



2008 First Quarter Markets Report

ISO New England Inc.

Market Monitoring

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1. Introduction

1.1 About ISO New England

Created in 1997, ISO New England (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

Since February 1, 2005, the ISO has operated as a Regional Transmission Organization (RTO), assuming broader authority over the daily operation of the region's transmission system and possessing greater independence to manage the region's bulk electric power system and competitive wholesale electricity markets. The ISO also continues to work closely with regulators and stakeholders, including participants in the marketplace. The ISO operates the Day-Ahead and Real-Time Energy Markets, the Forward Capacity Market (FCM), the Regulation Market, the reserve markets, and the annual and monthly auctions of Financial Transmission Rights (FTRs).

1.2 About This Report

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. The INTMMU issues periodic reports, including this quarterly report and the annual report, as part of its monitoring responsibility. The quarterly report is required by Section III of the Transmission, Markets and Services Tariff (Market Rule 1), Appendix A, Section 11.2.2.

This 2008 First Quarter Markets Report, as required by Section III of the Transmission, Markets and Services Tariff (Market Rule 1), Appendix A, Section 11.2.2, is an assessment of New England's wholesale electricity marketplace during the first quarter of 2008.

2. Summary of First Quarter Results

Each quarter, the ISO reports on the wholesale electricity markets that it administers. This report covers the period from January 1, 2008 to March 31, 2008 (the “Reporting Period”). The report contains the ISO analyses and summaries of market performance. Significant events and results during the Reporting Period included:

- **Market Monitoring** – The ISO monitors the market to ensure efficient and competitive market results. There were no mitigation events in the Real-Time Energy Markets, Day-Ahead Net Commitment Period Compensation payments, Day-Ahead Energy Market or of Real-Time Net Commitment Period Compensation payments during the Reporting Period.
- **OP-4 Events** – There were no OP-4 events that occurred during the Reporting Period.
- **Weather** – Average temperatures for February and March were similar to previous years, while average temperatures for January were three to five degrees higher than normal.
- **Peak Load** – On January 3, 2008, the first quarter’s peak was set at 21,774 MW. This was 3.5% higher than the 2007 first quarter peak.
- **Electric energy prices** – The average Hub Real-Time and Day-Ahead electric energy prices for the Reporting Period were \$79.01/MWh and \$79.26/MWh, respectively. The average Hub system Real-Time price and Day-Ahead price in January were \$85.53/MWh and \$83.99/MWh, in February were \$74.25/MWh and \$75.33/MWh, and in March were \$76.95/MWh and \$78.19/MWh, respectively.

3. Electric Energy Markets

Key factors that influence the market price for electric energy are supply and demand. Supply is influenced in turn by fuel prices and the frequency and location of transmission constraints.

3.1 Demand

The total energy needed to serve demand, including transmission losses, within the New England control area is referred to as the Net Energy for Load (NEL).¹ NEL supplied to the system in the first quarter of 2008 decreased by 1.0% relative to the first quarter of 2007. Since NEL is influenced by weather, to allow for more accurate comparisons of load growth across years, the ISO calculates the weather-normalized NEL (i.e., the NEL that would have been observed if weather were normal). The quarter showed a weather-normalized decrease by 1.2% in NEL in 2008 compared to 2007 values, as shown in Table 1.²

Table 1 – Net Energy for Load

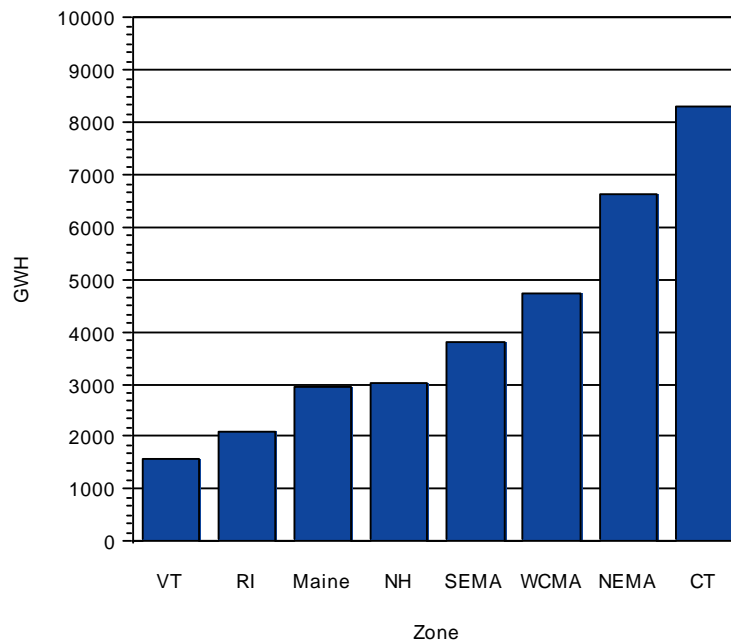
Net Energy For Load	(GWh)			
	2008	2007	Diff.	%Chg.
Q1 Recorded	33,612	33,939	-327	-1.0
Q1 Weather Normalized	33,369	33,779	-410	-1.2

¹ NEL is calculated as generation in New England (excluding generation used to support pumping at pumped storage hydro generators) plus net interchange with other control areas.

² To adjust for the effect of weather, the ISO adjusts energy consumption to reflect the departure of the experienced weather during a period from 20-year average, or “normal” levels using statistically derived factors. If temperatures are more severe than normal, consumption is adjusted downward; if milder than normal, an upward adjustment is made. Summer months also account for the effect of humidity on consumption levels.

Figure 1 shows the demand for each load zone during the Reporting Period. Unlike Net Energy for Load (NEL), Figure 1 shows total energy consumption, including net interchange and electric energy consumption used for pumping at certain hydro units.

Figure 1 – Demand by Load Zone, 2008 Q1

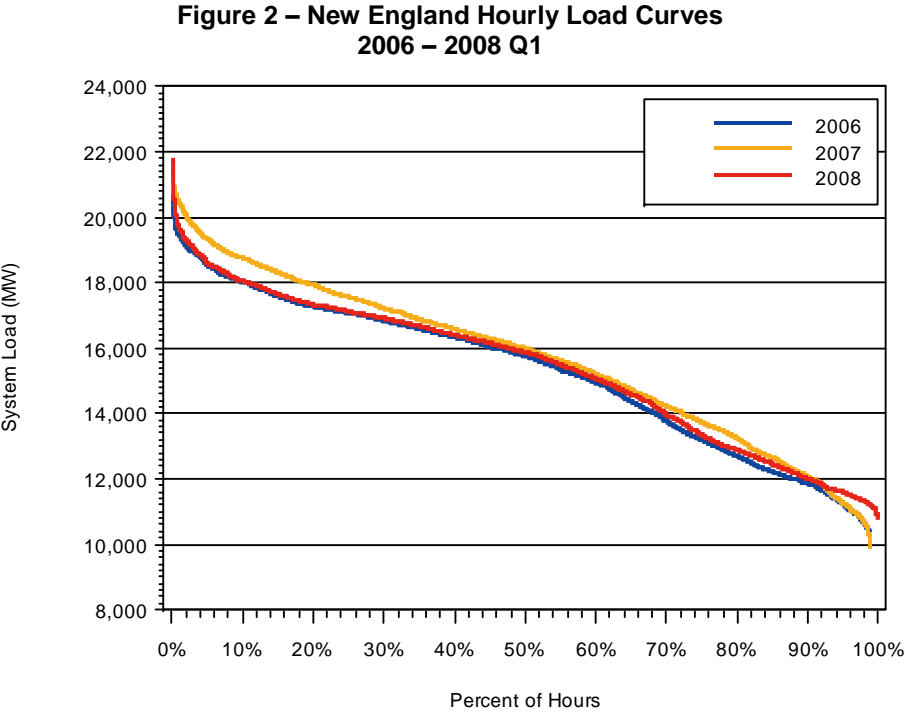


The first quarter system peak hourly load of 21,774 MW occurred on January 3, 2008. As shown in Table 2, this was 3.52% above the peak of 21,034 MW in the first quarter of 2007.

Table 2 – Peak Load Statistics, 2008 Q1

Peak Hourly Load	2008	2007	Change	% Chg.
Recorded Actual (MW)	21,774	21,034	740	3.52

Figure 2 shows load levels for the first quarters of the past three years as load-duration curves, with the hourly 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.



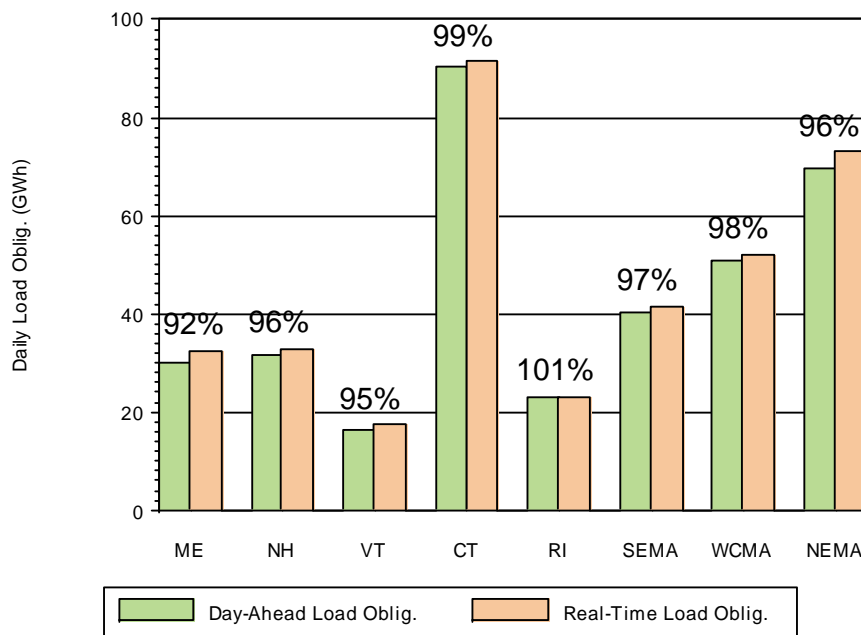
3.1.1 Load Obligation

During all Reporting Period hours, the day-ahead load obligation averaged about 96.9% of the real-time load obligation. This percentage varied across zones. Figure 3 presents the statistics for the Reporting Period by zone. The Rhode Island and Connecticut load zones cleared the highest percentage, clearing 101% and 99% of real-time load obligation in the Day-Ahead Energy Market, respectively.

Cleared Day-Ahead load obligations for a zone can be higher than Real-Time load obligation due to forecasting errors by participants, or expectations of price differences that create opportunities for participants to arbitrage prices using virtual transactions. A cleared decrement bid is included

in day-ahead load obligation while the real-time financial settlement of an increment bid is not included in real-time load obligation

Figure 3 – Average Day-Ahead Load Obligation vs. Real-Time Load Obligation by Zone, 2008 Q1



3.1.2 Day-Ahead Demand and Virtual Trading Trends

Figure 4 shows the average hourly submitted and cleared quantities of demand, virtual demand, and virtual supply for the Reporting Period. Around 63% of cleared demand bids were fixed demand bids, insensitive to price, while approximately 27% were price-sensitive demand bids. The remaining 10% of cleared day-ahead demand was virtual demand bids.

Figure 4 - Average Hourly Submitted and Cleared Demand, Virtual Demand, Q1

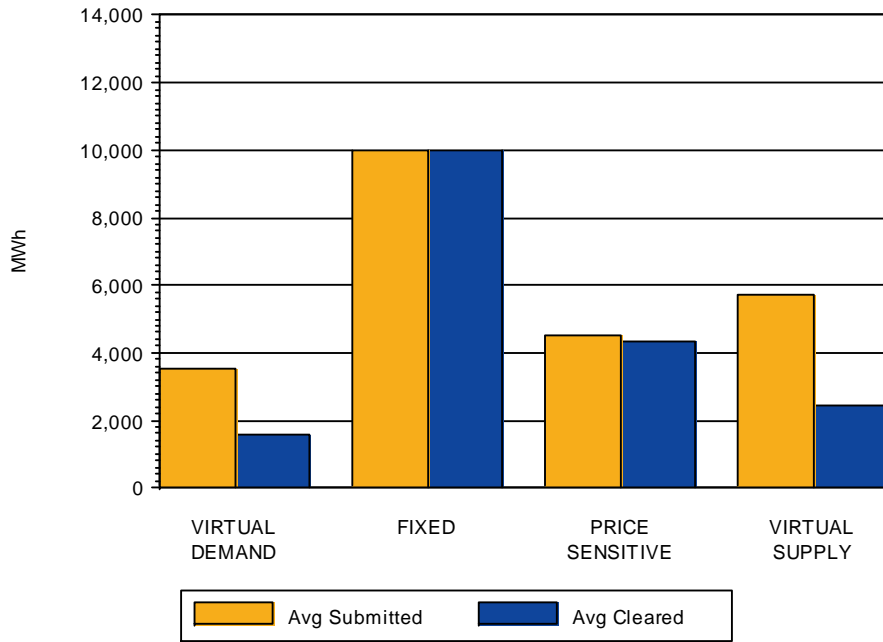
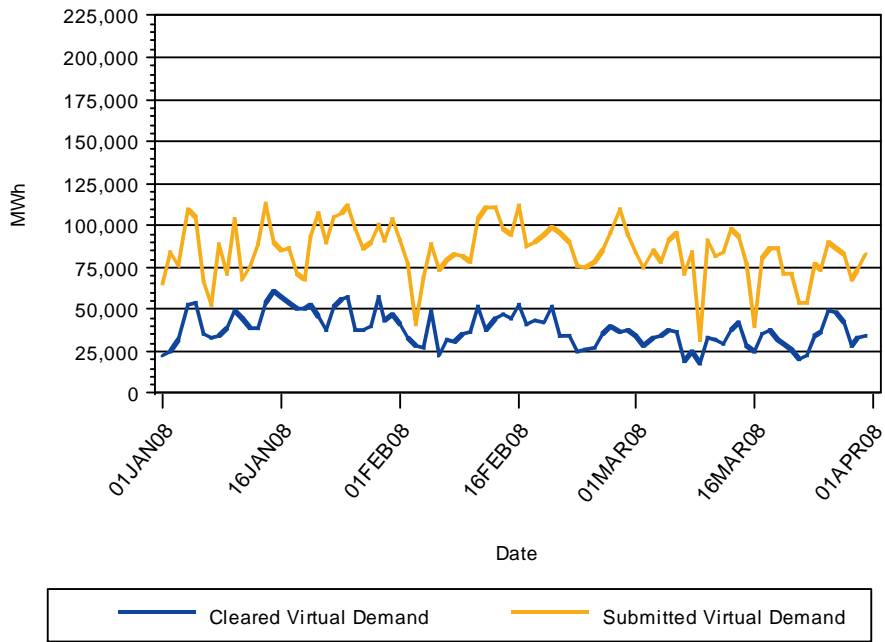
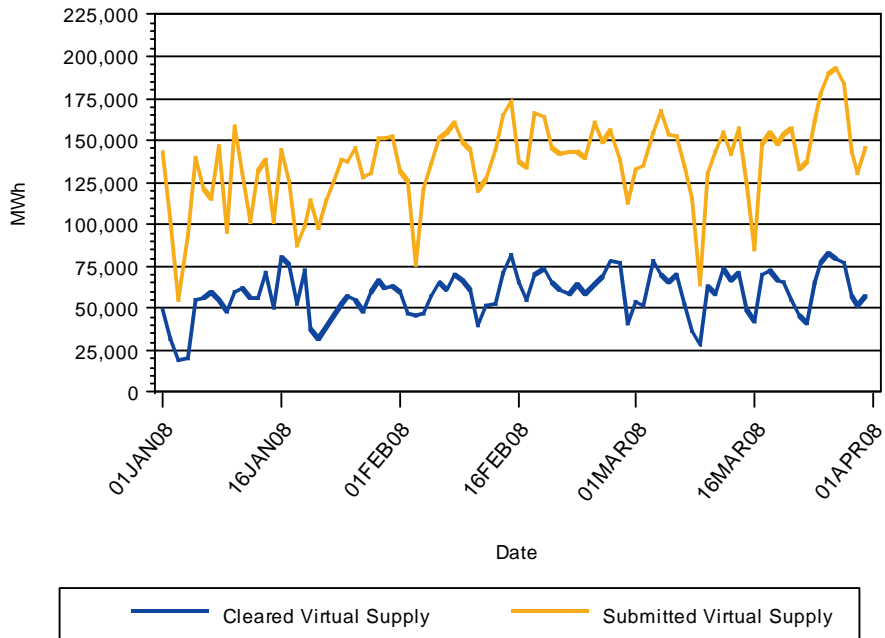


Figure 5 and Figure 6 show the daily total of the hourly submitted and cleared virtual transactions over the three-month Reporting Period. Submitted quantities of virtual transactions varied more than cleared volumes during the period. About 38,263 MWh of virtual demand bids and about 58,518 MWh of virtual supply offers cleared on average per day during the period.

**Figure 5 – Submitted and Cleared Virtual Demand
Daily Totals, 2008 Q1**



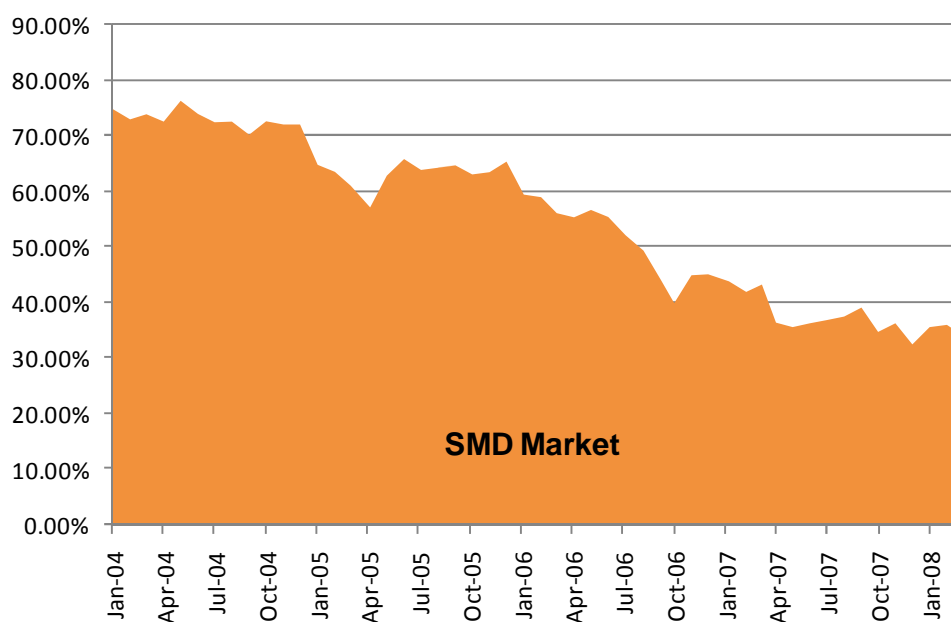
**Figure 6 – Submitted and Cleared Virtual Supply
Daily Totals, 2008 Q1**



3.1.3 Forward Contracting

As shown in Figure 7, calculations for January 2004 through March 2008 averaged about 35% of the total real-time load obligation was either forward contracted or covered by a physical hedge. This is a decrease over what was seen during the same period last year, when the degree of forward contracting was 43% of real-time load obligation in each month. The information shown in Figure 7 tends 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 non-dispatched generators are available. Hence, while these numbers are useful, they are only indicative of the forward positions held by participants.

Figure 7 - 2008 Q1 Lower Bound of Real-Time Load as Hedged through ISO Settlement System

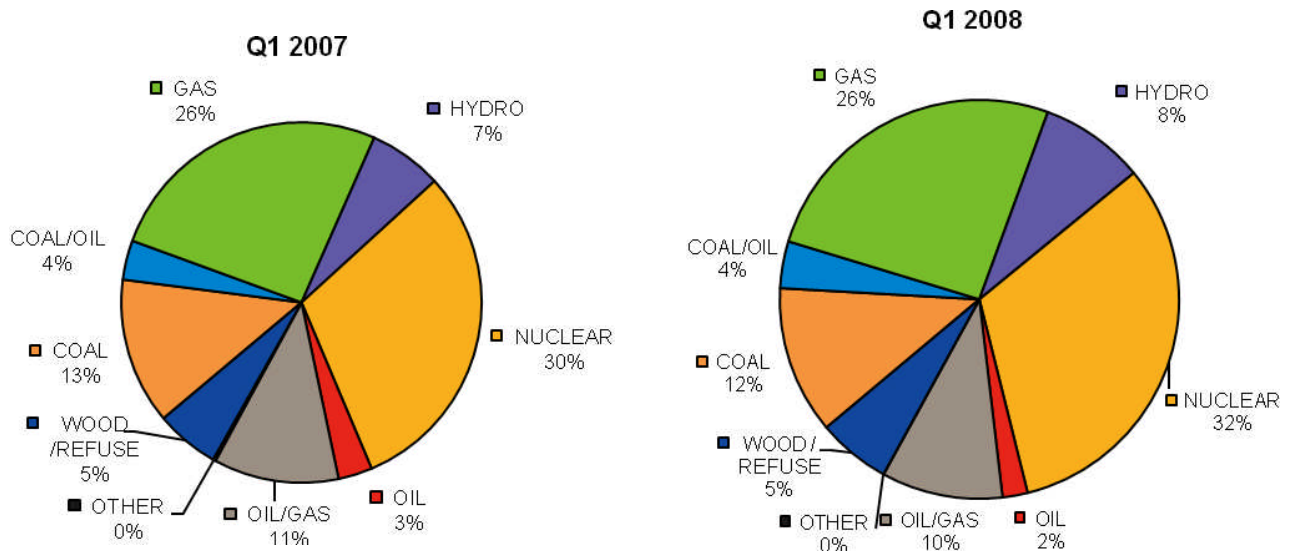


3.2 Supply

Figure 8 shows generation by fuel type as a percentage of total generation for the first quarters of 2007 and 2008. The percentages are relatively constant from 2007 to 2008. Overall, first quarter generation decreased by 1.0% year-over-year, from 33,939 GWh in 2007 to 33,612 GWh in 2008, while non-weather normalized NEL decreased by 1.2%. Net interchange with other control areas decreased from -2,772 GWh in the first quarter of 2007 to -3,410 GWh in the first quarter of 2008. Energy exported increased by 187 GWh in the first quarter of 2008 from the same period in 2007, while energy imported increased by 451 GWh in the first quarter of 2008 from

the same period in 2007. Generation used to support pumping at pumped storage hydro generators is not included in NEL.

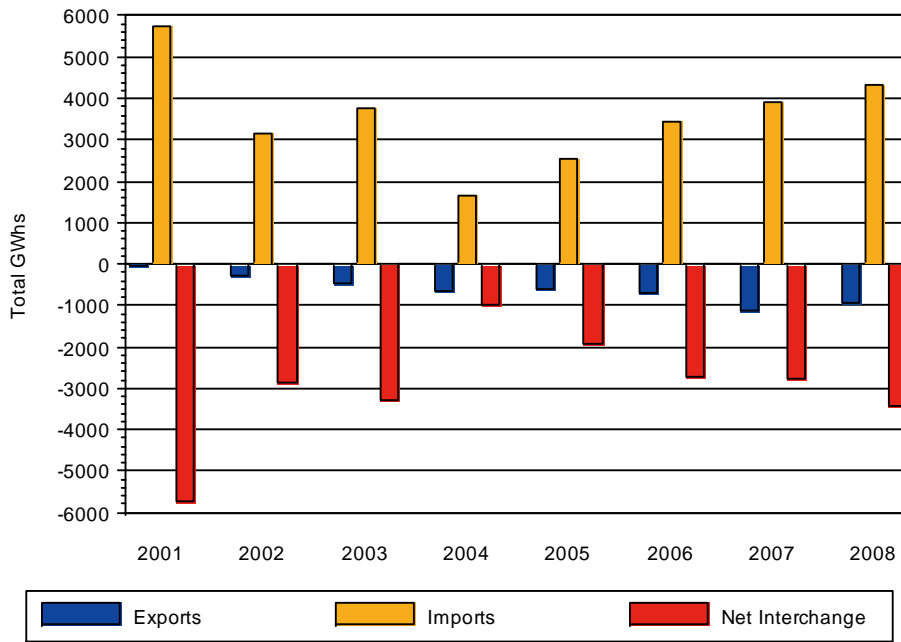
Figure 8 – Actual Generation by Fuel Type



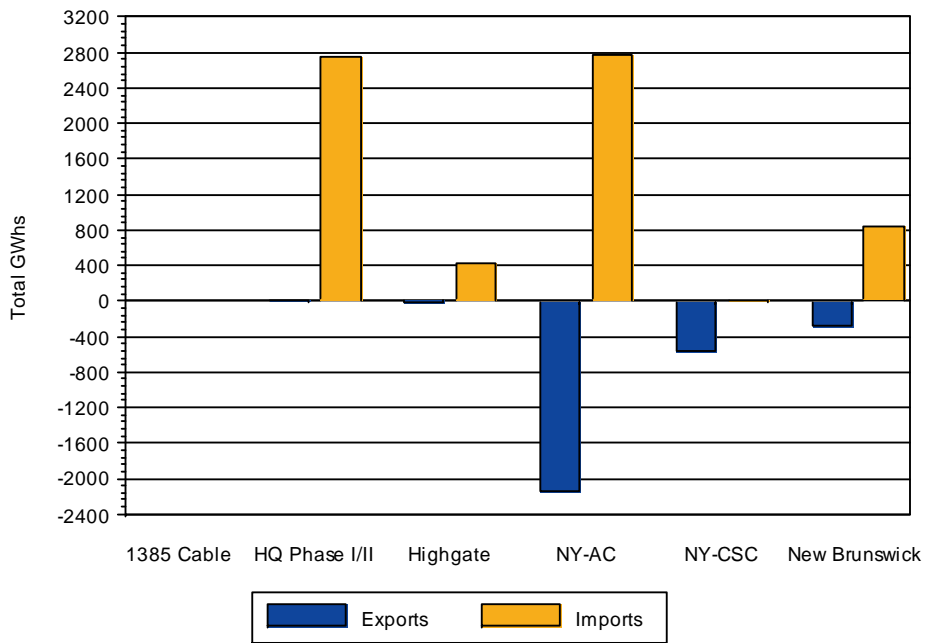
New England was a net importer from Canada and New York during the Reporting Period. Overall net imports were 10.1% of the quarterly NEL in New England.

Figure 9 shows total interregional power flows for the first quarters of 2001 through 2008. Figure 10 shows interregional power flows during the Reporting Period by external node. The NY-AC interface is the collection of AC tie lines connected to New York through Connecticut, Massachusetts, and Vermont. The NY-CSC interface is the Cross-Sound Cable.

**Figure 9 – New England Imports, Exports and Net Interchange
All Interfaces: 2001 – 2008 Q1**



**Figure 10 – New England Imports, Exports by Interface
2008 Q1**

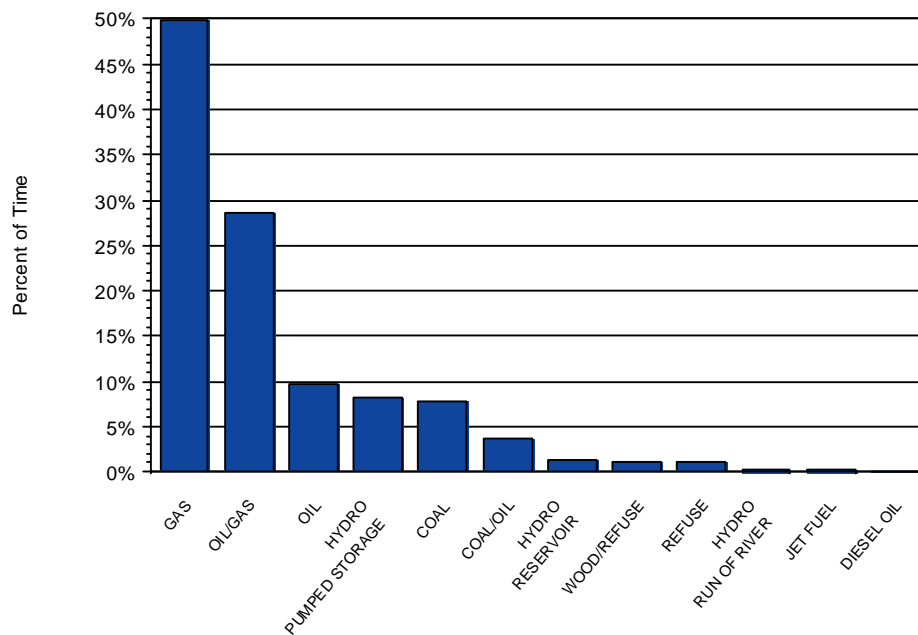


3.3 Electric Energy Prices

3.3.1 Marginal Input Fuel Types

Figure 11 shows the real-time marginal, or price-setting, input fuels during the Reporting Period as a percentage of pricing intervals. 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 the Reporting Period and are not included in the figure. The figure shows that units burning natural gas were marginal about 50% of the time during the period. Oil/Gas units, many of which burn gas as their primary fuel, were marginal about 29% of the hours. These results show the extent to which New England power prices are dependent on gas unit offers.

**Figure 11 – Marginal Units by Unit Type
2008 Q1**



3.3.2 Electric Energy Prices and Fuel Prices

Table 3 shows the price per MMBtu for the major fuels used during the Reporting Period.

Table 3 – Fuel Price Statistics for Q1 2008, \$/MMBtu

Fuel Type	Average Price	Low Price	High Price
Natural Gas	10.47	8.07	20.10
No. 6 Oil 1%	11.66	10.62	12.66
Low Sulfur Coal	2.96	2.25	3.40
High Sulfur Coal	2.63	2.04	3.40

Figure 12 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 12 – Daily Avg. Real-Time System Price of Energy vs. Variable Production Costs 2008 Q1

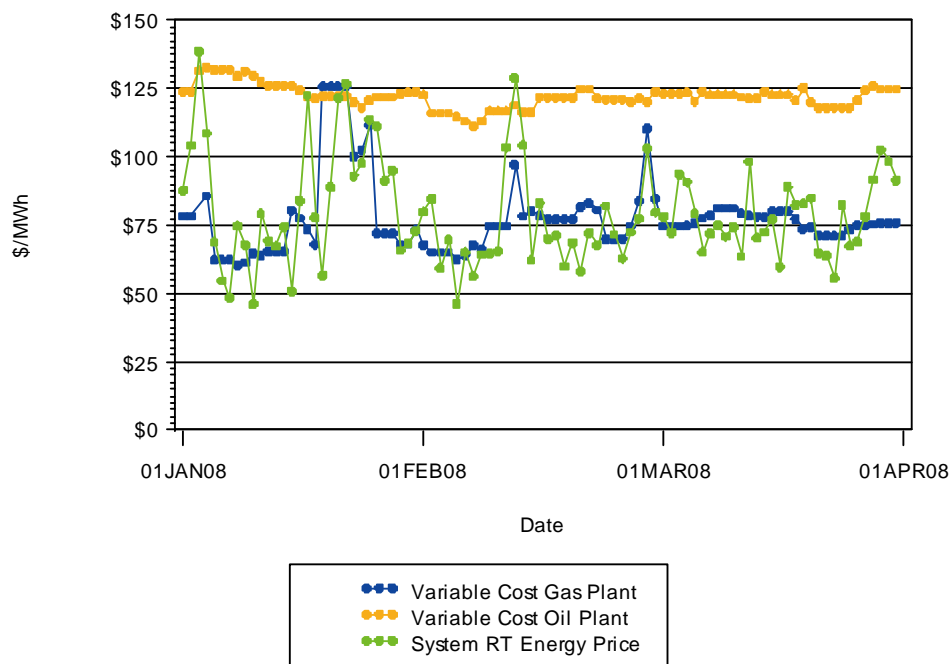


Table 4 shows average first quarter price indices for natural gas and No. 6 oil (1%), with each fuel indexed to its value in the year 2000. These two fuels are shown because they are on the margin for a majority of the time in New England, as was shown in Figure 11. The price of natural gas and No. 6 oil (1%) both increased in the first quarter of 2008 relative to the same period in 2006. Note that between 2007 and 2008, No. 6 oil (1%) prices increased at a higher rate than natural gas prices and oil has become the more expensive fuel on average. This change in relative prices alters the merit order dispatch with No. 6 oil units becoming more expensive, and dispatched less frequently, than natural gas units.

Table 4 – Fuel Price Index for First Quarters, Year 2000 Basis

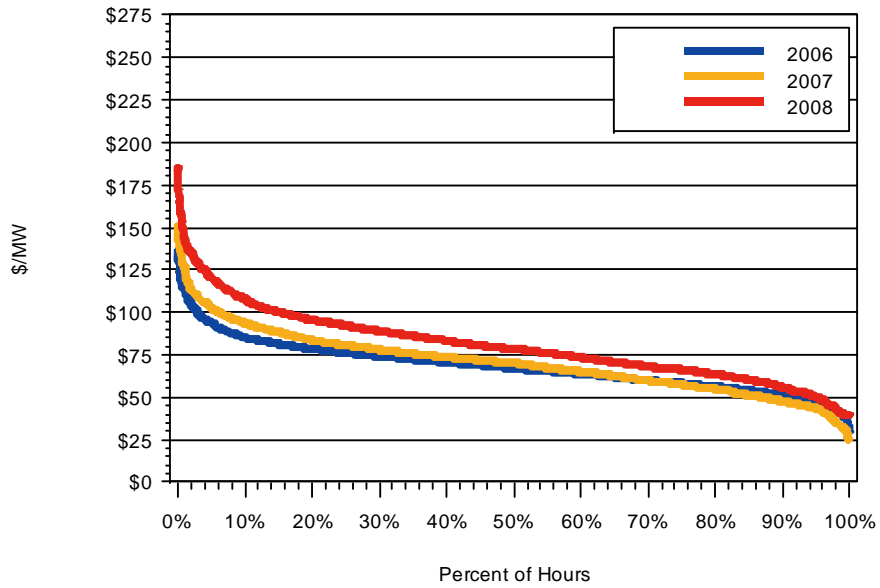
Fuel	2000	2001	2002	2003	2004	2005	2006	2007	2008
Natural Gas	1.00	1.73	0.71	2.18	1.93	2.04	2.09	2.10	2.57
No. 6 Oil (1%)	1.00	1.11	0.77	1.50	1.21	1.48	2.20	1.82	3.34

3.3.3 Energy Prices Throughout the Quarter

Figure 13 and Figure 14 show the day-ahead and real-time system electric energy prices for New England during the first quarters of the most recent three years as duration curves, with prices ordered from highest to lowest.³ For each first quarter, 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 prices during the first quarter of 2008 were only slightly higher than those during the first quarter of 2007 for about 80% of hours in both the Day Ahead and Real-Time Energy Markets.

³ System price is the load-weighted average of the nodal LMPs

**Figure 13 – New England Hourly DA System Price Duration Curves
2005- 2008 Q1**



**Figure 14 – New England Hourly RT System Price Duration Curves
2005- 2008, Q1 Prices < \$275**

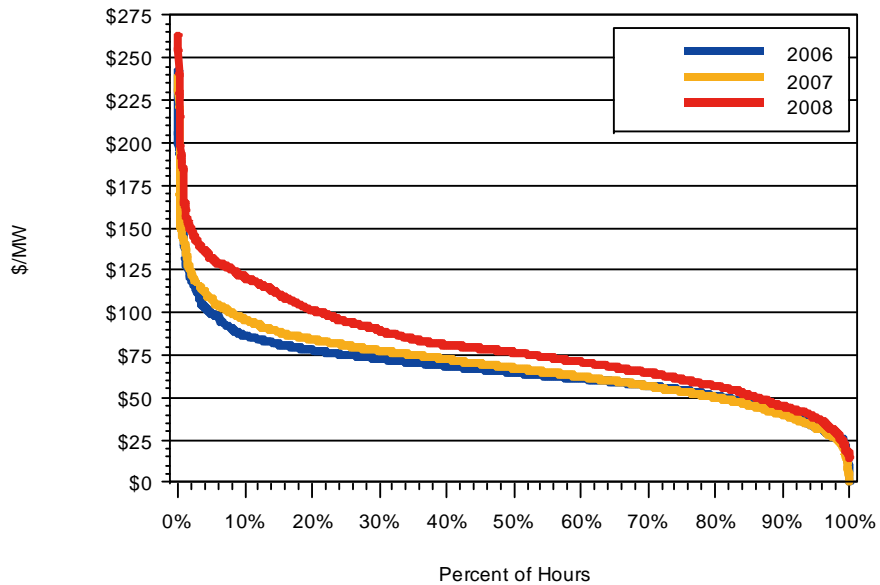


Figure 15 - Average Quarterly Load-Weighted System Day-Ahead and Real-Time LMPs

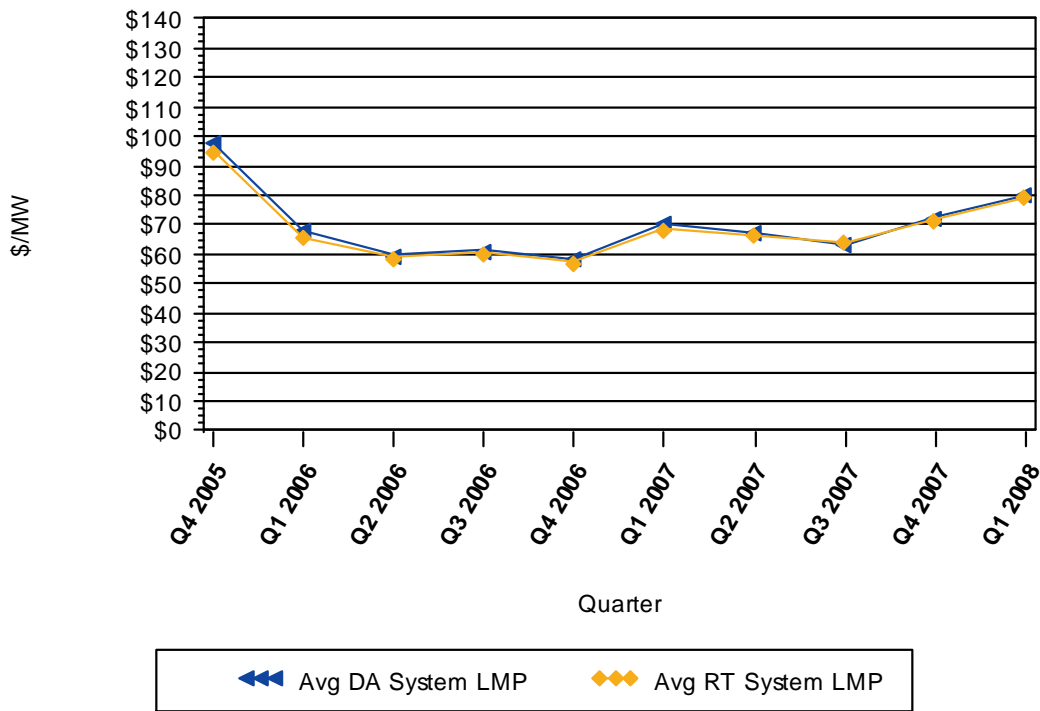


Figure 15 shows average quarterly prices from 2005 Q4 – 2008 Q1. Prices for the first quarter of 2008 were about \$10/MW higher than the first quarters of 2007 and 2006. Table 5 shows the quarterly average, minimum and maximum LMP values at the Hub, eight load zones, and the five external nodes that are priced in New England.⁴ Export constraints and negative marginal losses resulted in the Maine load zone having the lowest average prices of the load zones while import constraints caused Connecticut to have the highest average day-ahead and real-time load zone prices.

Average day-ahead LMPs were higher than average real-time LMPs in all zones. Zonal price differences between the Day-Ahead and Real-Time Energy Markets averaged about \$0.69/MWh. The largest difference was in Connecticut at \$2.12/MWh and the smallest in WCMASS at \$0.19/MWh.

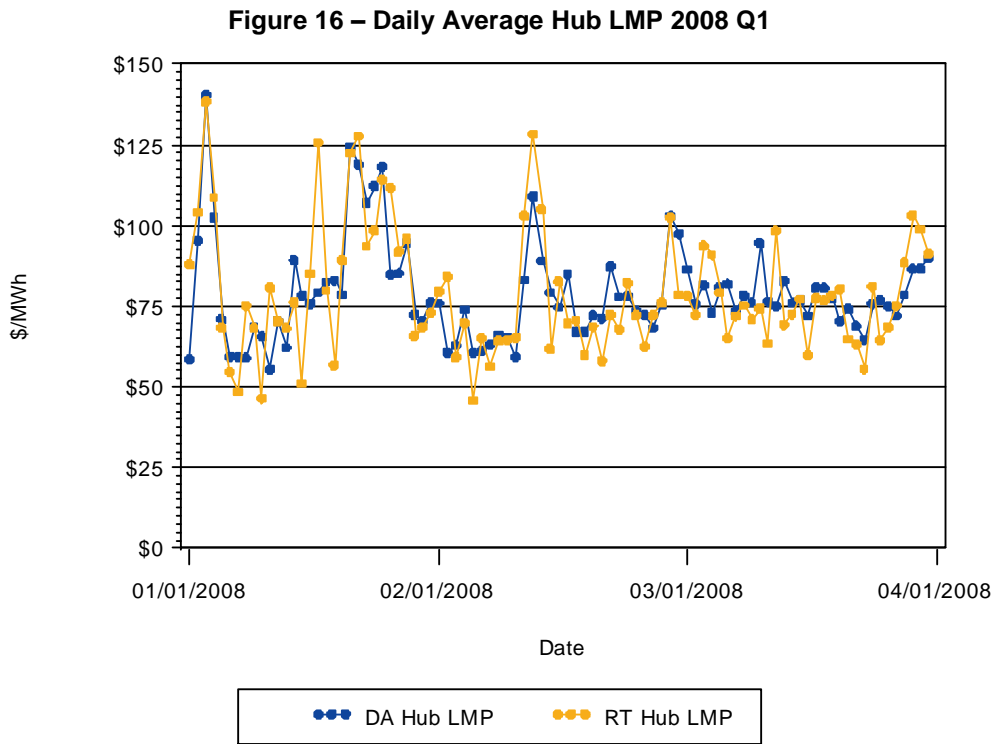
Fifty-six percent of the 2,183 hours during the quarter had Day-Ahead prices that were higher than their real-time counterparts. The standard deviation of the differences between day-ahead and real-time hourly prices was \$22.19/MWh.

⁴ On June 27, 2007, the 1385 cable was separated out from the NY –NE external interface and is now modeled as an individual external pricing node.

Table 5 – Summary Hourly LMP Statistics by Location, 2008 Q1, All Hours

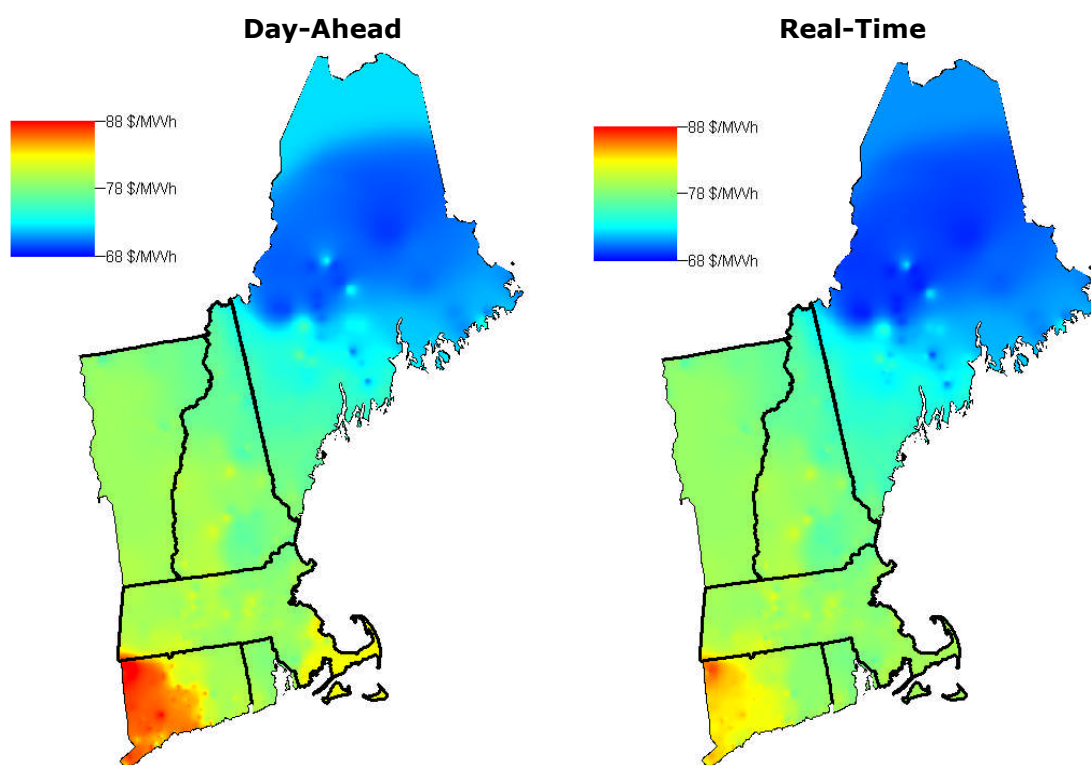
Location/Zone	LMP (\$/MWh)					
	Avg DA	Avg RT	Min DA	Min RT	Max DA	Max RT
Internal Hub	\$79.26	\$79.01	\$34.35	\$0.00	\$185.77	\$288.08
Maine Load Zone	\$74.84	\$73.93	\$32.37	\$0.00	\$180.53	\$275.22
New Hampshire Load Zone	\$78.08	\$77.78	\$32.90	\$0.00	\$183.53	\$284.07
Vermont Load Zone	\$79.17	\$78.89	\$34.35	\$0.00	\$185.85	\$288.19
Connecticut Load Zone	\$84.26	\$82.14	\$34.83	\$0.00	\$187.80	\$287.06
Rhode Island Load Zone	\$78.82	\$78.45	\$34.06	\$0.00	\$183.89	\$284.94
SEMASS Load Zone	\$80.22	\$79.08	\$34.39	\$0.00	\$185.59	\$288.41
WCMASS Load Zone	\$79.91	\$79.72	\$34.53	\$0.00	\$186.54	\$288.78
NEMA/Boston Load Zone	\$78.91	\$78.66	\$34.21	\$0.00	\$184.71	\$285.39
NB-NE External Node	\$72.39	\$70.87	\$18.79	\$0.00	\$178.67	\$263.37
NY-NE AC External Node	\$79.24	\$79.18	\$34.10	\$0.00	\$185.12	\$289.63
HQ Phase I/II External Node	\$77.15	\$76.87	\$33.57	\$0.00	\$181.62	\$278.93
Highgate External Node	\$73.94	\$73.58	\$32.36	\$0.00	\$173.92	\$268.01
Cross Sound Cable External Node	\$85.10	\$82.62	\$34.96	\$0.00	\$199.76	\$297.28
1385 Cable	\$86.14	\$83.64	\$35.04	\$0.00	\$200.43	\$299.91

Figure 16 shows daily average Hub LMPs during the Reporting Period.



On the maps in Figure 17, average quarterly nodal LMPs are shown in color gradations from blue (representing \$60/MWh) to red (representing \$75/MWh).

**Figure 17 – Average Nodal Prices
2008 Q1**



3.3.4 Wholesale Prices in Other Northeastern Pools

Table 6 shows quarterly average system prices for the three Northeast ISOs: PJM, NYISO, and the ISO. Hourly system prices were calculated for New England and New York based on

locational prices and locational loads, while prices for PJM are its published hourly system prices.⁵

**Table 6 – NE, NY, and PJM Average Electric Energy Prices
2008 Q1**

Control Area	Day-Ahead (\$/MWh)			Real-Time (\$/MWh)		
	All Hours	On-Peak	Off-Peak	All Hours	On-Peak	Off-Peak
NE	\$80.07	\$90.00	\$71.04	\$79.27	\$89.14	\$70.28
NY	\$82.94	\$97.42	\$69.85	\$82.70	\$96.15	\$70.54
PJM	\$66.10	\$77.22	\$55.98	\$66.77	\$77.13	\$57.33

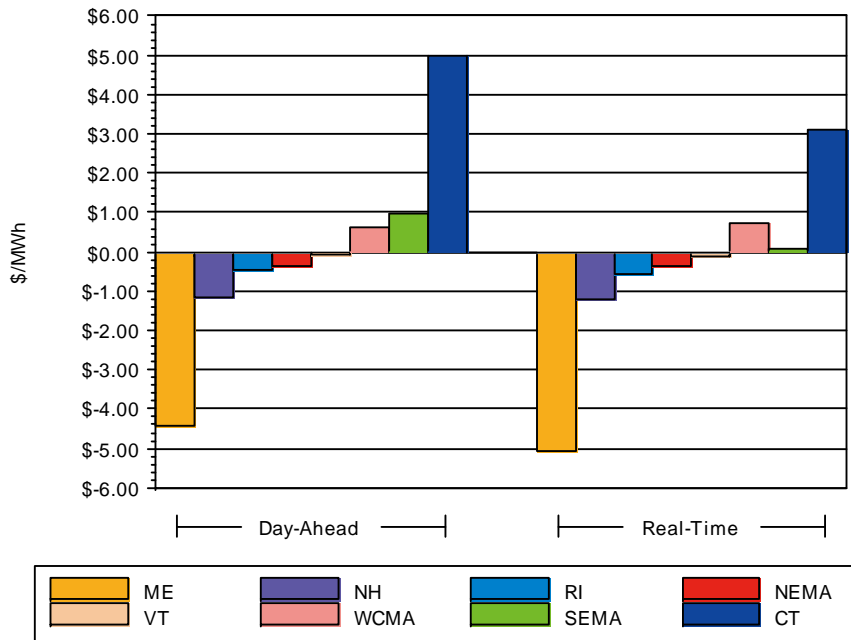
New England’s average Day-Ahead and Real-Time prices were lower than those in NY for all hour type categories, with the exception of Day-Ahead off-peak hours. When compared to PJM, New England’s average prices were higher in all hours. Variations in average prices among the power pools are affected by differences in generator fuel mix, transmission congestion, daily and seasonal load patterns, and load concentration in congested areas.

3.3.5 Effects of Transmission Congestion and Marginal Losses on LMP

LMPs reflect the cost of delivering electric energy to a specific location on the grid including marginal production costs and the marginal costs of transmission congestion and losses. This can result in price separation between locations which is a key element of efficient pricing. Figure 18 shows the average hourly LMP differences between each zone and the hub for the Reporting Period. The differences are due to the joint impact of the marginal costs of congestion and losses. Notable in the figure are the negative average differences in LMP in the Maine, New Hampshire, Rhode Island, NEMA and VT load zones (compared to the Hub) and the positive average differences in the WCMA, SEMA and Connecticut load zones (compared to the Hub).

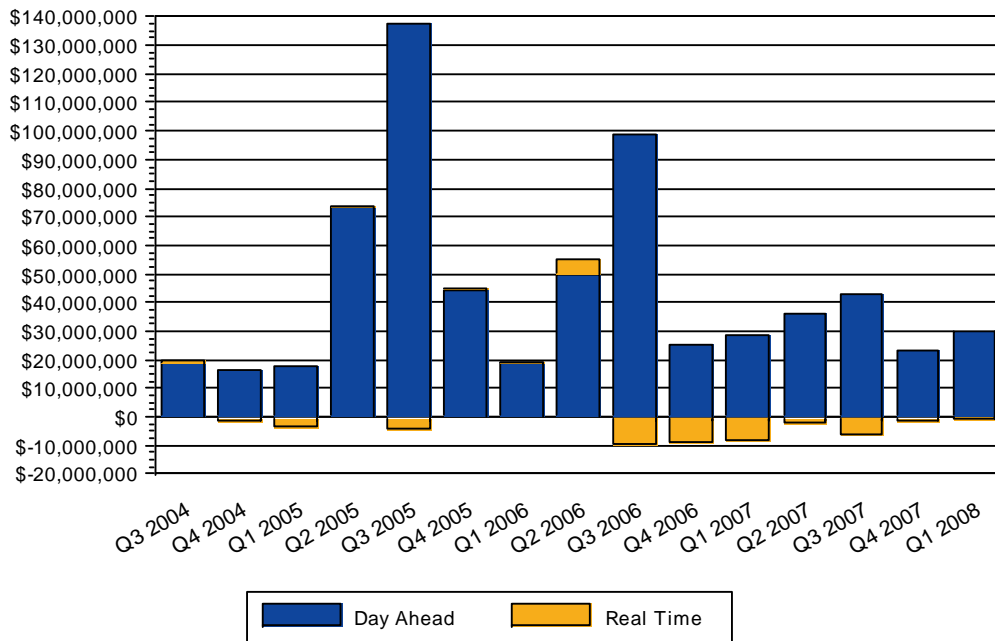
⁵ PJM’s web site is available at <<http://www.pjm.com>>. NYISO’s web site is available at <<http://www.nyiso.com>>. Quarterly average system prices are not load-weighted.

**Figure 18 – Average Hourly LMP Difference from Hub
2008 Q1**



Net congestion revenues are collected in the congestion revenue balancing fund and are used to pay FTR holders. Congestion revenue in the Day-Ahead Market was \$30.7 million for the first quarter of 2008 and \$28.2 million for the first quarter of 2007. The Real-Time revenue was -\$963,995 in the first quarter of 2008 and -\$8.3 million in the first quarter of 2007. Figure 19 shows total congestion revenue by quarter since the third quarter of 2004.

Figure 19 – Total Congestion Revenue by Quarter



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. For the Reporting Period, the Marginal Loss Revenue Fund totaled \$30.2 million.

3.4 Electric Energy Market Conclusions

Energy market operations were normal during the Reporting Period, with Hub LMPs that averaged \$79.26/MWh in the Day-Ahead Energy Market and \$79.01/MWh in the Real-Time Energy Market. Prices were highest in Connecticut and lowest in Maine.

4. Locational Forward Reserve Market

ISO operating procedures require reserve capacity to be available (i.e., electrically synchronized to the system and at rated capability) within 10 minutes to meet the first-largest system contingency and within 30 minutes to meet one-half of the second-largest system contingency. In general, capacity equal to one-half of the 10 minute reserve requirement must be synchronized to the power system, or spinning (Ten-Minute Spinning Reserve (TMSR)), while the rest of the 10-minute requirement may be nonsynchronized. The entire 30-minute requirement may be nonsynchronized (including Ten-Minute Non-Spinning Reserve (TMNSR), and Thirty-Minute Operating Reserve (TMOR)) or the higher-quality TMSR. In addition to being able to meet system wide requirements, 30-minute reserves must be available to meet the local second contingency requirements for the constrained areas of NEMA/Boston, Connecticut, and Southwest Connecticut.⁶ The Locational Forward Reserve Market (FRM), implemented as part of ASM II in October 2006, is a market-based method for compensating generating resources for providing operating reserves. 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. Tables 7 and 8 pertain to the auction that ended in September of 2007 regarding the Winter Period.

4.1 *Forward Reserve Market Auction Results*

The FRM requirements for each reserve zone (NEMA/Boston, CT, SWCT, and Rest-of-System) are shown in Table 7. Reserves that clear in SWCT count toward both SWCT and CT requirements. Reserves that clear in any of the local reserve zones (i.e., Rest-of-System, SWCT, CT, and NEMA/Boston) count toward the total system requirement in addition to the local requirement.

⁶ The local areas of NEMA/Boston, CT, and SWCT have no 10-minute reserve requirements. Local first-contingency recovery requirements can be met by operating at the N-1 import-interface limit.

Table 7 – Winter 10/2007- 05/2008 Forward Reserve Auction Requirement by Reserve Zone

Location Name	Product Type	Total Reserve Requirement (MW)	Cleared Reserve Requirement (MW)	Shortfall Target-Cleared MW
Total System	TMNSR	850.0	850.0	0
Total System	TMOR/TMNSR	1,550.0	1,550.0	0
Rest of System (outside SWCT, CT, NEMA)	TMNSR	798.0	798.0	0
SWCT	TMOR	611.0	324.5	(286.5)
CT	TMOR	1,366.0	949.5	(416.5)
NEMA/Boston	TMOR	1,180.0	1,180.0	0

The TMNSR and TMOR requirements for the total system, Rest-of-System and NEMA reserve zones were met in the winter 2007 auction, while the TMOR requirements for SWCT and CT were not met. In SWCT, all 324.5 MW of offers cleared. The cleared quantity was 286.5 MW short of the requirement of 611 MW. In the CT reserve zone, all 949.5 MW of offers cleared. The CT reserve zone was 416.5 MW short of its requirement. A total of 235 MW cleared in NEMA/Boston. The Total Reserve Requirement was reduced by 900 MW in NEMA/Boston due to external reserve support.

Table 8 shows the quantity of reserve offered and cleared for each reserve location by product type along with clearing prices. Because the locational TMOR reserve requirements were not met in SWCT and CT, the auction cleared at the administrative offer cap of \$14,000/MW Month. While there are no locational TMNSR requirements, participants can offer TMNSR to meet the TMOR requirement.

Table 8 – Winter 10/2007- 05/2008 Offered and Cleared by Reserve Zone and Product Type

Reserve Zone	Product Type	Total Supply Offers (MW)	Cleared Supply (MW)	Clearing Price (\$/MW-Month)
Rest of System (outside SWCT, CT, NEMA/Boston)	TMNSR	1192.3	805.0	\$9,050
Rest of System (outside SWCT, CT, NEMA/Boston)	TMOR	448.0	0	\$0
SWCT	TMNSR	0.0	0.0	\$14,000
SWCT	TMOR	324.5	324.5	\$14,000
CT	TMNSR	0.0	0.0	\$14,000
CT	TMOR	625.0	625.0	\$14,000
NEMA/Boston	TMNSR	45.0	45.0	\$14,000
NEMA/Boston	TMOR	395.5	235.0	\$8,500

4.2 Forward Reserve Market Results

Resources designated to meet a Forward Reserve obligation are required to offer energy at or above a monthly threshold price. The monthly threshold price is set using a formula announced as part of the forward reserve auction notice. The formula includes a heat rate that is fixed for the duration of the service period and a fuel price index that varies monthly.

Table 9 shows the threshold price for each month in the Reporting Period and the percentage of hours in which the real-time LMP for the NEMA and Connecticut load zones and the Hub exceeded the threshold price. The target frequency is 2.5% or less. There was significant deviation from the design target during January 2008, however results from February and March are more in-line with the design target.

Table 9 – 2008 Q1 Percentage of On-Peak Hours with Real-Time LMPs Greater than or Equal to FRM Threshold Price for the Hub, CT & NEMA Load Zones

Month	Hub (%)	CT (%)	NEMA (%)
Jan 2008	27%	27%	27%
Feb 2008	4%	6%	4%
Mar 2008	0%	3%	0%

The clearing prices from the forward-reserve auction are converted into an hourly payment rate based on on-peak hours.⁷ Generating units designated to meet daily forward reserve obligations are paid the hourly price. A market participant is penalized if it does not meet its forward reserve obligation by designating resources and offering these resources into the Real-Time Energy Market at or above the threshold price. Participants are also penalized if an assigned resource is not able to provide energy within 10 or 30 minutes if called on during real-time operations.^{8,9} The penalty for failing to designate a resource to meet a reserve obligation is 1.5 times the forward-reserve payment rate, in addition to the loss of the forward-reserve payment for the hour that the participant would otherwise have received.¹⁰ The penalty rate for failing to activate when called on by the ISO is 2.25 times the forward-reserve payment rate or the hourly price for electric energy, whichever is higher. Table 10 summarizes total payments, penalties, and net dollars for all forward reserve resources, by month. Generators that fail to provide energy when given dispatch instructions by the ISO incur penalties based on the cost of replacement energy.

⁷ Since ASM II implementation, the auction clearing prices are adjusted to reflect the FCM transition payment before being converted into an hourly rate.

⁸ Since ASM II implementation, participants are not assessed the failure-to-reserve penalty for periods when the unavailability is due to an approved annual maintenance outage.

⁹ Since ASM II implementation, failure-to-activate penalties are applied only when control room operators have approved a contingency unit-dispatch software case.

¹⁰ The forward-reserve payment rate is the auction price for the applicable reserve product in the applicable reserve zone, measured in \$/MW-month, divided by the number of on-peak hours in the applicable month.

Table 10 – Monthly Total Forward Reserve Market Payments and Penalties, 2008 Q1

Month	Total Payments	Total Penalties	Net Dollars
Jan 2008	\$16,410,366.13	-\$887,993.71	\$15,522,372.42
Feb 2008	\$16,273,020.65	-\$1,092,824.66	\$15,180,195.99
Mar 2008	\$15,724,962.04	-\$797,055.26	\$14,927,906.78

Table 11 – Real-Time Reserve Credits and Forward-Reserve Obligation Charges, 2008 Q1

Month	Real-Time Reserve Credit	Forward reserve Energy Obligation Charge
Jan 2008	\$2,809,305.93	-\$281,636.41
Feb 2008	\$5,991,112.29	-\$210,112.74
Mar 2008	\$1,553,040.52	-\$63,376.68
Total	\$10,353,458.74	-\$555,125.83

4.3 *Forward Reserve Market Conclusions*

The Forward Reserve Market and real-time reserve pricing appear to be working as designed. The quantity of supply offered in local areas may increase in future auctions, as it did in the earlier system-wide auctions.

5. Forward Capacity Market (FCM)

In March 2006, a settlement was filed at FERC to replace the previous SMD ICAP Market with a Forward Capacity Market (FCM). Payment under the FCM will not begin until 2010, approximately two and one-half years after the first FCM auction that was completed in February 2008. The FERC settlement includes a transition payment mechanism, which began on December 1, 2006, that provides payment certainty until the auction commitment year and FCM payments begin. Table 12 shows the FCM transition payments made to capacity resources during the Reporting Period.

Table 12 – FCM Transition Period Payment Summary

Obligation Month	UCAP Supply MW	FCM Transition Payment	Transition Payment \$/MW-Month
Jan 2008	35,840.08	\$109,312,258.99	3,050
Feb 2008	35,919.03	\$109,553,054.89	3,050
Mar 2008	38,236.09	\$116,620,065.30	3,050

6. Regulation Market

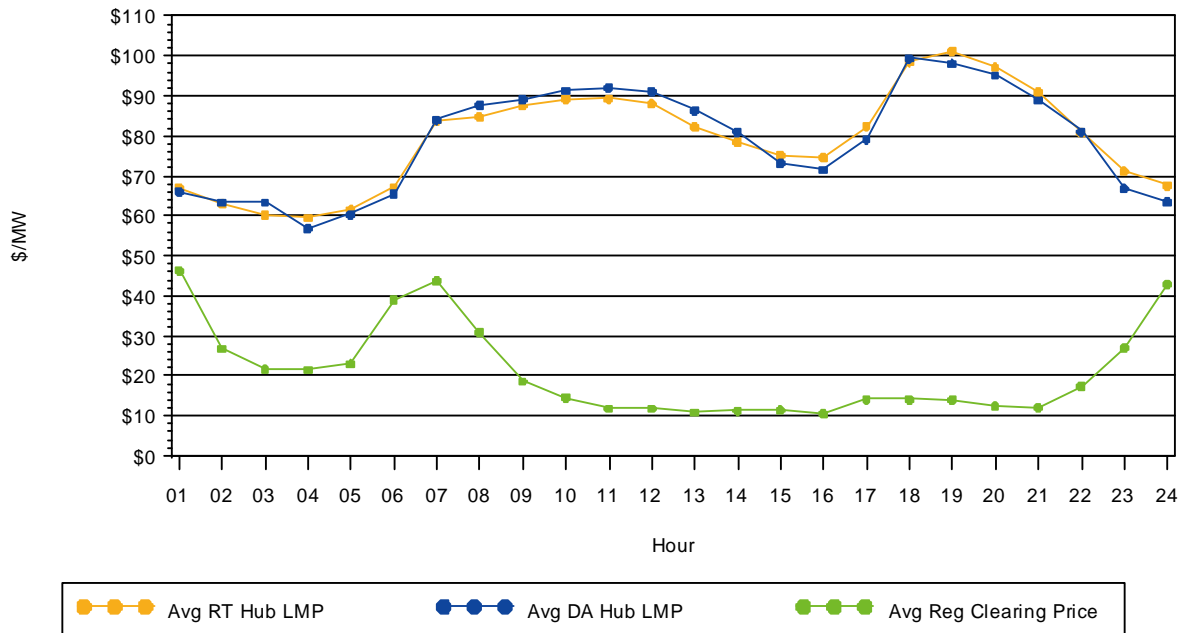
Regulation is necessary to balance supply levels with the second-to-second variations in demand. To respond to these slight changes on the system, specially equipped generators are sent signals to increase or decrease generation output every four seconds. This system balancing maintains proper power flows into and out of the New England Control Area.

The hourly Regulation Market clearing price averaged \$21.25/MWh during the Reporting Period. Total Regulation Market payments were \$13.59 million, including \$6.86 million in real-time opportunity cost payments. Table 13 shows summary information about clearing prices in the Regulation Market during the Reporting Period.

Table 13 – Regulation Market Clearing Prices Summary (\$/MWh), 2008 Q1

\$/MWh	Average	Median	Minimum	Maximum
Jan 2008	\$19.29	\$12.00	\$6.98	\$100.00
Feb 2008	\$22.96	\$11.00	\$6.65	\$100.00
Mar 2008	\$21.50	\$10.99	\$6.00	\$100.00

**Figure 20 – Average Hourly Regulation Clearing Prices and Hub DA & RT LMPs
2008 Q1**



7. 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 ISO’s operating procedures.¹¹ The ISO commits some generation outside of the market-clearing process to maintain power system reliability and meet these requirements. Figure 21 shows the energy output that resulted from these supplemental commitments in the Day-Ahead Energy Market, RAA process, and Real-Time Energy Market during the Reporting Period.

¹¹ The system operating procedures are available on the ISO’s Web site at <http://www.iso-ne.com/rules_proceeds/operating/isonone/index.html>.

**Figure 21 – Total Monthly Energy Output from Reliability Commitments
Day-Ahead, RAA, and Real-Time, 2008 Q1**

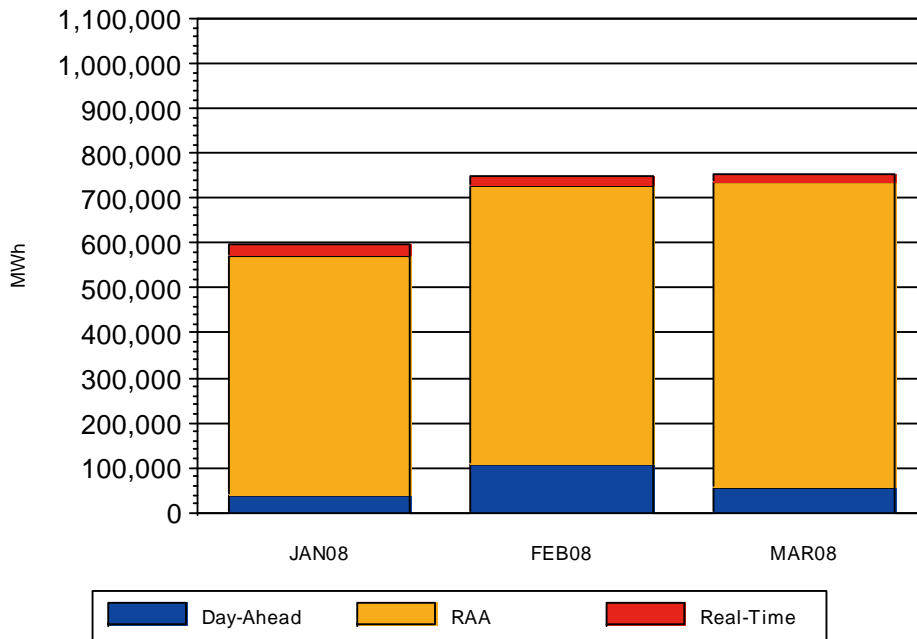


Table 14 shows total energy output from supplemental commitments made to supply local second contingency reserves by month and load zone.¹² Almost all second contingency commitments were made in the SEMA and Connecticut Zones. Norwalk-Stamford Connecticut, Southwest Connecticut, and the rest of Connecticut have local second-contingency reserve requirements on a regular basis. Within Connecticut, commitments are first made to solve constraints in the Norwalk/Stamford area, then Southwest Connecticut, and finally the rest of Connecticut, because commitments made in one of the sub-areas may also resolve constraints in the larger area. Energy output from second contingency commitments totaled 818,185 MWh during the Reporting Period.

¹² Local second contingency commitments were formerly called reliability must run (RMR) commitments.

**Table 14– Energy Output from Second Contingency Commitments
by Month and Load Zone, MWh, 2008 Q1**

		Jan 2008	Feb 2008	Mar 2008	Quarter Total
ME	Day-Ahead	360	0	0	360
	RAA/Real-Time	13,494	3,790	8,021	25,305
	Total Second Contingency Commitments	13,854	3,790	8,021	25,665
CT	Day-Ahead	34,941	106,878	56,129	197,948
	RAA/Real-Time	13,189	18,536	69,967	101,692
	Total Second Contingency Commitments	48,130	125,414	126,096	299,640
SEMA	Day-Ahead	1,938	0	0	1,938
	RAA/Real-Time	146,536	139,789	148,883	435,208
	Total Second Contingency Commitments	148,474	139,789	148,883	437,146
WCMA	Day-Ahead	0	0	0	0
	RAA/Real-Time	0	5,547	726	6,273
	Total Second Contingency Commitments	0	5,547	726	6,273
NEMA	Day-Ahead	0	1,045	0	1,045
	RAA/Real-Time	2,160	26,936	19,320	48,416
	Total Second Contingency Commitments	2,160	27,981	19,320	49,461

Table 15 shows total energy output from commitments made during the Reporting Period to provide reactive power by month and load zone. These commitments provide high voltage control or low voltage support. Total energy from reactive power commitments was about 125,806 MWh during the Reporting Period. Voltage control commitments are generally driven by hours when load levels are low, while voltage support commitments are needed for contingency coverage during high load periods.

Table 15 – Energy Output from Voltage Commitments by Load Zone, MWh, 2008 Q1

		Jan 2008	Feb 2008	Mar 2008	Quarter Total
NEMA	Day-Ahead	1,170	0	0	1,170
	RAA/Real-Time	40,486	30,240	53,910	124,636
	Total Voltage	41,656	30,240	53,910	125,806

8. Net Commitment Period Compensation

Reliability commitments can be viewed as the bulk power system's insurance policy. It provides a margin of additional supply above what is otherwise needed to meet real-time system demand. Reliability commitments call on units that are not economic given the LMP, and thus must be paid their costs not covered by the LMP. This payment is called Net Commitment Period Compensation, or NCPC. This compensation is based on the generator's submitted costs for providing energy, including start-up and no-load costs.

First and Second Contingency NCPC payments totaled approximately \$70.8 million during the Reporting Period. Figure 22 provides quarterly totals for NCPC payments. Table 16 shows second contingency payments by load zone.

Figure 22 – NCPC Payments by Quarter, 2003- 2008

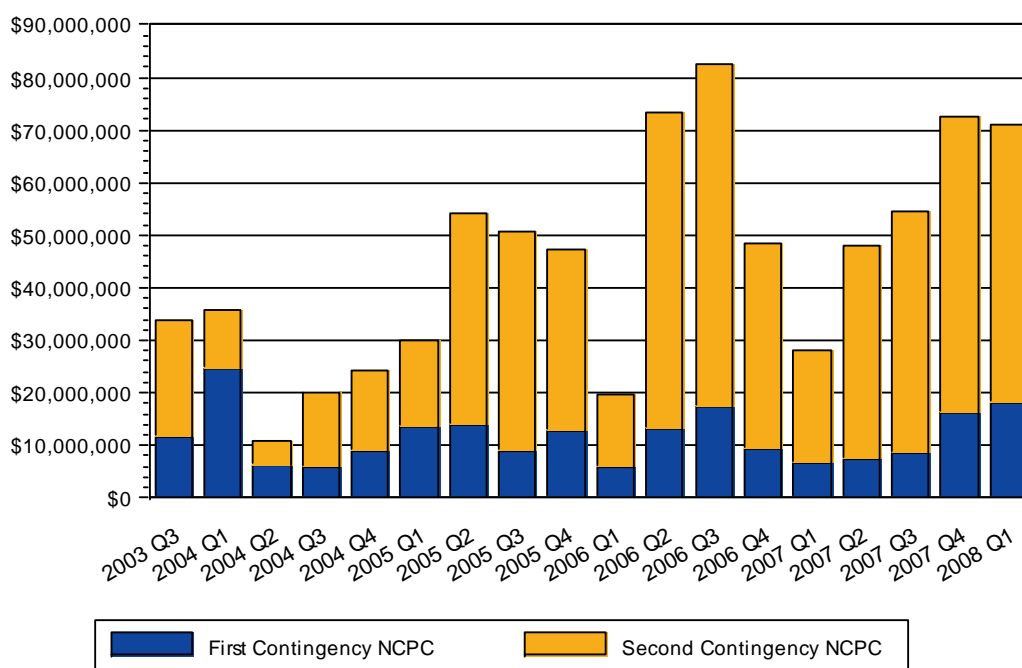


Table 16 – Total Second Contingency NCPC by Load Zone, 2008 Q1

Load Zone	Day-Ahead Payments	Real-Time Payments
Connecticut Load Zone	\$246,742	\$6,156,775
NEMA Load Zone	\$199,844	\$5,159,742
SEMA Load Zone	\$1,349,384	\$37,752,923
WCMA Load Zone	\$0	\$1,095,528

Table 17 and Table 18 show the average allocation of NCPC by month for the Reporting Period. Average charges are calculated based only on days with charges.

Table 17 – First Contingency Net Commitment Period Compensation Allocations for Days with Charges, \$/MWh, 2008 Q1

Month	Day-Ahead First Contingency	Real-Time First Contingency
JAN 2008	0.05	1.01
FEB 2008	0.00	0.41
MAR 2008	0.08	1.86

Table 18 – Second Contingency Net Commitment Period Compensation Charge Allocations for Days with Charges by Load Zone, \$/MWh, 2008 Q1

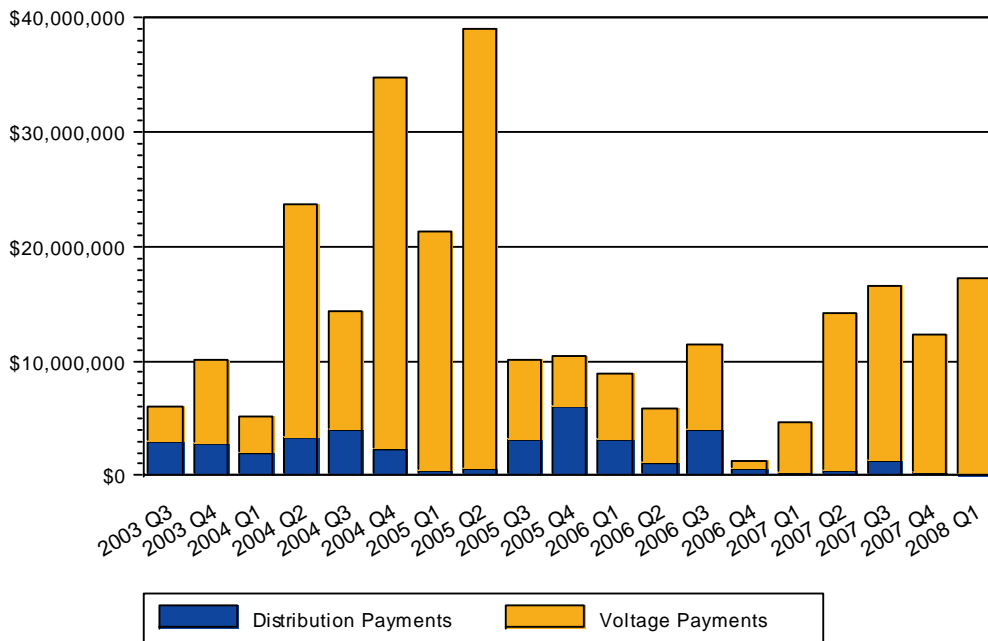
Month	CT Day-Ahead Second Contingency	CT Real-Time Second Contingency	NEMA Day-Ahead Second Contingency	NEMA Real-Time Second Contingency
JAN 2008	0.00	0.00	0.00	0.00
FEB 2008	0.18	1.30	0.00	3.64
MAR 2008	0.22	1.43	2.95	1.21

Month	SEMA Day-Ahead Second Contingency	SEMA Real-Time Second Contingency	WCMA Day-Ahead Second Contingency	WCMA Real-Time Second Contingency
JAN 2008	0.00	0.00	0.00	0.00
FEB 2008	4.97	11.91	0.00	0.33
MAR 2008	0.12	8.09	0.00	0.47

9. Voltage and Distribution Tariff Charges

Generators providing voltage or distribution service are compensated for shortfalls between their energy revenues and energy offers in the same way as generators flagged Second Contingency receive NCPC.¹³ Figure 23 shows voltage and distribution payments for the first quarter of 2003 through the first quarter of 2008. Total voltage payments in the Reporting Period were \$17,264,892 while distribution payments amounted to \$54,108. The majority of the payments, in both categories, came from real-time commitments. Table 19 shows voltage payments by load zone. Voltage payments are allocated to all New England transmission users based upon network load, while distribution payments are assigned directly to the transmission owner requesting that the generator be committed. Do we want to state why there has been an increase in voltage payments since 2006 Q4?

Figure 23 – Tariff Payments by Quarter, 2003 - 2008



¹³ Distribution service is called Special Constraint Resource service. Generators providing distribution service are called by the local transmission owner in an area to support the local transmission system.

Table 19 – Total Voltage Payments by Load Zone, 2008 Q1

Load Zone	Day-Ahead Payments	Real-Time Payments
NEMA	\$161,072	\$17,103,820

10. Reliability Agreements

Reliability Agreements provide eligible generators with monthly fixed-cost payments for providing reliability service. Reliability Agreements are paid for by network load in the zone that benefits from the reliability support provided. During the Reporting Period, Reliability Agreements were in effect for 9 generating stations, with a total of 18 units and 3,389¹⁴ MW. These 9 stations include West Springfield 1-3, Pittsfield/Altresco, and Berkshire Power in Western Massachusetts as well as Middletown, Montville, Milford, New Haven Harbor, Bridgeport Harbor, and Norwalk Harbor 1 and 2 in Connecticut.¹⁵

The net cost of Reliability Agreements to load during the Reporting Period was \$43.1 million.

11. Managing Congestion Risk – FTRs

Financial Transmission Rights (FTRs) 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. 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.

11.1 Auction Results

The January, February, and March monthly auctions included previously awarded FTRs from the January 2007 through December 2007 long-term auction. Fifty-percent of the transmission capacity of the New England control area was auctioned in the long-term auction, and 95% of the remainder was available in each of the monthly auctions. The long-term awarded FTRs are held aside in the following monthly auctions, decreasing the volume of FTRs that can be awarded in those auctions. Between 38 and 43 bidders participated in each monthly auction during the Reporting Period. This is consistent with levels of participation in auctions in prior months. The value of the first quarter was about \$7.35 million, the total value of all FTRs active in the quarter was about \$25.7 million, which includes the quarterly share of the January-March 2008 auction value (90/365) of \$74.7 million. Bids and offers cleared with negative prices that totaled to \$2.08 million. The \$7.35 million value for the first quarter monthly auctions is realized by netting \$2.08 million in net payments to FTR holders with negative prices from \$9.43 million in net collections from FTRs with positive prices.

¹⁴ 2007 CELT Report, Summer Capacity

¹⁵ Additional information about Reliability Agreements is posted on the ISO's Web site at < http://www.iso-ne.com/genrtion_resrcs/reports/rmr/index.html >.

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. The remaining 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.

Table 20 shows auction revenue distribution by category. The monthly revenues include monthly-normalized long-term auction revenues.

Table 20 –ARR Allocations, 2008 Q1

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 2008	\$-8,584,300	\$13,535	\$14,415	\$8,167,223	\$0	\$8,195,173	\$389,126	\$8,584,300
FEB 2008	\$-8,454,938	\$11,002	\$19,604	\$8,199,925	\$0	\$8,230,532	\$224,407	\$8,454,938
MAR 2008	\$-8,890,077	\$12,265	\$15,179	\$8,344,593	\$0	\$8,372,038	\$518,039	\$8,890,077

Table 21 displays the total distribution of ARR dollars to the various zones for each month including monthly-normalized long-term auction revenues.

Table 21 – ARR Award Allocation by Zone (\$), 2008 Q1

Month	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
JAN 2008	\$161,420	\$384,871	\$378,450	\$4,231,414	\$60,858	\$1,828,995	\$680,632	\$1,093,283
FEB 2008	\$168,325	\$405,944	\$391,957	\$3,780,407	\$63,259	\$2,198,024	\$677,186	\$884,052
MAR 2008	\$166,053	\$383,987	\$363,915	\$4,055,121	\$63,012	\$2,135,115	\$671,959	\$498,427

Figure 24 presents the overall pattern of inter-zonal FTR purchases (in MW-Months) for each of the on-peak auctions during the Reporting Period relative to the Hub. Zone-to-zone FTR purchases were decomposed into their zone-to-Hub and Hub-to-zone components. In the figure, negative values indicate that the net of all FTRs purchased between the Hub and the particular zone was toward the Hub (e.g., Maine), while positive values indicate net purchases from the Hub to the zone (e.g., NEMA and Connecticut, import-constrained areas).

**Figure 24 – On-Peak Zonal FTR Awards by Month Relative to Hub
2008 Q1**

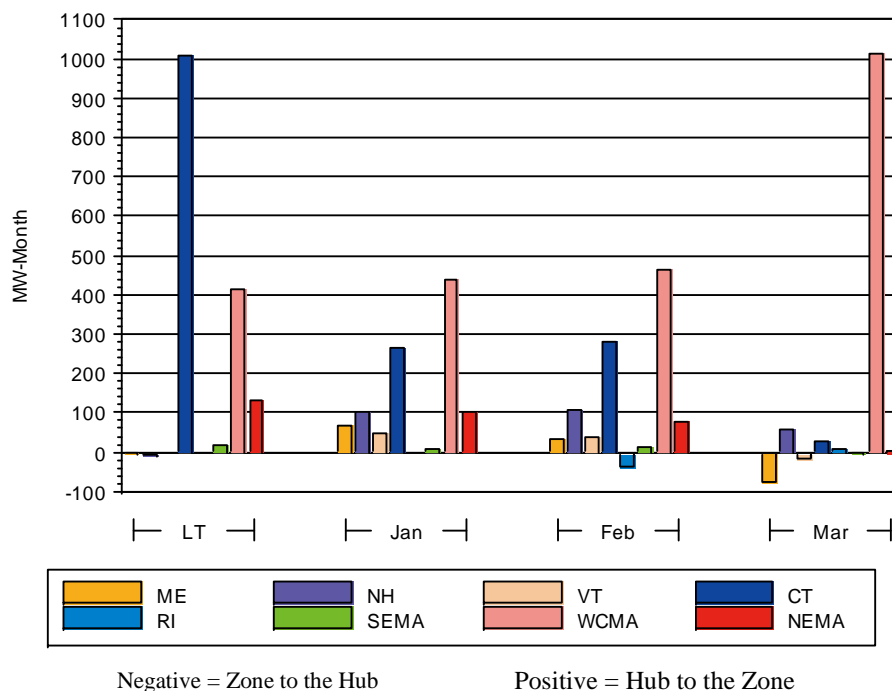
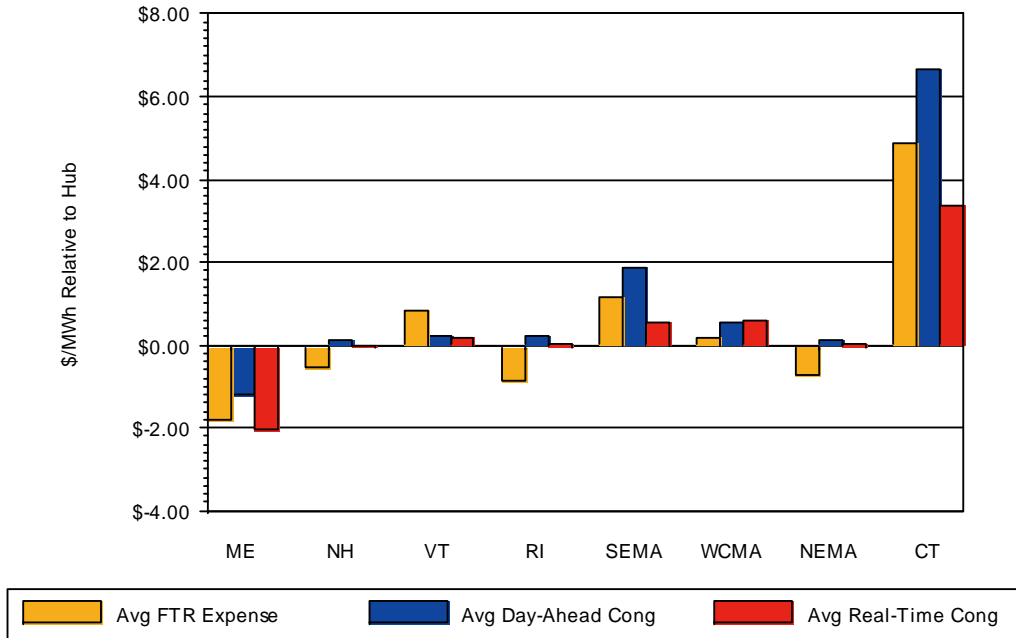
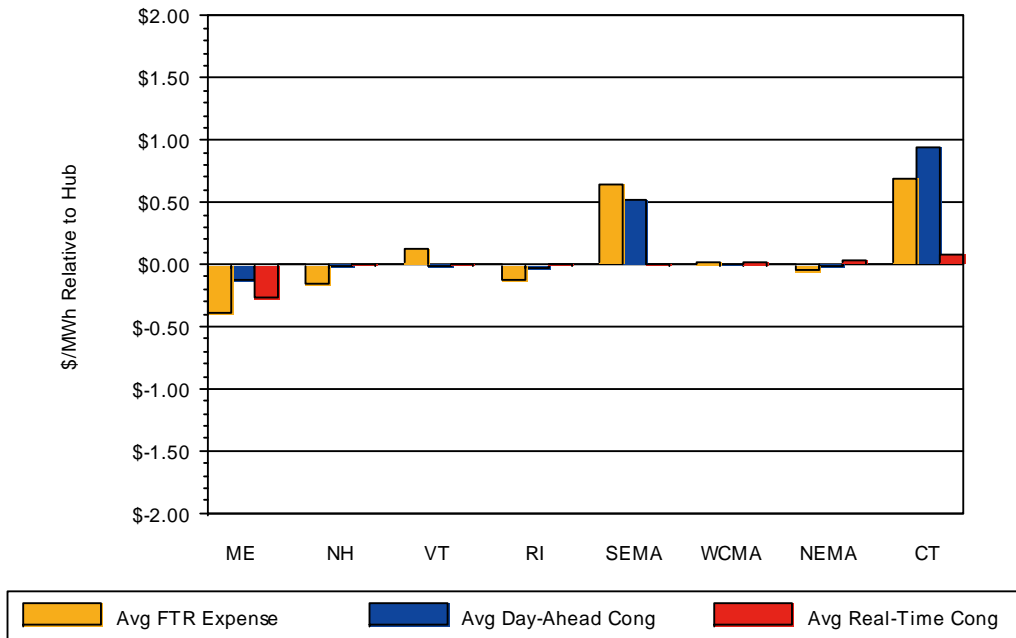


Figure 25 and Figure 26 present the relationship (on an equivalent \$/MWh basis) of the cost to procure an FTR with the actual day-ahead and real-time congestion costs over the Reporting Period. The figures incorporate both the monthly and long-term auction results in the presentation of the cost of an FTR.

**Figure 25 – FTR Auction Prices vs. Day-Ahead and Real-Time Congestion
2008 Q1, On Peak**



**Figure 26 – FTR Auction Prices vs. Day-Ahead and Real-Time Congestion
2008 Q1, Off Peak**



11.2 Financial Transmission Rights Clearing Prices

FTR clearing prices statistics are based on actual FTR awards. A negative price indicates that the awardees were paid to take the FTR obligation. This occurs when participants purchase FTRs in the opposite direction of expected congestion, such as from Connecticut (import-constrained) to Maine (export-constrained).

Table 22 compares maximum, minimum and average clearing price statistics for recent auctions. On-peak, off-peak and combined calculations are shown. Long-term auction values have been converted to \$/MW-Month for comparison.

Table 22 - FTR Auction Clearing Price Statistics

Auction Clearing Price (\$/MW-Month)							
	Avg. Combined	Avg. On-Peak	Avg. Off-Peak	Max On-Peak	Min On-Peak	Max Off-Peak	Min Off-Peak
Jan-Dec 2008 LT	\$4,788.77	\$8,207.56	\$1,471.14	\$37,515.50	-\$12,975.78	\$13,362.52	-\$4,279.26
Jan 2008	\$396.37	\$554.74	\$239.13	\$2,616.98	-\$798.47	\$967.01	-\$104.07
Feb 2008	\$386.68	\$599.59	\$175.73	\$2,652.06	-\$718.60	\$1,139.83	-\$69.18
Mar 2008	\$419.76	\$559.29	\$282.69	\$3,334.77	-\$713.31	\$1,212.61	-\$56.73

Table 23 lists the highest priced sink-source combinations as purchased in the monthly auctions during the Reporting Period. In general, the table reflects the use of FTRs as a congestion hedge between generation-rich areas, such as Maine, and the most constrained areas on the system, such as the Connecticut and NEMA zones. Many of the highest revenue-producing sources were nodes.

Table 23 – Top Five Highest Priced FTR Sink-Source Combinations, Monthly Auction

Auction	On-Peak Auction		
	Source	Sink	Award Price
JAN 2008	LD.E_BRGWTR13.8	LD.MARSHFEL115	\$1,789.73
JAN 2008	LD.MILL_ST 115	LD.KINGSTON115	\$1,789.73
JAN 2008	LD.PARKVIEW115	LD.HATCHVIL115	\$1,780.37
JAN 2008	LD.BATES_ST115	LD.CROSS_RD115 111X LD	\$1,757.64
JAN 2008	LD.MIDLBORO115 M1 LD	UN.CANAL 18.0CAN2	\$1,754.03
FEB 2008	UN.PILGRIM 22.8PILG	LD.FISHR_RD115	\$2,333.37
FEB 2008	LD.E_BRGWTR13.8	LD.MARSHFEL115	\$2,310.83
FEB 2008	LD.MILL_ST 115	LD.KINGSTON115	\$2,310.83
FEB 2008	LD.BATES_ST115	LD.CROSS_RD115 111X LD	\$2,286.45
FEB 2008	UN.SYKES_RD13.8FLRV	LD.CROSS_RD115 111X LD	\$2,280.95
MAR 2008	LD.SANDY_PD23	UN.OTIS 115 OAKB	\$2,029.17
MAR 2008	LD.E_BRGWTR13.8	LD.MARSHFEL115	\$1,966.28
MAR 2008	LD.MILL_ST 115	LD.KINGSTON115	\$1,966.28
MAR 2008	LD.BATES_ST115	LD.CROSS_RD115 111X LD	\$1,943.68
MAR 2008	UN.SYKES_RD13.8FLRV	LD.CROSS_RD115 111X LD	\$1,936.65

11.3 Financial Transmission Rights Payment Results

FTR holders are paid through the Transmission Congestion Revenue Balancing Fund. Monthly revenues, target allocations, and allocations paid are shown in Table 24. The first four columns show the sources of revenue paid into the fund for each month of the Reporting Period. The next two columns show the positive target allocations that are owed to FTR holders and the shortfall or surplus for the month. The final column shows the percentage of the target allocation that is actually paid for each month.

Table 24 – Congestion Revenue Fund, 2008 Q1

Month	Fund Adjustment	Day Ahead Congestion Revenue	Real Time Congestion Revenue	Negative Target Allocation	Positive Target Allocation	Monthly Fund Surplus or Shortfall	Percent Positive Allocation Paid
JAN 2008	\$5,659.76	\$4,442,671	\$-102,253	\$-3,487,921	\$6,670,302	1,163,697	100.00%
FEB 2008	\$-8,200.70	\$7,461,782	\$-546,660	\$-4,278,697	\$11,388,921	\$-203,302	98.21%
MAR 2008	\$-1,771.50	\$18,162,128	\$-315,080	\$-3,639,767	\$16,530,707	\$4,954,336	100.00%

11.4 Financial Transmission Rights Conclusions

Revenues from the FTR Auctions during the first quarter for 2008 totaled about \$7.35 million. The total value of all FTRs active in the quarter was about \$25.7 million, which included the

quarterly share of the January-December 2008 auction value (90/365) of \$74.7 million. Bids and offers cleared with negative prices that totaled to \$2.08 million. The \$7.35 million value for the auction is realized by netting \$2.08 million in net payments to FTR holders with negative prices from \$9.43 million in net collections from FTRs with positive prices.

12. Demand Response

Demand response in wholesale electricity markets refers to resources that reduce consumption of electric energy from the high-voltage transmission system in response to either high wholesale prices or system reliability events in exchange for compensation based on wholesale market prices.¹⁶ The ISO administers the Demand Response Programs for the New England wholesale electricity market. During the first quarter of 2008, the ISO administered several demand response programs. Other demand resources such as energy efficiency, load management, and distributed generation tend to reduce end-use demand on the electricity network across many hours, but usually not in direct response to changing hourly wholesale price incentives. All types of demand resources may provide relief from capacity constraints, the activation of reserve, or promote more economically efficient uses of electrical energy. Along with adequate supply and robust transmission infrastructure, demand resources are an important component of a well-functioning wholesale market.

The ISO operates three reliability-activated and two price-activated demand-response programs for the New England wholesale electricity market. Another group of demand resources known as other demand resources (ODRs) came into being with the implementation of the FCM transition period. The reliability-activated demand-response programs and ODRs are considered capacity resources and are eligible to receive FCM transition payments.

Reliability Programs

The demand-response programs that help preserve system reliability are as follows:

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

¹⁶ Demand resources include sites enrolled individually and collections of multiple sites enrolled by one customer.

- **Real-Time Two-Hour Demand-Response Program**—requires demand resources to respond within two hours of the ISO’s instructions to interrupt.
- **Real-Time Profiled-Response Program**—designed for participants with loads under their direct control that are capable of being interrupted within two hours of the ISO’s instructions to interrupt. Individual customers participating in this program are not required to have an interval meter. Instead, participants are required to develop and submit to the ISO for approval a monitoring and verification plan for each of their individual customers.

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

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

Other Demand Resources:

- **Other Demand Resources (ODRs)** —other demand resources were established by the FCM Settlement Agreement and are eligible to receive FCM transition payments. These resources consist of energy efficiency, load management, and distributed generation projects implemented by market participants at retail customer facilities:

12.1 Demand Response Results

As of March 31, 2008, 2,653 assets were enrolled in the ISO’s demand response programs, comprising 1,674 MW of potential demand interruption or curtailment. Table 25 displays enrollment by zone and by program, as well as the changes in each category from the same period in 2007. Figure 27 shows the amount of enrolled megawatts of Demand Response participation from January 2005 through March 2008.

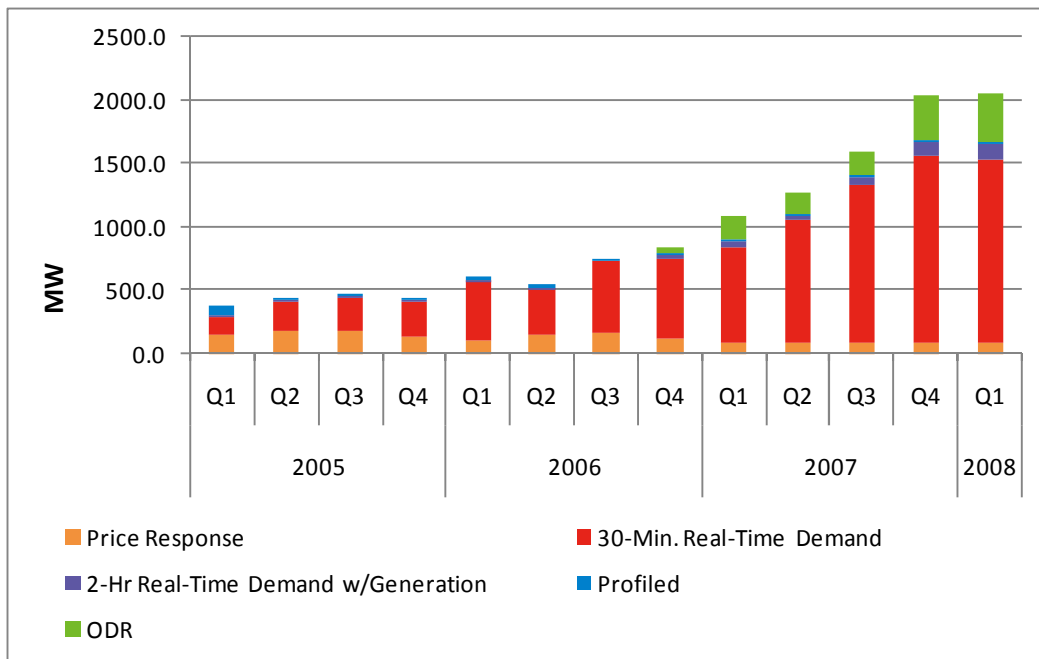
The quantity of enrolled MW has increased 85% since March 30, 2007, with the majority of the increases coming from greater participation in the Reliability based Real-Time 30-Minute and Real-Time 2 Hour Demand-Response Programs. In the Connecticut load zone, enrollment increased to 761 MW in the second quarter of 2008 from 514.9 MW during the same period in 2007.

Table 25 – Demand Response Program Enrollments

	March 2008					
	Assets	MW	Real-Time Price	Real-Time 30-Min	Real-Time 2-Hour	Profiled
CT	1,395	761.0	7.3	753.7	0.0	0.0
SWCT*	694	372.5	0.7	371.8	0.0	0.0
ME	53	415.4	0.0	324.5	79.8	11.0
NEMA	321	150.5	30.9	119.6	0.0	0.0
NH	77	42.0	4.5	33.8	3.7	0.0
RI	198	75.9	16.5	54.5	5.0	0.0
SEMA	243	64.1	9.7	49.9	4.5	0.0
VT	61	41.4	6.3	22.3	6.9	5.9
WCMA	305	103.8	22.3	84.4	17.8	0.0
Total	2,653	1,674.7	97.5	1,442.7	117.6	16.9
% Change from March 2007	62.0%	84.6%	0%	93.1%	155.0%	0%

*SWCT assets are included in CT values and are not included in total.

Figure 27 - Demand Response Enrollment by Program



Demand response programs provided 67,334 MWh of demand reductions during the Reporting Period. The majority of these reductions were from the two price-activated programs: Real-Time Price Response and the Day-Ahead Load Response Program. There were no reliability programs activated during the Reporting Period. Payments to resources providing demand reduction totaled \$5.9 million during the Reporting Period.

13. Market Monitoring and Mitigation

Market Rule 1, Appendix A, regarding Market Monitoring, Reporting and Market Power Mitigation, provides for the monitoring and, in specifically defined circumstances, the mitigating of behavior that interferes with the competitiveness and efficiency of the Energy Market and NCPC payments. No mitigation events occurred in either the Day-Ahead or Real-Time Energy Markets or in NCPC payments during the Reporting Period.

14. Generating Unit Availability

In its continuing effort to monitor and analyze the availability of New England’s generating units, the ISO’s System Planning department routinely analyzes generating unit availability. This type of analysis is important in assessing whether the market is providing the proper incentives for availability, a key factor in maintaining both reliability and market competitiveness. Historical generator availability is presented below to provide a more encompassing view of trends in unit performance.

Table 26 illustrates the Weighted Equivalent Availability Factors¹⁷ (WEAF) of New England generating units during the first quarter of 2008. As illustrated, the monthly system WEAF decreases through the quarter with February 2008 having the highest WEAF (92%), as generator maintenance increases and System Operators prepare for the spring shoulder load period.

Table 26 New England 2008 Monthly Weighted Equivalent Availability Factors (%) by Unit Type

	Jan-08	Feb-08	Mar-08
System Average	90	92	85
Fossil Steam	86	90	85
<i>Coal</i>	83	84	80
<i>Coal/Oil</i>	93	96	96
<i>Oil</i>	74	82	93
<i>Oil/Gas</i>	98	100	78
<i>Wood/Refuse</i>	94	94	90
Nuclear	100	100	100
Jet Engine	98	99	91
Combustion Turbine	93	95	95
Combined Cycle	87	90	76
<i>Pre-1999 Combined Cycle</i>	91	99	85
<i>New (Installed 1999-2008) Combined Cycle</i>	86	88	74
Hydro	97	98	100
Pumped Storage	99	90	81
Diesel	98	99	100

¹⁷ The term “Weighted” means that averaging is proportional to unit size, so that a 100 MW unit counts ten 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.

Figure 27 shows total peak day outages in megawatts for 1st Quarter 2007 through 1st Quarter 2008 and the amount of capacity on outage as a percentage of total available capacity (seasonal claimed capability). This figure illustrates how both the spring and fall months have the largest number of outages, while the summer period has the smallest number. Peak day outages were lower in January and March in 2008 compared to 2007, but higher in February 2008 compared to the same period in 2007.

Figure 28 –Average Generator Outages on Peak Demand Day of Month

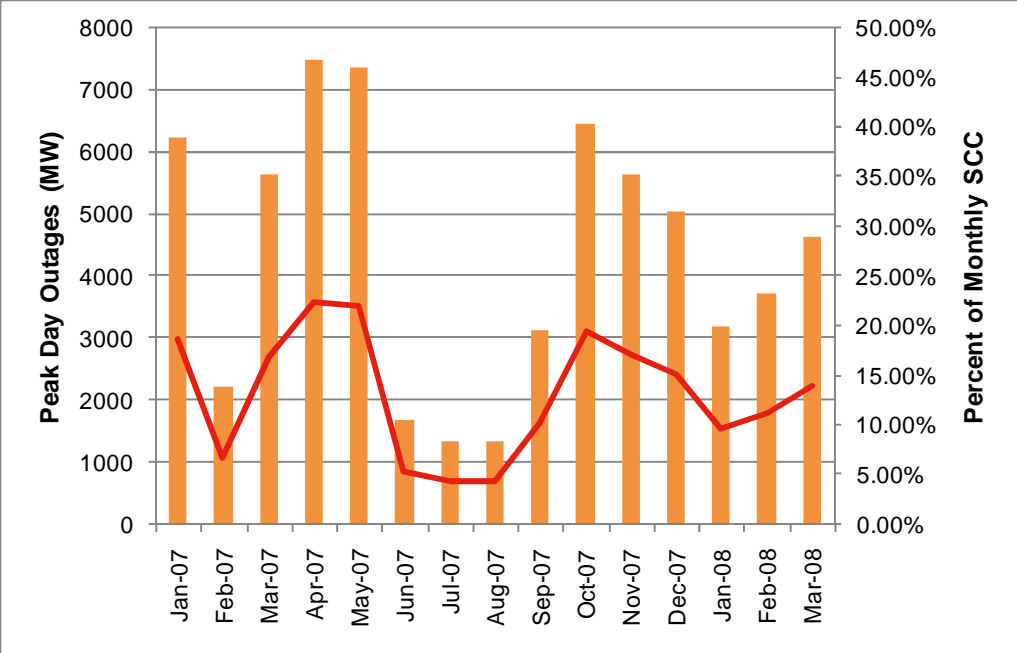
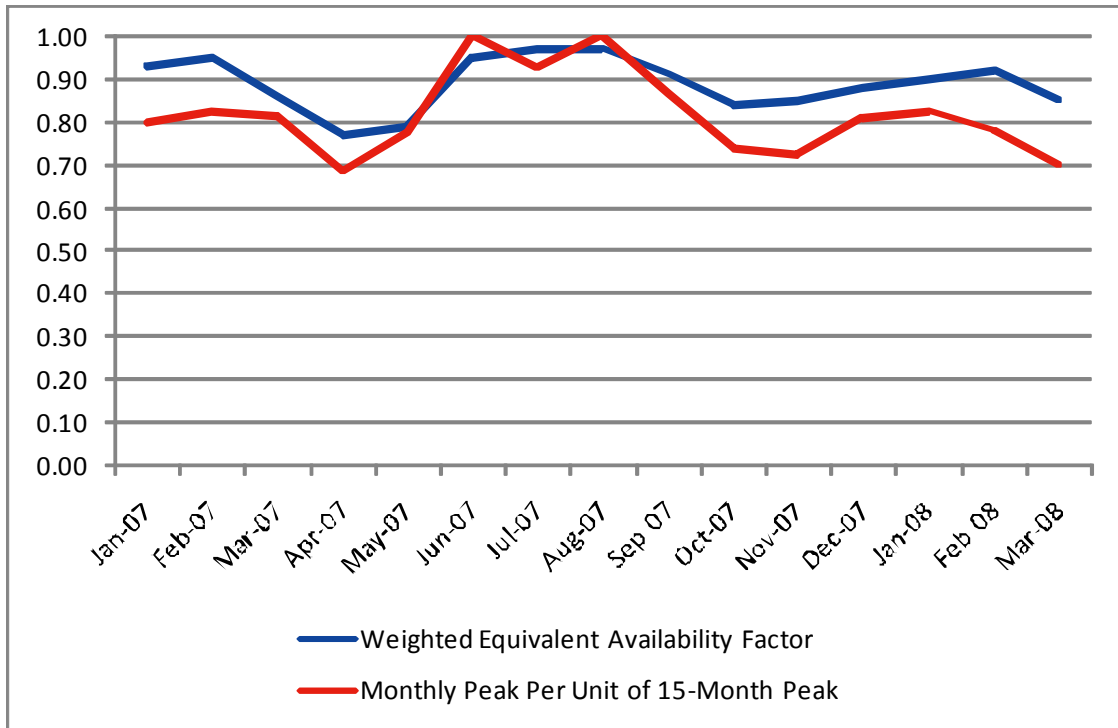


Figure 28 illustrates how the availability of the New England generating units tracks the monthly electrical demands. Specifically, Figure 29 illustrates the monthly WEAFF compared to the monthly peak electricity demand as a percentage of the 15-month period peak demand. For the 15-month period of January 2007 through March 2008, the peak of 26,264 MW occurred in August 2007. Similar to the information portrayed in Figure 28, the average availability for the New England generating units is lowest during the months that have the lowest demand. In contrast, when New England experiences the highest demand, the average availability of New England generators is the greatest.

Figure 29 – Monthly Peak Demand and Average Availability (WEAF)



15. Administrative Price Corrections

The ISO continually monitors the processes associated with the calculation of LMPs. In the event of a data input failure, hardware or software failure or outage, program failure, or binding constraint errors, corrective actions may be taken to ensure that the resulting LMPs are as accurate as is reasonably possible.

Figure 30 shows the number of hours with real-time LMP corrections made during each month during the Reporting Period. In many cases, corrections affected LMPs at only a few individual nodes. Real-time nodal prices were unaffected.

There were no revisions to day-ahead prices during the Reporting Period.

Figure 30 – Real-Time Energy Market LMP Corrections by Month

