RTO/ISO Market Monitoring Report
Docket No. ZZ10-4-000

August 26, 2010

VIA ELECTRONIC FILING

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: ISO New England Inc. 2010 Second Quarter Quarterly Markets Report; Docket No. ZZ10-4-000

Dear Secretary Bose and Deputy Secretary Davis:

Enclosed herewith please find the *2010 Second Quarter Quarterly Markets Report* (the "Report") of ISO New England Inc.'s (the "ISO") Internal Market Monitor. The Internal Market Monitor provides the Report in accordance with Section 12.2.2 of Appendix A to Market Rule 1.[1]

The Report analyzes the second quarter performance of the region's wholesale electric energy, reserve and capacity markets using supply offers, demand bids, economic data, fuel prices, market results, and other information regarding the wholesale electric markets.

The following person is identified as the contact person regarding this filing:

[1] Market Rule 1 is Section III of the ISO New England Inc. Transmission, Markets and Services Tariff, FERC Electric Tariff No. 3 (the "Tariff"). Section III.A.12.2.2 of Appendix A to Market Rule 1 provides as follows:

> III.A.12.2.2. Quarterly Report. The Internal Market Monitor will prepare a quarterly report consisting of market data regularly collected by the Internal Market Monitor in the course of carrying out its functions under this Appendix A and analysis of such market data. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the Information Policy.

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The ISO has sent electronically a link to the Report as posted on the ISO website to all New England Power Pool ("NEPOOL") Participant Committee members and the electric utility regulatory agencies for the six New England states that comprise the New England Control Area.

Respectfully submitted,

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Enclosure

2010 Second Quarter
Quarterly Markets Report

Internal Market Monitor
August 24, 2010

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Preface

The Internal Market Monitor ("IMM") of ISO New England ("ISO") publishes a Quarterly Markets Report ("QMR") that assesses the state of competition in the wholesale electricity markets operated by the ISO. The report addresses the development, operation, and performance of the wholesale electricity markets administered by the ISO and presents an assessment of each market based on market data, performance criteria, and independent studies.

This report fulfills the requirement of Market Rule 1, Section 12.2.2, Appendix A, *Market Monitoring, Reporting, and Market Power Mitigation*:

> The [IMM] will prepare a quarterly report consisting of market data regularly collected by the Internal Market Monitor in the course of carrying out its functions under this Appendix A and analysis of such market data. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the Information Policy.

This report covers the period from April 1, 2010 to June 30, 2010 (the "Reporting Period"). The report contains the ISO analyses and summaries of market performance. All information and data presented here are the most recent as of the time of publication. Some data presented in this report are still open to resettlement.

For background on, and an in-depth explanation of the day-ahead and real-time energy markets in New England, refer to the 2009 Annual Markets Report posted on the ISO New England website.[1]

Underlying natural gas data furnished by: ICE Global markets in clear view[2]

Oil prices are provided by Argus Media

[1] http://www.iso-ne.com/markets/mktmonmit/rpts/other/amr09_final_051810.pdf

[2] http://www.theice.com

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Section 1 Executive Summary

The Internal Market Monitor has analyzed second quarter performance of the region's wholesale electric energy, reserve and capacity markets using supply offers, demand bids, fuel prices, market results, and other economic data regarding the wholesale electric markets. Overall the markets have performed well and outcomes have been competitive. In addition to the standard battery of analysis, this quarterly report includes:

1. An analysis of the performance of the market on June 24, 2010;

2. A review of the performance of the day-ahead energy market with special attention to the amount of load clearing;

3. An assessment of the accuracy of the load forecast prepared by ISO operations and used in the real-time balancing market; and

4. A review of virtual transactions, submitted volumes and cleared positions.

Key observations and conclusions from these analyses are presented below with more detailed discussion included in the body of the report.

1.1 Second Quarter Findings

- The Internal Market Monitor has concluded that the Energy Market is competitive during the Reporting Period. System-wide concentration remains low. Energy Market prices are consistent with input fuel prices, predominantly natural gas (see Section 2.1).

- Day-Ahead Energy Market prices during the Reporting Period averaged \$43.27/MWh at the Hub, and real-time prices averaged \$45.55/MWh (see Section 2.4).

- The monthly average real-time price exceeded the average day-ahead price in May and June, and was lower in April. This continues a change in the relationship between monthly average real-time and day-ahead prices first observed in the latter half of 2009.

- Peak Load during the Reporting Period was 24,239 MW, and occurred on June 28. Actual Net Energy for Load ("NEL") increased by 5.6% from Q2 2009, while weather-normalized NEL increased by 2.9% (see Section 3.5).

- On June 24, 2010, ISO operations dispatched 669 MW of demand response. In aggregate, 653 MW of demand response resources reduced consumption. Performance of the demand response was mixed. Of the resources called 140 MW provided reductions that fell within 10% of the desired reduction amount. (see Section 2.4.7)

- The IMM has observed a drop in day-ahead demand clearing. Preliminary analysis suggests that the drop in demand clearing is not the result of anticompetitive behavior in the day-ahead market, but rather the result of changes in the shape of the price sensitive portion of the demand curve and a leftward shift in the supply curve (see Section 2.4.3).

- Because of the drop in supply cleared day-ahead, ISO operations has been committing supplemental resources to balance the system in real-time. In response to some large observed differences between the load forecasts used to make supplemental commitments and actual loads, IMM prepared an analysis to determine if there was a systematic problem with the load forecast. The IMM has found that:
    - The load forecasts are essentially unbiased;
    - The majority of the observed load forecast error can be explained by weather forecast error; and
    - Price spikes experienced on days with large load forecast error appear to be the result of the interaction of supply and demand in the presence of stochastic shocks to either supply (unit outages) or load, rather than the consequence of withholding (see Section 2.4.6).

- The Internal Market Monitor has observed a reduction in the volume of both submitted virtual supply offers and virtual demand bids. The change in the day-ahead/real-time price relationship has reduced the opportunities for virtual supply in the day-ahead market, so the observed decline in virtual supply positions is consistent. The decline in virtual bids is more surprising and seems to be explained by a combination of the risk associated with taking virtual bidding positions given the volatile day-ahead/real-time price relationship and the high transaction costs associated with taking these positions (see Section 2.4.4).

- The summer 2010 Forward Reserve Market ("FRM") auction cleared the requirements in all locations. The Connecticut zone had a surplus of offers and cleared below the cap at $13,900/MW-month. (see Section 2.6).

- The first Forward Capacity Market ("FCM") delivery period began on June 1, 2010. $127M in FCM payments were made in June (see Section 2.7). Post June 1, the IMM has observed no systematic change in the offer behavior associated with resources with Capacity Supply Obligations ("CSOs") relative to behavior that prevailed prior to the FCM delivery period.

- There were four Real-Time Energy Market mitigation events during the Reporting Period, and two participants that had FTR revenues reduced pursuant to the FTR revenue capping provisions of Market Rule 1, Appendix A, section 8.4. In the Reporting Period, the IMM made one new non-public referral to the Federal Energy Regulatory Commission ("FERC") (see Section 2.4.5).

1.2 Second Quarter Issues

- In order to ensure efficient and secure real-time operations all resources must follow dispatch instructions. On June 24, 2010, the Internal Market Monitor observed that the majority of the dispatched demand response resources either underperformed or overperformed. The performance discrepancies appear to be the result of several factors, including: possible incentive problems in the Day-Ahead Load Response Program ("DALRP"), a desire or need by some demand response providers to use the event to audit new assets, and the FCM provisions that allow overperforming demand response resources to receive an allocation of the penalties paid by underperforming resources. The IMM has not completed its analysis of all of these factors and the available data is limited at this time. The IMM will continue to monitor the performance of demand response resources and may recommend design changes in the future (see Section 2.4.7).

- Currently, a Shortage Event begins after the ten-minute non-spinning reserve constraint has been violated for thirty contiguous minutes. In any interval in which the ten-minute non-spinning reserve constraint is violated, there is insufficient capacity available to meet the ten minute requirement, even after redispatch, and the thirty minute operating reserve is zero. On June 24, 2010, this condition occurred for one five-minute dispatch interval. The penalty structure in the FCM assumes that the performance of resources with CSOs will be evaluated when the system is tight. However, requiring this condition to continue for thirty contiguous minutes before declaring a shortage event is extreme, rare, and may not meet the intent of the overall FCM performance penalty structure. The IMM will conduct additional analysis of the role of this feature in the FCM design and may recommend design changes in the future (see Section 2.7.1).

1.3 Second Quarter Recommendations

- The IMM recommends that the ISO consider revising the market rules so that Real-Time Net Commitment Period Compensation ("NCPC") charges are not allocated to virtual transactions. At the same time it would be beneficial to review the entire set of rules addressing the allocation of NCPC.

  Virtual transactions in the day-ahead market play an important function, generally increasing liquidity, improving commitment, and limiting market power. The clearing of virtual transactions tends to converge the day-ahead and real-time prices and, thereby, to reduce the need for supplemental commitments in real-time and the NCPC costs associated with supplemental commitments. The IMM has observed that the total amount of NCPC charged to virtual transactions over the last six months has been remarkably high relative to the overall profitability of the positions taken. In the first six months of 2010, the profitability of virtual positions totaled $8.4 million. The total allocation of Real-Time NCPC charges to these positions totaled $6.4 million. Net of the Real-Time NCPC-related transaction costs, virtual positions realized a total profit of $2 million. The imposition of such high transaction costs may threaten the viability of virtual transactions in the day-ahead market, with serious implications for the performance of the Day-Ahead market. (see Section 2.4.4).

- The IMM recommends that the ISO consider modifying the market rule to allow the FRM threshold price be calculated daily using a daily fuel price index. The current FRM design requires market participants with resources assigned to meet an FRM obligation to offer reserve service at an incremental offer price at or above the FRM threshold price. This price is calculated monthly based on a monthly fuel price index and a calculated heat rate. The IMM has observed that volatile fuel prices within a month can result in divergence between daily resource fuel costs and the static monthly threshold price, leading to suboptimal resource offers. (see Section 2.6).

Section 2 Results

This section details the findings and outcomes that occurred in the wholesale electric energy markets during the Reporting Period.

2.1 Assessment of Market Competitiveness

To assess the competitiveness of the wholesale electric energy markets in New England, the IMM examines two types of measures of market competitiveness: structural measures that look at market concentration, and price-based measures that compare price outcomes to the marginal cost of production.

2.2 Structural Measures

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

Monthly systemwide HHIs for New England internal resources, based on summer capabilities and the resources' lead participant, averaged 624 in the second quarter 2010. This value has been relatively constant over the past three years. The result indicates that the New England electric energy markets are well within the "not concentrated" range. However, the systemwide HHI ignores transmission constraints and therefore may understate market concentration and consequently the degree to which some participants possess market power in load pockets.[3] Also, systemwide HHI may overstate market concentration because it does not account for contractual entitlements to generator output, which can decrease the incentive for resources to exercise market power.

The Residual Supplier Index ("RSI") is the percentage of demand (in MW) that can be met without the largest supplier. When the RSI exceeds 100%, the system has sufficient capacity from other suppliers to meet demand without any capacity from the largest supplier. When the RSI is below 100%, a portion of the largest supplier's capacity is required to meet market demand, and the supplier is pivotal. A pivotal supplier can drive prices above the competitive level, subject only to offer caps, mitigation measures, and the price elasticity of demand. As RSIs rise, the ability of market participants to exert market power decreases.

Figure 2—1 shows RSIs as a percentage of total hours for the Reporting Period. RSIs generally are lowest during periods of high demand, indicating a drop in the level of competition as the system approaches its capacity limit. This analysis shows that pivotal suppliers existed during 38 hours at the system level during the Reporting Period. The RSI averaged 143% during the Reporting Period.

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

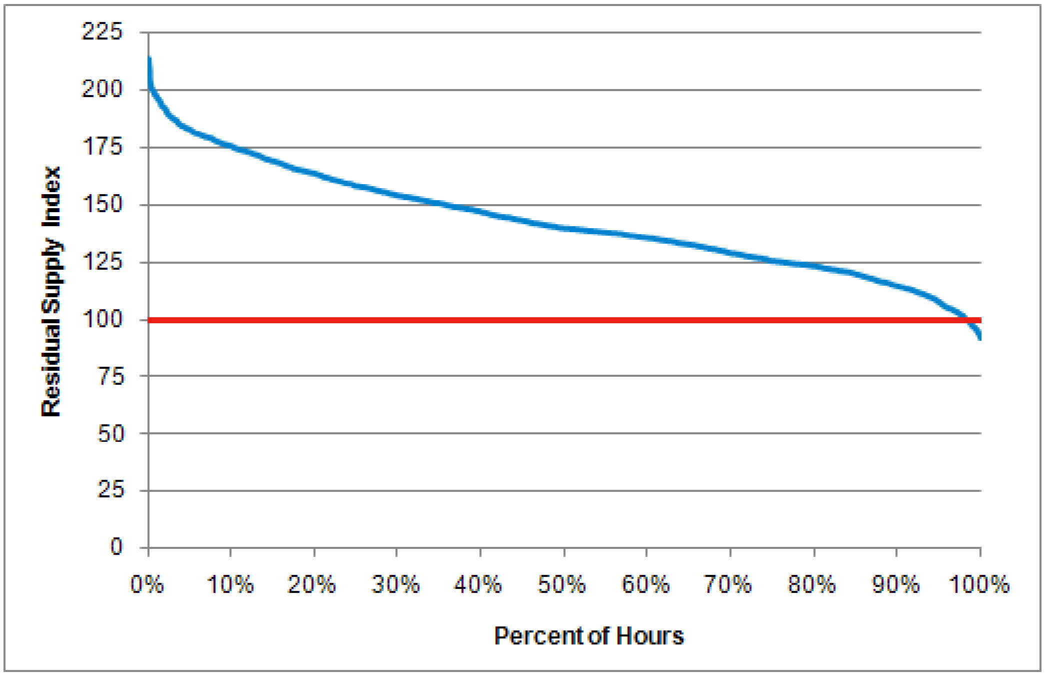


Figure 2—1: RSIs as a Percentage of Total Hours, Q2 2010.

2.3 Comparison of Fuel Prices and Electric Energy Prices

Another indicator of market competitiveness is how electricity prices respond to changes in their input costs. Since fuel costs are by far the largest short-term cost component of generating electricity, electricity prices should change as fuel prices change.

Figure 2—2 shows the daily average day-ahead hub price plotted against the daily average variable production cost of the marginal gas-fired unit in New England. The day-ahead spot prices for fuel are used to calculate the variable costs estimates. Unexpected system conditions, such as an unplanned generator or transmission-line outages, may cause energy-price spikes that are not completely explained by fuel prices. The results indicate that at the systemwide level, electricity prices continue to move closely with input fuel prices, particularly natural gas, supporting the conclusion that the electricity market is competitive.

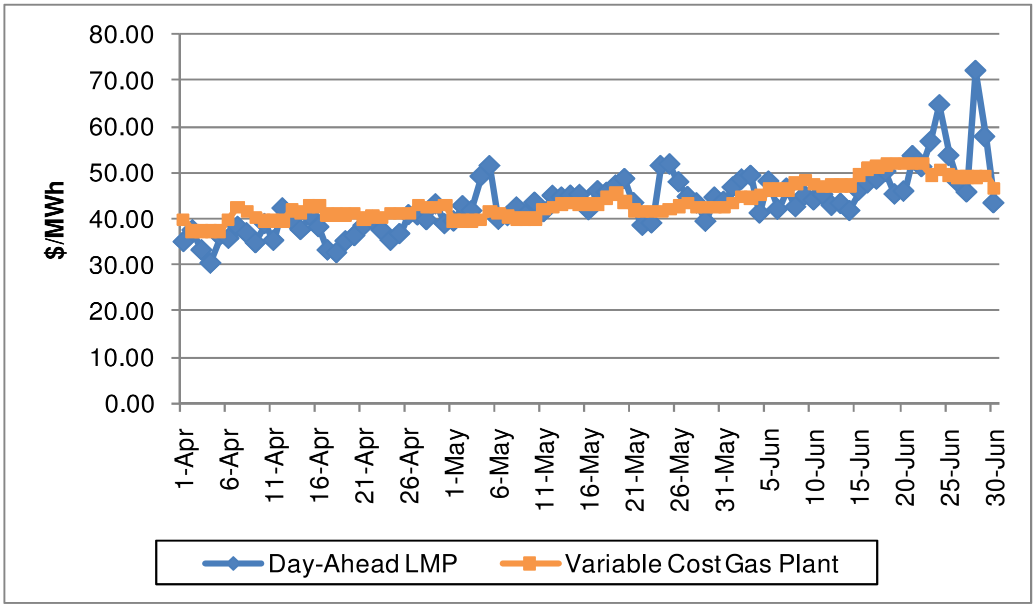


Figure 2—2: Daily Average Day-Ahead Hub Price v. Variable Production Costs, Q2 2010.

Figure 2—3 shows the real-time marginal, or price-setting, input fuels during the Reporting Period as a percentage of total marginal (five minute) 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 the other setting price for the unconstrained area. Units burning natural gas were marginal for 76% of the pricing intervals during the Reporting Period. Fuel oil and other petroleum products (diesel, kerosene, jet fuel) were marginal one percent of the time in the Reporting Period. In the most of the remaining intervals, coal or pumped storage hydro generators were on the margin.

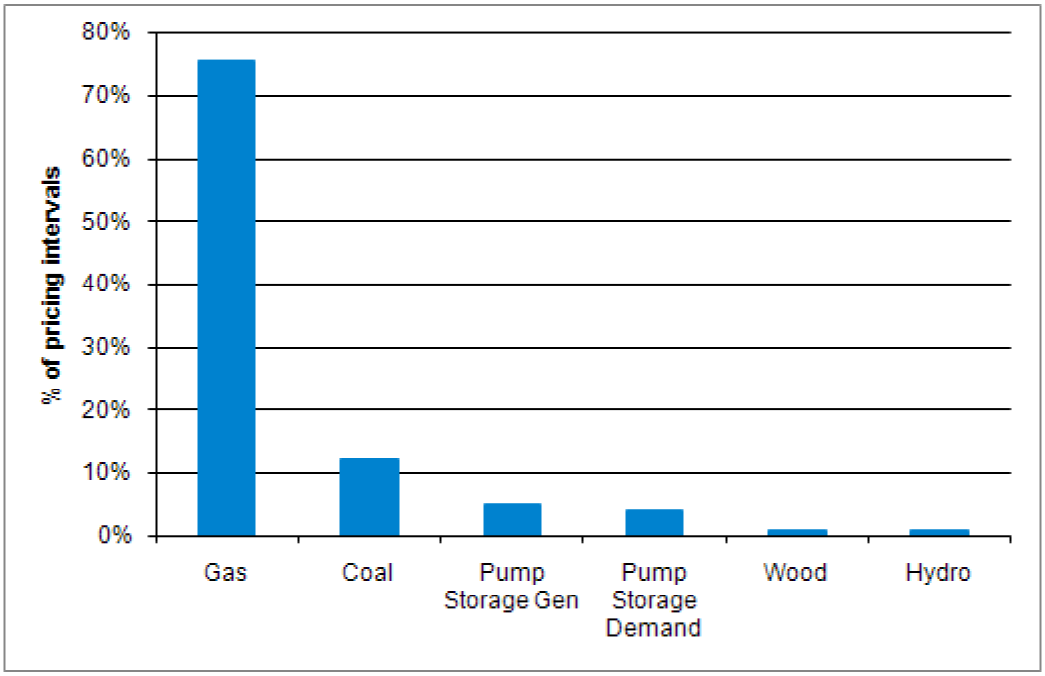


Figure 2—3: Marginal Units by Fuel Type, Q2 2010.

2.4 Day-Ahead and Real-Time Energy Market Outcomes

Table 2—1 summarizes quarterly day-ahead and real-time prices at the Hub, comparing second quarter 2010 prices with first quarter 2010 prices and second quarter 2009 prices. The average day-ahead energy price at the Hub for the Reporting Period was $43.27/MWh, 22% above the Q2 2009 level. The average real-time energy price at the Hub was $45.55/MWh, 29% above the Q2 2009 level. Changes in Locational Marginal Prices ("LMPs") at the Hub are almost entirely due to changes in input fuel prices.

In mid-2009, the typical difference or premium between the average monthly day-ahead and real-time prices changed from positive (day-ahead higher than real-time) to negative (day-ahead lower than real-time). Improvements to the transmission system in Southwest Connecticut and Southeastern Massachusetts have reduced the amount of capacity committed out-of-market for local second contingency protection, thereby reducing the amount of capacity committed above minimum requirements and improving dispatch and pricing. The reduction in on-line capacity contributed to additional short-term volatility in the real-time market in the latter part of 2009, a pattern that has continued through second quarter 2010.

Table 2—1
Quarterly Day-Ahead and
Real-Time Hub Prices, $/MWh

	Q2 2010	Q1 2010	Q2 2009
Day-Ahead	$43.27	$50.45	$35.52
Real-Time	$45.55	$51.71	$35.24

Maine had the lowest average, minimum, and maximum hourly LMP values, compared with the Hub and eight load zones that are priced in New England, while Connecticut had the highest LMPs. The low prices in the Maine load zone are in part explained by export constraints and higher marginal losses. In contrast, Connecticut's higher prices are the result of import constraints. See section 3.1 in the statistical appendix for more information on average zonal LMPs.

2.4.1 Spark Spreads

A spark spread is a measure of the gross margin (energy revenues minus fuel costs) from converting fuel to electricity based on the wholesale price of electricity and the cost of producing electricity with a given fuel and technology. Figure 2—4 presents monthly estimated natural gas spark spreads based on the unweighted monthly average real-time Hub price for on-peak hours in \$/MMBtu from April 2009 through June 2010 and the estimated cost of a typical gas-fired combined cycle unit in New England, assuming the Algonquin gas price and a 7,800 Btu/kWh heat rate. The results show that gas-fired combined-cycle plants are earning a positive gross margin during on-peak hours, with the day-ahead and real-time spark spreads averaging \$7.40/kW-month and \$8.35/kW-month, respectively, over the past twelve months.

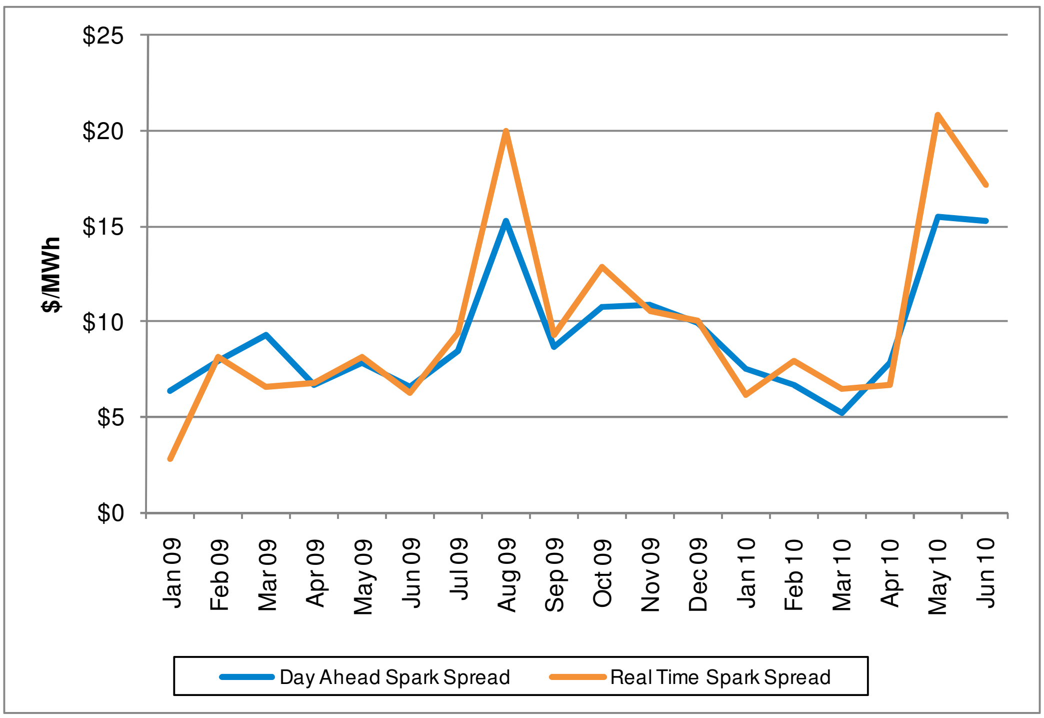


Figure 2—4: Estimated Spark Spreads, April 2009-June 2010.

2.4.2 Self Scheduled Generation

Self-scheduling is of interest because self-scheduled generators choose the quantity they sell into the day-ahead market regardless of the market clearing price, rather than let the day-ahead market clear the resource based on its supply offer. Excessive self-scheduling can limit the flexibility of the mix of generation available in the day-ahead market and ultimately in real-time, increasing the overall cost of satisfying load. Participants may choose to self-schedule their generators' output for a variety of reasons. For example, those with day-ahead generation obligations may self-schedule in real-time to ensure that they meet their day-ahead obligations. Participants with fuel contracts that require them to take fuel also may self-schedule. In addition, participants may self-schedule resources to prevent units

from being cycled off overnight and then started up again the next day. In the Reporting Period, day-ahead self-scheduled generation averaged 60.3% of DALO. Self-scheduled generation in the Reporting Period was down 4.35% when compared with Q2 2009. Table 2—2 compares day-ahead self-scheduled generation as a percentage of Day-Ahead Load Obligation (or "DALO") for the Reporting Period with Q1 2010 and Q2 2009.

Table 2—2
Day-Ahead Self-Scheduled Generation
as a Percent of Day-Ahead Load Obligation, GWh

	Q2 2010	Q1 2010	% Change (Q2 2010 to Q1 2010)	Q2 2009	% Change (Q2 2010 to Q2 2009)
Day-Ahead Self Schedules	19,443	21,400	-9.1%	20,329	-4.35%
Day-Ahead Load Obligation	32,221	35,339	-8.8%	32,125	0.30%
Percent	60.3%	61.0%	-0.3%	63.3%	-4.64%

2.4.3 Day-Ahead Demand Clearing

Relative to first quarter 2010 and second quarter 2009, the IMM has observed a drop in the volume of demand clearing the day-ahead market as a percentage of actual real-time load. That said, over the past 18 months, with the exception of Q4 2009 and now Q2 2010, DALO as a percentage of Real-Time Load Obligation ("RTLO") has been relatively stable. See Figure 2—5. While the available data is limited and further analysis required, preliminary analysis suggests that the drop in demand clearing is not the result of anticompetitive behavior in the day-ahead market, but rather primarily the result of changes in the shape of the price sensitive portion of the demand curve and a leftward shift in the supply curve. The findings are summarized as follows:

- The drop in the amount of demand clearing does not appear to be the result of anticompetitive behavior in the day-ahead market:
  - There has been no discernable change in generator offer behavior no an increase in mitigation.
  - There has been no discernable change in the physical load bidding strategies of the region's load serving entities.

- There has been little change in the volumes of virtual demand bids submitted and cleared.

- There has been a sharp reduction in the volume of virtual supply offers submitted and cleared.

- Beginning in May there was a contraction of supply due to long term outages which shifted the supply curve to the left.

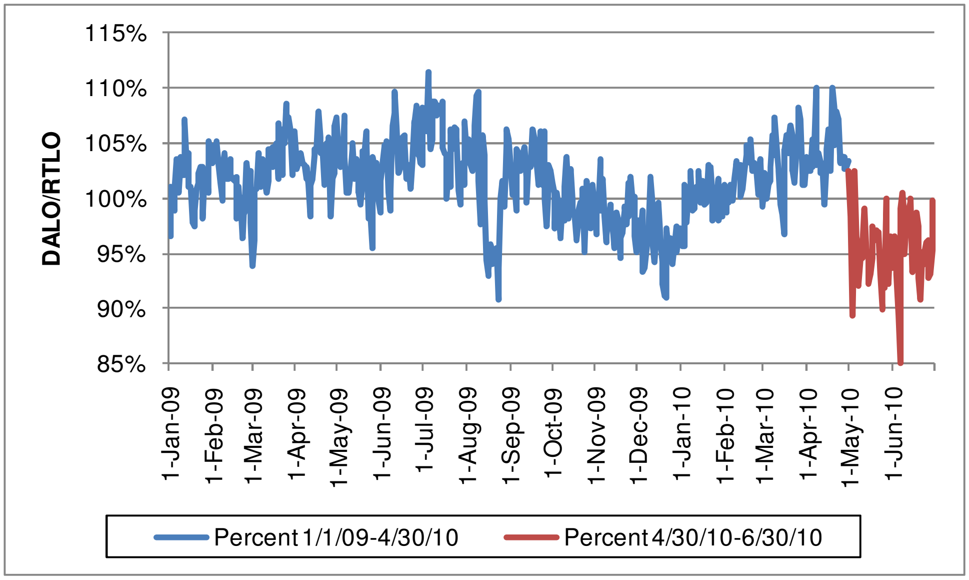


Figure 2—5: Daily Day-Ahead Load Obligation as a percentage of Real-Time Load Obligation, January 2009-June 2010.

Real-Time price volatility increased noticeably beginning Q3 2009, due in part to the impact on LMP of the increased frequency of binding reserve constraints. At the same time the average price difference between the day-ahead and real-time prices changed from predominantly positive to predominantly negative. See Table 2—3. The day-ahead price was $1.78/MWh lower than the real-time price on average over the past year. With more volatility and higher average prices in the real-time market, all other things equal, one would expect increased load participation in the day-ahead market. Over the past four quarters, day-ahead clearing has been both greater than 100% of RTLO and less than 100% of RTLO. It is premature to say that the current state reflects a systematic change of affairs or is just a temporary phenomenon as market participants adjust to conditions in the marketplace. The IMM will continue to monitor participant bidding and offer behavior.

Table 2—3
DALO/RTLO, Volatility Statistics, and Price Statistics, Q1 2009-Q2 2010.

Variable	2009 Q1	2009 Q2	2009 Q3	2009 Q4	2010 Q1	2010 Q2
DALO/RTLO[4]	102.12%	103.25%	102.53%	97.86%	101.62%	98.13%
RT Price Volatility[5]	19.80	9.74	16.11	22.77	23.76	22.01
DA Price Volatility[6]	18.22	6.34	9.33	15.83	16.42	11.06
RT Reserve Price[7]	0.28	0.47	0.37	1.78	1.74	2.61
DA Premium[8]	1.37	0.28	-1.92	-1.57	-1.26	-2.36

[4] DALO/RTLO = Day-Ahead Load Obligation / Real-Time Load Obligation

[5] RT Price Volatility = Standard deviation of hourly Real-Time Hub LMP

[6] DA Price Volatility = Standard deviation of hourly day-ahead Hub LMP

[7] RT Reserve Price = Average real-time ten minute spinning reserve price

[8] DA Premium = Average day-ahead Hub LMP – Average real-time Hub LMP

2.4.4 Virtual Transactions

Over the last year the volume of submitted and cleared virtual supply offers has decreased and the volume of virtual demand bids has stayed flat, despite real time prices exceeding day ahead prices. Given the apparent shift in the relationship between average day-ahead and real-time prices, a decrease in the volume of virtual supply offers submitted is to be expected over time, as would an increase in the volume of virtual demand bids and physical load bid into the day-ahead market during the second half of 2009 through 2010. This behavior would be consistent with a profit-maximizing strategy of buying at low prices day-ahead and selling at high prices in real-time.

The IMM has studied virtual transaction activity over the past 18 months. The IMM notes that many sophisticated[9] participants, both hedgers and speculators,[10] have lowered virtual demand bid trading volumes, while other, smaller speculative participants have increased virtual demand bid trading volumes.
This behavior is broadly consistent with the following:

- Changes in the day-ahead/real-time price relationship have reduced the opportunities for virtual supply in the day-ahead market.
- The risk associated with taking virtual bidding positions given the increased volatility of real time prices.
- The high transaction costs associated with taking virtual positions.

Day-Ahead and Real-Time Price Difference
As Figure 2—6 below shows, in mid-2009, the price difference between day-ahead and real-time changed from positive to negative, and resulted in virtual demand bids being profitable prior to being allocated a portion of NCPC charges.[11] The price difference switched to positive for the month of April 2010 for on-peak hours and overall, then back to negative for the months of May and June 2010. When the price difference changed to positive in April 2010, virtual demand bids generally would have lost money. While some market participants may have been slow to recognize changes in system operations prior to April 2010, the positive difference between day-ahead and real-time in April would have affected participants hoping to buy at low prices day-ahead and sell at high prices in real-time.

[9] A "sophisticated participant,, for the purpose of this analysis, is a participant that has been an active trader of virtual transactions over a long period of time.

[10] For the purpose of this analysis, "speculative" means a virtual position that does not have associated physical load or generation and "hedge" is defined as a virtual position that is associated with physical load or generation. Hedge positions may not include virtual positions taken to offset risks associated with bilateral contracts or other agreements.

[11] Virtual demand is allocated a portion of day-ahead economic, day-ahead LSCPR, and real-time economic NCPC. Virtual supply is allocated portion of real-time economic NCPC.

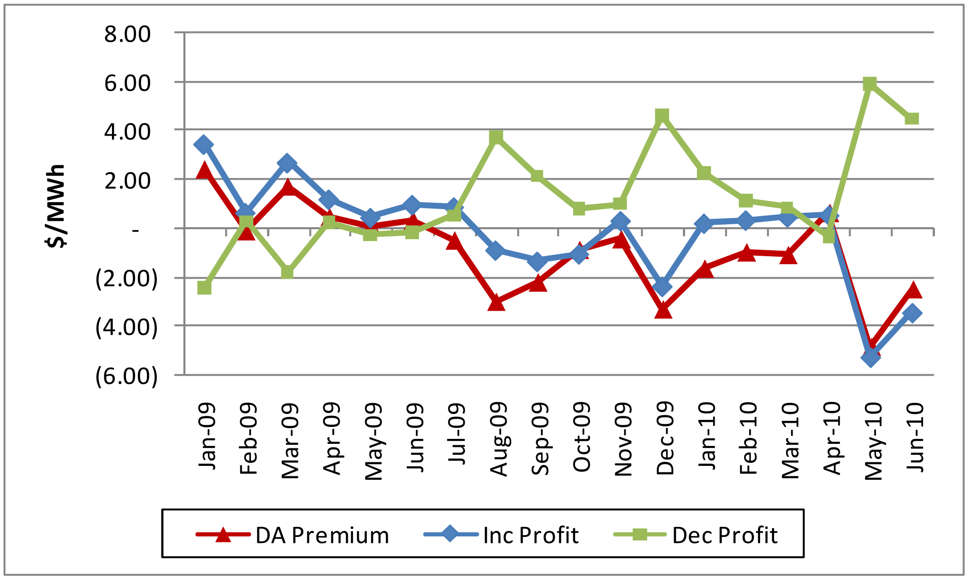


Figure 2—6: Virtual Profits and Average Day-Ahead-Real-Time Hub Prices (all hours), January 2009-June 2010.

Virtual Supply Offers

The IMM reviewed submitted and cleared virtual supply offers from the highest participants from January 2009 through June 2010. Figure 2—7 below shows submitted and cleared virtual supply offer volumes. There has been a 58% decrease in submitted virtual supply offers from January 2009 through June 2010. The IMM has noted that a number of speculative participants have stopped submitting virtual supply offers, or changed their bidding strategy.

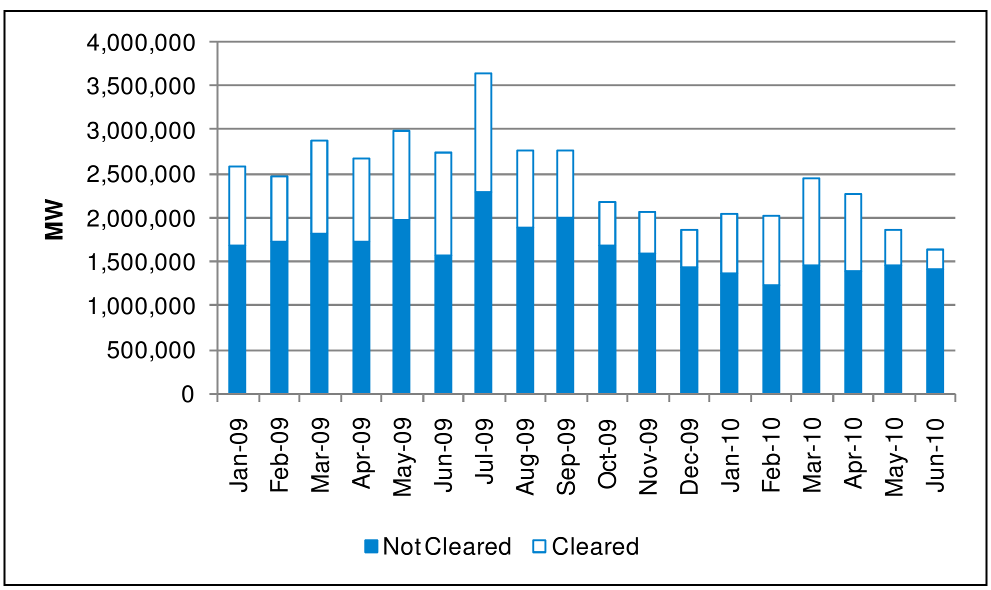


Figure 2—7:- Submitted and Cleared Virtual Supply Offer Volumes, January 2009 - June 2010.

Virtual Demand Bids

Figure 2—8 presents submitted and cleared virtual demand bids. The IMM has observed that the volume of submitted virtual demand bids continues to decrease slightly, even though overall this instrument continues to be profitable.[12] Virtual demand bids were not profitable in April 2010 in on-peak hours because the difference between the day-ahead and real-time price changed from negative to positive for the first time in seven months. In May and June, the difference between the day-ahead and real-time price changed back to negative. The volatility in swings in the difference between the day-ahead and real-time price also affected the submission of virtual demand bids for some participants. While a number of market participants reduced submitted virtual demand bid volumes, other participants have increased volumes.

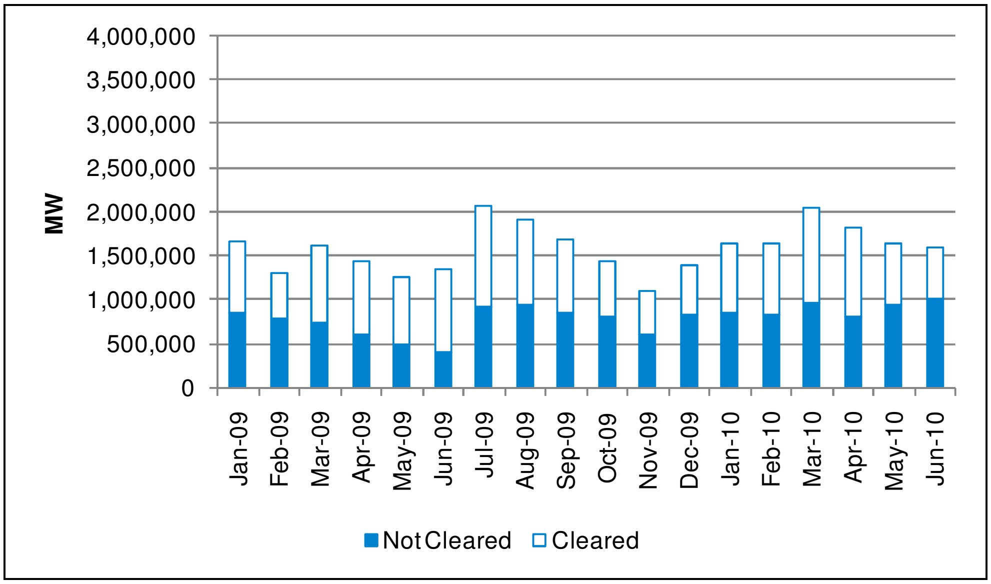
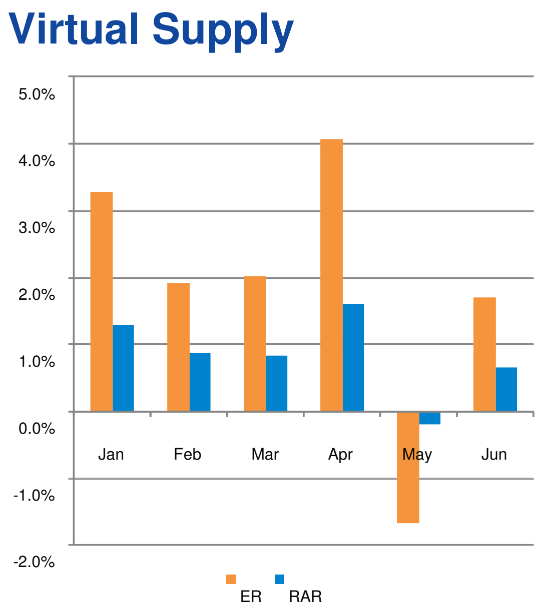


Figure 2—8: Submitted and Cleared Virtual Demand Bids, January 2009 - June 2010.

Figure 2-7 charts the average rates of return that would have been realized on a one MW virtual supply or demand position placed and cleared at the hub in each hour. While on average, the positions would have performed reasonably well during the study period, the averages mask the underlying volatility of the rates of returns on such positions and thus the risk associated with submitting virtual offers or bids into the day-ahead market. To provide some perspective regarding the relative impact of risk on rates of return, consider an analysis that estimates a risk adjusted rate of return for each position. The IMM estimated a risk adjusted rate of return for each position by computing the probability that actual returns would exceed a target rate of return (return risk) and the probability that the actual rate of return would be less than zero (capital risk). The risk adjusted rate of return equals the target rate return + return risk x the average returns exceeding the target x (1 – capital risk). The target rate of return is assumed to be the rate of return on a riskless portfolio consisting of U.S. Government 30 day treasury bills. This approach internalizes the volatility of rate of return into a single measure and allows for a comparative assessment of the rate of return on a risky position in virtual transactions against an alternative riskless position.

[12] This is gross of NCPC charges.



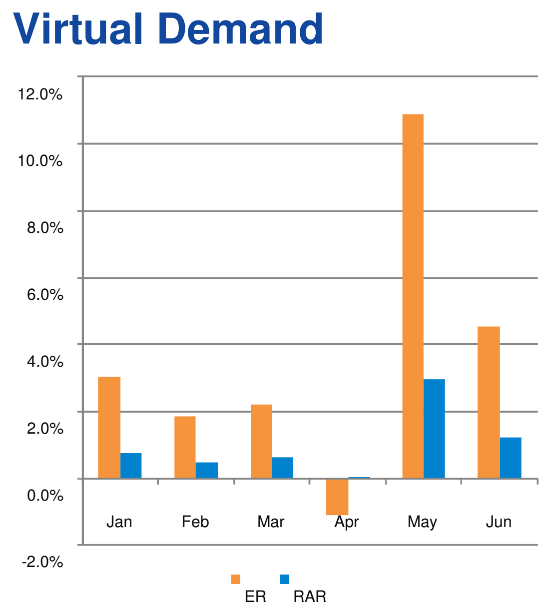


Figure 2—9: Returns on a 1 MW position cleared in every hour assuming that the sample distribution equals the actual distribution.

On a risk adjusted basis, the proxy virtual positions presented here does appear to outperform the risk-free position in treasury bills. However, gains on these positions are concentrated in relatively few hours, which are distributed according to an ill-defined if not random process. Thus, to realize these rates of return a participant must be willing and able to absorb losses on the position in many if not most of the hours. Moreover, while a sophisticated participant may be able to devise a strategy that has a higher probability of success than the naïve strategy described here, the willingness of a participant to take virtual positions will be strongly influenced by the high transaction costs imposed in the form of Real-Time NCPC charges.

NCPC Charges to Virtual Transactions

The IMM has observed that the total amount of NCPC charged to virtual transactions over the last six months has been remarkably high relative to the overall profitability of the positions taken. In the first 6 months of 2010, the profitability of virtual positions totaled $8.4 million. The total allocation of Real-Time NCPC charges to these positions totaled $6.4 million. Net of Real-Time NCPC-related transaction costs, virtual positions realized a total profit of $2 million. See Table 2—4.

Table 2—4
Net Revenues and Real-Time NCPC Charges to Virtual Transactions
January - June 2010.

Virtual Instrument	Revenues and Charges	January-June 2010
Demand	Net Revenue (before NCPC Charges)	9,983,479
	Allocated Real-Time NCPC Charges	(4,062,555)
	Revenue net of RT NCPC Charges	***5,920,924***
Supply	Net Revenue (before NCPC Charges)	(1,597,514)
	Allocated Real-Time NCPC Charges	(2,302,119)
	Revenue net of RT NCPC Charges	***(3,899,633)***
Total	Net Revenue(before NCPC Charges)	8,385,964
	Allocated Real-Time NCPC Charges	(6,364,674)
	Revenue net of RT NCPC Charges	***(2,021,290)***

Virtual transactions in the day-ahead market play an important function, generally increasing liquidity, improving commitment, and limiting market power. The action of virtual positions tend to converge the day-ahead and real-time prices, in so doing reducing the need for supplemental commitments in real-time and the uplift costs associated with these actions. The imposition of this disproportionately high level of transaction costs may threaten the viability of virtual transactions in the day-ahead market, with serious implications for the performance of the day-ahead market. The IMM recommends the ISO consider revising the market rules so that Real-Time NCPC charges are not allocated to virtual transactions. At the same time it would be beneficial to review the entire set of rules addressing the allocation of NCPC.

2.4.5 Financial Transmission Rights

The April, May, and June monthly auctions included previously awarded Financial Transmission Rights ("FTRs") from the January 2010 through December 2010 annual auction. The annual awarded FTRs are held out of the monthly auctions, decreasing the volume of FTRs available for award in the monthly auction. Fifty-percent of the transmission capacity of the New England control area was auctioned in the annual auction. The monthly auctions in the first quarter of 2010 sold 95% of the network capacity available after the annual auction awards were accounted for.

Between 39 and 43 bidders participated in each monthly auction during the Reporting Period. This is consistent with levels of participation in auctions in prior months. In the monthly auctions, a total of 5,242 bids or offers cleared with negative prices, yielding an approximate total negative net value of -$1.23 million. Positive priced transactions numbered 23,182, with a net value of $4.59 million. The combined net value of fourth quarter FTR auctions (the amount distributed as Auction Revenue Rights ("ARRs") was about $3.36 million. The three auctions combined resulted in a total of 147,196 MW of FTR transactions worth a combined absolute value of $5.82 million.

2.4.6 Load Forecast

In response to some large observed differences between the load forecast used to make supplemental commitments and actual loads, IMM prepared an analysis to determine if there was a systematic problem with the ISO load forecast. IMM focused on the peak load forecast made at 22:00 the night before the Operating Day. The analysis examined peak forecast error to determine whether the forecast error is biased and second, the analysis estimated the impact of the forecast error on LMP changes. A significant bias, *i.e.*, the tendency to under- or over-forecast would suggest that the forecast could be improved with by adding underlying variables that explain the bias. The IMM has found that:

- The 22:00 peak load forecast has little bias.
- The observed forecast error can be attributed to weather forecast error. Load forecast error is reduced when the ISO updates weather information during the market day.
- Load forecast errors due to poor weather forecasts are unlikely to cause significant price changes. Simulation of the market showed that:
    - The ISO's process of updating load forecasts and appropriately adjusting the operating plan during the market day (and in particular on the morning of the market day) reduces the potential impact of any error in the 22:00 forecast on real-time LMP.
    - Significant LMP spikes are more likely a result of sudden, large, and unexpected changes in the supply-demand balance, such as system contingencies.

Examination of Forecast Bias

Analysis of the mean algebraic percent error ("MALPE") was conducted to detect bias in the forecast. In addition, decomposition of mean squared error ("MSE") and econometric analysis were applied to determine whether the error term contains information that could have been identified by a better forecast. A theoretically perfect forecast would have only random errors (*i.e.*, errors that could not be explained). The MSE decomposition splits the error into random and non-random components. The econometric analysis regressed the forecast error on terms that might explain the error, classifying error into explainable and unexplainable components. The results for the three approaches are summarized below.

- *Mean Algebraic Percent Error ("MALPE")*
  Only slight bias was detected by the measurement of errors. The average daily peak-load hour MALPE over the 18 month period studied was (-0.17%) indicating a slight under-forecast for that period. On a monthly basis this rarely exceeded plus/minus 0.5%. The (-0.17%) average would represent 34 MW on a 20,000 MW load.
- *Means Squared Error ("MSE") Decomposition*
  The amount of error that is potentially non-random, that represents potential for forecast improvement is low and has fallen recently. The MSE shows 90% of MSE is due to random factors and only 10% of the MSE could be reduced by either better modeling or better inputs.
- *Econometric Analysis of Error Term*
  Regression Analysis shows weather is highly correlated to forecast error. A better weather forecast will reduce the forecast error and bias.

Overall, the analysis supports the finding that the bias is small and most of the error can be explained by imperfect weather forecasts. The regression analysis suggests that better weather forecasts, if available, would improve the load forecast further.

Effect on LMP

To analyze the impact of load forecast error on LMPs, three recent days with significant difference between the 22:00 load forecast and the actual load were selected, May 24, 25 and 27.[13] Two scenarios were examined: the first measures the impact on LMP of a large unexpected change in the supply-demand balance, and the second examines the impact of smaller, more gradual changes in load expectations. The study also examines both a peak defined as a single hour and a peak defined as three contiguous hours. Under the one hour peak, the forecasted peak load is replaced with the actual for only one hour. Under the three-hour peak, the two hours surrounding the forecasted peak are also replaced with the actual load, leading to possible commitment of longer run-time units rather than higher cost quick-start units with one-hour run times. Table 2—5 presents a summary of the load forecast error and resulting change in LMP.

Table 2—5
Load Forecast Error and Simulated Price Effects, May 24, 25, and 27, 2010.

		One Hour Peak Price Change	One Hour Peak Forecast Error (MW)	Three Hour Peak Price Change	Three Hour Peak Forecast Error (MW)
Scenario 1	Sudden, large change in supply-demand balance				
	- May 24, 2010	48.0%	588	70.1%	565
	- May 25, 2010	198.9%	905	63.6%	872
	- May 27, 2010	-63.7%	(2,642)	62.2%	(2,728)
Scenario 2	Small change in supply-demand balance, reflecting updated load forecasts				
	- May 24, 2010	0.0%	207	3.8%	188
	- May 25, 2010	-31.5%	(125)	23.1%	(75)
	- May 27, 2010	-17.4%	(673)	21.4%	(745)

The results indicate, as expected, that the highest price impact occurs with the single hour peak that differs from the forecast with no chance to update the forecast during the day. Sudden changes in the supply-demand balance, most often associated with system contingencies, do not allow sufficient lead-time to alter commitment and are likely to produce more pronounced LMP changes, as expensive generating units are used to satisfy the load change. Increases in LMP on the order of 50 to 200 percent can be expected.[14]

Scenario two provides a more realistic representation of the typical impact of load forecast error on prices. In this scenario changes in load expectations are incorporated through the day into the operating plan prior to the system actual peak. Given gradual, smaller changes in load expectations with sufficient lead time to alter commitment, longer lead-time (and lower incremental cost)

[13] This analysis was performed using an energy market simulator, PROBE. This model creates an energy price forecast by determining an "optimal" commitment and dispatch of generators given hourly system load. The objective of the simulation is to minimize total system costs for satisfying load during a 24-hour market day, given system constraints.

[14] The observed 199% increase is the result of using a diesel-fired peaking unit, to satisfy a large unexpected change in load. The observed 48% increase is the result of moving from a modern gas-fired combined cycle under the forecast, to an older gas-fired steam turbine under the higher actual load.

resources are committed and subsequently dispatched to meet demand. In this case, the changes in LMP were on the order of five to 20%.[15]

The analysis suggests that, at least on the days under study, large Real-Time price movements would best be explained by sudden, large and unexpected changes in supply-demand balance, rather than by load forecast errors for which adjustments tend to be made during the operating day.[16] While the study is not exhaustive, the findings are consistent with expectations given the underlying fundamentals of the marketplace. The IMM will continue to assess market price formation in the presence of load uncertainty and may publish additional findings in the future.

2.4.7 Market Performance on June 24, 2010

The IMM analyzed market conditions and performance during the hours when the actions of Operating Procedure No. 4 ("OP4") event were invoked on June 24. The main observations and conclusions are as follows:

- Overall the markets performed well and participants acted competitively.
- Higher than forecasted temperatures and approximately 1,800 MW of generator trips and reductions across the day resulted in capacity shortages.
- The ISO invoked OP4, Actions During a Capacity Deficiency.
- The Thirty Minute Operating Reserve ("TMOR") constraint bound for four hours.
- The Ten Minute Non-spinning Reserve ("TMNSR") constraint was violated for one five minute dispatch interval.
- Manual market interventions by the operators were limited to actions required to manage constraints not included in the dispatch algorithm.
- The ISO dispatched 669 MW of demand response resources, and 653 MW responded.
- The IMM observed that the majority of the dispatched demand response resources either underperformed (reduced less than their CSO) or over-performed (reduced more than their CSO).

Operational Overview

Table 2—6 lists the implementation time of each OP4 action on June 24. In addition to the OP4 actions taken by the control room operators, real-time-only contracts were cut from 12:00 until 17:00,

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[15] Note that the three-hour price changes in the table are shown as absolute values, to avoid potentially understating average price changes over three hours that have inconsistent signs. Illustratively, the 23% change in price was the result of moving from marginal units consisting of steam turbine gas, combined-cycle duct-firing and dispatchable hydro under the forecast load to a less-expensive marginal unit cohort consisting of steam-turbine gas and combined-cycle non-duct-firing capacity. In this case, the revised forecast load for the morning slightly exceeded actual peak load, leading to prices based on actual peak loads being lower prices based on forecast load.

[16] Price change results should be regarded as indicative of direction and magnitude only. A number of modeling limitations (*e.g.*, lack of reserves modeling, PROBE's commitment logic (which simulates the day-ahead market), etc.) lead to imprecision in our simulation results.

and M/LCC #2 was declared between 12:45 and 19:00. ISO operations took these actions to manage real-time conditions that included unexpected generator outages and reductions and higher-than-expected system loads associated with higher than forecasted temperatures.[17]

Table 2—6
OP4 Actions, June 24, 2010.

OP-4 Action	Action Description	Begin Time	End Time
1	Power caution; Deplete 30-min reserves	13:45	17:15
2	Dispatch real-time demand resources	13:45	17:15
3	Voluntary load curtailment	14:30	16:30
4	Power watch	14:30	15:15
5	Request emergency energy	14:30	16:30

Action 1 (power caution; deplete 30-minute reserves) and Action 2 (dispatch real-time demand resources) were invoked at 13:45. Between 14:27 and 15:24, five peaking units failed to start when called online to provide energy. At 14:30, operators initiated OP4 Action 3 (voluntary load curtailment), Action 4 (power watch), and Action 5 (request for emergency energy) because the capacity margin was around zero and the reserve surplus was negative.

Figure 2—10 below shows a graphical timeline of dispatch of the real-time demand response and system load on June 24, 2010. Between 14:00 and 15:00, system load fell from approximately 23,400 MW to 22,600 MW. Out of the 800 MW of load reduction, an estimated 653 MW is attributable to demand response. The remaining reduction in load was caused by severe weather patterns in southwestern Connecticut. Thunderstorms began to enter the Southwest Connecticut region at 13:50 and were directly over the southwest Connecticut region by approximately 14:15. The storms caused a fall in ambient air temperature, which resulted in reduced load in the area. In addition to the temperature changes, lightning strikes caused power outages in the region, which further reduced system load.

[17] Temperatures hit 94°F in Boston, eight degrees above forecast.

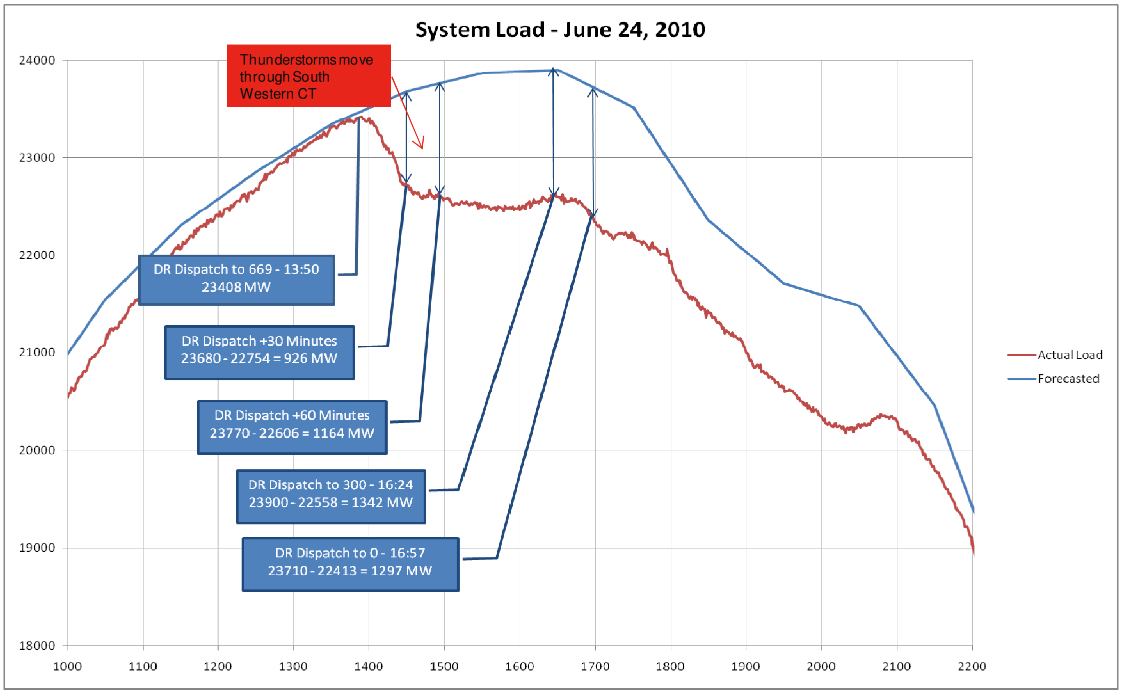

Figure 2—10: System Load and Demand Response event timeline, June 24, 2010.

Price Analysis

Real-time Hub LMPs remained under $50/MWh from hour-ending 01:00 ("HE 1") through HE 8. During HE 12 reserve constraints bound effecting system redispatch to manage reserves, yielding a reserve market clearing price of $56.92/MWh. At approximately 12:20, additional generation tripped, exacerbating the already tight capacity conditions. At 13:45, ISO operators invoked OP4 Action 1 (depletion of 30-minute reserves) and Action 2 (dispatch real-time demand response). The TMOR constraint was violated, the reserve prices increased to $100/MWh in HE 14 and the hourly integrated real-time Hub LMP increased to $250.19/MWh. During HE 15, real-time LMPs reached their peak for the day. The hourly integrated real-time Hub LMP for HE 15 was $270.74/MWh, due in part to a reserve price of $129.17/MWh for the hour. In one five minute interval the real-time LMPs were $1,174.50/MWh due in part to a reserve price of $950/MWh that was realized when the TMOR and TMNSR constraints were violated. Figure 2—11 below shows Real-Time hourly LMPs and reserve prices for June 24.

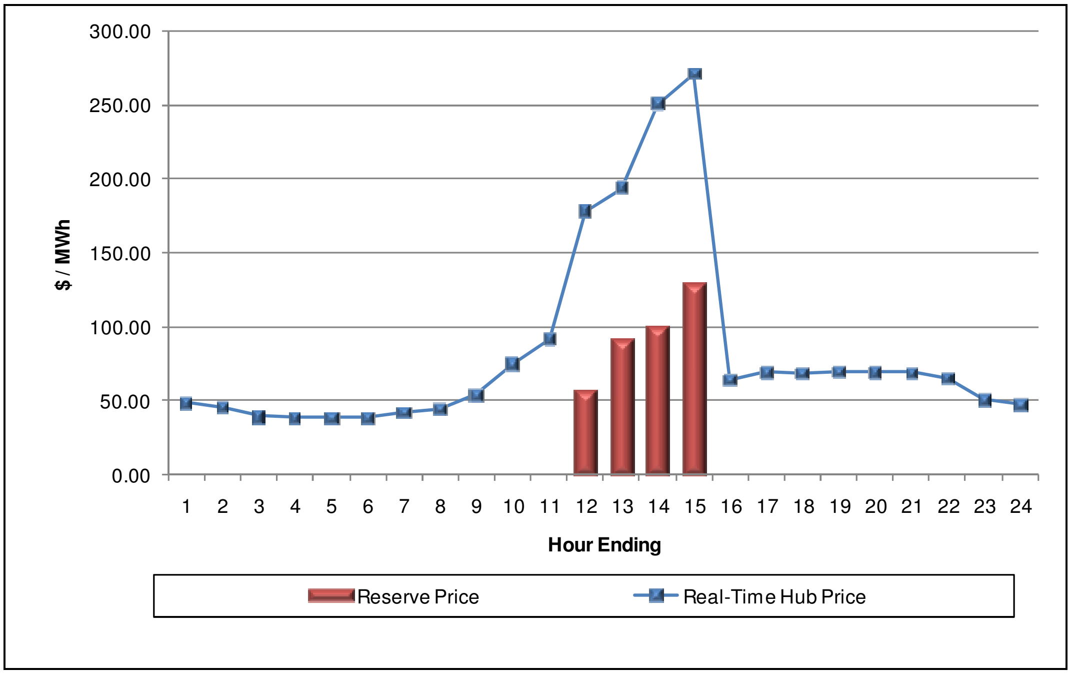

Figure 2—11: Real-Time Hourly Zone, Hub, and Reserve Prices, June 24, 2010.

Through the combined effects of demand response reductions and load drops due to thunderstorms in southwest Connecticut, load dropped substantially and by 14:40 constraints on all reserve products ceased to bind and there was sufficient capacity to meet all requirements. For HE 16, the hourly integrated real-time Hub LMPs was $64.51/MWh. The hourly integrated Hub LMPs remained under $70/MWh for the remainder of the day.

Generator Bidding Behavior

On June 24, one participant was identified as the pivotal supplier needed to meet load. The participant's offer behavior on June 24 was consistent with its behavior on days when it was not pivotal. Overall, the IMM did not observe significant offer changes for participants on June 24 compared to other days in June.

Demand Resource Performance

June 24th provided the first opportunity for demand resources with a Capacity Supply Obligation to perform in a market context in response to real-time dispatch instructions. Table 2-7 shows average demand response performance during the OP4 event on June 24. From 13:48 until 16:24, the ISO dispatched 669 MW of demand response to curtail the rising system load. By 16:24, loads had decreased enough to permit the reduction of dispatched demand response from 669 MW to 300 MW. The control room operators stopped dispatching demand response at 16:57.

While the demand resources appeared to have performed well in aggregate, on a zonal and an individual resource basis, performance was mixed. At the zonal level, only Rhode Island and Western Massachusetts performed within 10% of the net CSO. [18] All other zones performed by reducing load

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

by either too much or not enough. Demand resources in Maine overperformed by reducing load to 144% of net CSO, a reduction of 72.78 MW above the desired level. On the other hand, Connecticut underperformed by reducing 75% of net-CSO, a 56.83 MW deficiency in demand reduction.

Table 2-7
Demand Response Performance, June 24 2010.

Load Zone	Total Net CSO	Average Aggregate Performance*	Percent
Connecticut	226.83	170	75%
WCMA	79.59	79	99%
NEMA	70.74	46	65%
SEMA	45.23	30	66%
Rhode Island	27.76	27	97%
Vermont	23.71	29	122%
New Hampshire	29.11	33	113%
Maine	166.22	239	144%
New England	**669**	**653**	**98%**

* Preliminary; performance levels measured between 13:50 and 16:24.

As the performance data is disaggregated from the zonal level to the resource level, performance becomes even more skewed. Figure 2—12 shows demand resource performance by resource as a percent of CSO MW as a histogram (10% interval bins). For the June 24 event, resources that performed within the 90-110% generator dispatch threshold of CSO totaled 141 MW, or 22% of the total demand resource CSO of 669 MW.

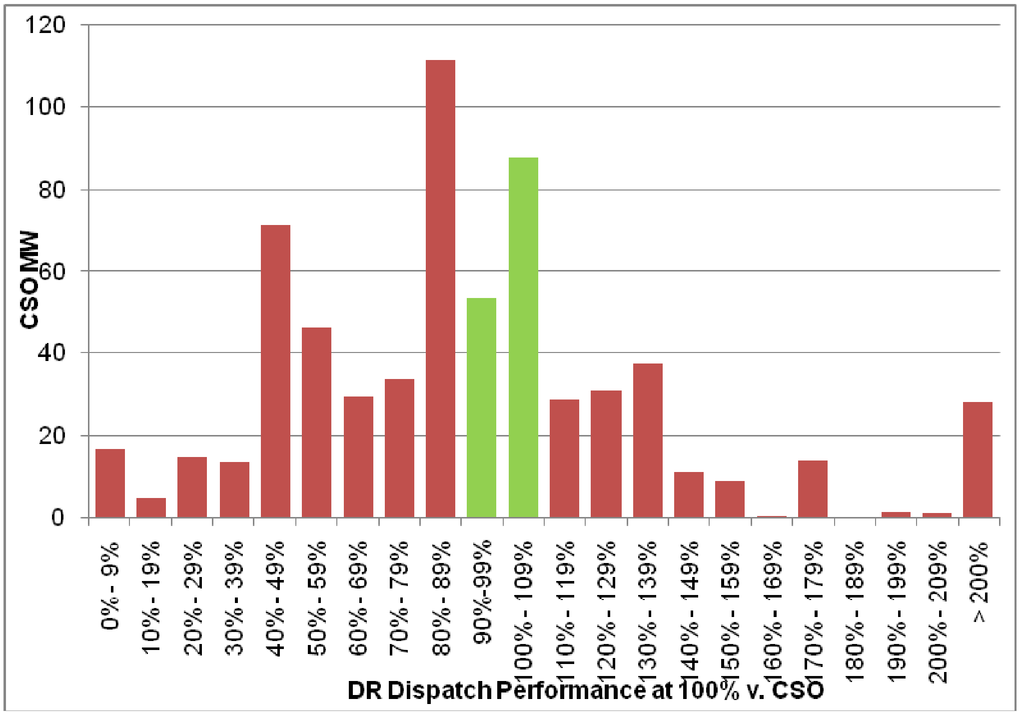

Figure 2—12: Histogram of Demand Resource Performance at 100% dispatch, demand resource reduction as a % of CSO during OP4 Event, June 24, 2010.

The performance discrepancies identified above appear to be the result of several factors, including: possible incentive problems in the DALRP, a desire or need by some demand response providers to use the event to audit new assets, and the FCM provisions that allow overperforming demand response resources to receive an allocation of the penalties paid by underperforming resources. The IMM has not completed its analysis of all of these factors and the available data is limited at this time. The IMM will continue to monitor the performance of demand resources and may recommend design changes in the future.

2.5 Regulation Market

Total Regulation Market payments during the Reporting Period were $3.14 million. Regulation requirements have been adjusted downward in 2010 because of the high level of compliance with applicable NERC Balancing standards. Table 2—8 summarizes market outcomes for Regulation for the Reporting Period.

Table 2—8
Regulation Market Outcomes

	Q2 2010	Q1 2010	% Change (Q2 2010 to Q1 2010)	Q2 2009	% Change (Q2 2010 to Q2 2009)
Capacity Credit	966,827	1,501,440	-36%	2,324,263	-58%
Opportunity Cost	1,264,120	1,881,347	-33%	1,272,011	-1%
Service Credit	906,252	1,590,210	-43%	2,698,087	-66%
Total Regulation Payments	3,137,199	4,972,997	-37%	6,294,361	-50%
Average $/MW	6.98	8.19	-15%	10.00	-30%
Average Hourly Requirement (MW)	57	78	-27%	94	-39%

2.6 Forward Reserve Market

The Connecticut zone had a surplus of offers and cleared below the cap at $13,900/MW-month. External Reserve Support was sufficient to meet the requirements in both the NEMA/Boston and SWCT zones. Offers for TMOR were submitted and cleared in Southwest Connecticut. No offers for TMOR were submitted into NEMA/Boston. Table 2—9 provides a summary of the auction requirements, offers and clearing prices for the summer 2010 FRM auction.

Table 2—9
Summer 2010 Forward Reserve Market Auction Results

Zone	Product	Second Cont. Req. (MW)	External Reserve Support (MW)	Local Reserve Req. (MW)	MW Offered	MW Cleared	Surplus/ Shortfall	Clearing Price ($/MW-Month)
Systemwide	TMOR	N/A	N/A	700	1,141.1	944.5	441.1	5,950
Systemwide	TMNSR	N/A	N/A	900	2,038.6	1,078.6	1,138.6	5,950
SWCT	TMOR	587	782	0	402.05	402.1	402.1	13,900
CT	TMOR	1,225	0	1,225	1,261.65	1,225.0	36.7	13,900
NEMA/Boston	TMOR	1,290	1,370	0	0	0	0	N/A

In the Connecticut ("CT") reserve zone total offers exceeded the 1,225 MW requirement by only 36 MW, or 2.94%. The CT clearing price of $13,900 MW-month was only 0.7% lower than the price cap of $14,000. This outcome appears reasonable considering that the zone had just enough capacity offered to clear the requirement.

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

- The market is concentrated despite the gradual increase in the number of participants. The largest supplier in the auction had approximately 40% of the supply in CT. However,

significant new entry is expected in the near future, suggesting that there are no barriers to entry.

- A game theoretic analysis found that there is no incentive for withholding from the auction for any of the participants. Both the dominant supplier and the other, smaller, suppliers benefit most by offering all their available capacity into the auction.

2.6.1 Forward Reserve Market Threshold Price

The FRM requires resource owners to select and assign resources to meet their FRM obligations by offering energy into the real-time market at a price at or above the FRM threshold price. The threshold price is set with the expectation that the LMP will exceed the threshold price between 2% and 3% of the time.[19] The existing design calculates a FRM threshold price applicable to resource assignments in the month at the beginning of each month. The FRM threshold price is not updated during the month. If fuel prices within a month vary substantially from the index used to set the FRM threshold price, the difference between a resource's actual marginal costs, as reflected in its reference price, and the FRM threshold price can become large.

Figure 2—13 summarizes this risk using data between October 1, 2006 (major changes to the FRM were implemented on that date) and May 12, 2010. The graph shows that the use of a monthly FRM threshold price rather than a daily threshold price creates a significant energy opportunity cost risk, or alternatively mitigation risk.

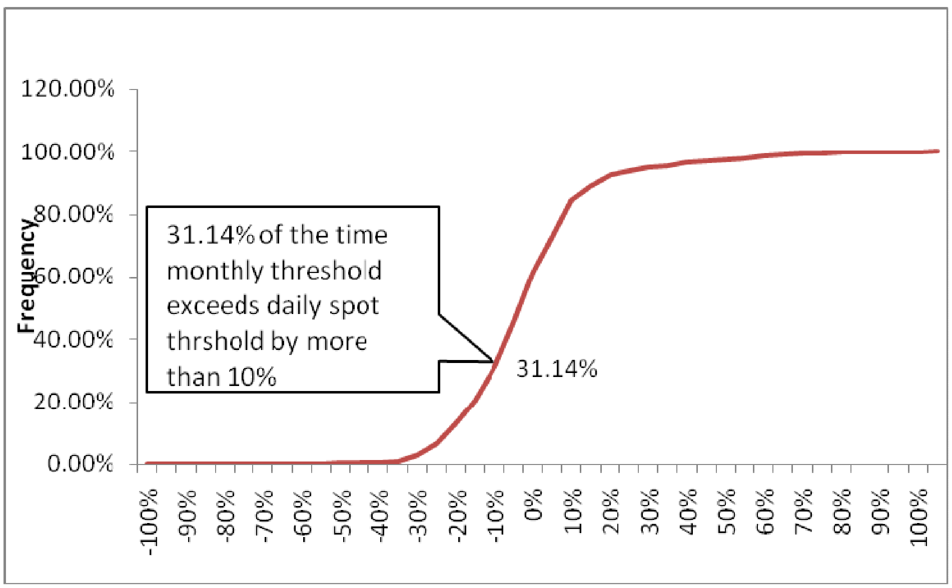

Figure 2—13: Distribution of dollar difference between monthly and daily threshold prices, 10/1/2006 to 5/12/2010.

The horizontal axis measures the dollar difference between an FRM threshold based on a monthly fuel index and one based on a daily fuel index. A negative number means that the fuel price has

[19] Appendix A does not exempt such resources from mitigation. It is inappropriate for resources with costs significantly below the FRM threshold price to be assigned an FRM obligation and mitigation would be appropriate in that case. In practice this has happened very rarely.

declined since the start of the month and that a threshold price set daily would be below the monthly threshold price by the amount on the axis. The point called out in the graph shows that the daily threshold price would have been below the actual (monthly) FRM threshold price by at least 10% more than 31.14% of the time.

The IMM recommends that the FRM threshold price be calculated on a daily fuel price index. A possible drawback with using the same-day fuel price index is that the threshold price could not be published in advance of the 18:00 bidding dead-line (re-offer period) for the next day. The gas price indices are published between 15:00 and 18:00. While usually the prices are available shortly after 15:00, enough publication uncertainty exists that the ISO cannot collect the data until approximately 18:00. Oil prices are published later, but have much less volatility. An alternative approach would be to use the fuel prices from the day before. This introduces a one-day lag in the fuel prices but provides suppliers certainty. Analysis of historical data suggests that the difference is minimal from a statistical point of view. Either approach would provide an improvement over the current methodology.

2.7 Forward Capacity Market

June 1, 2010 marked the beginning of the first Forward Capacity Market commitment period. The net payments to resources with a CSO totaled approximately $128 million. The total net payment is the sum of the following.

- Supply Credit: The capacity payment rate times the total amount of Capacity Supply Obligations in the month
- PER Adjustment: The Peak Energy Rent rate multiplied by the total amount of Capacity Supply Obligations subject to PER in the month
- Excess DR Penalties: The total unallocated DR Penalties in the month
- Reliability Credit: Payments to resources retained for reliability

Table 2—10 shows payments made in June 2010 to generator, demand, and import resources for their capacity during the obligation month.

Table 2—10
FCM Payments and Charges, June 2010

Month	Capacity Zone	CSO MW	Supply Credit	PER Adjustment	Excess DR Penalties	Reliability Credit	Total Payment
Jun-10	Rest-of-Pool	32,707	$137,125,881	-$8,354,906	-$1,197,977	$282,690	$127,855,688

2.7.1 Resource Performance

All capacity resources with a CSO are subject to performance evaluation during each obligation month of a commitment period. Generation and import resources are evaluated during shortage events. The performance of demand resources is evaluated when dispatched and is measured during performance hours.

According to the market rules, a shortage event is triggered and generator performance is measured when the Reserve Constraint Penalty Factor ("RCPF") for TMNSR reaches its maximum level of $850/MWh for 30 contiguous minutes. On June 24, TMNSR reached $850/MWh for one five minute interval at 14:20, five intervals short of the necessary six intervals required to initiate a shortage event. The penalty structure in the FCM assumes that the performance of resources with CSOs will be evaluated when the system is tight. However, requiring the system to experience this condition for thirty contiguous minutes before declaring a shortage event is extreme, rare, and may not meet the intent of the FCM performance penalty structure. The IMM will conduct additional analysis of the role of this feature in the FCM design and may recommend design changes in the future.

The performance of active Demand Resources is measured when the resources are dispatched and the performance of passive resources is measured during performance hours. There are four types of Demand Resources: Real-Time Demand Response resources ("RTDR"), Real-Time Emergency Generation resources ("RTEG"), On-Peak resources, and Seasonal Peak resources. RTDR and RTEG are active demand resources required to respond to dispatch instructions from the ISO. On-Peak and Seasonal Peak resources, on the other hand, are passive demand resources that do not receive dispatch instructions. Instead, these resources curtail their electricity use at set times throughout the year. On-Peak resources must reduce consumption during summer peak hours (non-holiday weekdays, 13:00 to 17:00, during June, July, and August) and winter peak hours (non-holiday weekdays, 17:00 to 19:00, during December and January). Seasonal Peak resources must reduce consumption during the summer months of June, July, and August and during the winter months of December and January in hours on non-holiday weekdays when the real-time system hourly load is equal to or greater than 90% of the most recent "50/50" System Peak Load Forecast. Resources that deliver less reduction than their CSO are assessed a penalty, while market participants that deliver in excess of their CSO are eligible to receive a performance incentive. The following table displays a pool-level summary of demand resource performance by type for the past 13 months.

Table 2—11
Demand Response Performance, June 2010

Month	DR Type	Perf. Hours	CSO MW	Capacity Value (MW)	Negative Capacity Variance (MW)	Positive Capacity Variance (MW)	Perf. Penalty ($)	Perf. Incentive ($)
Jun-10	ON PEAK	88	501.48	571.56	-48.12	89.42	-$216,531	$402,377
Jun-10	REAL TIME	3	826.33	731.21	-236.22	141.10	-$1,062,972	$634,937
Jun-10	REAL TIME EG	0	644.85	404.38	-252.31	11.85	-$1,135,404	$53,303
Jun-10	SEASONAL PEAK	19	145.67	181.04	0.00	28.07	$0	$126,315

2.8 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 nine generating stations, with a combined total capacity of 2,835 MW. The nine stations include

West Springfield 3 and GT-1 and GT-2; Pittsfield/Altresco; and Berkshire Power in Western Massachusetts; as well as Middletown 2-4 and 10; Montville 5, 6, 10 and 11; Milford, New Haven Harbor; Bridgeport Harbor 2; and Norwalk Harbor 1 and 2 in Connecticut. The net cost of Reliability Agreements to load during the Reporting Period was $4.9 million through June 1. Reliability Agreements were eliminated on June 1.

2.9 Mitigation

According to Market Rule 1, Appendix A, the IMM has the authority and responsibility to mitigate electric energy offers under certain circumstances, as well as apply rules that identify participant behavior that results in NCPC payments in excess of defined thresholds and virtual transactions that increase the hourly value of an FTR the participant holds. There were three Real-Time Energy Market mitigation events and one Real-Time NCPC mitigation event during the Reporting Period. There were no Day-Ahead Energy Market mitigation events, or Day-Ahead NCPC mitigation events during the Reporting Period.[20] There were two participants that had FTR revenues reduced pursuant to the FTR revenue capping provisions of Market Rule 1, Appendix A, section 8.4.

2.10 Behavior Requiring Referral to FERC

Market Rule 1, Appendix A, provides the IMM with a limited set of circumstances for applying mitigation activities without additional FERC involvement: energy market mitigation, NCPC mitigation, and FTR capping. When the IMM identifies other forms of potentially noncompetitive market participant behavior, Market Rule 1 requires the IMM make a referral to the FERC.

In the Reporting Period, the IMM made one new non-public referral to FERC. There are six open referrals made by the IMM before FERC. No referrals were closed in the Reporting Period.

[20] The process of NCPC mitigation relies on final settlements and therefore lags behind the market day when the mitigation thresholds were violated.

2.11 Administrative Price Corrections

There were no revisions to day-ahead prices during the Reporting Period. Table 2—12 shows the ISO's administrative price corrections to real-time prices. LMP corrections were made in 42 hours in real-time during the Reporting Period.

Table 2—12
Administrative Price Corrections

Reason	Number of Occurrences
Data error	0
Hardware/software scheduled outage	3
Hardware/software outage unscheduled	0
Software limitation	21
Software error	1
Dead bus logic	17

Section 3 Statistical Appendix

This section provides additional data supporting the analyses, conclusions and recommendations contained in this report.

3.1 Day-Ahead and Real-Time Energy Markets

Table 3—1 shows the quarterly average, minimum, and maximum hourly LMP values for the Reporting Period for the Hub, eight load zones, and the six external nodes that are priced in New England.

Table 3—1
Hourly LMP Statistics by Location, Q2 2010, All Hours

Location/Zone	LMP ($/MWh)					
	Avg. DA	Avg. RT	Min. DA	Min. RT	Max. DA	Max. RT
Internal Hub	$43.27	$45.55	$18.04	$0.00	$117.20	$270.74
Maine Load Zone	$39.96	$42.28	$15.58	$0.00	$107.61	$256.70
New Hampshire Load Zone	$41.73	$44.36	$16.27	$0.00	$112.18	$266.27
Vermont Load Zone	$44.20	$46.17	$17.18	$0.00	$116.96	$275.52
Connecticut Load Zone	$45.45	$47.10	$18.60	$0.00	$120.20	$280.49
Rhode Island Load Zone	$42.05	$44.81	$17.87	$0.00	$112.96	$269.15
SEMASS Load Zone	$42.08	$45.02	$17.92	$0.00	$112.49	$271.50
WCMASS Load Zone	$43.79	$45.99	$18.17	$0.00	$119.65	$271.75
NEMA/Boston Load Zone	$42.14	$45.50	$17.92	$0.00	$112.14	$418.24
NB-NE External Node	$38.69	$41.07	$5.00	$0.00	$104.68	$256.39
NY-NE AC External Node	$43.22	$46.73	$18.34	$0.00	$109.58	$278.04
HQ Phase I/II External Node	$41.32	$44.05	$17.54	$0.00	$109.96	$262.94
Highgate External Node	$40.62	$43.53	$15.57	$0.00	$103.48	$262.57
Cross Sound Cable External Node	$45.53	$47.61	$18.80	$0.00	$120.07	$283.02
Norwalk Harbor - Northport Cable External Node	$44.48	$47.16	$8.44	$-9.40	$106.95	$282.04

Figure 3—1 shows daily average Day-Ahead and Real-Time Hub LMPs during the Reporting Period.

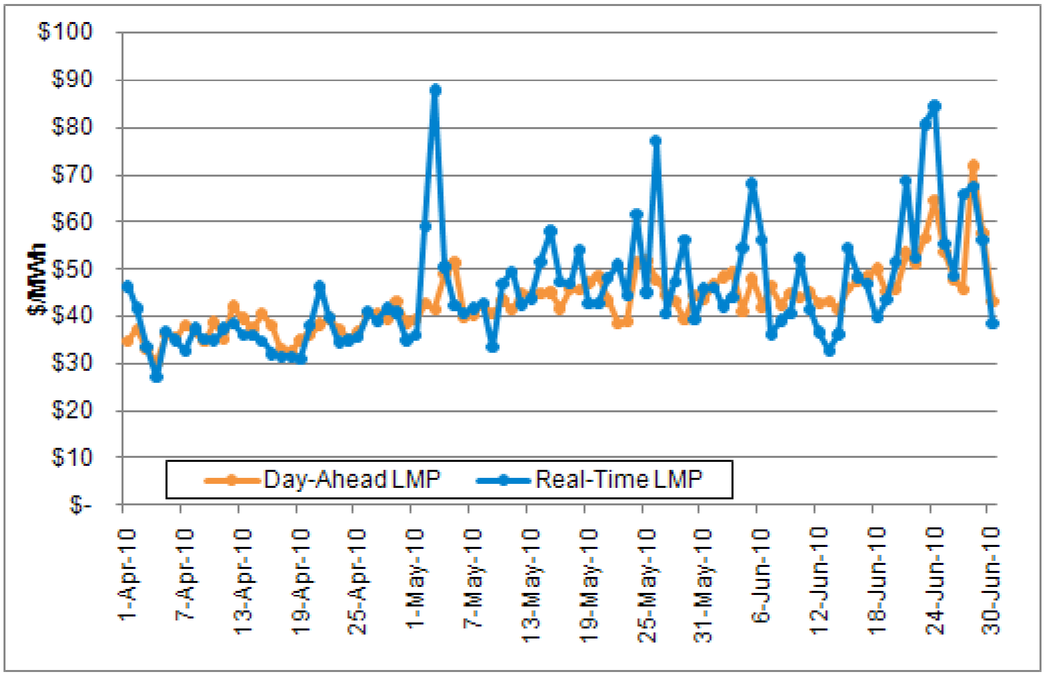

Figure 3—1: Average Day-Ahead and Real-Time Hub LMPs, Q2 2010.

On the maps in Figure 3—2, average quarterly nodal LMPs are shown in color gradations from blue (representing $36/MWh) to red (representing $50/MWh).

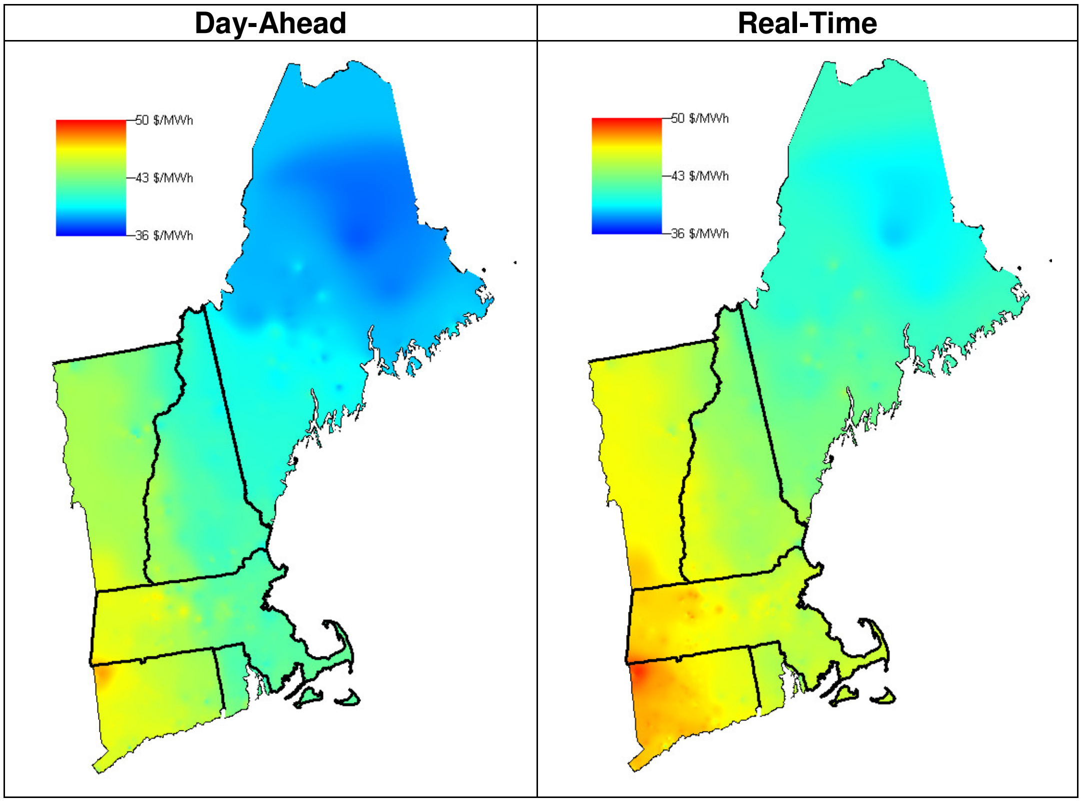

Figure 3—2: Average Nodal Prices, Q2 2010.

Figure 3—3 and Figure 3—4 show the day-ahead and real-time system electric energy prices for New England during the second quarters of 2009 and 2010 as duration curves, with prices ordered from highest to lowest.

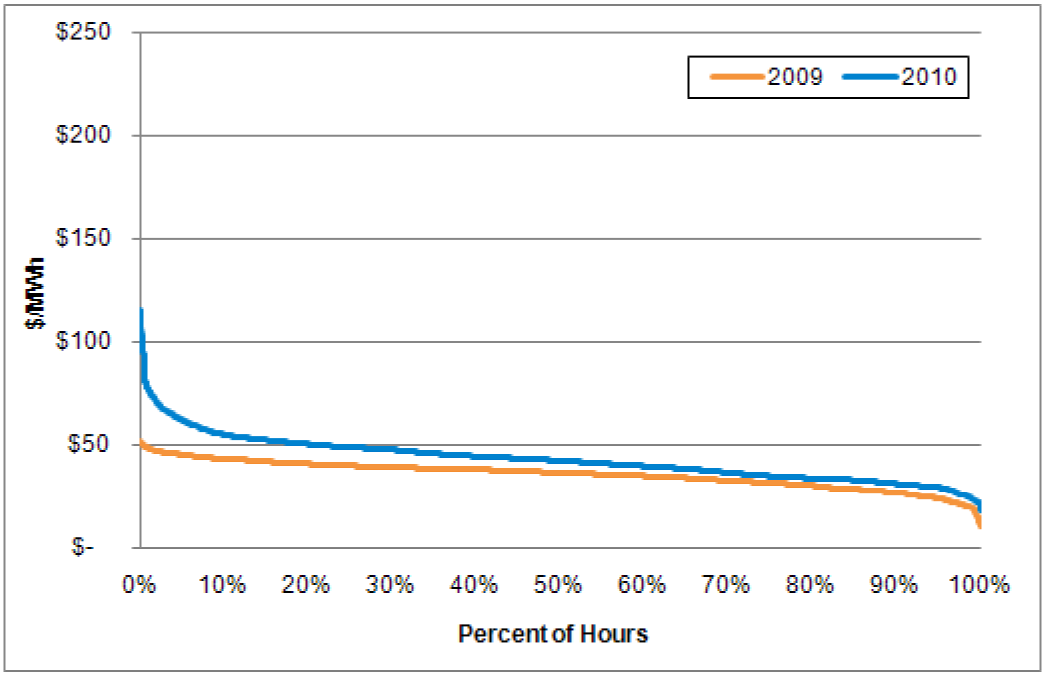

Figure 3—3: New England Hourly Day-Ahead System Price Duration Curves, Q2 2009 and Q2 2010.

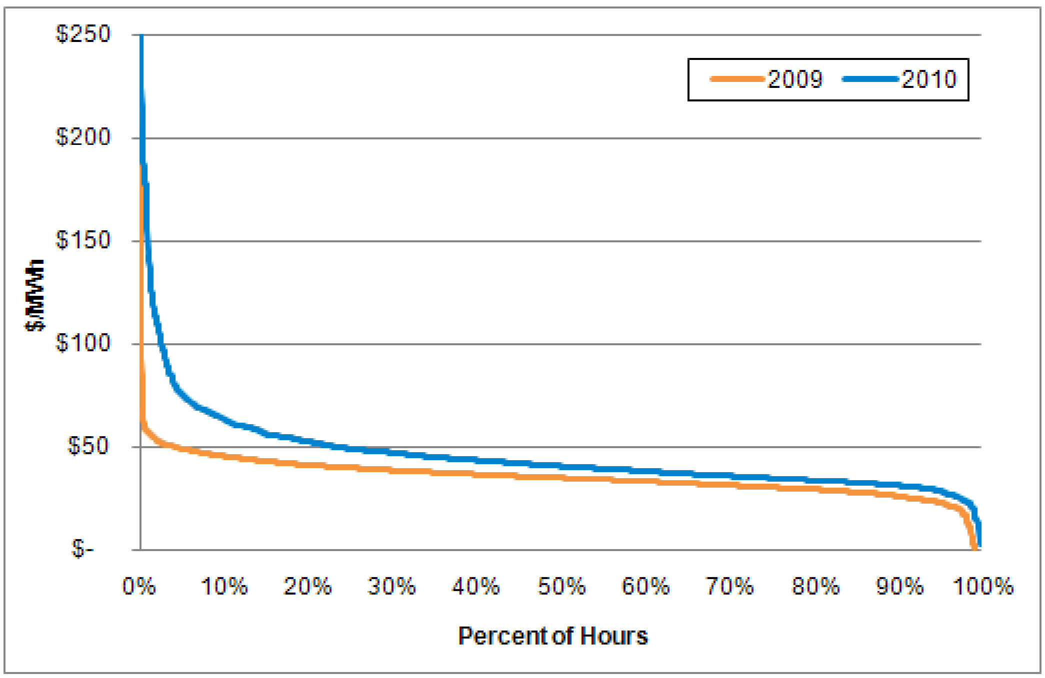

Figure 3—4: New England Hourly Real-Time System Price Duration Curves Q2 2009, and Q2 2010, Prices < $250.

Note: There was one hour in Q2 2010 with a system price greater than $250.00/MWh.

Figure 3—5 presents average DALO vs. RTLO for the Reporting Period by zone. Over all Reporting Period hours, the average DALO was about 92.8% of RTLO. This percentage varied across zones.

The Rhode Island and NEMA load zones cleared the highest percentage, clearing 98% and 97% of RTLO in the Day-Ahead Energy Market, respectively.

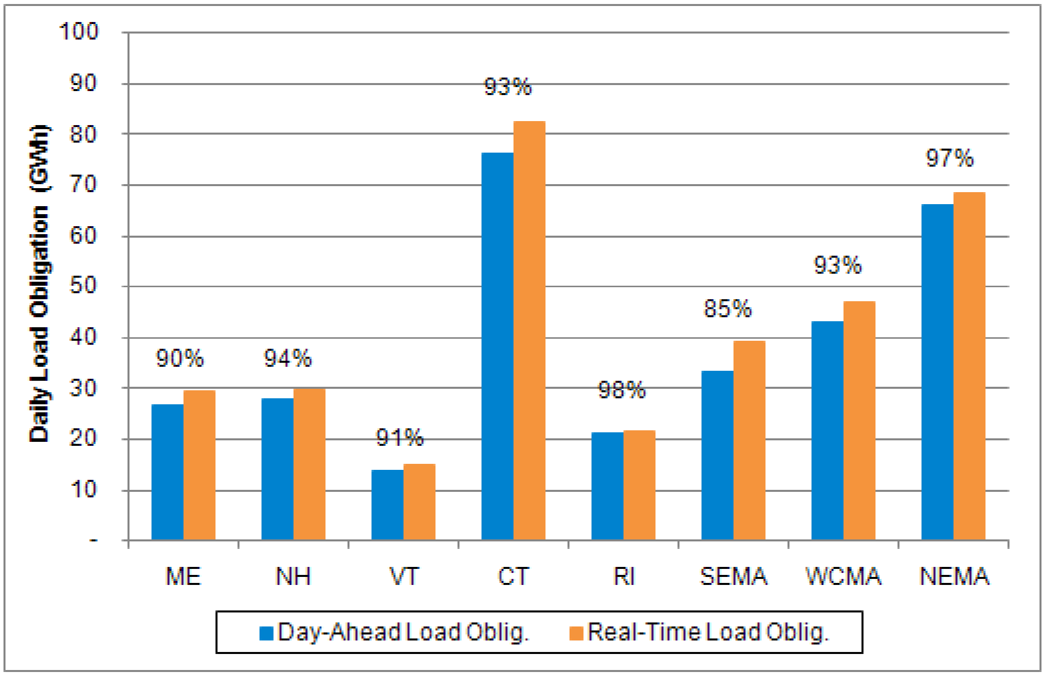

Figure 3—5: Average Day-Ahead Load Obligation vs. Real-Time Load Obligation by Zone, Q2 2010.

Table 3—2 shows hourly generation cleared in the day-ahead market as a percentage of actual load for June 24, 2010.

Table 3—2
Hourly Cleared Day-Ahead Physical Supply
as a percent of Load Forecast, June 24, 2010

Hour	Cleared Generator Supply, Day-Ahead Market	Real-Time System Load	Day-Ahead Gen. Supply / System Load
1	14,582	14,628	100%
2	13,997	14,069	100%
3	13,693	13,483	102%
4	13,414	13,221	101%
5	13,583	13,311	102%
6	14,011	13,880	101%
7	14,806	15,449	96%
8	16,945	17,074	99%
9	18,133	18,602	98%
10	18,745	19,832	95%
11	19,658	21,059	93%
12	20,283	22,028	92%
13	20,562	22,688	91%
14	20,696	23,247	89%
15	20,643	22,870	90%
16	20,895	22,521	93%
17	20,914	22,535	93%
18	20,538	22,177	93%
19	19,718	21,452	92%
20	19,207	20,683	93%
21	19,197	20,282	95%
22	18,510	19,823	93%
23	16,849	18,107	93%
24	15,387	16,139	95%

A summary of virtual transaction activity is presented in Table 3—3 below. Virtual demand increased from Q2 2009 to Q2 2010; 25% more of virtual demand was submitted. Virtual supply decreased from Q2 2009 to Q2 2010. The year over year increase in virtual load and decrease in virtual supply is the market response to overall changes in the day-ahead to real-time price relationship discussed above.

Table 3—3
Virtual Transaction Outcomes

	Q2 2010	Q1 2010	% Change (Q2 2010 to Q1 2010)	Q2 2009	% Change (Q2 2010 to Q2 2009)
Frequency (count)	433,304	412,762	5%	535,027	-19%
Incs Submitted (MWh)	5,774,269	6,522,470	-11%	8,408,802	-31%
Incs Cleared (MWh)	1,520,720	2,447,914	-38%	3,122,482	-51%
Decs Submitted (MWh)	5,036,995	5,336,882	-6%	4,037,739	25%
Decs Cleared (MWh)	2,275,077	2,706,333	-16%	2,533,485	-10%

Figure 3—6 and Figure 3—7 show the daily total of the hourly submitted and cleared virtual transactions over the Reporting Period.

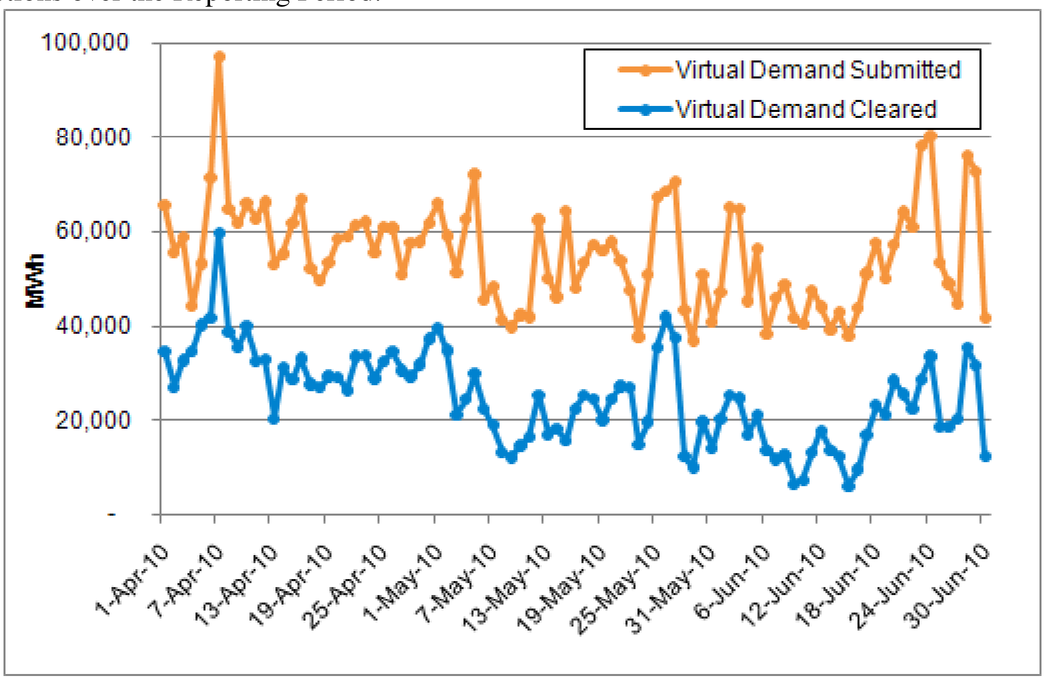

Figure 3—6: Submitted and Cleared Virtual Demand Daily Totals, Q2 2010.

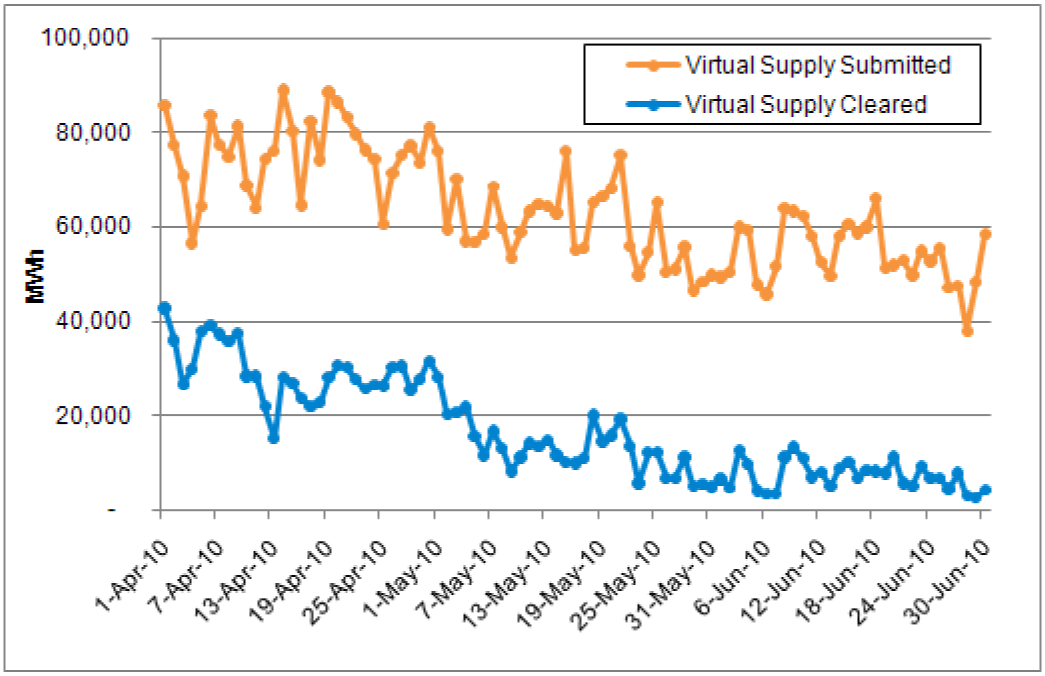

Figure 3—7: Submitted and Cleared Virtual Supply Daily Totals, Q2 2010.

The declaration of a Minimum Generation Emergency resets the economic minimums of resources down to their emergency minimums (if available) to gain additional dispatchable range and administratively sets LMPs to zero. Table 3—4 shows real-time self-scheduled generation as a percentage of total electric energy for minimum generation hours.

Table 3—4
Real-Time Self-Schedules and Total Energy
for Minimum Generation Emergency Hours, MWh

	Q2 2010	Q1 2010	% Change (Q2 2010 to Q1 2010)	Q2 2009	% Change (Q2 2010 to Q2 2009)
Real-Time Min Gen Self Schedules	157,498	141,522	11.3%	352,258	-55.3%
NEL	158,903	157,707	0.8%	373,259	-57.4%
Percent	99.1%	89.8%	10.4%	94.4%	5.0%

Total NCPC payments during the Reporting Period totaled $17.4 million, as shown in Table 3—5.

Table 3—5
Total NCPC Payments by Quarter and Category

NCPC Category	Q2 2010	Q1 2010	Q2 2009
Economic and 1st Contingency Payments	$15,316,336	$6,046,635	$4,165,339
Second Contingency Payments	$1,668,796	$176,510	$4,853,283
Voltage Payments	$274,960	$341,371	$1,026,546
Distribution Payments	$149,042	$42,435	$11,640
Total	*$17,409,134*	*$6,606,951*	*$10,056,807*

3.2 Capacity

Table 3—6 shows the FCM transition payments made to capacity resources during the Reporting Period. The transition payments ended at the end May 2010, and the first FCM capability period began on June 1, 2010.

Table 3—6
FCM Transition Period Payment Summary

Obligation Month	UCAP Supply MW	FCM Transition Payment	Transition Payment Rate $/MW-Month
April 2010	39,201.10	$160,724,517.50	$4,100
May 2010	37,799.58	$154,978,271.64	$4,100

Table 3—7 summarizes average threshold prices and offers by interface; and Table 3—8 presents external capacity transaction penalty and requirement shortfall information for Q1 2010 and the Reporting Period.

Table 3—7
External Capacity Transaction Average Threshold Prices and Offers Q2 2010-Q1 2010

Interface	Q2 2010		Q1 2010	
	Average Offer Threshold Price	Average Offer	Average Offer Threshold Price	Average Offer
New Brunswick (4010)	$76.68	$76.23	$104.53	$98.45
Roseton (4011)	$84.42	$81.88	$201.81	$174.90
HQ Phase 1 (4012)	$85.43	N/A	$132.93	N/A
HQ Highgate (4013)	$85.43	N/A	$132.93	N/A
Shoreham (4014)	$143.28	N/A	$289.14	N/A
Northport (4017)	$62.24	N/A	$282.92	N/A

N/A: For locations 4012, 4013, and 4014, there are no competitive offers over these interfaces. Location 4015 is not allowed to have competitive offers over that interface.

NOTE: This table has data through April only, as FCM rules came into effect after that.

Table 3—8
External Capacity Transaction Penalties and Shortfalls, Q2 2010-Q1 2010

	Q2 2010	Q1 2010
Failure to Offer Penalties ($)	$14,142	$116,073
Failure to Deliver Penalties ($)	$162,987	$100,011
Percent Requested but not Delivered	0.74%	0.19%

NOTE: This table has data through April only, as capacity market rules came into effect after that.

3.3 Fuel Prices

Table 3—9 shows summary price statistics for selected fuels over the reporting period. Natural gas prices rose in the Reporting Period when compared to Q1 2010. The price of No. 6 oil (1%) continued to rise.

Table 3—9
Fuel Price Statistics for Q2 2010, $/MMBtu

Fuel Type	Average Daily Price	Minimum Daily Price	Maximum Daily Price
Natural Gas	$4.66	$3.96	$5.53
No. 6 Oil 1%	$11.46	$10.10	$12.89
Low Sulfur Coal	$2.64	$2.42	$2.76
High Sulfur Coal	$2.46	$2.20	$2.56

3.4 Weather

Figure 3—8 shows global temperature anomalies[21] for June 2010, obtained from the National Oceanographic and Atmospheric Administration ("NOAA").[22] June's combined global land and ocean surface temperature made it the warmest June on record and the warmest on record averaged for any April-June and January-June periods, according to NOAA. Worldwide average land surface temperature was the warmest on record for June and the April-June period, and the second warmest on record for the year-to-date (January-June) period, behind 2007. Warmer-than-average conditions dominated the globe, with the most prominent warmth in Peru, the central and eastern contiguous U.S., and eastern and western Asia. Regionally in June, temperatures were highest in southern New England, with Massachusetts 13th highest on record, Connecticut 8th warmest on record, and Rhode Island 4th warmest on record.

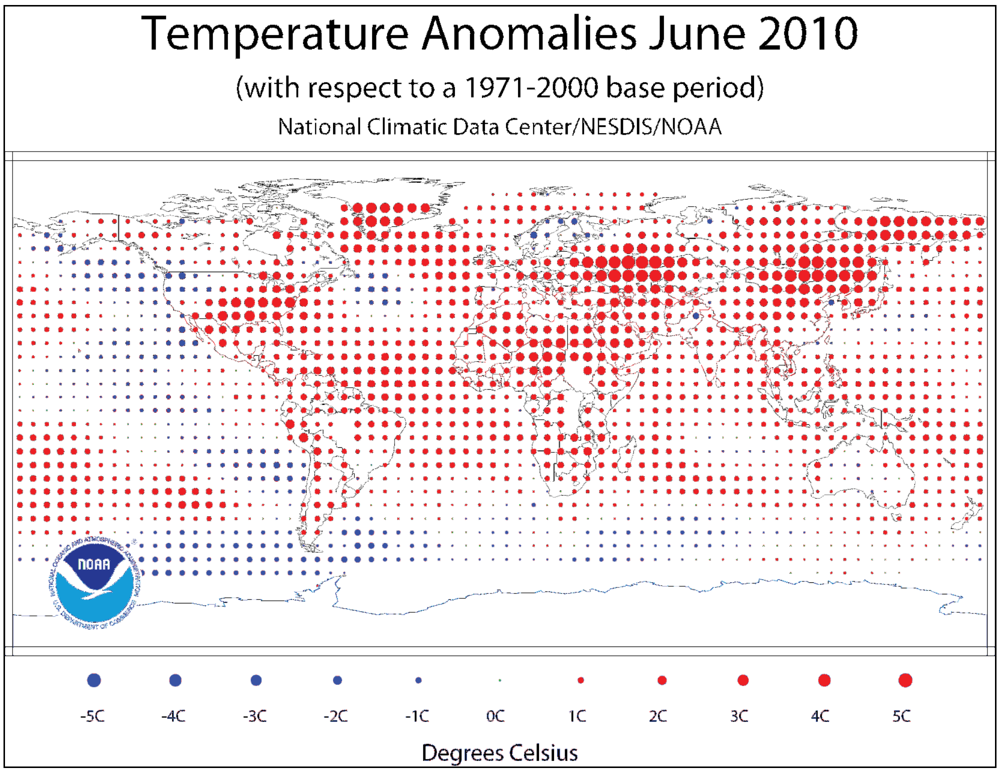

Figure 3—8: Global Temperature Anomalies, June 2010.
(**Source:** NOAA)

3.5 Demand for Electricity

Table 3—10 shows that actual NEL increased by 5.6%, while weather normalized NEL increased by 2.9% when compared to the second quarter of 2009. The peak demand for the Reporting Period

[21] Temperature anomaly refers to the difference from average. The global temperature is calculated using anomalies because they give a more accurate picture of temperature change. If calculating an average temperature for a region, factors like station location or elevation affect the data, but when looking at the difference from the average for that same location, those factors are less critical. *See* http://www.noaanews.noaa.gov/stories2010/20100715_globalstats_sup.html.

[22] Available at http://www.noaanews.noaa.gov/stories2010/20100715_globalstats.html.

occurred on June 28, hour ending 14. Peak demand was 31.2% above the peak of 18,468 MW for the second quarter 2009.

Table 3—10
Net Energy for Load

	(GWh)			
	Q2 2010	Q2 2009	Diff.	%Chg.
Q2 Recorded NEL (GWh)	30,764	29,137	1,627	5.6%
Q2 Normalized NEL (GWh)	30,573	29,712	861	2.9%
Q2 Recorded peak demand (MW)	24,239	18,468	5,771	31.2%

Figure 3—9 presents New England hourly duration curves for Q2 2010 and Q2 2009.

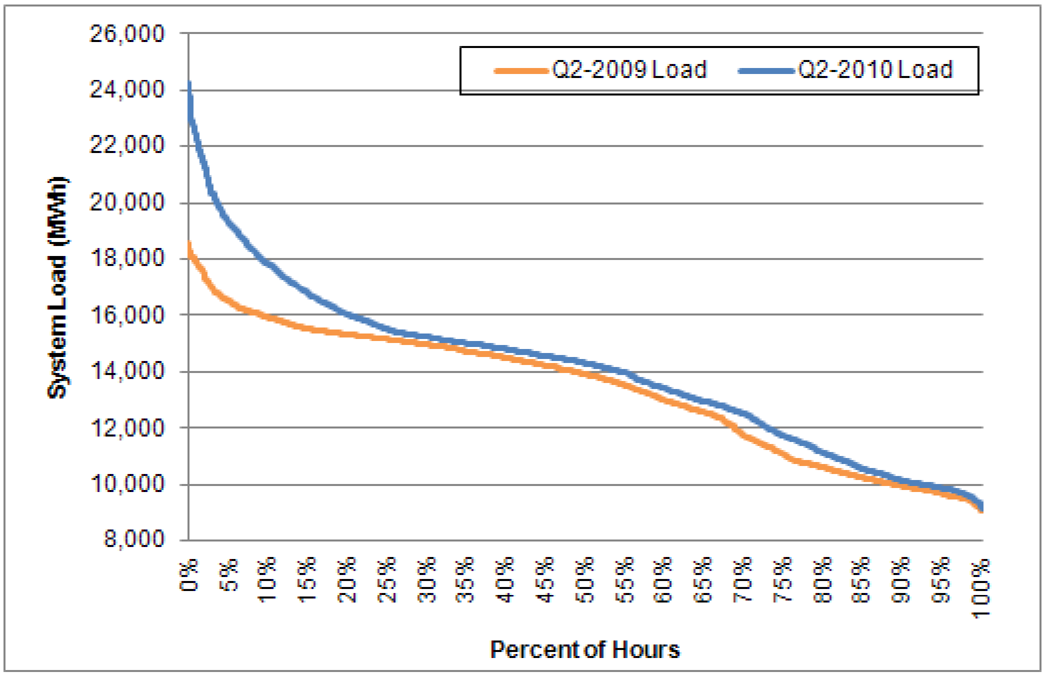

Figure 3—9: New England Hourly Load Duration Curves, Q2 2009 and Q2 2010.

3.6 Supply of Electricity

Figure 3—10 compares generation by fuel type as a percentage of total generation for Q2 2009 and Q2 2010.

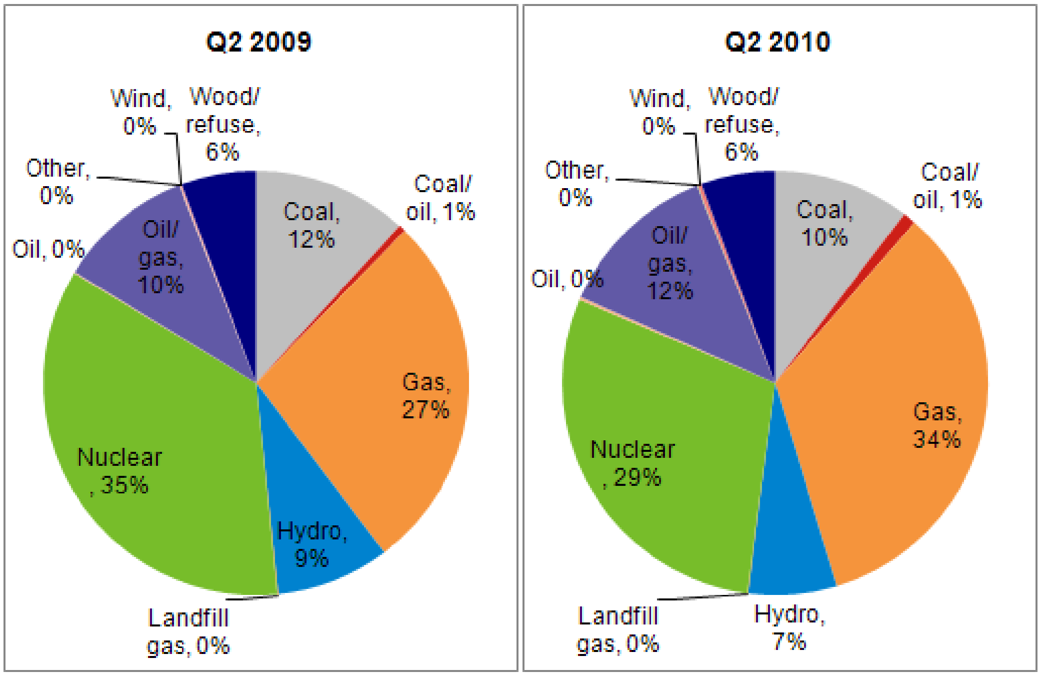

Figure 3—10: Percent of Generation by Fuel Type, Q2 2009 and Q2 2010.

3.7 Demand Response Program and Demand Resource Enrollments

Table 3—11 and Table 3—12 present enrollment in demand response programs by zone and by program under the Forward Capacity Market.

Table 3—11
Demand Resource Asset Enrollment
by Demand Resource Type and Load Zone (as of 6/1/2010)

Zone	June 1, 2010 – Enrolled Amount (MW)				
	Real-Time Demand Response Resource	Real-Time Emergency Generation Resource	On-peak demand resource	Seasonal Peak Demand Resource	Grand Total
ME	336.005	20.836	74.990	0.000	431.831
NH	50.991	32.325	52.529	0.000	135.845
VT	51.022	14.445	46.128	0.000	111.595
CT	316.927	323.057	73.378	235.724	949.086
RI	54.985	38.957	47.198	0.808	141.948
SEMA	71.056	47.795	64.835	3.366	187.052
WCMA	165.726	64.336	68.975	18.876	317.913
NEMA	92.673	88.731	109.564	0.000	290.968
Total	1,139.385	630.482	537.597	258.774	2,566.238

Table 3—12
Real-Time Price Response Program* (RTPR) and
Day-Ahead Load Response (DALRP) Enrollment (as of 6/1/2010)**

Zone	June 1, 2010 – Enrolled (MW)	
	RTPR	DALRP
ME	-	6.600
NH	4.450	5.700
VT	1.840	46.593
CT	2.250	9.000
RI	12.900	11.300
SEMA	8.300	16.300
WCMA	14.150	15.200
NEMA	19.100	124.370
Total	62.990	235.063

* Displayed data is the enrolled amount of assets in the RTPRP
**Displayed data is the day-ahead Maximum Interruptible Capacity of assets that are active in the DALRP.

3.8 Financial Transmission Rights

Table 3—13 compares maximum, minimum and average clearing price statistics for auctions in the Reporting Period. On-peak, off-peak and combined calculations are shown. Annual auction values have been converted to $/MW-Month for comparison.

Table 3—13
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 2010 LT	$106.03	$186.07	$25.99	$974.70	$-313.01	$120.55	$-52.47
April 2010	$84.02	$122.65	$45.39	$935.52	$-422.09	$208.44	$-89.53
May 2010	$121.63	$190.35	$52.90	$892.79	$-286.89	$216.22	$-77.32
June 2010	$110.36	$183.82	$36.91	$946.91	$-432.84	$191.54	$-91.08

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 3—14 shows the total distribution of ARR dollars to the various zones for each month. The annual auction revenue presented for comparison is the annual value divided by 12 for a monthly value.

Table 3—14
ARR Award Allocation by Zone ($), Q2 2010

Month	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
April 2010	$73,138	$26,712	$32,578	$1,198,992	$25,976	$56,383	$165,162	$185,515
May 2010	$75,015	$35,444	$38,625	$1,475,683	$38,486	$77,296	$223,332	$244,090
June 2010	$75,944	$35,218	$36,787	$1,724,849	$42,975	$83,983	$237,796	$242,066

Table 3—15 lists the highest priced sink-source combinations as purchased in the monthly auctions during the Reporting Period.

Table 3—15
Top Five Highest Priced FTR Sink-Source Combinations, Monthly Auction

Auction	On-Peak Auction		
	Source	Sink	Award Price
April 2010	LD.E_SPRFLD115	LD.BRECKWOD115	$1,293.60
April 2010	LD.E_SPRFLD115	LD.CLINTON 115	$1,108.42
April 2010	LD.E_SPRFLD115	UN.W_SPRFLD13.8WS10	$1,108.42
April 2010	LD.ORCHARD 115	LD.AGAWAM 115	$834.11
April 2010	LD.E_SPRFLD115	LD.BUCK_PD 115	$828.00
May 2010	UN.ENFLD_ME115 IND5	LD.NE_SIMSB115	$1,379.75
May 2010	LD.BOGGY_BK46	LD.SALISBRY69	$1,355.00
May 2010	LD.HNKLY_PD115	UN.FALSVL 69 FALS	$1,115.94
May 2010	LD.E_SPRFLD115	UN.W_SPRFLD13.8WS10	$1,058.67
May 2010	LD.E_SPRFLD115	UN.W_SPRFLD13.8WSP3	$1,058.67
June 2010	LD.E_SPRFLD115	LD.BRECKWOD115	$1,007.17
June 2010	LD.E_SPRFLD115	UN.W_SPRFLD13.8WS10	$836.97
June 2010	LD.E_SPRFLD115	UN.W_SPRFLD13.8WSG1	$836.97
June 2010	LD.E_SPRFLD115	LD.BAIRD 14	$806.97
June 2010	.Z.MAINE	.Z.CONNECTICUT	$775.34

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 ARRs process. During this process, auction revenues are awarded primarily to congestion-paying load-serving entities.

Table 3—16 shows auction revenue distributed by category. The annual auction revenue presented for comparison is the annual value divided by 12 for a monthly value.

Table 3—16
ARR Allocations, Q2 2010

Month	Net FTR Auction Revenue	ARR Allocation ($)						
		Excepted Trans. Dollars	NEMA Contract Dollars	Load Share Dollars	Annual Firm Trans. Svc. Dollars	Total ARR Allocation	QUA Alloc. Dollars	Total Auction Revenue Distrib. (ARR + QUA)
April 2010	$-2,161,215	$125	$8,743	$1,755,588	$0	$1,764,455	$396,760	$2,161,215
May 2010	$-2,414,708	$131	$10,472	$2,197,368	$0	$2,207,972	$206,737	$2,414,708
June 2010	$-2,759,666	$133	$10,437	$2,469,047	$0	$2,479,618	$280,048	$2,759,666

FTR holders are paid through the Transmission Congestion Revenue Balancing Fund. Monthly revenues, target allocations, and actual allocations paid for the Reporting Period are shown in Table 3—17. 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 in each month.

Table 3—17
Congestion Revenue Fund, Q2 2010

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
April 2010	$-172,556	$4,356,547	$266,419	$-2,027,067	$6,477,476	$0	100.00%
May 2010	$-921,516	$7,220,377	$304,381	$-5,023,005	$11,626,248	$0	100.00%
June 2010	$-97,038	$2,039,458	$-82,128	$-974,830	$2,835,122	$-0	100.00%

3.9 Forward Reserve Market

Table 3—18 summarizes forward reserve credit, penalties, and net forward credit for all forward reserve resources, as well as all real-time reserve credit, by month for the Reporting Period. The total net forward reserve credit for the Reporting Period was $37.1 million, which includes $35.1 million in forward reserve credit and $2.0 million in total failure to reserve penalties. The Net Real-Time Credit for the Reporting Period was $6.7 million, including $5.8 million in Real-Time Credit and $881,000 in Forward Reserve Obligation Charges.

Table 3—18
Monthly Total Forward Reserve Market Payments and Penalties, Q2 2010

Month	Forward Credit	Total Penalties	Net Forward Credit	Real-Time Credit	Forward Reserve Obligation Charge	Net Real-Time Credit
April 2010	$12,382,993	$-159,948	$12,223,045	$1,145,827	$0	$1,145,827
May 2010	$13,042,636	$-340,748	$12,701,888	$3,644,060	$-531,364	$3,112,696
June 2010	$11,663,965	$-1,510,596	$10,153,369	$1,890,634	$-349,453	$1,541,181
Total	**$37,089,594**	**$-2,011,292**	**$35,078,302**	**$6,680,520**	**$-880,816**	**$5,799,704**

3.10 Real-Time Reserve Prices

Table 3—19 shows, by reserve zone, the average five-minute-interval real-time reserve clearing prices during intervals with nonzero prices and the percentage of nonzero price intervals for the Reporting Period. Pricing and the amount of nonzero pricing intervals are similar across reserve zones and products for the Reporting Period, indicating there were few local reserve contingencies.

Table 3—19
Real-Time Reserve Clearing Prices for Nonzero Price Intervals, Q2 2010

	TMSR		TMNSR		TMOR	
Reserve Zone	Price ($/MWh)	% Nonzero Intervals	Price ($/MWh)	% Nonzero Intervals	Price ($/MWh)	% Nonzero Intervals
CT	37.90	6.97%	82.38	2.10%	71.76	0.85%
SWCT	37.90	6.97%	82.38	2.10%	71.76	0.85%
NEMA/Boston	38.08	6.93%	83.81	2.06%	74.88	0.82%
Rest of System	38.08	6.93%	83.81	2.06%	74.88	0.82%

3.11 Reliability Commitments

Figure 3—11 shows the average amount of capacity committed after the clearing of the day-ahead market and not dispatched above its economic-minimum limit for the past 15 months. The reduction in commitments for local second contingency and voltage protection in 2008-2009 reduced the amount of capacity committed above minimum requirements.

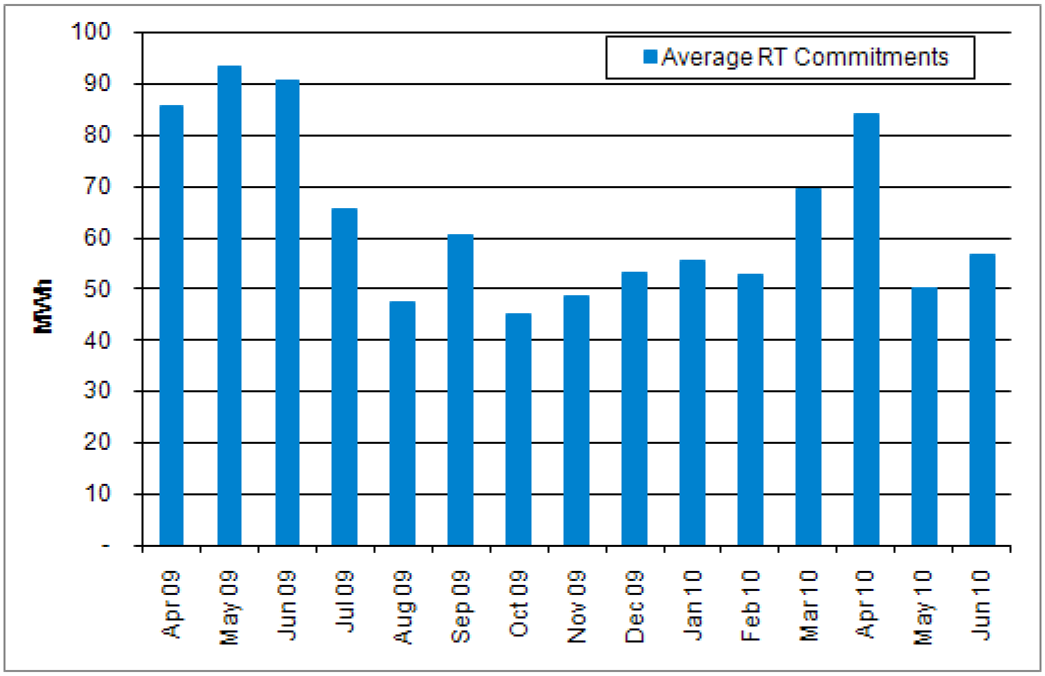

Figure 3—11: Average Generation Committed after Day-Ahead and Operated at Economic Minimum, MW per Month, April 2009-June 2010.

Table 3—20 shows total generation from resources receiving supplemental commitments and NCPC as a percent of total net energy for load (or NEL, a measure of total energy use in New England). Table 3—21 presents total Second Contingency NCPC payments by load zone for the Reporting Period.

Table 3—20
Total Generation from Supplemental Reliability Commitments Paid NCPC, MWh, by Type

Month	Second Contingency	Voltage	Distribution	Economic and 1st Contingency	Total	New England Net Energy For Load	% of Total Energy
April 2010	13,943	0	273	25,599	39,815	9,372,621	0.4%
May 2010	11,409	3,819	71	145,413	160,712	10,170,592	1.6%
June 2010	0	8,646	412	105,218	114,276	11,219,828	1.0%
Quarter Total	**25,353**	**12,465**	**756**	**276,229**	**314,803**	**30,763,041**	**1.0%**

Table 3—21
Total Second Contingency
NCPC Payments by Load Zone, Q2 2010

Load Zone	Day-Ahead	Real-Time	Total
Connecticut	$40,296	$1,471,585	$1,511,881
NEMA/Boston	$582	$122,794	$123,376
WCMA		$33,539	$33,539
Total	**$40,878**	**$1,627,918**	**$1,668,796**

3.12 Interregional Power Flows

New England was a net importer of electric energy during the first quarter of 2010. Net imports totaled 1,990 GWh in Q2 2010. Figure 3—12: shows total interregional power flows by quarter from the second quarter of 2009 through the second quarter of 2010.

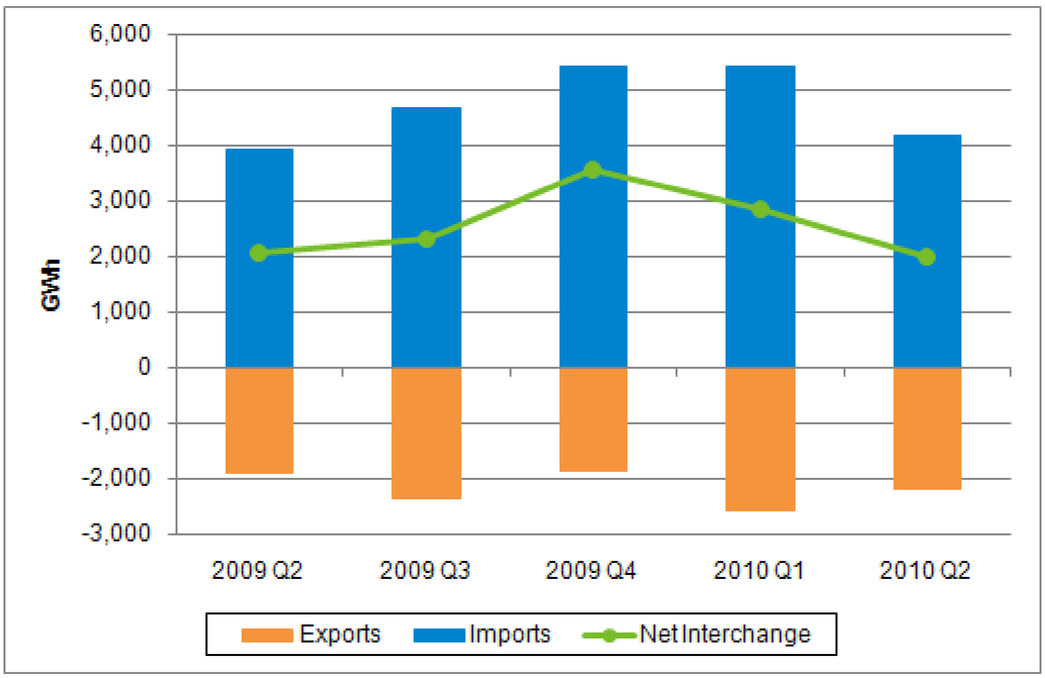

Figure 3—12: Quarterly New England Imports, Exports and Net Interchange, Q2 2009-Q2 2010.

Figure 3—13 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 that are modeled as a single interface (which now includes the formerly-separate Norwalk-to-Northport 1385 line as well). The NY-CSC interface is the Cross-Sound Cable connecting Connecticut to Long Island.

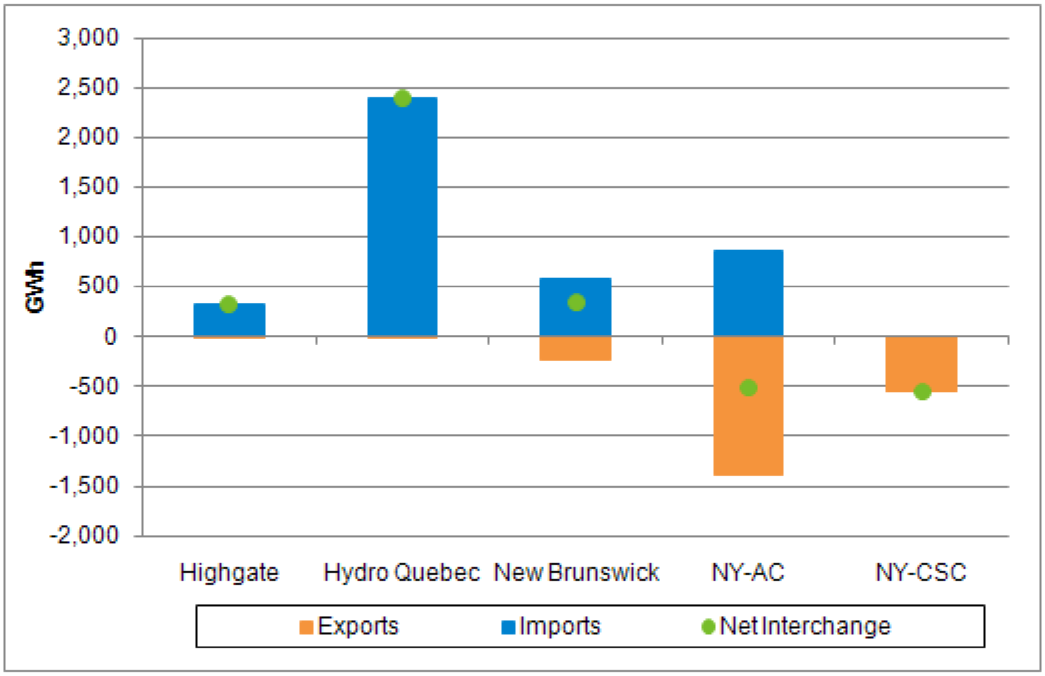

Figure 3—13: New England Imports and Exports by Interface, Q2 2010.