January 2005, 2,707 MW were under Reliability Agreements, with an additional 4,625 MW awaiting either FERC approval or a reliability determination by the ISO.[37] In total, these megawatts constitute over 20% of total pool capacity.

[36] Additional information about Reliability Agreements is posted on the ISO’s Web site at < http://www.iso-ne.com/settlement_reports/Reliability_Agreement_Information/ >.

[37] The status of these agreements is as of March 31, 2005. On March 22, 2005, FERC issued an order (see ER05-163) making Milford Power rates effective, subject to refund on November 3, 2004. As of March 31, no billing had been done pursuant to that order. The statistics for Milford are classified as pending for this report.

Figure 41

MW Covered by Reliability Agreements



3.4.3 Reliability Agreement Conclusions

FERC has ordered that Reliability Agreements should terminate immediately upon the implementation of a LICAP market. While FERC has accepted Reliability Agreements, the agreements are intended as an interim measure to ensure that generators needed for reliability are recovering adequate revenues until ta market-based mechanism that appropriately compensates generators providing reliability services is implemented.

An increasing number of units have sought Reliability Agreements, with the associated costs increasing rapidly. Reliability Agreements do not send useful investment signals to potential new entrants. Rather, they are a stopgap measure intended to retain existing generators.

3.5 Peaking Unit Safe Harbor Implementation

On April 25, 2003, FERC issued its *Order Accepting, in Part, Requests for Reliability Must-Run Contracts and Directing Temporary Bidding Rules* (the Devon Order).[38] The Devon Order directed the ISO to replace the existing rules for mitigation in chronically congested areas, referred to as the Proxy CT or Designated Congestion Area (DCA) rules, with new rules applying special mitigation formulae to units with low capacity factors in DCAs.

[38] 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 (i.e., those with an annual capacity factor of less than 10%) in DCAs to include levelized fixed costs in their energy offers without risk of mitigation. The rule was intended to increase opportunities for fixed-cost recovery and to produce signals for investment through higher LMPs in these areas during periods of energy scarcity.[39]

As of the end of 2004, 42 generating units met the low-capacity factor and DCA-location criteria for PUSH treatment. This total includes multiple units at the same station. Of these 42 generating units, 20 were offering their generation under PUSH rules with positive fixed-cost adders. Ten had Reliability Agreements and offered their generation under the terms of those agreements and not as PUSH units.

PUSH units are often dispatched out of merit to provide local reserves, not as part of the systemwide economic dispatch. When operated this way, PUSH units are compensated through ORCs for any shortfalls between their offers and their energy-market revenues. In 2004, PUSH units received approximately $22.5 million in RMR ORCs and $2.7 million in Economic ORCs. PUSH units also received about $250,000 in SCR payments and $85,000 in VAR tariff-reliability payments. The PUSH offer rules will expire upon implementation of the locational capacity market.

3.6 Managing Congestion Risk–Financial Transmission Rights

3.6.1 Overview of Financial Transmission Rights

Financial Transmission Rights are financial instruments that entitle the holder to a share of the Day-Ahead Energy Market and Real-Time Energy Market congestion revenues. The holder of an FTR is entitled to receive, or required to make, payments based on the FTR-megawatt quantity and the difference between the congestion components of the day-ahead LMPs at the FTR's location of origin (source) and delivery (sink) points. While FTRs were designed to provide load-serving participants with a financial hedge against differences in LMPs due to transmission congestion, they can be purchased by any participant or by a nonparticipant that meets the financial assurance criteria. FTRs are not associated with the actual physical delivery of energy, and FTR holders do not have any obligation to deliver energy.

In any hour, an FTR may result in either payments due (positive target allocations) or payments owed (negative target allocations). Specifically, a participant holding an FTR defined from Point A to Point B will be entitled to compensation only if the hourly congestion component of the

[39] Additional information about PUSH is available on the ISO Web site at <http://www.iso-ne.com/smd/market_monitoring_and_mitigation/PUSH_Implementation/>.

LMP at Point B is higher than that at Point A. If the hourly congestion component is higher at Point A, the FTR becomes an obligation. In this case, the FTR holder is obligated to pay.

FTRs can be acquired in three ways:

- FTR Auction—The ISO conducts periodic auctions to allow bidders to acquire and sell monthly and longer-term FTRs. The bidders in the FTR auction initially define all available FTRs. FTRs purchased in long-term auctions can be sold into the monthly auctions.

- Secondary Market—The FTR secondary market is an ISO-administered bulletin board where existing FTRs are electronically bought and sold on a bilateral basis.

- Unregistered Trades—FTRs can be exchanged bilaterally outside of the ISO-administered process. However, the ISO compensates only FTR holders of record and does not recognize business done in this manner for day-ahead congestion-settlement purposes.

The ISO pays FTR holders with positive target allocations from congestion revenues generated by the Day-Ahead and Real-Time Energy Markets and from FTR holders with negative target allocations. In 2004, congestion revenue and negative target allocations were not high enough to meet the entitlements of FTR holders with positive allocations. This type of result is caused by periods of congestion that occur when the claimed capability of a transmission line or interface is reduced. The derating reduces the allowed flow over the line or interface, thereby reducing the congestion revenues. When this flow is below the amount sold in the FTR auctions, less revenue is collected than is owed to FTR holders. While the amount of FTRs sold over a line or interface is lower than the element's full rating, it is not possible to accurately foresee the amount of deratings that will occur during periods of congestion. The ISO is working to improve the estimation procedure.

3.6.2 Auction Results

In 2004, there were two long-term auctions, covering January through June 2004 and July through December 2004. Each one auctioned 50% of the system's transmission capacity. In addition, FTR auctions were held for each month in 2004. In each of these auctions, up to 95% of the remaining balance of the transmission system capacity was made available. The first long-term auction covering an entire year was held in December 2004 for the period of January to December 2005. The number of participants bidding in each auction ranged from 26, in the January through June 2004 auction, to 37 in the August 2004 monthly auction. Auction revenues for the 12 monthly and two six-month auctions covering 2004 totaled $91.7 million. Auction revenue for 2003 was much lower at $28 million, which partly reflects the mid-year SMD implementation.

Market Rule 1 specifies that auction revenues must first be allocated to entities in the form of Qualified Upgrade Awards (QUAs). By paying for transmission upgrades, the entities have increased the transfer capability of the New England transmission system and enabled more FTRs to be available in the FTR auction. Auction revenues are then allocated to entities through the Auction Revenue Rights (ARRs) process. During this process, auction revenues are awarded primarily to congestion-paying load-serving entities. Sixty-five percent of the revenue generated by the FTR auctions in 2004 was returned to congestion-paying entities in the NEMA/Boston and Connecticut load zones. Table 30 shows total auction revenue distribution for 2003 and 2004.

The ARR process further allocates ARR dollars to the four categories listed below and as shown in Table 31:

- Long-term firm through- or out-service transactions that deal with the delivery of electricity through or from New England to another control area

- Excepted transactions—special grandfathered transactions (listed in Attachment G of the ISO New England Transmission, Markets and Services Tariff)[40]

- NEMA contracts—other long-term contracts with delivery in northeastern Massachusetts

- Load share—the ARR allocation paid to congestion-paying entities in proportion to their real-time load obligation at the time of the pool's coincident peak for the month

The largest portion of auction revenue was returned to those who paid for congestion on the system. Table 31 shows ARR distribution by category. See Section 7.6 in the statistical appendix for additional information about the distribution of auction revenues.

Table 30 - Total Auction Revenue Distribution, 2003 and 2004

Year	QUA Dollars	ARR Dollars	Total Auction Allocation
2003	$384,186	$28,162,540	$28,546,726
2004	$3,080,554	$88,620,763	$91,701,316

[40] The tariff is available on the ISO's Web site at <http://www.iso-ne.com/FERC/filings/tariff/>.

Table 31 - Auction Revenue Distribution by Category, 2004

ARR Allocation	Amount
Long-Term Firm Trans. Svc. Dollars	$0
Excepted-Transaction Dollars	$130,445
NEMA Contract Dollars	$2,859,480
Load-Share Dollars	$85,630,838
Total	$88,620,763

Figure 42 shows monthly auction-cleared MW volumes and revenues, while Figure 43 shows long-term auction-cleared MW volumes and revenues. As expected, revenues were highest for auctions held to cover the peak summer months, when the likelihood of congestion is highest, and lower during shoulder months, when congestion is likely to be lower.

Figure 42

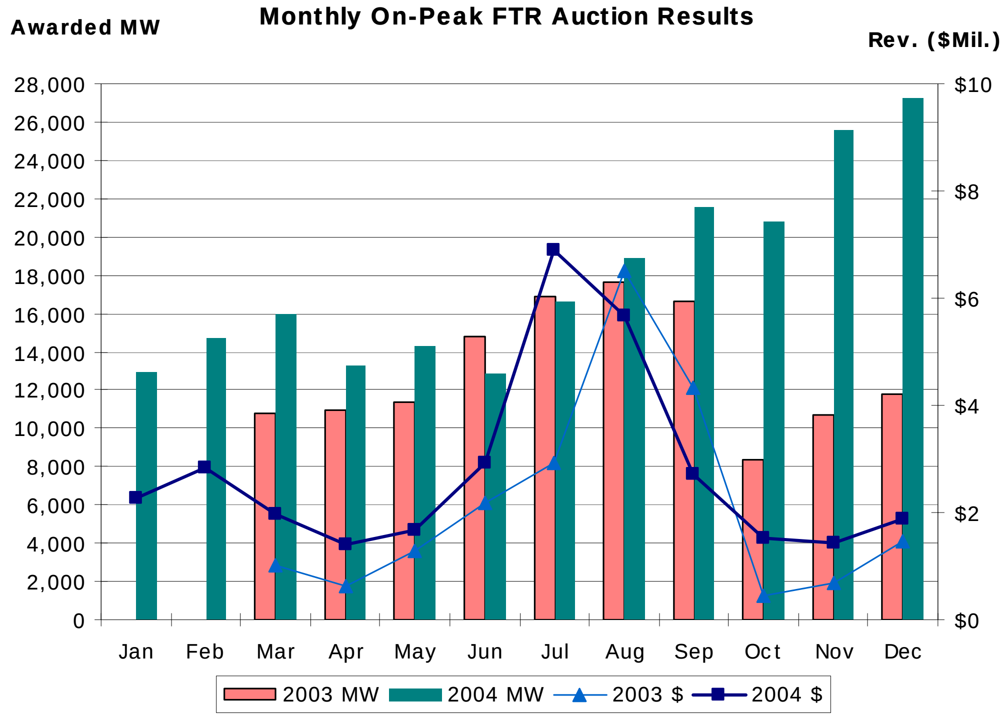
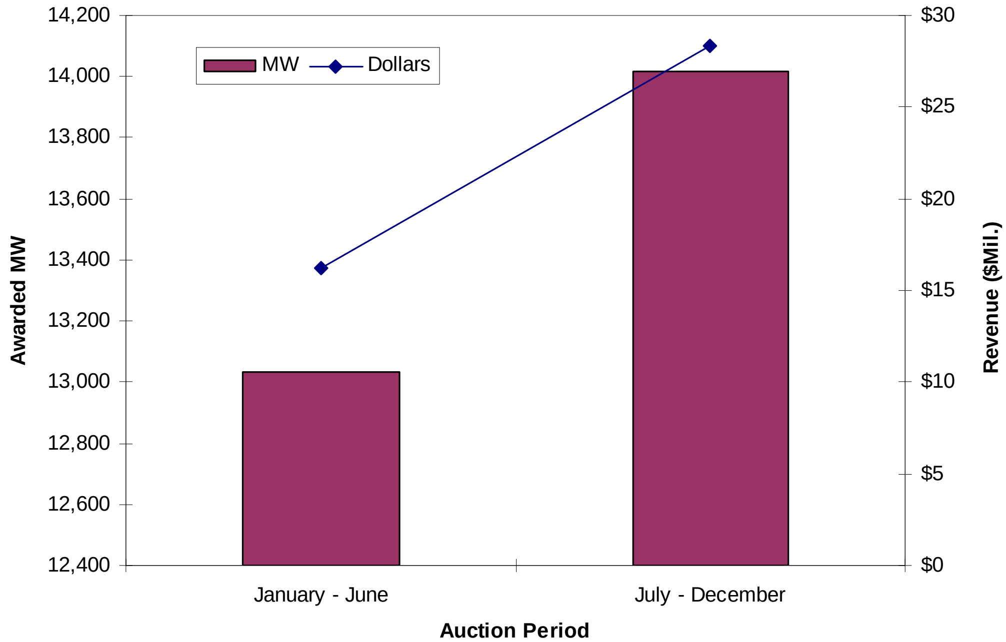


Figure 43

Six-Month On-Peak FTR Auction Results



Total FTR volumes shown in Figure 42 and Figure 43 exceeded system capacity in some months. While the physical line or interface limit applies to the net FTRs sold over a particular line or interface, FTRs flowing in one direction may counterbalance FTRs flowing in the opposite direction. FTRs that are issued in the opposite of prevailing congestion patterns allow more FTRs to be sold in the prevailing direction in much the same way that simultaneous imports and exports over the same external interface can allow total transactions to exceed the import or export limit, while net transactions are still below the limit. Holders of these counterbalancing FTRs receive payment from the auction process for taking the FTRs, but they must assume the risk of holding an FTR with a negative target allocation. A negative target allocation requires a payment through the ISO settlement system. The negative target allocations are used to pay the positive allocations to the FTRs sold above the physical transfer limit of a line or interface.

Figure 44 and Figure 45 compare LMP congestion components in the Day-Ahead and Real-Time Energy Markets with FTR auction prices. In on-peak hours, FTR auction prices were directionally consistent with actual congestion in six of the eight load zones. FTR prices and congestion levels were relatively small in the two zones where they were not directionally consistent (Vermont and WCMA). Although FTR auction bids and congestion in Connecticut were directionally consistent, the amount paid for the FTRs was disproportionately high. In general, off-peak results also were directionally consistent or the actual FTR cost was small. The notable exception is Vermont, where FTRs were positively priced at over $0.25/MWh, while day-ahead congestion was slightly negative. Given the volatile nature of congestion, these results are reasonable and suggest that the auction process is functioning as designed.

Figure 44

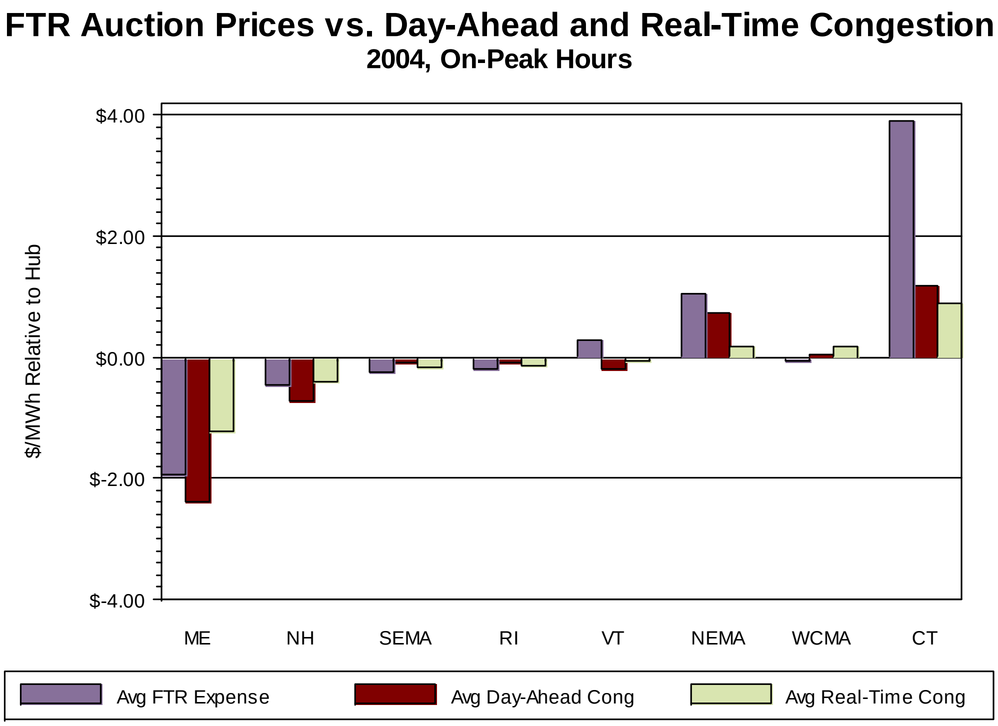
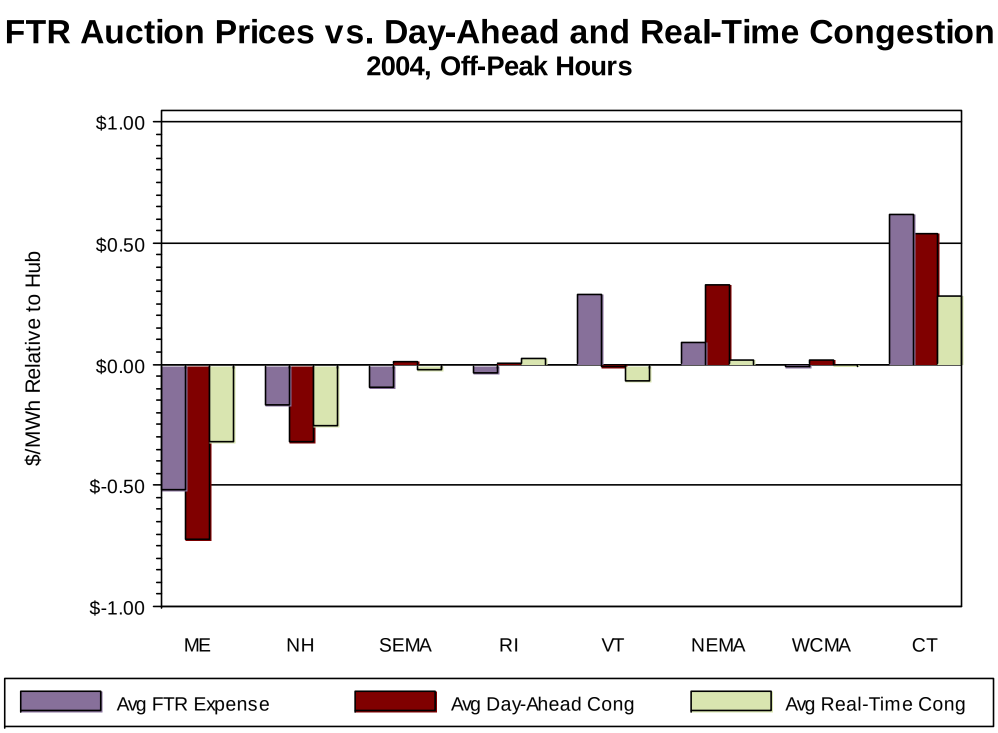


Figure 45



3.6.3 Financial Transmission Rights Payment Results

The FTR auction-clearing process includes a simultaneous feasibility test intended to ensure that the transmission system can support the awarded set of FTRs during normal system conditions, and, subsequently, that there is enough congestion revenue to cover FTR holders. At times, however, actual transmission system conditions differ from the assumptions used in the auction process, and revenues collected are not adequate to meet FTRs with positive target allocations. For example, if congestion occurs during a period when a transmission interface is derated, fewer megawatts of congestion revenue will be collected than were sold at auction. This occurred in seven months in 2004, and, overall in 2004, revenues were not sufficient to meet the full entitlements of FTR holders. Payments due to FTR holders with positive target allocations totaled \$110.8 million, while available funds, from congestion revenue and negative FTR allocations, totaled \$99.3 million. Monthly revenues, allocations, and allocations paid are shown in Table 32.

When there is a shortfall in congestion revenues, all holders of FTRs with positive target allocations receive a prorated share of their entitlements. Even if congestion on the path of a specific FTR were adequate to meet entitlements for that FTR's holder, the holder would receive a prorated share of the entitlement if the revenues for all FTRs fall short.

November 2004 had an especially large shortfall, with FTR holders receiving only 69% of their target allocations. This shortfall was due to a number of short-notice transmission outages that were not included in the assumptions for this month's FTR auction. In particular, outages that reduced the Boston interface limit and caused congestion contributed to the shortfall. In many hours, the NEMA day-ahead congestion component was in the \$20 to \$30/MWh range. FTR holders had entitlements based on the congestion price and the normal capacity of the interface. Load-serving entities paid congestion costs based on the actual reduced interface. This combination of high congestion prices and reduced interface limits led to an imbalance between entitlements and revenues.

In 2003, the Congestion Revenue Fund collected approximately \$19 million in excess of what was owed to FTR holders. As required by Market Rule 1, these revenues were distributed to entities that paid transmission congestion costs during 2003, and were not available to FTR holders in 2004.

The Transmission Congestion Revenue Fund consists of four components, as shown in the following formula:

> Monthly Transmission Congestion Revenue = (Day-Ahead + Real-Time Congestion Revenue) + (absolute value of the sum of negative FTR target allocations over all hours in the month) + (excess Monthly Congestion Revenue from previous months) + (fund adjustment)

The first five columns of Table 32 show the amount each component (including FTRs with negative allocations) contributed to the monthly Congestion Revenue for each month of 2004. The next three columns show the positive target allocations that were paid from the fund to FTR holders, the monthly surplus or deficiency of congestion revenue, and the fund's ending balance, which rolls from month to month. Months with shortfalls result in FTR holders being paid a reduced percentage of their monthly entitlement, which reduces the usefulness of the congestion hedge for the month. Months with surplus funds result in FTR holders being paid their full allocation. The last column shows the percent of positive allocations that FTR holders received in each month.

Table 32 - 2004 Congestion Revenue Fund

Month	Beginning Balance	Fund Adjustment	Day-Ahead Congestion Revenue	Real-Time Congestion Revenue	Negative Target Allocations	Positive Target Allocations	Monthly Fund Surplus or Shortfall	Ending Balance	Percent Positive Allocation Paid
Jan.	$0	$5,066	$12,886,085	-$1,046,123	-$1,369,491	$14,583,011	-$1,368,492	$0	91%
Feb.	$0	-$12,759	$4,738,282	-$213,064	-$567,962	$5,387,299	-$306,878	$0	94%
Mar.	$0	$1,884	$2,852,901	-$25,716	-$727,764	$4,205,383	-$648,550	$0	85%
Apr.	$0	$586	$8,617,267	-$153,452	-$2,302,302	$13,573,832	-$2,807,129	$0	79%
May	$0	-$6,996	$9,399,789	-$263,293	-$3,513,562	$16,182,901	-$3,539,839	$0	78%
Jun.	$0	$39	$8,540,637	-$238,294	-$1,993,714	$10,786,923	-$490,827	$0	95%
Jul.	$0	$404	$7,925,774	-$15,123	-$1,708,437	$9,436,027	$183,465	$183,466	100%
Aug.	$183,466	$3,397	$7,270,611	$223,814	-$2,828,077	$9,171,759	$1,337,606	$1,337,605	100%
Sep.	$1,337,605	$1,287	$4,107,427	$107,413	-$2,187,602	$6,628,647	$1,112,687	$1,112,688	100%
Oct.	$1,112,688	$4,622	$2,404,129	-$521,314	-$734,838	$3,427,855	$307,108	$307,108	100%
Nov.	$307,108	$421	$4,751,930	-$509,155	-$633,904	$7,523,734	-$2,339,526	$0	69%
Dec.	$0	$5,186	$8,889,344	-$172,584	-$1,538,472	$9,894,671	$365,747	$365,747	100%

3.6.4 Financial Transmission Rights Conclusions

Net FTR auction revenues totaled $91.7 million in 2004. Auction revenues from positively priced FTRs were approximately $105.5 million, while payments to participants who "bought" negatively priced counterbalancing FTRs were approximately $13.1 million. Small payments also were made to owners of FTRs who had bought the FTRs in earlier, long-term auctions but then sold all or a portion of their FTRs for the month back into the monthly auctions.

FTR holders had positive target allocations totaling $110.8 million. Because the Congestion Revenue Fund was not adequate to meet all of FTR holders' entitlements, only $99.3 million of the target positive allocations were paid. Thus, the total pay-off of FTRs was less than the cost to procure FTRs. Negative target allocations, which are liabilities for FTR holders, totaled $20.1 million. This amount was greater than the $13.1 million paid to participants that held these FTRs.

Participants that serve load can use FTRs to hedge against congestion costs, but several FTR holders participate in the market purely as financial players. Approximately 18% of FTR payouts went to entities that did not own generation or transmission or have significant load obligations in New England.

3.7 Demand Response

3.7.1 Overview of Demand Response

Demand response in wholesale electricity markets refers to resources that reduce their electricity consumption in response to either high wholesale prices or system reliability events in exchange for compensation based on wholesale market prices.[41] Demand response can help address short-run reliability problems by reducing supply needs. It also can reduce spot-market price spikes and provide a hedge against price risks for wholesale purchasers. Along with a well-designed market, ample supply, and robust transmission infrastructure, demand response is an important part of a wholesale market.

The ISO administers the Demand Response Program for the New England wholesale electricity market. During 2004, the ISO administered several programs, as follows:

- Real-Time Demand Response Program (30-minute and two-hour response)
- Real-Time Price Response Program
- Real-Time Profiled Response Program

The Real-Time Demand Response Program provides resources with two options for curtailing consumption. Response times must be within either 30 minutes or two hours after receiving instructions from the ISO to curtail consumption, and the ISO guarantees a minimum curtailment period of two hours for each event after the response must begin. Demand-response resources enrolled in this program are paid the greater of the real-time LMP applicable to their load zone, or the floor price, which is $500/MWh in the 30-minute program and $350/MWh in the two-hour program. Demand-response resources are also eligible to receive ICAP payments. Failure to perform during a curtailment event results in the forfeiture of the ICAP payment accumulated for the month, and the resource’s curtailment capability going forward being derated accordingly. Participation in the Real-Time Demand Response Program requires metering capable of recording the resource’s electricity usage in five-minute intervals, as well as Internet-based communication capability.

In the Real-Time Price Response Program, demand-response resources are paid real-time prices for voluntary reductions in electricity usage when the forecast hourly zonal price (based on the results of the Day-Ahead Energy Market or subsequent Reserve Adequacy Analyses) is greater than or equal to $100/MWh. Customers either submit their meter readings to the ISO each day, on the same schedule as other meter data, or before the end of the 90-day resettlement period.

[41] Demand resources include sites enrolled individually and collections of multiple sites enrolled by one customer.

The Real-Time Profiled Response Program includes demand-response resources that are capable of being interrupted within two hours of an ISO instruction to do so. Each individual customer participating in this program does not require five-minute metering capability. Rather, the load response for the individual or group of individual loads can be estimated using an ISO-approved measurement and verification plan. For example, statistical sampling can be used to estimate load reductions for projects, such as aggregated residential super-thermostat programs, hot water heaters, pool pumps, and distributed generation.

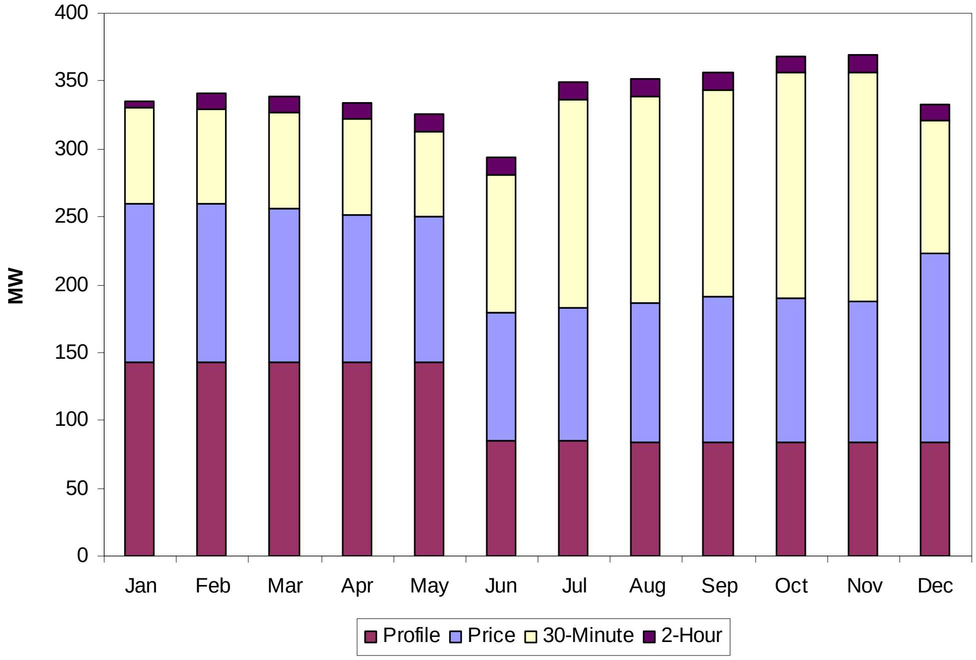
A Day-Ahead Demand Response Program has been approved by FERC and is scheduled to start on June 1, 2005. The design efforts to create a Day-Ahead Demand Response Program began more than two years ago in the spring of 2002. After considering various options, the ISO concluded that the best Day-Ahead Demand Response Program would provide a day-ahead option for each of the existing real-time programs. This solution requires little reconfiguration of the existing programs and optimizes coordination between the new Day-Ahead Demand Response Program and the existing real-time programs.

3.7.2 Demand-Response Results

As of September 1, 2004, 486 assets were enrolled in the real-time programs, comprising 356 MW of potential demand interruption or curtailment. Almost 180 MW of that total was in the Connecticut load zone, with the majority in Southwest Connecticut. Figure 46 shows demand-response program enrollments by month. Enrollment in 2004 has remained roughly constant at about 350 MW, which is similar to results for the second half of 2003. For more information on demand-response programs, see Section 7.7 in the statistical appendix.

Figure 46

Enrollments in Demand Response Programs, 2004



The Real-Time Price Response Program was activated on 59 days during 2004.[42] Activation may be zone-specific or regionwide. Participation in price-response events is voluntary; enrolled resources may choose to curtail or not curtail their energy usage during an event. Although resources are called on to curtail consumption when prices are forecast to exceed $100/MWh, actual participation depends on the business condition for each individual customer, the load at the time of the event, and price levels, with response increasing as prices approach the $1000/MWh energy-offer cap. The program resulted in 17,639 MWh of load curtailments in 2004. The number of resources that curtailed and the total load curtailed varied from event to event. The highest level of participation was in the winter months of January 2004 and December 2004, while participation during the summer months was relatively low, consistent with moderate weather and generally modest prices.

Table 33 shows the Real-Time Price Program results for 2004. Resources that were curtailed during 2004 received payments totaling $1,919,141. The monthly average payment ranged from $100/MWh to $125/MWh.

[42] The Real-Time Price Response Program is activated for the next day when real-time LMPs are projected to equal or exceed $100/MWh, based on the results of the Day-Ahead Energy Market or subsequent Reserve Adequacy Analyses.

Table 33 - 2004 Real-Time Price-Response Program by Month

Month	Number of Days Activated	MWh Interrupted	Payment	Average Payment per MWh
January	16	4,841	$597,385	$123.40
February	5	1,031	$103,143	$100.04
March	0	0	$0	$0.00
April	1	58	$5,824	$100.41
May	2	122	$15,205	$124.63
June	6	564	$56,634	$100.41
July	0	0	$0	$0.00
August	2	142	$14,213	$100.09
September	2	265	$26,523	$100.09
October	0	0	$0	$0.00
November	7	2,379	$240,235	$100.98
December	18	8,237	$859,980	$104.40
Total	59	17,639	$1,919,142	$108.80

In 2004, the ISO did not activate the Real-Time Demand or Real-Time Profiled Response Programs in response to a system emergency. However, an audit of the programs was conducted on August 20, 2004. The audit ran from 11:00 a.m. to 1:30 p.m. for the resources that are required to respond within 30 minutes. The two-hour and profiled-response resources were tested concurrently, but their audit extended through 3:00 p.m. Demand-response resources were not warned ahead of time that an audit was being scheduled. From the resources' perspectives, all aspects of the audit event were identical to a real event.

Table 34 details the results of the test (in cumulative MWhs) for each program. Overall, a 46.4% response rate was achieved for a total of 763 MW of load curtailed. Approximately 33% of the megawatts enrolled in the reliability programs overall did not respond during the test event; the majority of the unresponsive megawatts were enrolled in the Profiled Response Program.

However, performance of resources in the 30-minute Real-Time Demand Response Program was substantially better than average, with a response rate of 83% on a systemwide basis. Within the Connecticut load zone, where most of these resources are located as a result of the Southwest Connecticut "Gap" Request for Proposals (described below), the response rate was greater than 100%. The higher response rates in Connecticut correspond to the higher capacity payments and correspondingly higher penalties for nonperformance applied to demand resources participating in the Southwest Connecticut "Gap" Request for Proposals. The generating resources in the 30-minute Real-Time Demand Response Program, which reduce load by starting emergency generation, provided 61% of the overall curtailed MWh during the audit. The resources in the

30-minute Real-Time Demand Response Program, which reduce load without using emergency generation, provided 33% of the overall curtailed MWh.

Table 34 - Performance Data for August 20, 2004, Real-Time Demand and Profiled Response Programs Test, Cumulative MWh

Program	Hour Ending	Enrolled MW	Interruption MW	Payment	Performance Factor
2-Hour Demand Response	12	12.26	1.55	$543.20	12.7%
	13	12.26	3.01	$1,053.85	24.6%
	14	12.26	3.02	$1,056.30	24.6%
	15	12.26	3.03	$1,060.50	24.7%
Sub-Total (MWh)		**49.02**	**10.61**	**$3,713.85**	**21.6%**
30-Minute Demand Response	12	102.56	63.12	$31,560.50	61.5%
with Emergency Generation	13	102.56	99.88	$49,941.00	97.4%
	14 *	51.28	49.71	$24,855.00	96.9%
Sub-Total (MWh)		**256.41**	**212.71**	**$106,356.50**	**83.0%**
30-Minute Demand Response	12	50.01	42.66	$21,329.50	85.3%
without Emergency Generation	13	50.01	49.68	$24,840.00	99.4%
	14 *	25.00	25.59	$12,795.00	102.3%
Sub-Total (MWh)		**125.01**	**117.93**	**$58,964.50**	**94.3%**
Profiled Response Program	12	83.24	1.40	$140.00	1.7%
	13	83.24	0.00	$0.00	0.0%
	14	83.24	0.18	$17.70	0.2%
	15	83.24	11.04	$1,103.60	13.3%
Sub-Total (MWh)		**332.94**	**12.61**	**$1,261.30**	**3.8%**
Grand Total (MWh)		**763.38**	**353.87**	**$170,296.15**	**46.4%**

* Represents equivalent capacity for half of Hour 14 (2:00 p.m.).

3.7.3 Demand-Response Improvements

No fundamental changes were made to any of the demand-response programs in 2004. However, several administrative changes were made. Many of these changes were in response to needs expressed by program participants as part of the 2003 independent evaluation of the demand-response programs:

- The baseline computation was changed so that demand-response assets are able to participate in the program more quickly. Previously, the ISO required the availability of 10 days of data for computation to set the initial baseline. Now, only five days of data must be available, thereby accelerating the process for making participants eligible to respond to events. This applies to all programs except the Profiled Response Program, which does not require a baseline.

- The ISO developed a Web Notification Page to enable program participants to obtain definitive information from the ISO's Web site regarding load-event start and restoration times.

- The deadline for submitting meter data was increased from 36 hours to 60 hours after the operating day. This provides enrolling participants a wider window within which to submit meter data, which enables more participants to be paid in the monthly settlement process, versus the 90-day resettlement.

- Policies regarding when to activate assets in the Real-Time Price Response Program using the super low-tech metering option were clarified. Participants using the super low-tech option read meters infrequently and have 90 days to submit data.

- New data validation procedures were implemented, and policies regarding the submission of meter data with missing or zero values were clarified.

3.7.4 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 the period 2004 to 2008. The stated goal was to improve electric system reliability in Southwest Connecticut through the summer of 2007, at which time a 345 kV transmission-loop expansion is expected to come into service.

Four types of resources were eligible to respond to the RFP:

- quick-start generation, both new and incremental capacity from existing generation

- demand-reduction resources

- emergency-generation resources

- conservation and load-management projects

Demand-reduction and emergency-generation resources are required to participate in the 30-minute Real-Time Demand Response Program. The RFP did not state a preference for any specific resource type. The evaluation criteria in the RFP stated that the ISO's objective was to minimize the expected cost of achieving its reliability goals. The RFP also listed other evaluation factors, such as location, permitting, and proposed in-service date.

In response to this RFP, the ISO received 34 proposals from 25 companies. The proposals totaled 1,081 MW encompassing demand response, on-peak conservation and load management, and peaking-generation resources. The ISO contracted with seven companies. The companies' projects involve multiple resources at various locations. Some selected resources were in service by June 1, 2004, while others were scheduled to be available later, with approximately 260 MW to be available by the summer of 2007.

Table 35 summarizes the types of resources selected under the procurement and their in-service dates.

Table 35 - Resources Selected in SWCT RFP for 2004–2007

Resource Type	Customer Type	2004	2005	2006	2007
C&LM	Commercial	0.7	4.3	5.0	5.3
C&LM Total		**0.7**	**4.3**	**5.0**	**5.3**
Emergency Generation	Commercial	13.9	43.7	49.3	51.8
	Education	2.0	2.8	2.8	2.8
	Healthcare	0.0	9.7	9.7	9.7
	Municipal	10.2	33.5	33.5	33.5
	Other	69.3	69.3	69.3	69.3
Emergency Generation Total		**95.4**	**158.9**	**164.5**	**167.0**
Load Reduction	Commercial	16.6	26.1	31.1	33.6
	Healthcare	0.0	0.3	0.3	0.3
	Municipal	3.1	3.4	3.4	3.4
	Residential	0.9	19.1	39.7	40.2
	Small Commercial	2.5	10.0	10.0	10.0
Load-Reduction Total		**23.1**	**58.9**	**94.5**	**87.4**
Grand Total		**119.2**	**222.1**	**254.0**	**259.8**

The ISO selected sufficient MW to meet identified reliability needs based on the 2004 NEPOOL load forecast. The resources selected provided 119 MW in 2004, increasing to 260 MW by 2007. The expected total cost for the four-year contract period is $128 million.

In combination, the selected resources represent the lowest cost, most viable, and best-located resources. They will provide Southwest Connecticut with additional emergency resources to reduce the risk of load shedding under high-peak loads and during other periods of system stress.

3.7.5 Demand-Response Conclusions

In 2004, the Real-Time Price Response Program had the largest number of participants and was activated more often than any other demand-response program. The number of assets enrolled in the Real-Time Price Response Program increased from 332 in 2003 to 367 in 2004, while the number of megawatts enrolled declined from 130 MW to 108 MW during the same period. However, total megawatts of curtailment during events increased significantly from 4,223 in 2003 to 17,639 in 2004.[43] The ISO is working with the region's stakeholders to develop a Demand Response Reserves Pilot Project, which would enable such resources to participate in the Ancillary Service Markets. The use of demand response resources as operational reserves could improve market efficiency, increase system reliability, and give demand-response providers market-based incentives to bring additional demand resources into the market. Demand response is an important component of the wholesale electricity market without which the wholesale electricity markets would continue to be incomplete and produce less-efficient outcomes. However, current participation is modest relative to total demand and appears to have leveled off over the past two years. Increasing participation is an important objective and essential to the long-run success of the New England markets, which may require increased incentives and better coordination between the wholesale electricity markets and retail-rate design at the state level.

[43] Additional information about demand response is available on the ISO Web site at <http://www.iso-ne.com/FERC/filings/Other_ISO/ER02-2330_12-30-04.pdf>.

4 Oversight and Analysis

This section covers market monitoring and generator performance and includes an analysis of competitive market conditions.

4.1 Market Monitoring and Mitigation

4.1.1 Overview of Market Monitoring and Mitigation

Market Rule 1, Appendix A, *Market Monitoring, Reporting, and Market Power Mitigation*, provides for the monitoring and, in specifically defined circumstances, the mitigation of behavior that interferes with the competitiveness and efficiency of the Energy and Regulation Markets and Operating Reserve Credit payments. As specified in the rule, the ISO monitors offers to gauge the market impact of specific bidding behavior. Whenever one or more of a participant's offers or declared generating unit characteristics: 1) exceed specified offer thresholds, 2) exceed market-impact thresholds, or 3) are not explained by the participant as consistent with the behavior of competitive offers, the ISO substitutes a default offer in place of 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 pool-wide to pivotal suppliers.

4.1.2 Market Monitoring and Mitigation Results

In 2004, the ISO rarely intervened in the markets. During the year, congestion in the Day-Ahead Energy Market and the Real-Time Energy Market was generally limited. Congestion mitigation was triggered twice, both times in December. In addition to taking these specific actions, the Internal Market Monitoring Unit has had nearly daily discussions with individual participants concerning specific market behavior. The pool-wide thresholds did not trigger mitigation of energy suppliers that were pivotal in 2004.

Lessons learned from the January 2004 Cold Snap led the INTMMU to implement a number of improvements in the reference-price calculations for natural gas units. For example, the reference-price fuel adjustments for gas units now use the actual price point on the relevant pipeline for each generator instead of using an average of the pipeline price points.

The INTMMU also has incorporated lessons learned from its review of the January 2004 Cold Snap into plans for the future monitoring of cold-snap events, which will include the evaluation of participant explanations of behavior. The INTMMU has sought to improve communication and coordination with regulators and other monitoring entities to ensure adequate monitoring and information exchange during critical periods. These efforts include the development of a protocol for exchange and protection of confidential information. Finally, in response to recommendations from the January 2004 Cold Snap review, the INTMMU has established access to the natural gas pipeline electronic bulletin boards to better monitor fuel availability.

4.1.3 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. The INTMMU uses all available data to determine if 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 has been physically withheld, further contact is made to obtain appropriate additional information. Once the review is completed, if the ISO determines that physical withholding has taken place, sanctions may be imposed as outlined in Appendix B of Market Rule 1.

During 2004, the INTMMU never determined that a plant inspection was warranted as a result of monitoring for potential physical withholding of a resource. In a number of cases, however, the INTMMU requested detailed plant information and operator logs. The INTMMU visited a number of plants during the year as part of its routine information-gathering process.

4.1.4 Market Monitoring Special Reports

As part of its responsibility to ensure that the markets are operating efficiently and performing in accordance with the market rules, the INTMMU conducts special studies and analyses as needed. In 2004, these studies included an extensive report on the January 2004 Cold Snap and various presentations to the NEPOOL Markets Committee. (See Section 2.1.7.1.)

4.2 Analysis of Competitive Market Conditions

This section presents analyses of competitive market conditions during 2004. It includes analyses of market share, pricing efficiency, and market entry.

4.2.1 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.

However, the HHI is not a sufficient indicator of market concentration in wholesale electricity markets. For example, the calculation does not capture any measure of the overall supply/demand balance. The calculation also does not reflect contractual entitlements to generator output, and hence may tend to overstate concentration. Also, 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.

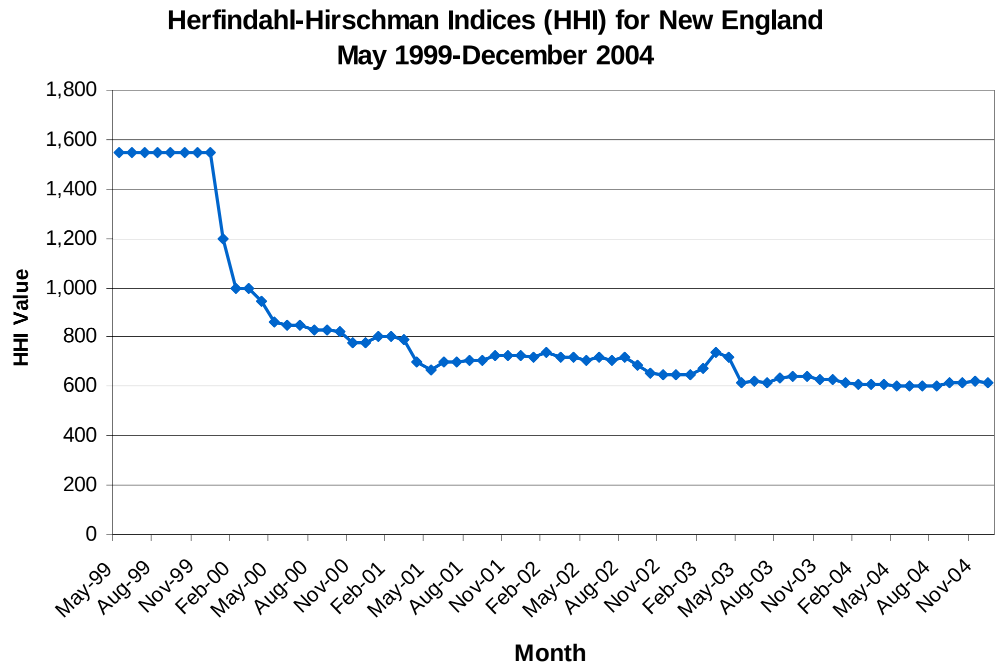
The above limitations notwithstanding, HHI is still a useful indicator to monitor. Market concentration measured by the HHI is conventionally divided into three regions that can be broadly characterized as: *not concentrated* (HHI below 1,000), *moderately concentrated* (HHI between 1,000 and 1,800), and *highly concentrated* (HHI above 1,800). Although the resulting classifications provide a framework for market concentration analysis, they are imprecise. Although a low-concentration index does not guarantee that a market is competitive, higher values indicate greater potential for participants to exercise market power.

Figure 47 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 indicates the following results:

- A steady decline from the opening of wholesale electricity markets in New England
- A slight up-tick in the winter of 2002/2003 (due to the assignment to a participant of certain generators that were previously unclassified as to generator ownership)
- A slight upward movement during the third quarter of 2003 due to the commencement of the commercial operation of a large generating facility owned by an existing participant
- Little variation during 2004

The HHI for 2004 of about 600 is low by traditional standards.

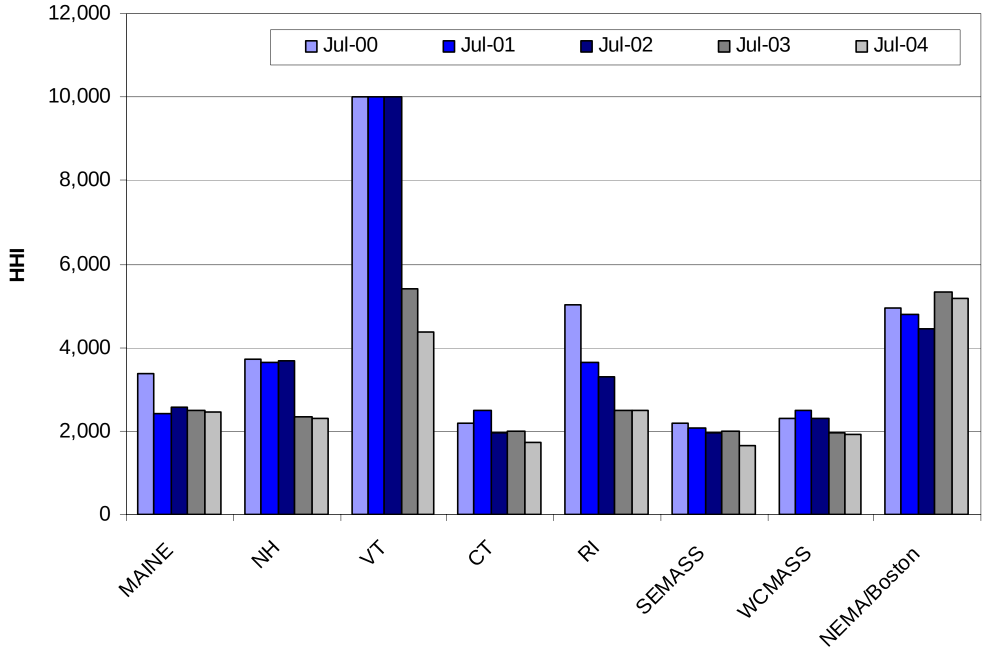
Figure 47



As part of its market assessment function, the ISO, also develops an HHI for each load zone. Figure 48 shows the HHI for each load zone. The Vermont and NEMA/Boston load zones have the highest HHIs, indicating the highest potential for market-power concerns. The Vermont calculation should be viewed with caution, as this state has a relatively small capacity to generate electricity, significant import capability, and vertically integrated utilities. The NEMA/Boston load zone, which frequently needs out-of-merit operation for transmission support, has an HHI in the highly concentrated range. The HHI in the Connecticut load zone declined from 2003 to 2004, as new capacity came into service.

Figure 48

HHI By Load Zone



4.2.2 Forward Contracting

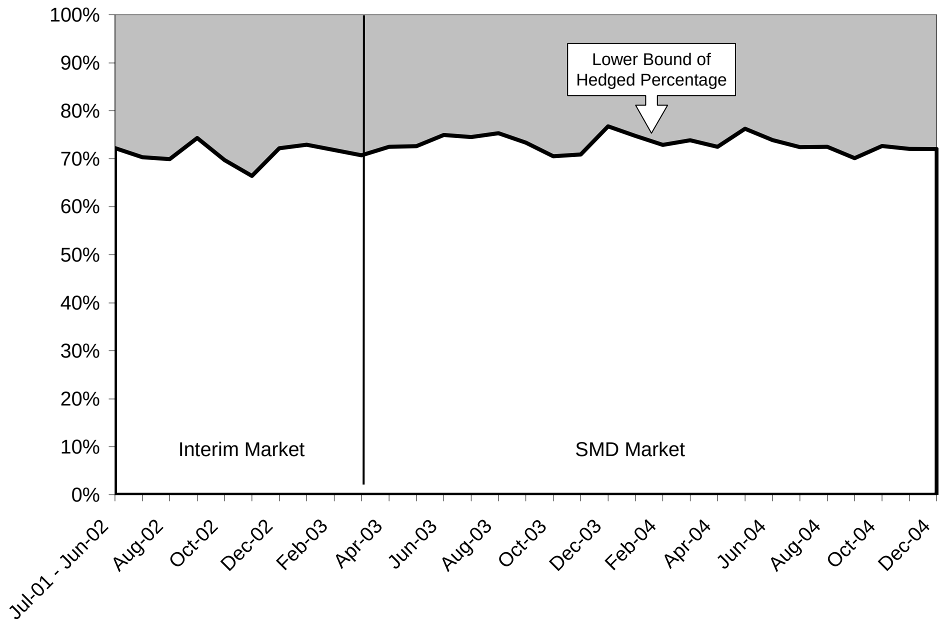
Estimates of the level of forward contracting and self-supply generation in New England are important in evaluating how well New England's markets are working. Forward contracting not only insulates load from short-term price volatility but also serves as an incentive for generators to offer generation at marginal cost.[44]

Calculations for January through December 2004 show that, on average, at least about 73% of total real-time load obligation was either forward contracted or covered by a physical hedge. For each month of 2004, as shown in Figure 49, the degree of forward contracting was at least 70% of real-time load obligation. The results for 2003 were similar. 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. They also understate the physically hedged load to the extent that nondispatched generators are available. Hence, while these numbers are useful, they are only indicative of the forward positions held by participants.

[44] Newbery, David, 1995, "Power Markets and Market Power," *The Energy Journal*, Vol. 16, No. 3.

Figure 49

Lower Bound of Real-Time Load as Hedged through ISO Settlement System

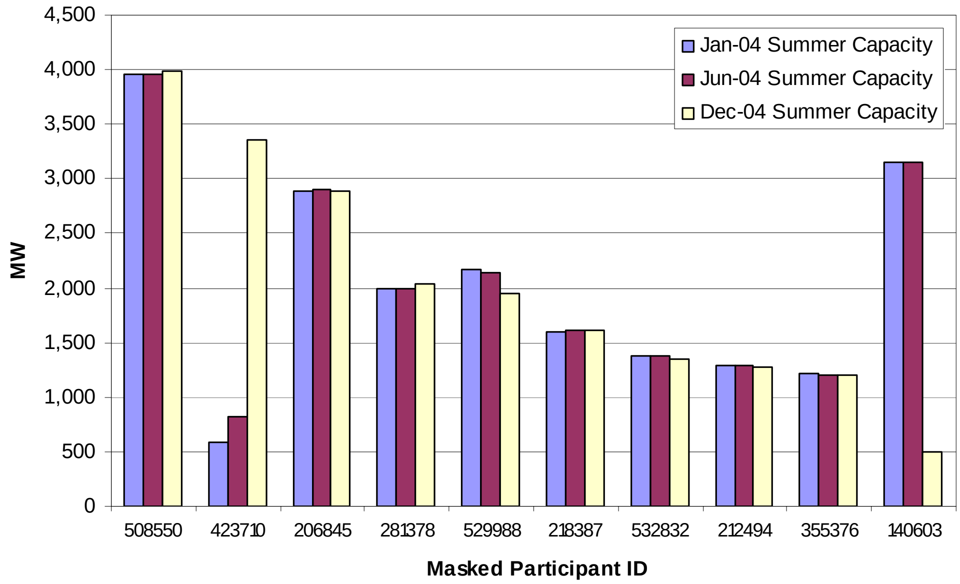


4.2.3 Market Share by Participant Bidder

Figure 50 shows generation capability for the 10 lead participants with the largest portfolios during 2004. Although one participant's portfolio grew significantly over the year and another's declined dramatically, the aggregate size of the 10 largest portfolios was roughly the same at the end of the year as it was at the beginning. While the ownership of the largest portfolios has changed from year to year, the size of the largest portfolios has been similar.

Figure 50

Generation Capability by Lead Participant



4.2.4 Residual Supply Index

The Residual Supply Index (RSI) measures the hourly percentage of load (MWh) that can be met without the largest supplier. It provides an indication of individual bidders' potential to influence the market-clearing price. The index is computed as follows:[45]

$$\text{RSI} = \frac{(\text{total supply - largest seller's supply})}{(\text{total demand})}$$

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 price 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 market competitiveness than is 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 mark-up, which is the market metric

[45] Total supply is defined as the total of generators' economic maximums. Demand is defined as actual load.

developed in the competitive benchmark analysis (described in Section 5.2.5).[46] That is, as RSIs fall, mark-ups tend to rise.

On July 9, 2003, in *Docket No. ER03-849-000*, FERC accepted the ISO's request to implement a pivotal-supplier trigger for evaluating a pivotal supplier's energy supply offers for possible mitigation.[47] 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.[48] The calculation of the RSI, described above, is consistent with the requirements outlined in the docket.

Table 36 shows the number of hours in each month in 2004 during which the RSI was below 100% and below 110%. RSIs are generally lowest during high-demand periods. This analysis shows that pivotal suppliers existed during a limited number of hours in 2004. Only 43 hours had values below 100%, with most of those occurring during the high-demand days of the January 2004 Cold Snap. The RSI analysis conforms with other analyses that show relatively good market performance. This RSI analysis is somewhat conservative and may overstate the number of hours in each month during which one or more suppliers were pivotal. It 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.[49] The ISO will continue to monitor and assess the existence and influence of pivotal suppliers on the market.

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[46] Sheffrin, Anjali, 2001, *Preliminary Study of Reserve Margin Requirements Necessary to Promote Workable Competition*, California ISO, November 19, 2001, Revision. <http://www.caiso.com/docs/2001/11/20/200111201556082796.pdf>.

[47] 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, no matter how high the offer price, to maintain reliability. 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/FERC/orders/General_Mitigation_Order_070903.pdf>.

[48] The supply margin for an hour (i.e., the available generation beyond the amount needed to meet demand for that hour) is the total of energy supply offers for that hour, up to and including economic maximum, less the total system load (as adjusted for net interchange with other control areas and including operating reserve).

[49] Green, Richard, 1999, "The Electricity Contract Market in England and Wales," *Journal of Industrial Economics*, Vol XLVII, No 1, pp 107-124.

Table 36 - Residual Supply Index, 2004

Month	Number of Hours RSI < 110%	Number of Hours RSI < 100%	Average Monthly RSI	Maximum RSI	Minimum RSI
January	99	37	128	184	85
February	0	0	143	180	114
March	0	0	147	184	116
April	0	0	136	171	112
May	7	0	140	189	107
June	32	3	144	197	98
July	37	0	140	188	101
August	64	3	138	196	98
September	0	0	150	204	113
October	0	0	142	347	113
November	0	0	146	194	113
December	8	0	143	182	103
Total	247	43	141	347	85

4.2.5 Competitive Benchmark Analysis

In 2002, the INTMMU developed a tool (the ISO model) for conducting competitive benchmark analyses. The ISO model is designed for evaluating the competitive performance of New England's wholesale electricity markets using a method similar to one developed by Bushnell and Saravia (2002).[50] This tool is used 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 each market participant acted as a price-taker, and the market operated with perfect efficiency. 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 that is not needed to serve demand in a given hour. The model used in 2004 was modified slightly from previous years to more accurately reflect system-dispatch and generator costs.

Table 37 compares the benchmark price to two other measures of the wholesale market price: 1) the ISO's real-time LMP at the Hub, and 2) the bid intercept price, or the price at which market demand intersects the aggregate supply curve derived from all generating units' supply offers but

[50] Bushnell, James, and Celeste Saravia, 2002, *An Empirical Analysis of the Competitiveness of the New England Electricity Market*, University of California Energy Institute, January. The study report can be found at <http://www.iso-ne.com/special_studies/Other_Special_Studies/>.

ignoring unit-operating constraints (i.e., the bid intercept). Comparing the two market-based prices with the benchmark over time can help assess the competitiveness of the market.

The metric used to compare these market price measures is the Quantity-Weighted Lerner Index (QWLI). The conventional Lerner index, defined as the price-cost margin in percentage terms, is widely used to assess the competitiveness of market outcomes.[51] The QWLI weights each hour's Lerner index by total systemwide load. The QWLI is more appropriate than a simple arithmetic average of the hourly Lerner Index because load varies hourly.

Table 37 shows that the QWLI for 2004 fell from 2003 for both the real-time Hub price and the aggregate bid-intercept price. The 2004 results are consistent with outcomes expected in a competitive market, with small to no mark-up by either measure. While the QWLI is a useful and intuitive measure of market competitiveness, it is subject to an uncertain amount of modeling error due to the necessary simplification of assumptions and the need to rely on estimates of generator-input cost and efficiency. Thus, it is more appropriate to examine trends and large movements in the QWLI than to place emphasis on modest year-to-year changes. The calculated QWLIs have trended downward overtime, which points to the ongoing competitiveness of the New England markets.

Table 37 - ISO Model Market Price Measures

Price Measure	2004 Price ($/MWh)	Quantity-Weighted Lerner Index	
		2003	2004
Competitive Benchmark Price	$54.49		
Real-Time Hub Price	$52.13	9%	3%
Aggregate Bid-Intercept Price	$48.95	-4%	-6%

Table 38 - QWLI for On-Peak and Off-Peak Hours

Hours	Real-Time Hub Price	Aggregate Bid-Intercept Price
On-peak	9%	-3%
Off-peak	-19%	-16%

Table 38 presents the QWLI for on-peak and off-peak hours. In the off-peak hours, energy prices are well below the estimated benchmark level, indicative of a large amount of off-peak self-scheduling, as generators seek to avoid shutting down overnight. On-peak QWLIs are still well within the range of outcomes above zero that can be considered competitive. There is no well-established threshold of competitiveness for QWLIs as there is for HHIs.

[51] Lerner Index = (P- MC)/P, where: P = price and MC = cost of the marginal resource.

The results of the model suggest that the market continued to behave competitively through 2004. The 2004 QWLIs are somewhat lower than those for 2003, indicating that the New England markets continue to be workably competitive.

4.2.6 Implied Heat Rates

A generator's heat rate is the rate at which it converts fuel (Btu) to electricity (KWh) and measures the thermal efficiency of the conversion process. The market prices for electricity and an input 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 needed efficiency for burning a particular fuel at prevailing market prices. Comparing a generator's heat rate with the heat rates of existing resources can provide indicators of 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 that of electricity, even generators with a high thermal efficiency may be unable to break even or earn a profit while producing electricity. A falling implied heat rate will reflect this outcome.

Table 39 shows estimates of the actual 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 39 - Actual Heat Rate by Generator Fuel Type, Btu/KWh

Generator Fuel Type	Estimated Average Heat Rate	Estimated Most Efficient Heat Rate
Coal	9,900	9,000
Jet fuel	11,500	9,000
Kerosene	14,000	11,000
Natural Gas	8,500	6,700
No2 Fuel Oil	14,700	11,000
Diesel	12,700	10,600
No 6 Fuel Oil	10,700	9,000

The implied forward heat rate is the ratio of the day-ahead Hub LMP and the next-day price for the applicable fuel in each hour. This rate is an approximation of the thermal efficiency that would be required to break even on the conversion of fuel to power. For example, if the day-ahead LMP were \$60/MWh and the day-ahead fuel price were \$6/MMBtu, the implied forward heat rate would be 10 MMBtu/MWh, or 10,000 Btu/KWh.[52] Generators with actual heat rates

[52] Note that heat rates are traditionally reported in Btu/KWh, which would be a multiple of 1000 times higher than the numbers calculated here.

lower than the implied heat rate at least break even on their conversion of fuel to electricity, ignoring variable operating and maintenance and emissions costs.

Figure 51 reports the monthly average implied forward heat rates for price points on three major interstate natural gas pipelines in New England.[53] It suggests seasonality in the implied forward heat rates, which is a function of the natural seasonality in natural gas and power prices. During January 2004, the implied heat rate was especially low, driven in part by high gas prices during this month's Cold Snap. The data suggest that gas-fired generators with a thermal heat rate less than 8.5 MMBtu/MWh were typically inframarginal (i.e., their offers were less expensive than the price-setting supply offers). The monthly averages obscure the daily fluctuations in implied heat rates that would make specific units in or out of economic-merit order on a given day.

Figure 51

Monthly Average Implied Forward Heat Rates in New England, Natural Gas and Electricity

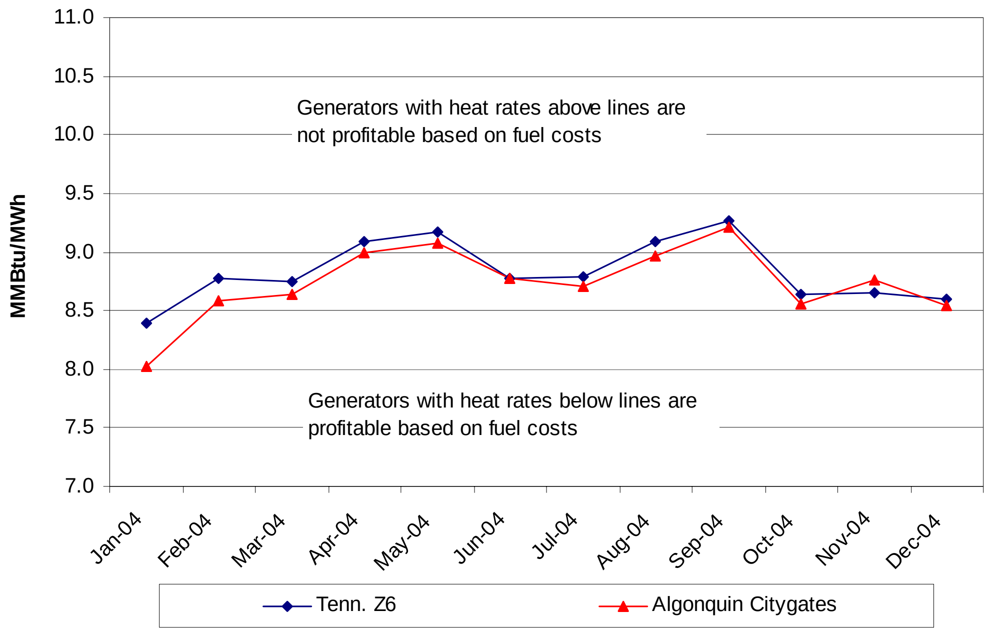


Figure 52 reports the implied forward heat rates for selected petroleum-based fuels. The spike in January 2004 reflects the events related to the January 2004 Cold Snap when gas and electricity prices spiked, causing most oil-fired generators to be inframarginal. Only during January would typical oil or jet fuel units have been inframarginal on average. This is consistent with operations observed by oil-fired units; most run only when electricity prices are relatively high. The downward trend in the implied forward heat rates in Figure 52 is mainly determined by oil-price trends. Figure 53 shows that the average coal-fired generator is typically inframarginal.

[53] Daily implied forward heat rates were calculated as the ratio of the daily average LMP and the fuel price. For each month, an average of all days in the month was calculated.

Figure 52

Monthly Average Implied Forward Heat Rates in New England, Petroleum-based Fuels and Electricity

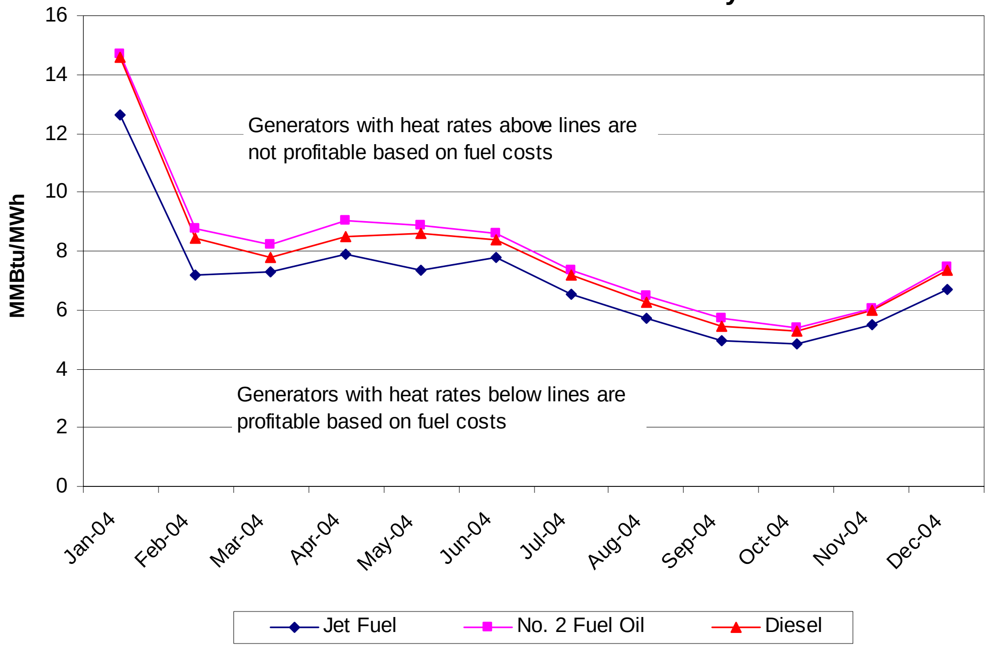
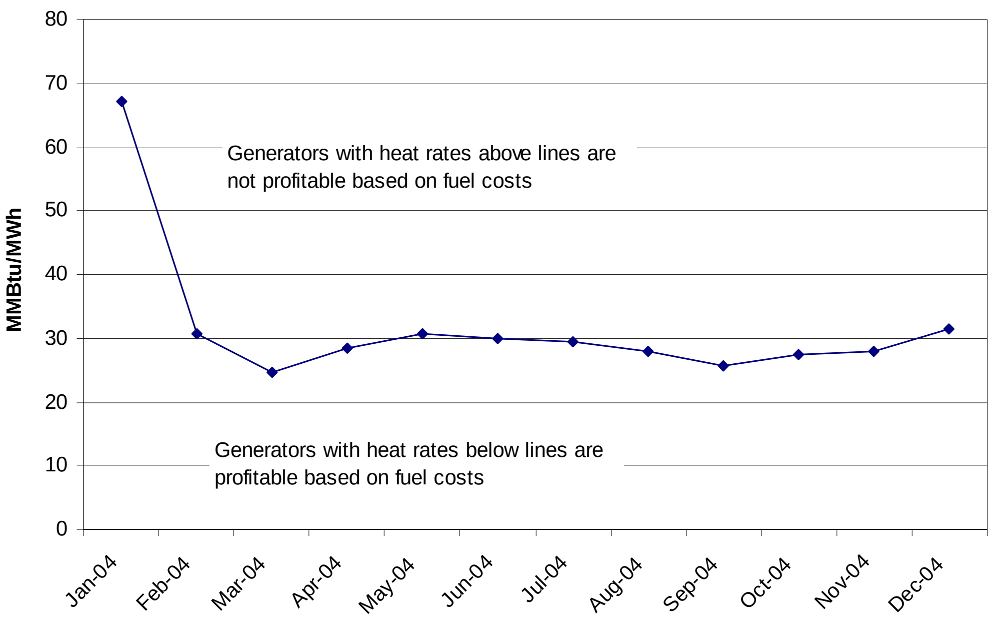


Figure 53

Monthly Average Implied Forward Heat Rates in New England, Coal and Electricity



4.2.7 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 and capacity markets and the Ancillary Services 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. On the other hand, 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 estimates of capacity and ancillary services revenue.

Figure 54 shows the net revenue from electric energy for hypothetical generators offering one megawatt into the energy market each hour of the year at various price points. Net revenue was calculated using the energy-clearing price, for hours in the Interim Markets period, and the real-time Hub LMP, for hours in the SMD period. It was assumed that the generator ran in every hour in which the electric energy price was equal to or greater than its offer. Net revenue was calculated by subtracting the offer from the electric energy price for each hour, and this value was summed over the year.[54] This calculation was performed for each offer point shown in the graph. Note that it is appropriate to use this methodology to calculate net revenues only for units or contracts with stable costs over time, such as nuclear, hydro, and coal generators.

Figure 54 shows that a unit with variable costs of $40/MWh that ran whenever energy prices exceeded that level would have received approximately $121,000/MW-Year in net revenue from New England's electric energy market in 2004. A New England generator with variable costs of $30/MWh (approximating a coal unit in New England) would have earned approximately $199,000/MW-Year in net-energy revenues in 2004. The net revenue for low price levels has been highest in the last two years, reflecting increased electricity prices driven primarily by high fuel costs. At high price levels, net revenues have been low for the past three years, due to relatively few high-priced hours compared to previous years.

[54] This assumes that the generator is a price taker, offering at its marginal cost.

Figure 54

**Net Revenue from Energy per MW at Various Offer Points
Calendar Years 2000, 2001, 2002, 2003, and 2004**

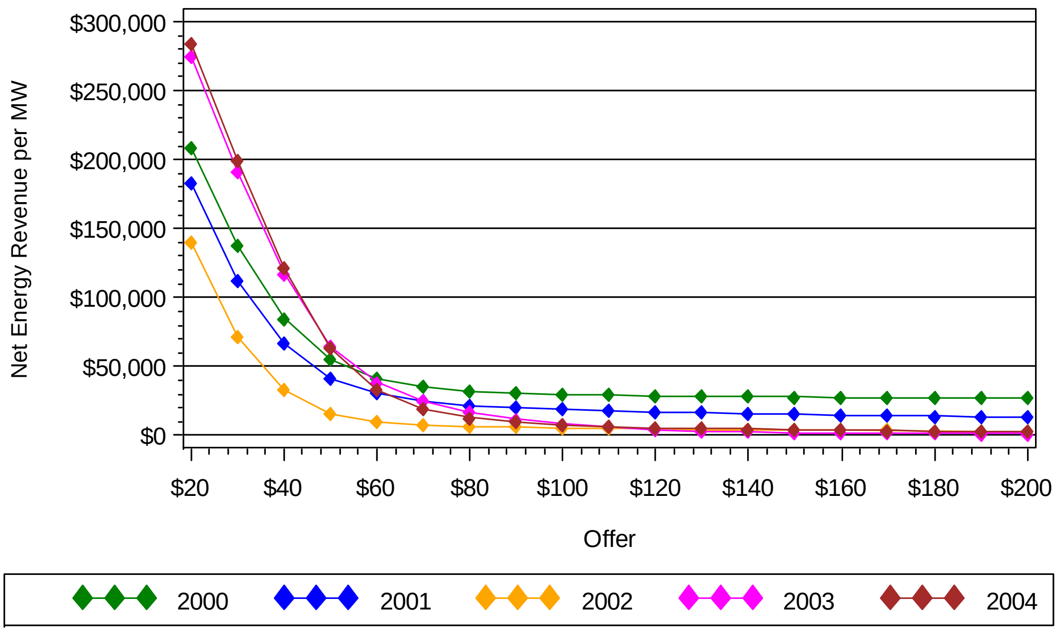


Table 40 presents an estimate of net revenues for two hypothetical gas-fired generators in New England during 2004. Gas-fired generators are modeled because they represent the typical new unit brought online in New England. Daily marginal costs are calculated for each hour using spot-fuel prices, the assumed heat rates, and other production costs, for both a representative 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. It was assumed that the generator ran each hour that the price was above its marginal cost. These calculations are a more accurate representation of net revenues for gas plants than can be determined from Figure 54, as gas prices vary substantially throughout the year. However, by ignoring start-up costs and generator inflexibility, particularly for combined-cycle units, the calculations overstate net revenues.

Under these assumptions, the combined-cycle plant would have earned about $63,000/MW in the energy market during 2004, while the combustion-turbine plant would have earned approximately $8,000/MW. If the combustion-turbine plant participated in the Forward Reserve Market, it could have earned another $44,500/MW. Capacity-market revenues were negligible for the year. For purposes of this analysis, unit outages were represented by reducing energy revenues by 5%.

The anticipated annual nonvariable costs of a new combined-cycle plant in New England, which include fixed O&M, taxes, depreciation, debt repayment, and a competitive return on investment, are in the range of $100,000/MW to $125,000/MW. The corresponding values for a combustion-turbine plant are in the range of $60,000/MW to $80,000/MW.[55] These calculations suggest that neither of the hypothetical plants burning natural gas at the delivered spot price in 2004 would have recovered its annual fixed costs plus a return on investment. Combined-cycle revenues were about one-half of what is needed, while combustion-turbine revenues were 70% to 80% of requirements. These results are similar to those of the last few years. In fact, the net revenue curve tends to overestimate the contribution toward generators' fixed costs and investment return since it ignores operational constraints that may prevent a plant from running in every profitable hour.

While this analysis is performed using LMPs at the Hub, differences in energy-market prices among sub-areas were modest and likely would have only a moderate effect on these results. In addition, it is likely that new entry costs are higher in some sub-areas such as Southwest Connecticut and Boston. Capacity and reserve revenues are the same throughout the system. The results correspond to the requests for Reliability Agreements (see Section 3.4) and the lack of new entry in constrained sub-areas. That is, a lack of location-specific capacity signals fails to indicate the need for additional capacity or transmission infrastructure in constrained areas. The ISO is working to gain approval and to implement locational capacity and reserve markets that should reduce the need for Reliability Agreements.

Long-run equilibrium analysis is not applicable to a single year in isolation since market outcomes vary over time. Nevertheless, it appears that at 2004 electric energy prices and fuel costs, the hypothetical generators' net revenues were lower than the amount needed to cover a new entrant's fixed costs and competitive rate of return on investment. This observation is indicative of relatively robust reserve margins, the lack of announcements of new projects, few units in the early stages of construction, and the cancellation of some new generation projects.

[55] These estimates are intended to be the relevant annual returns required for an entity contemplating an investment in new generation.

Table 40 - Yearly Total Net Revenue per MW for Hypothetical Generators

Generator	Marginal Cost Formula	Heat Rate (Btu/KWh)	($/MW-Year) 2004 Net Energy Revenue	Approximate Revenue From Capacity Sales*	Approximate Ancillary Services Revenue#	Approximate Total Revenue
Representative Combined-Cycle / Gas-fired	(Daily fuel cost x heat rate) + (VOM‡ of $1/MWh)	7,000	$63,000	$360	$1,350	$64,710
Representative Combustion-Turbine / Gas-fired	(Daily fuel cost x heat rate) + (VOM of $3/MWh)	10,500	$8,000	$360	$44,500	$52,860

*Capacity sales revenue is based on ISO ICAP supply auction clearing prices.

#Ancillary services revenue is based on the Regulation Market for combined-cycle, and the Regulation and Forward Reserves Markets for combustion-turbine. Forward Reserve revenues equal auction revenues minus average penalties.

‡Variable operations and maintenance costs.

4.2.8 Summary of Analyses

Overall, the concentration of generation ownership in New England's wholesale markets continued at low levels during 2004. Certain areas of the system, such as NEMA/Boston and Vermont, defined by transmission interfaces, continue to have high concentrations of unit ownership. Overall, generation portfolio sizes decreased during the year as asset ownership changed. While this is generally favorable, there remain areas of the system where the lack of diversity in unit ownership necessitates continued oversight and targeted mitigation rules.

Large increases in available generating capacity over the last five years have resulted in few hours during which suppliers were pivotal. However, unexpectedly high load levels or unit outages still can create pivotal suppliers, especially during high-maintenance periods in the spring and fall. Over time, growing electricity demand plus reserves reduce the current surplus, the instances of pivotal suppliers may increase; continued vigilance is needed.

The current surplus, coupled with the general lack of high-peak loads, helped to keep prices at competitive levels during 2004, as determined by the benchmark analysis. The net-revenue analysis indicates that the hypothetical profit margin for spot-market-only generators appeared to be below what would be predicted to be the requirements for new entry.

The ISO is working to enhance locational price signals. FERC's settlement process for locational capacity markets, in which the ISO is participating, will result in a market design that provides better investment signals in all areas. A locational reserve requirement reflected in the market rules also would better value new demand and supply options in constrained areas. That, in turn, would enhance the efficiency of the market, as price discovery would lead to more efficient investment decisions.

4.3 Generating Unit Availability

Table 41 below presents the annual Weighted Equivalent Availability Factors (WEAFs) of the New England generating units for 1995 to 2004.[56] As shown, availability decreased from 1995 to 1997 and then began increasing again in 1999 to just above 1995 levels. The decrease in 1996 through 1998 can be attributed to the extended outages of several nuclear units during this period. After the beginning of the Interim Markets in May 1999, the New England system WEAFs increased to a high of 89% in 2002 and then 88% in 2003 and 2004.

Table 41 - New England Annual WEAF[57]

New England System Weighted Equivalent Availability Factors (%)										
Year	1995	1996	1997	1998	1999*	2000	2001	2002	2003	2004
System Average	79	78	75	78	81	81	87	89	88	88

* The data for 1999 is for May–December only.

Figure 55 shows total generator outages in megawatts for the peak-load day of each month in 2004 and the amount of capacity on outages as a percentage of total available capacity (as measured by the summer claimed capability). The high number of outages in spring and fall is due largely to annual maintenance performed during the low-load shoulder seasons, which the ISO coordinates. Figure 55 illustrates that both the spring and fall months continue to have large numbers of outages, while the summer period has the fewest. January 2004 saw extremely cold temperatures throughout the New England region. During this period, a large amount of capacity was out of service in New England—over 8,000 MW on some days. Since this experience, the

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[56] 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, proportional to the megawatts that are unavailable.

[57] The statistics for the year 1995 through 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/hour information and outage information as defined in the billing rules. The data were used primarily by the NEPOOL Settlements Department for payment to the generators. Based on statistical analysis approved by the NEPOOL Power Supply Planning Committee, generators were allotted a certain amount of "maintenance-outage" weeks per year to perform scheduled maintenance. Units that had outages over this amount, or were out of service any other time, were considered to have forced outages. Statistics for May 1999 through 2004 were based upon competitive bid-based dispatch and calculated from a Short-Term Outage Database. This database is populated by the ISO Forecast and System Planning Departments, based on information received from generators and records of scheduled and unplanned outages as they occurred in real time.

ISO has initiated cold-weather operating procedures to further ensure the reliability of the New England power system (see Section 2.1.7.1 and Section 5.1).[58]

Figure 55

Generator Outages During Monthly Peak-Load Days
January - December 2004

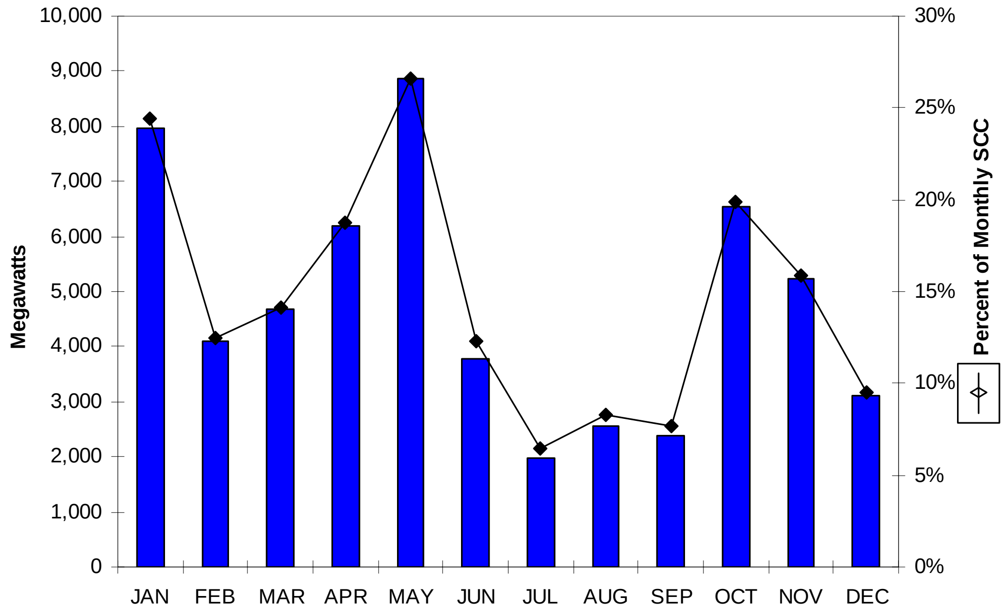


Figure 56 illustrates how the availability of the New England generating units tracks the monthly demand, as measured by the monthly peak demand. Again, the average availability for the New England generating units is lowest during the months that have the lowest peak demand (April, May, October, and November). When New England experiences the highest peak demand (July and August), the average availability of New England generators is the greatest.

[58] Market Rule 1, Appendix H, *Cold Weather Event Operations*, can be found on the ISO's Web site at < http://www.iso-ne.com/smd/market_rule_1_and_ISO_new_england_manuals/Market_Rule_1_And_Appendices/ >.

Figure 56

Monthly Peak Demand and Monthly Average Availability (WEAF)

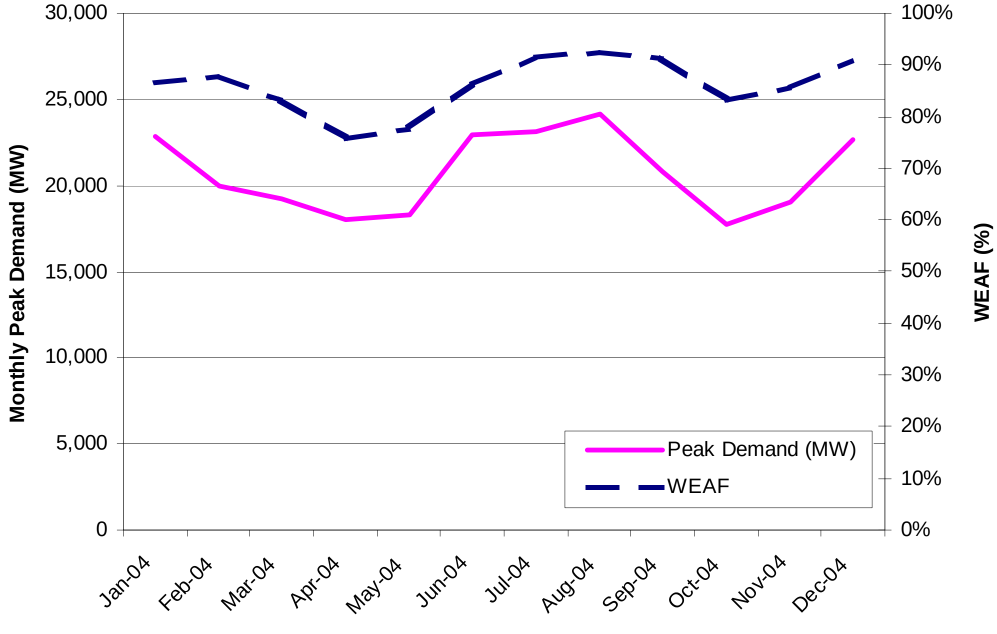


Figure 57 shows the average generation capacity on outage during each weekday peak over the past nine years, along with outages as a percent of installed capacity. The total amount of capacity on outages remained fairly constant over the past five years, even though a large amount of generation has been added to the system. The small increase in 2003 from the previous three years is mostly attributable to unplanned outages, and this increase continued into 2004. The average percentage of total system capacity unavailable each weekday fell from 19% in 2000 to 16% in 2004.

Figure 57

Average Megawatts of Outage Each Weekday

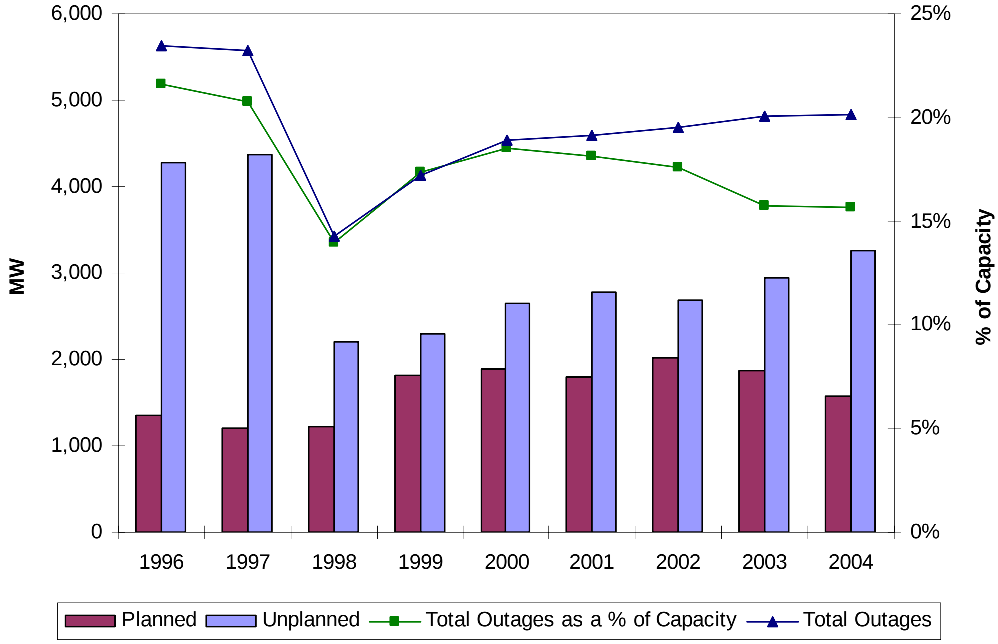
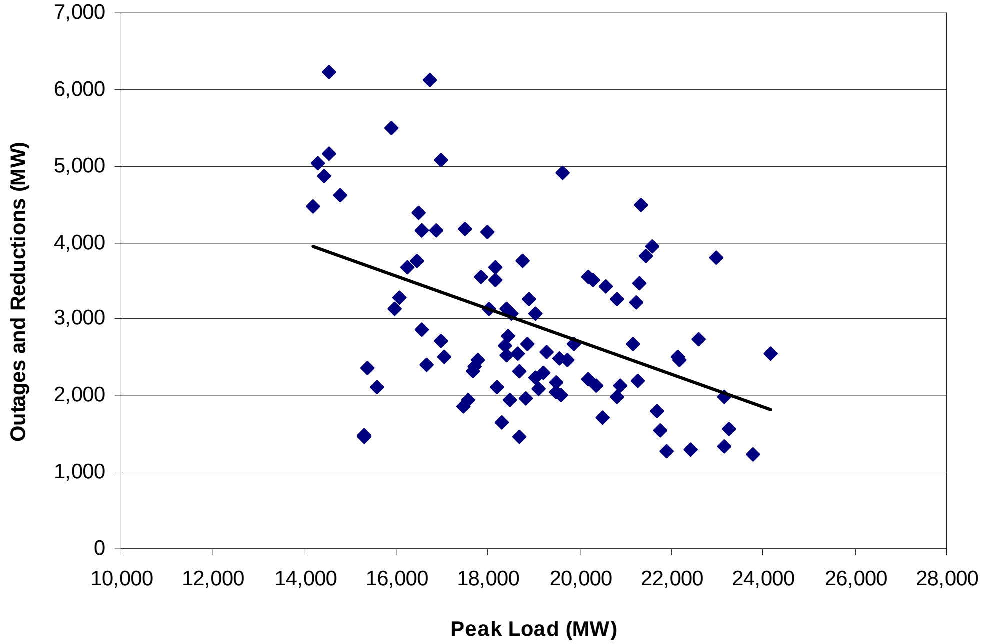


Figure 58 plots total generating-unit capability reductions and outages at the time of the peak hour against the actual peak demand each day during the summer peak-demand period of June through August 2004.[59] In general, there are few planned outages during the summer months, so that the data represent primarily forced outages. The figure includes a simple regression line showing a least-squares fit to the data.

[59] During a capability reduction, generators operate below their usual economic maximums due to mechanical problems or to perform maintenance.

Figure 58

Outages and Reductions vs. Daily Peak Load
June - August 2004



The scatter plot illustrates again that as demand levels increase, reductions and outages tend to decrease. This pattern suggests that the markets are providing incentives to make units available when they are most needed in the summer months, and that the ISO is scheduling short-term outages appropriately. However, during the January 2004 Cold Snap, there were an unusually high number of outages despite high demand. This suggests that while there are generally incentives to make units available when needed, these incentives are not always adequate.

5 ISO Market Operations

This section reports on enhancements to the markets and ISO operations, audit activity during 2004, the Quality Management System, and administrative price revisions.

5.1 Market and Operations Enhancements

5.1.1 Key Improvements to the Electricity Markets

The ISO and stakeholders have worked throughout 2004 to improve the efficiency, fairness, and transparency of the New England electricity markets and processes. Key improvements are detailed below.

- **Weekly Billing—**The ISO's settlement billing schedule changed from monthly to weekly on July 1, 2004. The switch went smoothly, and the first weekly settlement bill was issued July 15. This change reduced participants' financial assurance requirements. It also reduced collateral requirements on a regionwide basis by approximately 66%, from an average of $420 million to $143 million. This reduction has allowed participants to free up capital (in the form of cash, guarantees, letters of credit, and credit limits) that otherwise would have been required to maintain collateral requirements under the prior monthly billing cycle for the hourly markets. By reducing the outstanding amounts owed to and from participants, any payment defaults would be for lower amounts.

- **Transaction Charges for Virtual Trades—**There were no charges associated with the virtual transactions to offer virtual supply or bid virtual demand when these transactions were introduced to the New England market as part of SMD in March 2003. However, the ISO determined that it was necessary to implement a transaction charge on virtual trades to curb an increase in activity that caused the day-ahead case to take longer to solve. Effective April 1, 2004, the ISO tariff was revised to use a three-tier rate design. Under the new design, virtual transactions that were submitted but did not clear were charged $0.005 per transaction unit (TU), and those that cleared were charged $0.06 per TU. On August 4, 2004, FERC denied a re-hearing of the three-tier rate design that was sought by a coalition of New England municipal utilities.[60]

- **Elimination of New England-to-New York through- or out-service charges—**The 108th Amendment to the NEPOOL Agreement, effective December 1, 2004, eliminated through- or out-service charges for transactions through or out of NEPOOL and that have the New York Control Area boundary as their point of delivery. NYISO implemented a reciprocal agreement. The RTO tariff also adopted these provisions. The elimination of these charges should facilitate more efficient trading of electricity between New England and New York. The rate for through or out service was $16.87/kW-Year, or $1.93/MWh,

[60] See <http://www.iso-ne.com/FERC/orders/ER04-121-001_8-4-04.pdf>.

prior to its elimination. Ancillary services associated with New England-to-New York transactions are still required and will be paid for under the tariff.

- **Southwest Connecticut summer power reliability—**In April 2004, the ISO announced that it had secured emergency energy resources in Southwest Connecticut. The resources provided approximately 125 MW of additional capacity beginning June 1, 2004. They are scheduled to provide up to 260 MW by the summer of 2007 from demand resources, including both emergency generation and reductions in electricity use, and from conservation resources. The agreements, which run for four years, are needed to maintain reliable electric supplies especially during periods of high electricity demand, until a long-term solution to Southwest Connecticut's reliability problem is in place.

- **Lessons Learned from the January 2004 Cold Snap—**The *Final Cold Snap Report* provided over twenty recommendations for improving the reliability of the power system and the efficiency of the New England electricity markets during extreme cold weather events. The ISO prepared a *Management Response to the Final Report*, which concurred with all of the recommendations and specified action steps to address each of the recommendations.[61]

  Based on the efforts of the Electric/Gas Wholesale Initiative and the ISO/NEPOOL Cold Snap Task Force, the following short-term actions were completed or scheduled for completion prior to the winter 2004/2005 operating period:

  - Establishment of an Operations Committee, led by the ISO and the Northeast Gas Association, including the interstate gas pipelines and local gas distribution companies (LDCs), to improve near-term operations, planning, and coordination of maintenance of the electric and gas pipeline systems. Communication protocols will be consistent with the NEPOOL Information Policy, FERC Standards of Conduct, and antitrust law.

  - Implementation of remedial actions by asset owners to improve the availability and performance of their transmission, generation, and distribution assets during extreme winter weather conditions

  - A new operating procedure, OP 20, *Cold Weather Scheduling Procedures*, was developed. OP 20 was appended to Market Rule 1 as Appendix H, *Cold Weather Event Operations*, in 2005. OP 20/Appendix H was developed to address periods of extremely cold weather that would trigger:

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[61] The Management Response is available on the ISO Web site at <http://www.iso-ne.com/special_studies/January_14_-_16_2004_Cold_Snap_Reports/ISO_s_Management_Response_to_Final_Cold_Snap_Report.pdf>.

1. Elimination and cancellation of Economic Outages for the duration of the cold-weather period [62]

2. Efficient switching to alternative fuels for dual-fuel units

3. Modification of ISO unit-commitment processes and procedures and electricity-market trading deadlines to enhance coordination between the electric and gas market nomination timelines, allowing greater utilization of the existing gas infrastructure

Several other key long-term actions identified in the *Final Cold Snap Report* that will provide significant benefit to New England are as follows:

- Establishing best practices procedures in transmission line ratings and transfer-capability calculations to maximize import/export capabilities between New England and neighboring regions during extreme weather/abnormal events

- Developing economic incentives for the installation of expanded dual-fuel capability or firm transportation contracts for gas-only units and improved availability of equipment during extreme winter-weather events. These incentives are contained in the recent LICAP market proposal and the proposed enhancements to the Forward Reserve Markets.

- Investigating market-design improvements to allow increased flexibility for generator offers within the wholesale energy market

The action steps identified by the ISO and asset owners for winter 2004/2005 are expected to improve supply-side resource availability in New England by at least 2,000 MW over the performance during the January 2004 Cold Snap. The above action steps also are projected to improve generator availability during extreme cold-weather conditions, and all are focused on protecting the reliability of the power system and improving the efficiency of New England's electricity markets.

- **Information technology improvements—**During 2004, the ISO improved its information technology systems and infrastructure to support the reliable operation of the power system and the energy markets. Key improvements are as follows:

  - The ISO implemented new software and enhanced existing systems used by the power system operators to improve visual representations of the power system and the network model. Visual displays help control-room operators and other power system operations staff identify problems more quickly, which aids in the reliable operation of the system. Some of these improvements, such as enhancements to the Energy Management System (EMS), were made as a result

[62] ISO Operating Procedure No. 5, *Generation Maintenance and Outage Scheduling*, describes Economic Outages as outages requested for reasons unrelated to the physical condition of a generating unit. OP 5 is available at <http://www.iso-ne.com/smd/operating_procedures/>.

of recommendations included in an analysis of the August 2003 Northeast Blackout. Other improvements, such as the implementation of Powerworld software, were made on the ISO's own initiative.

- The ISO implemented other significant software applications in addition to the Powerworld software. Implementation of "PI" software improved the capture and retention of EMS and other system data. It also provides a foundation for further improving the availability and analysis of this data. The ISO made enhancements to the Day-Ahead Energy Market software, including the development of a day-ahead study application. The day-ahead study application, which was required as part of the ISO's transition to a RTO, is used primarily to analyze outages on the transmission system to minimize the economic impact of outages.

5.1.2 ORC and Transmission Tariff Payment Improvements

The ISO made a number of changes to the eligibility guidelines for ORC and transmission tariff service payments. These changes, listed below, were needed to ensure that payment is fair and to clarify eligibility for compensation in specific situations.

- **Payment eligibility for generators dispatched below the economic-minimum limit during minimum-generation conditions—**At times during minimum-generation conditions, the ISO dispatches generators below the units' economic-minimum limits. A rule change was made so that generators in this situation are eligible to receive real-time uplift payments. This change was implemented on January 13, 2004, and was effective retroactively to June 1, 2003.

- **Payment eligibility for generators with minimum run-time hours from the previous day—**Day-ahead and real-time uplift eligibility and settlement was changed to use the prior day's offers for minimum run-time hours that carried over from the prior day. Under this change, which was implemented effective February 1, 2004, if a pool-scheduled generator's minimum run time starts on one day and does not finish until another day, the generator will be paid uplift based on the first day's offer schedule until the minimum run time is satisfied. This eligibility rule applies regardless of whether the first day's offer is more expensive or less expensive than the second day's offer. This rule does not apply if the generation on the first day is solely to ramp up to the second day's schedule.

- **Payment eligibility for generators with contiguous self-scheduled and pool-scheduled hours—**In July 2004, ISO implemented changes to Market Rule 1, retroactive to March 1, 2004, that allowed generating resources that have contiguous self-scheduled and pool-scheduled hours to be eligible to receive day-ahead or real-time uplift for the pool-scheduled portion of their generation. Prior to these changes, pool-scheduled generators could not receive uplift if they had been self-scheduled at any point in the Day-Ahead Energy Market or had, in real-time, a self-scheduled hour during their minimum run time regardless of whether they had gone offline after the self-schedule had completed. Under the new rule, a generator with a self-schedule at least as long as its minimum run time would be eligible for uplift for pool-scheduled hours, either before or after the self-schedule was complete, even if it did not shut down. This change further required that a generator not bid self-schedules that would require a unit to begin operating after less than its minimum down time, so that each unit could respect its schedule without violating any of its other operating limits.

- **Day-ahead payment eligibility for generators with real-time self-schedules—**Day-ahead eligibility preprocessing was automated for generators that had real-time self-schedules in one day and were pool-scheduled in the Day-Ahead Energy Market for the following day. Under the change, a generator scheduled in the Day-Ahead Energy Market to satisfy a real-time minimum run time is ineligible for day-ahead uplift for the entire day-ahead dispatch period. Prior to this change, which was implemented on February 1, 2004, the preprocessing of generator eligibility required manual adjustment.

- **Payment eligibility for generators with self-scheduled and pool-scheduled generation in the same hour—**Eligibility for real-time uplift was modified for generators that are partially self-scheduled in an hour. Under the change, these generators will be eligible to receive uplift for the pool-scheduled generation above economic minimum unless the uplift is due to a regulation self-schedule. The change was effective December 1, 2004, and was implemented April 1, 2005.

- **Prorated payments for generators not completing their minimum run time—**A rule change was developed in 2004 and is currently pending before FERC that would modify the eligibility for real-time uplift for generators that do not complete their minimum run times. Under the change, when the ISO requests that a generating unit comes offline, or when the unit, itself, requests to come offline, and it is granted that request, the unit would be eligible for uplift to cover their full start-up and no-load to that point. A unit that trips offline during its minimum run time will be eligible for prorated start-up and no-load credits. This change would remove incentives for generators to remain online to meet uplift eligibility criteria when it is not economic for the pool for them to do so and allow a generator that trips offline to recover its start-up costs.

5.2 Audits

The ISO participated in several audits during 2004. These audits were conducted to ensure that the ISO followed the approved market rules and procedures and to provide transparency to New England stakeholders.

- **North American Electric Reliability Council *Control Area Readiness Audit Report*[63]—**In May 2004, NERC issued a report on its audit of the ISO's readiness to meet its responsibilities as a control-area operator. NERC committed to auditing control areas

[63]See <http://www.iso-ne.com/iso_news/2004_Archive/>.

as part of its response to the August 2003 Northeast Blackout. The report was positive, stating,

> *The New England region has tightly integrated reliability requirements into the design of the wholesale electricity market. This has led to a consistent set of market rules and operating procedures that prescribe the way the market operates and clearly identifies the responsibilities and obligations of all market participants. Having the reliability requirements clearly identified allows ISO-NE to focus on reliability issues and to ensure that the market can operate efficiently in all timeframes. The New England market approach, with its reliability-first philosophy, has led ISO-NE staff to develop a strong and well-developed culture of reliability. Everyone the audit team interviewed exhibited the reliability-first philosophy…The audit team believes that the ISO New England control area has the appropriate reliability plans, procedures, processes, tools, and trained personnel in place to respond to normal, emergency, planned and unplanned events on its system.*

In addition, the report identified several best practices for other NERC members.

- **SAS 70 Audit—**In December 2004, the ISO successfully completed a Statement on Auditing Standards 70 Type 2 Audit, which resulted in a positive opinion about the design of its controls and operating effectiveness. Developed by the American Institute of Certified Public Accountants (AICPA), the SAS 70 Audit is used by service organizations, such as independent system operators, to provide assurance regarding the validity and integrity of controls and systems used in the "bid-to-bill" business processes that govern wholesale electricity markets.

  The SAS 70 Type 2 Audit was a rigorous and detailed examination of the business processes and information technology used for activities related to bidding into the market, accounting, billing, and settlement for the market products of energy, transmission, capacity, and reserves. Conducted by the auditing firm PricewaterhouseCoopers LLP, the Type 2 Audit covered a six-month period, from May 1 to October 31, 2004. A SAS 70 Type 2 Audit is a more thorough review of business procedures than a Type 1 Audit, which is a general, one-time audit of business processes. The ISO had previously conducted a Type 1 Audit, and it plans to conduct a SAS 70 Type 2 Audit annually.

  The ISO elected to conduct internal audits in the Market Systems area as a compliment to the SAS 70 audit. These audits included testing the security of access to these systems.

- **Management Assertion Review—**In November 2004, PricewaterhouseCoopers LLP completed its review of the ISO New England Management Assertion regarding the summary of charges and payments for the period from March 1, 2003, to December 31, 2003, relating to the accuracy and completeness of the calculation of charges and payments and their compliance with NEPOOL Market Rule 1, the NEPOOL Manuals, the NEPOOL Open Access Transmission Tariff and the ISO New England Tariff for Transmission Dispatch, and Power Administration Services. PricewaterhouseCoopers LLP concluded that the ISO's Management Assertion was fairly stated in all material respects.

- **Operations Reviews—**Based on the ISO's audit-coverage strategy and input from the NEPOOL Operations Audit Steering Committee (OASC), the ISO's Internal Audit Department planned and performed detailed testing in the areas of control-room operations and Day-Ahead operations. NEPOOL's representative from Barker, Dunne and Rossi monitored the work. Reporting will be finalized and made available to Participants during the second quarter of 2005. Detailed testing of forecasting operations, planned during 2004, also was performed during March 2005.

- **Market System Software Recertification—**Prior to the implementation of SMD in March 2003, all market system-clearing engines were certified by an outside consultant, PA Consulting. The ISO went through a similar certification in 2004. PA Consulting issues a compliance certificate for an SMD module after performing detailed testing and analysis of the mathematical formulations. The certificate provides assurance that the software is operating as intended and is consistent with Market Rule 1 and associated manuals. In 2004, the process included testing of the following software systems: real-time Unit Dispatch Software/Scheduling Pricing Dispatch (UDS SPD), the LMP Calculator, Day-Ahead SPD (DA SPD), Simultaneous Feasibility Testing (SFT) software, Financial Transmission Rights clearing software, and Auction Revenue Rights clearing software. As of February 28, 2005, the ISO has received the final certificates for all these systems.

5.3 Quality Management System

As part of its commitment to efficient markets and reliability, the ISO has initiated a Quality Management System (QMS). The QMS encompasses ISO initiatives and process improvements that enhance the ISO's ability to run efficient markets, ensure that operations conform to the approved market rules, and provide increased transparency to market participants. These characteristics are essential for the New England electricity markets. Such efforts are especially important given the complexity of electricity markets and electricity market operations.

In 2004, the ISO completed a companywide gap analysis comparing current practices with the International Organization for Standards 9000 (ISO 9000) quality standards. The ISO used the results to develop a detailed plan for implementing compliance with what are now ISO 9001 standards during the first quarter of 2006.

The ISO established a Quality Management Steering Committee comprised of senior managers. The committee meets monthly to review progress towards ISO 9001 compliance and provides a structure for implementing quality management initiatives. In addition, quality representatives were designated throughout the company to provide a backbone for quality infrastructure.

The ISO undertook a companywide inventory and categorization of documents and records and established control processes for these tasks to move toward compliance with ISO 9001 standards for documents and records. This effort, which is ongoing, affects written documentation of business processes and other documents.

The ISO also will issue a quality manual for internal use that describes the implementation of the QMS to be compliant with the ISO 9001 structure. The manual clarifies the ISO's processes and its actions to comply with each clause of the ISO 9001 standard.

As part of the QMS and ISO 9001 initiatives, ISO management formed the Operational Excellence Program to improve reliability and market efficiency through the reduction of errors, waste, and risks. The goal is to achieve the highest level of customer satisfaction.

5.4 Administrative Price Corrections

5.4.1 Real-Time Price Corrections

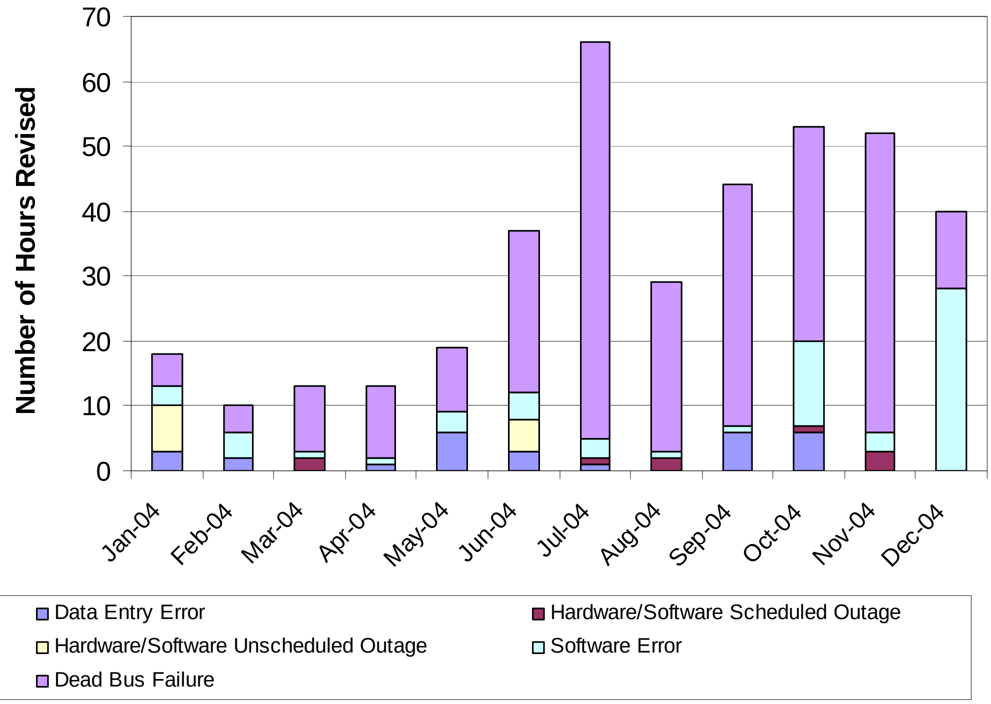
The ISO continually monitors the processes for calculating LMPs. In the event of a data-input failure, hardware or software failure or outage, software error, or binding-constraint error, the ISO will take actions to ensure that the resulting real-time LMPs are as accurate as reasonably possible. Figure 59 shows the number of hours with real-time LMP corrections during each month in 2004. Real-time LMPs were revised for 394 hours, or 4.5% all hours during the year. In many cases, corrections affected LMPs at only a few individual Pnodes; LMPs at the Hub and load zones did not change. Also, the dollar amount of the changes was often very small, with no minimum threshold triggering a change. The average of the absolute value of LMP changes at the Hub was $0.27/MWh.

Approximately 2% of the hours needing correction were associated with planned outages that were required for upgrading software or testing systems. These outages resulted in data being unavailable for a number of five-minute intervals when the hourly prices were initially calculated and posted. The prices for each affected hour were revised to incorporate data for the missing intervals.

The increase in price corrections in the second half of the year was primarily due to an increase in dead-bus logic failures (i.e., failures of price-calculation procedures for points on the grid that are not modeled through normal mechanisms). The ISO's pricing software includes dead-bus logic to account for periods when a bus becomes islanded, typically due to a transmission system outage. At times, the automated dead-bus logic is unable to find an appropriate price for a local Pnode. This usually involves a non-Pool Transmission Facility Pnode that must be mapped back to a PTF Pnode for loss-component purposes. This requires the ISO to manually map and assign the correct price to the dead Pnode (bus). The ISO is working to decrease the incidence of dead-bus logic failures through improved software.

Figure 59

Real-Time Energy Market LMP Corrections by Month



5.4.2 Events of April 19, 2004, and Authority to Revise Day-Ahead Energy Market Results

On April 18, 2004, the ISO posted incorrect prices for the Day-Ahead Energy Market for April 19. On April 30, the ISO made a filing with FERC requesting that: 1) FERC approve revisions to Market Rule 1 to clarify procedures for revising Day-Ahead Energy Market LMPs, and 2) FERC take notice that the ISO was correcting Day-Ahead Energy Market LMPs for April 19, 2004, to conform to the filed rate. The proposed revisions added a procedural mechanism to Market Rule 1 providing for the ISO to promptly flag and subsequently correct Day-Ahead Market results that may reflect significant data errors by the ISO or its systems. This proposed change provides an appropriate process by which the ISO can correct errors, in a manner that is transparent to stakeholders and the Commission, ensure just and reasonable rates, and fairly balance the goals of certainty and accuracy.

As the ISO explained in filings with FERC, the prices were calculated incorrectly due to errors in the transmission outage schedule database. First, due to a delay in the completion of a transmission outage, the database included data incorrectly indicating that two specific transmission outages would occur simultaneously. In fact, these two transmission outages were scheduled to occur sequentially, that is, the first outage would end before the second outage commenced. Second, after correcting the outage-scheduling error, the ISO identified a further error caused by the transposition of numbers. Numbers identifying which circuit breakers required outages with transposed digits were submitted by a satellite control center; the submitted and approved outage application identified Circuit Breakers 1235 and 1236, but should have indicated Circuit Breakers 2135 and 2136 at the same substation. These errors in the database created constraints that caused unusually high zonal prices in New Hampshire, Vermont, and WCMA. During these hours, some nodal LMPs in the New Hampshire, Vermont, and WCMA zones rose to very high levels, some higher than $3,700/MWh. Zonal prices in New Hampshire, the load zone where the effects were most pronounced, ranged between $100/MWh and $675/MWh throughout most of these hours.

FERC accepted the revisions to Market Rule 1, with some modifications, in a July 15, 2004, order.[64] This order provided clear procedures under which the ISO may flag and revise day-ahead prices. In the same order, FERC directed that revisions to April 19 prices would be considered at a hearing and settlement judge proceedings. An offer of settlement was accepted by FERC on May 6, 2005.[65]

[64] FERC Docket No. ER04-798-000.

[65] See 111 FERC ¶61,167.

6 Conclusions

The New England wholesale electricity markets continued to experience reliable operations and competitive outcomes in 2004. After adjusting for changes in fuel prices, electricity spot-market prices in 2004 were similar to 2003 prices and lower than those of the preceding years. Summer loads were lower than normal, but total annual energy consumption increased. There was a surplus of installed capacity. These observations are consistent with the results of market analyses that continue to show competitive market outcomes and, based on net-revenue analysis, little incentive to build new capacity in New England.

A review of the supply side of the market over the first five full years of market operations shows significant progress. About 9,500 MW of new, mostly gas-fired capacity has been added to the system. Average heat rates for liquid-fuel resources have fallen by 5.6%. These changes have reduced harmful emissions of SO_x, NO_x, and CO_2. Unit availability has increased by seven percentage points over the first five years. Regulation requirements have been reduced by 29% due to improved response to regulation signals by generating resources providing this service. And fuel-adjusted wholesale spot-market prices have declined by an estimated 5.7% over the period. These results all suggest that New England has seen significant benefits from the investment in new infrastructure and improved unit operations during the operation of the wholesale markets.

The ISO continues to make enhancements to its market design to improve incentives for efficient operation and investment. The most significant of these in 2004 was the introduction of an innovative Forward Reserve Market. The market functioned well in its first year of operation, with anecdotal evidence that resource owners had purchased firm fuel, installed dual-fuel capability, and reconfigured units to be better able to provide the forward-reserve product. The ISO also made many other more modest changes to the market rules and procedures for improving the incentives for market participants to operate in a way that provides reliability and efficient market outcomes. Enrollments in the demand-response programs have been flat over the last few years and are at modest levels relative to overall demand. Demand responsiveness to price changes is an important part of a well-functioning market, and the ISO will continue to improve the incentives to participate in the demand-response programs and work with the states to remove any barriers to revealing efficient prices to retail customers.

The most severe test of the New England Market and electricity infrastructure came during the January 2004 Cold Snap. Overall, the New England electricity markets and infrastructure produced reliable operations and competitive outcomes under extreme weather conditions. The period also revealed areas for improvement in both the electricity market design and the associated infrastructure and operations. Specifically, much of New England's gas-fired generation capacity was unavailable to operate due to lack of fuel, and additional generation was unavailable due to physical problems associated with the extreme cold weather.

The ISO and market participants developed a number of enhancements to the New England electricity market to address these issues. These include improved communication with the regional gas pipelines, better exchange of market and operations information with participants, increased ability for gas-fired units to operate on secondary fuels, and, in the most extreme circumstances, a revised electricity-market timeline to better enable gas-fired units to procure fuel. In the longer term, it is important for the markets to send stronger signals regarding unit availability during other extreme-reliability events, both through LMPs that reflect the cost of marginal generation and through the proposed availability provisions of the Locational Installed Capacity Market.

Out-of-market payments continue to be a concern in New England. Specifically, daily out-of-merit costs in constrained areas increased in 2004. The ISO has developed an action plan that includes upgrading the transmission infrastructure and making market-rule changes to reduce these costs, as well as implementing the proposed Ancillary Service Market to ensure reliable operation and market signals by targeting investment that resolves these problems. The megawatts covered by Reliability Agreements have also increased dramatically over the last year. The ISO's LICAP proposal is intended to address this issue and should be implemented in January 2006.

New England's electricity markets have performed well over the last year, both during the high-load summer months and during the January 2004 Cold Snap that tested much of the region's energy infrastructure. The ISO and stakeholders are currently addressing the issues of out-of-merit generation and Reliability Agreements through the Ancillary Service Markets and LICAP market to ensure both efficient markets and adequate levels of reliability in the future.

7 Appendix: Electricity Market Statistics

Appendix Contents

7.1 Appendix Introduction

This statistical appendix presents information and data about the New England electrical energy markets in more detail than in the body of the report. The appendix includes sections on electric energy prices; system loads; capacity, net interchange, and fuel mix; and market volumes. It also contains information on Auction Revenue Rights, the Congestion Revenue Fund, Operating Reserve Credit payments, and Regulation Market prices.

7.2 System Electrical Loads

The exhibits in this section present information about hourly, monthly, and yearly system electrical load levels. Table 42 shows summary statistics for hourly system load for the last four years.

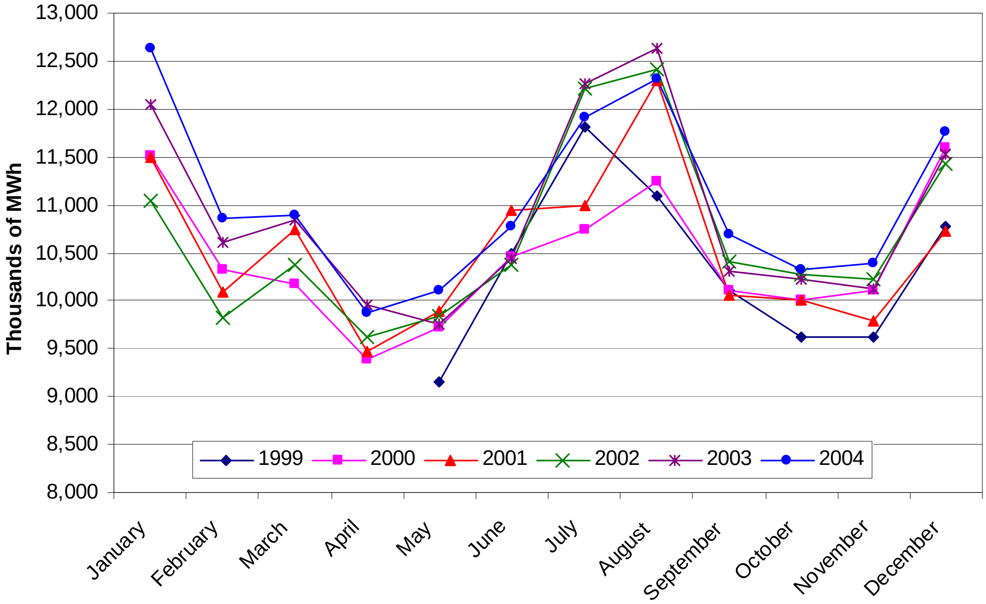
Table 42 - Hourly Load Statistics, 2001–2004

MW	2001	2002	2003	2004
Mean	14,381	14,550	14,921	15,086
Maximum	24,967	25,348	24,685	24,116
Minimum	8,765	8,748	8,934	9,152
Std. Deviation	2,840	2,975	2,928	2,883

Figure 60 shows monthly system energy consumption since May of 1999. The figure shows the effects of both weather and underlying demand growth on monthly energy levels. Eight months of 2004 had NEL values that were the highest over the period shown.

Figure 60

Monthly Total Load*, 1999 - 2004**



*NEPOOL Net Energy for Load is the total net energy used to serve load for the month in GWh. NEL is calculated as: Load = Generation - pumping + net interchange.
**1999 includes only May - December

7.3 Virtual Supply and Virtual Demand

The exhibits in this section present information on virtual demand and virtual supply by month at the Hub, load zones, and external nodes. Virtual trades that were submitted at individual Pnodes have been rolled up to the load-zone level.

Table 43 - Virtual Supply and Demand by Month

January 2004

Location	(MWh)			
	Submitted Virtual Supply	Cleared Virtual Supply	Submitted Virtual Demand	Cleared Virtual Demand
Internal Hub	177,138	100,984	267,545	131,302
Maine Load Zone	431,652	186,416	233,321	97,924
New Hampshire Load Zone	215,096	20,112	68,907	23,519
Vermont Load Zone	107,253	10,059	141,182	79,650
Connecticut Load Zone	528,078	59,222	298,404	118,747
Rhode Island Load Zone	7,777	4,976	13,012	846
SEMASS Load Zone	54,756	9,896	29,547	3,344
WCMASS Load Zone	236,436	131,459	86,431	13,846
NEMA / Boston Load Zone	40,165	3,173	3,929	3,163
NB-NE External Node	2,065	2,065	0	0
NY-NE AC External Node	141,008	121,898	3,760	333
HQ Phase I / II External Node	19	0	14	0
Highgate External Node	930	340	50,790	320

February 2004

Location	(MWh)			
	Submitted Virtual Supply	Cleared Virtual Supply	Submitted Virtual Demand	Cleared Virtual Demand
Internal Hub	78,915	41,770	157,794	100,752
Maine Load Zone	577,099	227,737	159,205	65,416
New Hampshire Load Zone	255,539	24,234	56,840	35,678
Vermont Load Zone	118,785	10,589	89,005	57,980
Connecticut Load Zone	779,865	33,162	99,804	64,035
Rhode Island Load Zone	11,569	1,462	16,246	3,467
SEMASS Load Zone	45,372	1,616	26,125	11,922
WCMASS Load Zone	246,196	83,861	45,479	13,044
NEMA/Boston Load Zone	54,639	1,286	3,126	376
NB-NE External Node	370	0	1,580	1,404
NY-NE AC External Node	35,410	34,775	14,813	4,889
HQ Phase I/II External Node	0	0	0	0
Highgate External Node	2,180	824	303,375	4,235
Cross Sound Cable External Node	0	0	1,574	934

March 2004

Location	(MWh)			
	Submitted Virtual Supply	Cleared Virtual Supply	Submitted Virtual Demand	Cleared Virtual Demand
Internal Hub	103,279	67,155	136,533	88,466
Maine Load Zone	546,330	270,399	174,098	97,259
New Hampshire Load Zone	181,431	17,565	61,656	31,517
Vermont Load Zone	97,095	13,628	75,578	43,219
Connecticut Load Zone	403,730	25,178	45,268	24,452
Rhode Island Load Zone	12,040	179	27,700	3,367
SEMASS Load Zone	55,789	9,579	26,355	4,325
WCMASS Load Zone	202,586	85,089	119,054	35,015
NEMA/Boston Load Zone	40,018	1,595	11,054	707
NB-NE External Node	0	0	8,595	8,363
NY-NE AC External Node	20,058	17,535	5,570	2,222
Highgate External Node	3,600	1,232	379,640	760

April 2004

Location	(MWh)			
	Submitted Virtual Supply	Cleared Virtual Supply	Submitted Virtual Demand	Cleared Virtual Demand
Internal Hub	139,585	83,347	142,341	80,500
Maine Load Zone	439,461	316,698	161,120	117,628
New Hampshire Load Zone	117,706	27,744	72,334	32,849
Vermont Load Zone	64,076	20,125	69,247	38,337
Connecticut Load Zone	255,627	19,044	36,160	5,085
Rhode Island Load Zone	22,306	6,998	29,570	3,849
SEMASS Load Zone	64,569	29,007	53,215	17,996
WCMASS Load Zone	200,840	89,921	121,526	28,386
NEMA / Boston Load Zone	15,582	2,389	12,646	1,396
NB-NE External Node	10,150	8,387	16,390	14,966
NY-NE AC External Node	41,167	33,269	8,029	300
Highgate External Node	800	335	361,475	890

May 2004

Location	(MWh)			
	Submitted Virtual Supply	Cleared Virtual Supply	Submitted Virtual Demand	Cleared Virtual Demand
Internal Hub	133,696	89,284	103,320	59,995
Maine Load Zone	466,545	348,755	223,929	120,669
New Hampshire Load Zone	176,498	28,806	64,508	16,525
Vermont Load Zone	57,522	16,336	72,189	44,552
Connecticut Load Zone	518,696	17,763	50,048	12,581
Rhode Island Load Zone	17,693	6,248	27,930	2,671
SEMASS Load Zone	23,523	6,930	43,066	7,287
WCMASS Load Zone	254,493	90,490	53,070	9,437
NEMA / Boston Load Zone	13,530	4,739	49,409	6,590
NB-NE External Node	2,430	2,030	508	481
NY-NE AC External Node	78,631	75,791	35,974	10,147
HQ Phase I / II External Node	480	240	0	0
Highgate External Node	0	0	373,415	954

June 2004

Location	(MWh)			
	Submitted Virtual Supply	Cleared Virtual Supply	Submitted Virtual Demand	Cleared Virtual Demand
Internal Hub	212,336	104,214	98,550	72,591
Maine Load Zone	427,784	286,451	167,400	93,602
New Hampshire Load Zone	140,471	24,312	56,866	28,223
Vermont Load Zone	78,088	20,782	257,568	44,441
Connecticut Load Zone	288,363	21,795	19,693	5,380
Rhode Island Load Zone	28,050	2,868	27,312	2,770
SEMASS Load Zone	64,183	20,342	25,889	2,169
WCMASS Load Zone	251,570	83,706	42,007	12,921
NEMA / Boston Load Zone	14,216	2,469	11,732	581
NB-NE External Node	0	0	211	211
NY-NE AC External Node	52,776	44,779	46,224	21,297
Highgate External Node	2,504	1,701	170,080	1,091

July 2004

Location	(MWh)			
	Submitted Virtual Supply	Cleared Virtual Supply	Submitted Virtual Demand	Cleared Virtual Demand
Internal Hub	120,440	68,837	125,061	91,421
Maine Load Zone	598,884	414,176	238,005	168,604
New Hampshire Load Zone	132,683	12,832	73,233	44,822
Vermont Load Zone	77,940	21,254	430,266	44,841
Connecticut Load Zone	406,498	59,285	28,977	9,551
Rhode Island Load Zone	21,614	1,260	19,668	1,645
SEMASS Load Zone	48,563	10,537	27,715	6,615
WCMASS Load Zone	194,190	43,586	49,556	19,700
NEMA / Boston Load Zone	12,182	1,321	11,912	1,109
NB-NE External Node	0	0	660	660
NY-NE AC External Node	18,578	16,659	48,794	16,130
Highgate External Node	1,040	754	3,985	3,830

August 2004

Location	(MWh)			
	Submitted Virtual Supply	Cleared Virtual Supply	Submitted Virtual Demand	Cleared Virtual Demand
Internal Hub	121,350	76,080	145,638	102,628
Maine Load Zone	779,464	480,012	326,234	253,413
New Hampshire Load Zone	104,668	13,135	81,349	49,752
Vermont Load Zone	69,958	18,619	454,768	61,006
Connecticut Load Zone	397,607	60,595	38,730	18,102
Rhode Island Load Zone	67,201	3,534	17,114	1,945
SEMASS Load Zone	42,535	13,360	32,285	11,415
WCMASS Load Zone	293,764	65,168	120,149	37,806
NEMA / Boston Load Zone	12,075	1,173	11,364	1,915
NB-NE External Node	0	0	780	320
NY-NE AC External Node	1,700	501	32,734	6,033
Highgate External Node	60	0	14,198	12,625
Cross Sound Cable External Node	0	0	150	0

September 2004

Location	(MWh)			
	Submitted Virtual Supply	Cleared Virtual Supply	Submitted Virtual Demand	Cleared Virtual Demand
Internal Hub	211,235	189,586	112,505	91,008
Maine Load Zone	673,519	458,983	289,933	200,817
New Hampshire Load Zone	100,812	22,079	79,222	52,350
Vermont Load Zone	34,252	10,882	426,699	45,535
Connecticut Load Zone	73,162	6,819	50,400	31,272
Rhode Island Load Zone	109,526	28,238	26,878	6,024
SEMASS Load Zone	75,202	34,668	42,540	13,505
WCMASS Load Zone	306,220	96,245	103,428	47,240
NEMA / Boston Load Zone	13,159	698	12,768	2,843
NB-NE External Node	0	0	10,790	3,971
NY-NE AC External Node	1,100	0	83,564	64,083
Highgate External Node	480	50	12,240	10,550

October 2004

Location	(MWh)			
	Submitted Virtual Supply	Cleared Virtual Supply	Submitted Virtual Demand	Cleared Virtual Demand
Internal Hub	146,995	126,541	166,435	115,993
Maine Load Zone	515,710	377,247	277,990	161,570
New Hampshire Load Zone	45,699	15,287	81,212	46,470
Vermont Load Zone	32,055	18,578	437,648	55,514
Connecticut Load Zone	68,515	16,596	26,400	11,321
Rhode Island Load Zone	43,505	5,460	25,145	2,815
SEMASS Load Zone	92,333	35,578	82,615	27,512
WCMASS Load Zone	205,097	57,654	156,425	56,268
NEMA / Boston Load Zone	21,653	6,442	33,771	11,275
NB-NE External Node	2,570	2,570	7,935	1,403
NY-NE AC External Node	1,829	100	75,605	26,976
Highgate External Node	420	26	15,940	13,867

November 2004

Location	(MWh)			
	Submitted Virtual Supply	Cleared Virtual Supply	Submitted Virtual Demand	Cleared Virtual Demand
Internal Hub	170,250	135,593	154,481	95,818
Maine Load Zone	561,447	415,030	251,434	198,280
New Hampshire Load Zone	48,455	12,862	68,935	46,484
Vermont Load Zone	32,928	22,283	414,372	53,607
Connecticut Load Zone	38,756	5,773	12,069	3,794
Rhode Island Load Zone	58,505	4,658	15,496	3,827
SEMASS Load Zone	31,840	12,778	34,338	13,209
WCMASS Load Zone	117,609	11,666	106,473	35,496
NEMA / Boston Load Zone	85,304	26,235	13,652	4,419
NB-NE External Node	0	0	8,835	8,815
NY-NE AC External Node	2,178	186	123,687	79,333
Highgate External Node	0	0	14,035	11,435
Cross Sound Cable External Node	0	0	60	30

December 2004

Location	(MWh)			
	Submitted Virtual Supply	Cleared Virtual Supply	Submitted Virtual Demand	Cleared Virtual Demand
Internal Hub	179,369	126,957	139,811	89,132
Maine Load Zone	544,054	368,297	195,984	132,268
New Hampshire Load Zone	29,744	23,651	115,904	58,303
Vermont Load Zone	35,841	32,469	450,267	61,122
Connecticut Load Zone	107,335	53,197	12,344	2,634
Rhode Island Load Zone	26,486	11,669	15,085	4,364
SEMASS Load Zone	25,618	17,401	36,320	14,985
WCMASS Load Zone	90,426	10,682	149,535	25,380
NEMA/Boston Load Zone	92,895	20,034	12,489	2,414
NB-NE External Node	0	0	17,630	17,630
NY-NE AC External Node	32,463	27,393	80,886	17,476
HQ Phase I/II External Node	150	150	0	0
Highgate External Node	320	4	11,055	7,830

7.4 Electric Energy Prices

The exhibits in this section show zonal average LMP data for 2004, compare year-to-year energy price trends, and show information about load levels and electric energy prices. Except where specifically noted, prices are not load-weighted. Table 44 shows LMP summaries for 2004.

Table 44 - LMP Summary Statistics, 2004

Location	LMP ($/MWh)						% of Hub		Real-Time as % of Day Ahead	Std. Dev.		Real-Time Std./Day-Ahead Std.
	Avg. Day-Ahead	Avg. Real-Time	Min. Day-Ahead	Min. Real-Time	Max. Day-Ahead	Max. Real-Time	Day-Ahead	Real-Time		Day-Ahead	Real-Time	
Internal Hub	$53.72	$52.13	$20.22	$0.00	$520.08	$920.29	100%	100%	97%	$20.23	$23.18	1.15
Maine Load Zone	$48.62	$47.79	$18.52	$0.00	$483.64	$850.83	90%	92%	98%	$18.41	$20.86	1.13
New Hampshire Load Zone	$52.09	$50.72	$19.82	$0.00	$508.19	$899.18	97%	97%	97%	$19.65	$22.45	1.14
Vermont Load Zone	$53.95	$52.32	$20.55	$0.00	$505.37	$880.25	100%	100%	97%	$19.86	$22.64	1.14
Conn. Load Zone	$54.62	$52.80	$20.49	$0.00	$578.56	$893.00	102%	101%	97%	$21.20	$23.53	1.11
Rhode Island Load Zone	$52.82	$51.21	$19.97	$0.00	$510.75	$902.88	98%	98%	97%	$19.85	$22.69	1.14
SEMASS Load Zone	$52.33	$50.72	$19.84	$0.00	$505.18	$908.94	97%	97%	97%	$19.64	$22.58	1.15
WCMASS Load Zone	$53.86	$52.33	$20.32	$0.00	$518.42	$911.69	100%	100%	97%	$20.14	$23.11	1.15
NEMA/ Boston Load Zone	$53.46	$51.46	$19.96	$0.00	$508.76	$903.10	100%	99%	96%	$20.40	$23.11	1.13
NB-NE External Pnode	$46.99	$46.20	$16.97	$0.00	$486.31	$852.70	87%	89%	98%	$18.55	$20.48	1.10
NY-NE AC External Pnode	$53.42	$51.84	$20.35	$0.00	$511.32	$873.04	99%	99%	97%	$19.85	$22.50	1.13
HQ Phase I/II External Pnode	$52.42	$50.60	$19.57	$0.00	$512.43	$889.04	98%	97%	97%	$19.92	$22.25	1.12
Highgate External Pnode	$51.18	$49.44	$19.64	$0.00	$481.45	$824.84	95%	95%	97%	$18.77	$21.12	1.13
Cross Sound Cable External Pnode	$53.62	$52.35	$20.45	$-1.90	$507.70	$893.54	100%	100%	98%	$19.64	$23.01	1.17

Table 45 and Table 46 show LMP summaries for the on-peak and off-peak hours during 2004. Demand for electricity is generally higher during the on-peak periods and lower in the off-peak periods, driven primarily by commercial and industrial sector use.

Table 45 - LMP Summary Statistics, On-Peak Hours, 2004

Location	LMP ($/MWh)					
	Avg. Day-Ahead	Avg. Real-Time	Min. Day-Ahead	Min. Real-Time	Max. Day-Ahead	Max. Real-Time LMP
Internal Hub	$61.07	$59.50	$38.56	$16.38	$520.08	$920.29
Maine Load Zone	$54.58	$53.85	$35.48	$15.42	$483.64	$850.83
New Hampshire Load Zone	$59.07	$57.87	$37.74	$15.96	$508.19	$899.18
Vermont Load Zone	$61.23	$59.48	$39.31	$16.22	$505.37	$880.25
Connecticut Load Zone	$62.32	$60.67	$39.35	$16.30	$578.56	$893.00
Rhode Island Load Zone	$60.00	$58.31	$38.20	$16.16	$510.75	$902.88
SEMASS Load Zone	$59.44	$57.75	$38.05	$16.20	$505.18	$908.94
WCMASS Load Zone	$61.24	$59.81	$39.17	$16.38	$518.42	$911.69
NEMA/Boston Load Zone	$60.92	$58.80	$38.28	$16.18	$508.76	$903.10
NB-NE External Pnode	$52.67	$51.26	$33.14	$14.99	$486.31	$852.70
NY-NE AC External Pnode	$60.70	$59.07	$39.24	$16.08	$511.32	$873.04
HQ Phase I/II External Pnode	$59.56	$57.29	$37.52	$15.92	$512.43	$889.04
Highgate External Pnode	$58.02	$54.82	$37.13	$14.65	$481.45	$824.84
Cross Sound Cable External Pnode	$61.02	$60.04	$39.43	$16.20	$507.70	$893.54

Table 46 - LMP Summary Statistics, Off-Peak Hours, 2004

Location	LMP ($/MWh)					
	Avg. Day-Ahead	Avg. Real-Time	Min. Day-Ahead	Min. Real-Time	Max. Day-Ahead	Max. Real-Time
Internal Hub	$47.44	$45.83	$20.22	$0.00	$274.92	$353.78
Maine Load Zone	$43.52	$42.61	$18.52	$0.00	$256.41	$333.80
New Hampshire Load Zone	$46.13	$44.61	$19.82	$0.00	$268.88	$345.27
Vermont Load Zone	$47.72	$46.19	$20.55	$0.00	$268.44	$346.65
Connecticut Load Zone	$48.04	$46.08	$20.49	$0.00	$270.88	$342.71
Rhode Island Load Zone	$46.67	$45.15	$19.97	$0.00	$270.18	$346.03
SEMASS Load Zone	$46.26	$44.71	$19.84	$0.00	$267.35	$342.43
WCMASS Load Zone	$47.56	$45.93	$20.32	$0.00	$274.08	$352.47
NEMA/Boston Load Zone	$47.08	$45.19	$19.96	$0.00	$269.17	$346.13
NB-NE External Pnode	$42.13	$41.87	$16.97	$0.00	$257.77	$333.11
NY-NE AC External Pnode	$47.20	$45.67	$20.35	$0.00	$270.47	$342.57
HQ Phase I/II External Pnode	$46.33	$44.89	$19.57	$0.00	$271.03	$342.36
Highgate External Pnode	$45.34	$44.84	$19.64	$0.00	$255.30	$333.80
Cross Sound Cable External Pnode	$47.29	$45.78	$20.45	$-1.90	$268.63	$342.01

Table 47 - Average 2004 Day-Ahead LMPs by Month and Load Zone

Month	Load Zone								
	Hub	CT	Maine	NEMA	NH	RI	SEMA	VT	WCMA
January	$81.17	$82.23	$73.63	$79.75	$79.08	$79.71	$79.02	$80.76	$80.97
February	$51.21	$52.15	$45.84	$50.42	$49.74	$50.33	$49.76	$51.39	$51.35
March	$47.94	$48.88	$44.31	$47.13	$47.36	$47.36	$46.59	$48.18	$48.00
April	$52.49	$53.88	$46.62	$51.43	$50.63	$51.79	$50.96	$52.95	$52.55
May	$55.59	$56.32	$49.30	$55.30	$53.65	$54.56	$54.02	$56.22	$55.64
June	$53.00	$54.24	$48.32	$52.46	$51.07	$52.01	$51.67	$52.88	$53.00
July	$50.40	$51.96	$45.10	$49.39	$48.81	$49.15	$48.79	$51.05	$50.60
August	$47.74	$49.20	$42.26	$46.97	$45.97	$46.69	$46.36	$47.77	$48.11
September	$43.91	$44.81	$38.32	$43.50	$41.74	$43.27	$43.10	$43.83	$44.30
October	$50.26	$50.75	$47.91	$50.86	$49.57	$49.67	$49.17	$51.05	$50.65
November	$50.99	$51.10	$47.05	$52.62	$49.39	$50.24	$49.93	$51.57	$51.19
December	$59.35	$59.31	$54.12	$61.03	$57.45	$58.44	$58.03	$59.10	$59.40

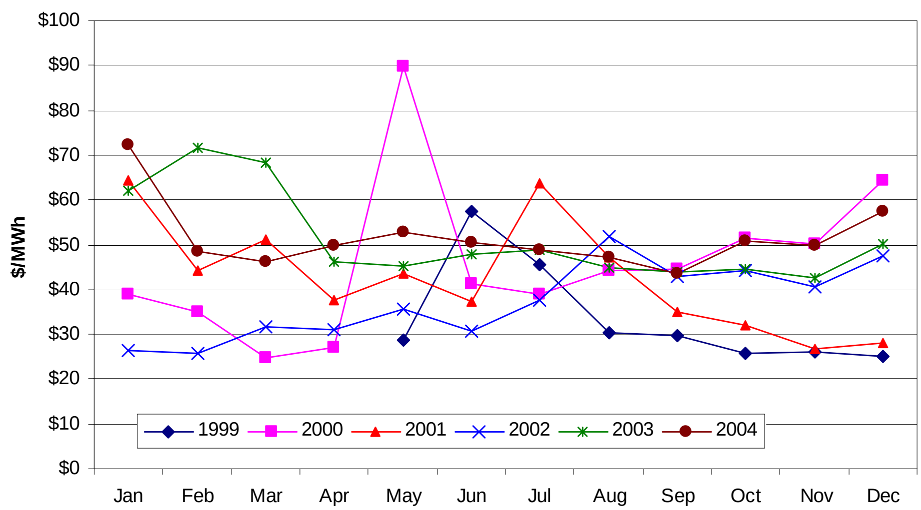
Table 48 - Average 2004 Real-Time LMPs by Month and Load Zone

Month	Load Zone								
	Hub	CT	Maine	NEMA	NH	RI	SEMA	VT	WCMA
January	$73.98	$73.35	$66.56	$72.55	$72.01	$72.57	$72.02	$73.52	$73.80
February	$49.11	$49.71	$44.08	$48.06	$47.57	$48.36	$47.74	$49.50	$49.32
March	$46.75	$47.06	$43.88	$46.02	$45.89	$46.24	$45.48	$46.75	$46.81
April	$50.42	$51.17	$45.99	$49.42	$48.77	$49.79	$48.93	$50.55	$50.49
May	$53.48	$53.88	$49.66	$53.23	$52.40	$52.45	$51.95	$53.78	$53.55
June	$50.71	$51.91	$47.52	$50.03	$49.71	$49.96	$49.39	$51.35	$50.86
July	$48.92	$51.43	$44.67	$48.06	$47.99	$47.60	$47.30	$49.85	$49.43
August	$47.54	$49.15	$41.85	$47.55	$45.84	$46.33	$46.22	$47.65	$48.15
September	$43.95	$45.22	$38.89	$43.42	$41.55	$43.38	$43.20	$43.64	$44.61
October	$51.37	$51.30	$48.80	$51.39	$50.53	$50.37	$49.52	$51.77	$51.56
November	$50.38	$50.76	$46.91	$49.58	$48.91	$49.57	$49.33	$50.72	$50.45
December	$58.28	$58.12	$54.00	$57.59	$56.83	$57.37	$56.95	$58.12	$58.27

Figure 61 shows the monthly average system real-time energy price for the last six years.

Figure 61

Load-Weighted Monthly Average Real-Time System Energy Prices*, 1999 - 2004



*Energy price is ECP for May 1999-February 2003, and System Weighted Real Time Price after March 2003.

Figure 62 shows yearly average actual and fuel-adjusted real-time electric energy prices for New England. The method for calculating the fuel-adjusted prices is covered in Section 2.1.5.2, Electric Energy Prices and Input Fuel Costs.

Figure 62

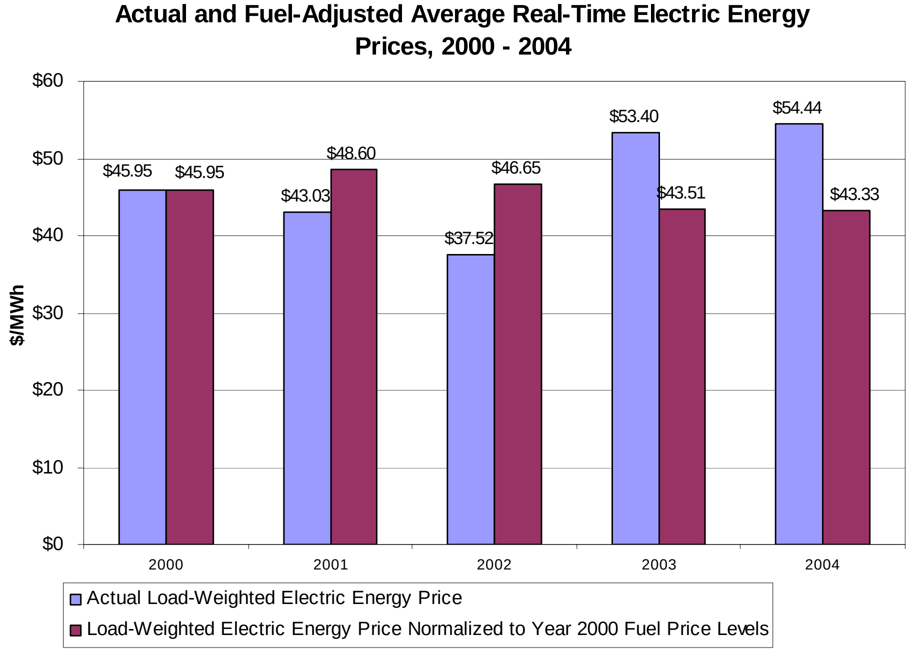
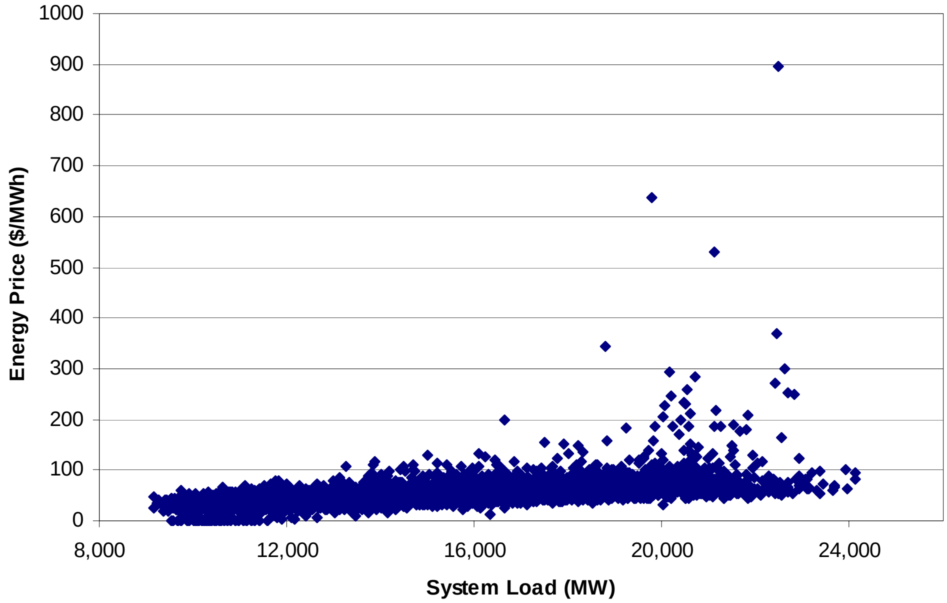


Figure 63 shows the relationship between demand levels on the system and the corresponding systemwide energy price. A distinctly positive correlation can be seen. The extremely high price ($900/MWh) occurred on January 14, 2004, during the January 2004 Cold Snap.

Figure 63

New England System Energy Price vs. System Load 2004

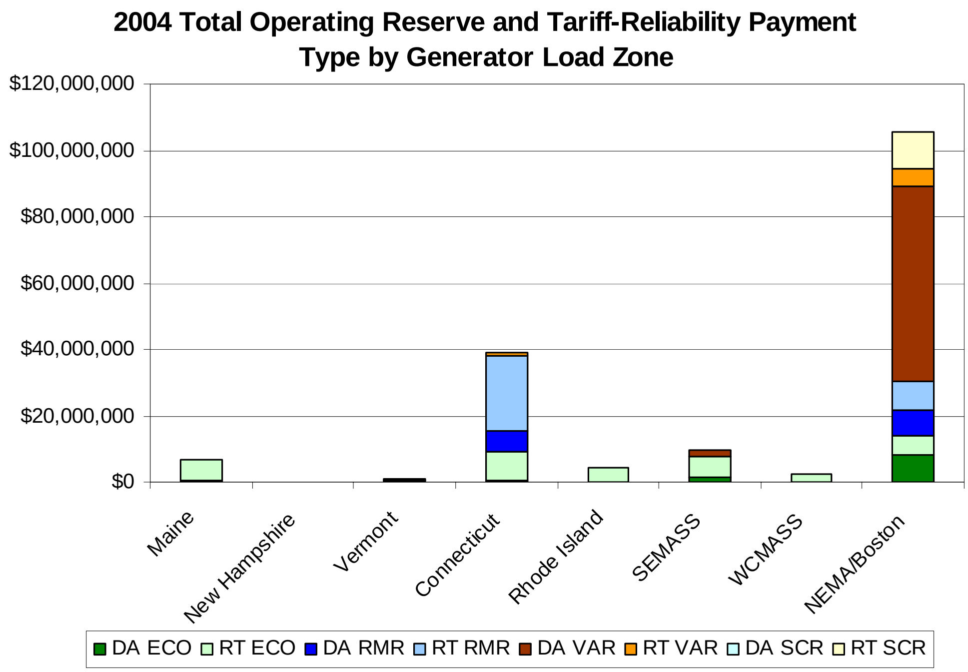


7.5 Operating Reserve Credit and Tariff-Reliability Payments

Figure 64 shows the total ORC and tariff-reliability service payments made to generators in 2004, according to the load zones in which the generators are located. Payments were made for the following categories:

- Reliability Must Run ORC
- Economic ORC
- Volt Ampere Reactive tariff-reliability service
- Special Constraint Resource tariff-reliability service

Figure 64


2004 Total Operating Reserve and Tariff-Reliability Payment
Type by Generator Load Zone
$120,000,000
$100,000,000
$80,000,000
$60,000,000
$40,000,000
$20,000,000
$0
Maine
New Hampshire
Vermont
Connecticut
Rhode Island
SEMASS
WCMASS
NEMA/Boston
DA ECO
RT ECO
DA RMR
RT RMR
DA VAR
RT VAR
DA SCR
RT SCR

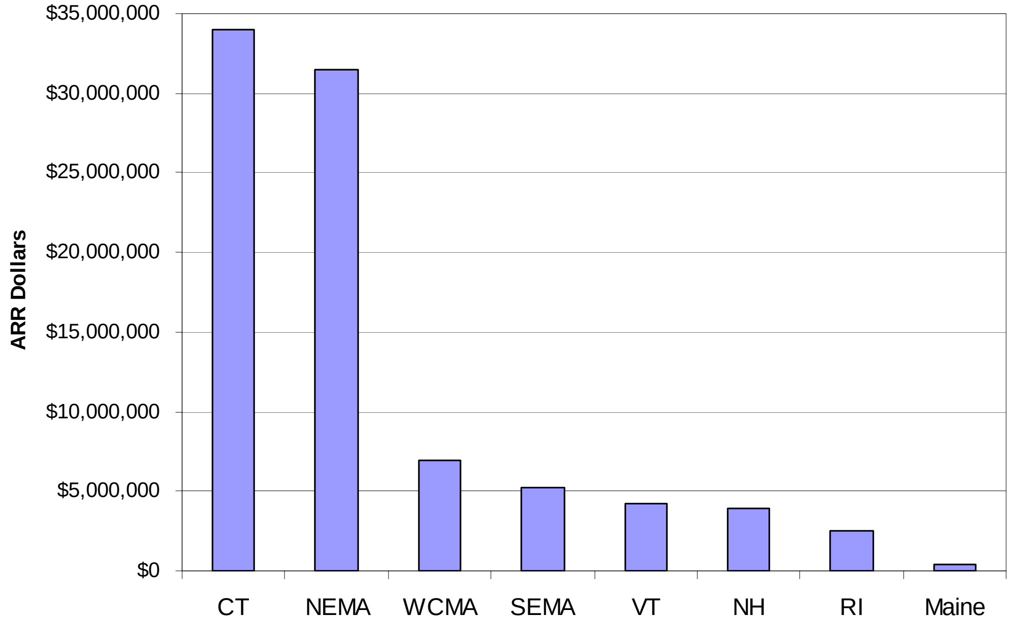
7.6 FTR Auction Revenue Rights

Table 49 - Auction Revenue by Category and Month, 2004

Month	Net FTR Auction Revenue	ARR Allocation					QUA Alloc. Dollars	Total Auction Revenue Distrib. (ARR + QUA)
		Excepted Trans. Dollars	NEMA Contract Dollars	Load Share Dollars	Long-Term Firm Trans. Svc. Dollars	Total ARR Allocation		
Jan	$5,682,236	$4,005	$134,243	$5,496,236	$0	$5,634,484	$47,752	$5,682,236
Feb	$6,284,151	$6,682	$141,898	$5,864,118	$0	$6,012,698	$271,453	$6,284,151
Mar	$5,579,759	$3,842	$133,437	$5,406,359	$0	$5,543,638	$36,120	$5,579,759
Apr	$4,395,625	$2,189	$103,817	$4,057,779	$0	$4,163,785	$231,840	$4,395,625
May	$5,133,762	$3,737	$130,370	$4,960,955	$0	$5,095,062	$38,700	$5,133,762
Jun	$6,261,208	$6,397	$173,264	$6,043,709	$0	$6,223,370	$37,838	$6,261,208
Jul	$13,714,644	$20,484	$514,320	$12,789,375	$0	$13,324,180	$390,464	$13,714,644
Aug	$12,797,906	$23,744	$465,151	$11,836,707	$0	$12,325,601	$472,305	$12,797,906
Sep	$8,769,949	$17,683	$288,807	$8,116,005	$0	$8,422,496	$347,454	$8,769,949
Oct	$7,619,634	$10,240	$235,320	$6,732,901	$0	$6,978,461	$641,173	$7,619,634
Nov	$7,389,959	$13,563	$221,706	$6,875,436	$0	$7,110,704	$279,255	$7,389,959
Dec	$8,072,484	$17,878	$317,146	$7,451,259	$0	$7,786,283	$286,201	$8,072,484
Total	**$91,701,316**	**$130,445**	**$2,859,480**	**$85,630,838**	**$0**	**$88,620,763**	**$3,080,554**	**$91,701,316**

Figure 65

ARR Distribution by Zone
January - December 2004



7.7 Demand Response Program

Table 50 reports the Demand Response Program assets that were both ready-to-respond and pending as of September 1, 2004. Because enrollments in the program increase up to and through the summer peak-demand season, and assets retire after the summer, September 1 is shown, as it is representative of the activity over the summer.

Table 50 - Demand Response Program Enrollments, September 1, 2004

	Ready-to-Respond Assets (MW)						Pending Assets (MW)					
Zone	No. of Assets	Demand Response 2 Hr	Demand Response 30 min.	Price Response	Profiled	Total	No. of Assets	Demand Response 2 Hr	Demand Response 30 min.	Price Response	Profiled	Total
CT	129	31.7	146.3	0.4	0.0	**178.5**	10.0	0.1	7.5	0.0	0.0	**7.6**
ME	5	1.5	0.0	1.0	76.0	**78.5**	0.0	0.0	0.0	0.0	0.0	**0.0**
NEMA	118	39.5	3.3	1.5	1.4	**45.7**	1.0	0.0	24.0	0.0	0.0	**24.0**
NH	3	1.2	0.4	0.0	0.0	**1.6**	0.0	0.0	0.0	0.0	0.0	**0.0**
RI	15	3.3	0.0	0.0	0.0	**3.3**	0.0	0.0	0.0	0.0	0.0	**0.0**
SEMA	92	9.4	0.5	0.0	0.0	**9.9**	2.0	0.2	0.0	0.0	0.0	**0.2**
VT	17	7.5	0.1	0.0	5.9	**13.5**	0.0	0.0	0.0	0.0	0.0	**0.0**
WCMA	105	13.6	2.2	9.3	0.0	**25.1**	2.0	0.1	0.3	0.0	0.0	**0.4**
Total	**484**	**107.6**	**152.9**	**12.3**	**83.2**	**356.0**	**15**	**0.4**	**31.8**	**0.0**	**0.0**	**32.2**

Table 51 – Demand Response Price Program Response by Zone

Load Zone	MWh Interrupted
Maine	849
New Hampshire	493
Vermont	999
Connecticut	5,872
Rhode Island	531
SEMA	1,994
WCMA	2,661
NEMA/Boston	8,463