# Six-Month Review of SMD Electricity Markets in New England

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# I. Executive Summary

This report assesses the first six months of New England's Standard Market Design ("SMD").[1] The initial SMD markets began operation on March 1, 2003 and include day-ahead and real-time energy markets, and a regulation market. The ISO is already developing operating reserve spot markets and other key enhancements to the initial SMD markets.

The report, which satisfies section 2.10 of Market Rule 1,[2] evaluates a number of areas of the market rules, operations, and outcomes. In general, the SMD markets were implemented successfully and the transition process has been relatively smooth. The ISO experienced no significant operational or reliability problems when it began operation of the SMD markets, despite tight supply conditions in natural gas markets and unusual weather patterns that led to uncommonly high electricity demand.

The implementation of the SMD markets marks an important step in the evolution of the electricity markets in New England. These new markets provide a much more efficient means to manage network congestion and set energy prices than the prior market design. The SMD energy markets efficiently dispatch generation on the basis of supply offers to satisfy energy demand and operating reserve requirements, while preventing power flows on the network from exceeding transmission constraints. The markets establish locational marginal prices ("LMPs")

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1 SMD is an acronym for "Standard Market Design," which is based on PJM's software platform and market rules. FERC subsequently adopted this term in its effort to develop guidelines for the development of consistent RTO energy and reserve markets.

2 The relevant section states:

> The ISO, in conjunction with the Independent Market Advisor, will conduct a review of the market after 6 months of operation, or after the first summer of operations, whichever occurs first. To the extent practical, the ISO shall retain all data needed to perform comparisons and other analyses of locational marginal pricing. The ISO shall report the results of its evaluation to the Participants, along with its recommendations, if any, for changes in the procedures.

Market Rule 1 – NEPOOL Standard Market Design, §2.10 Performance Evaluation, jointly filed by ISO New England, Inc. and NEPOOL in Docket ER02-2330-000, July 13, 2002, *accepted in part*, *New England Power Pool and ISO New England, Inc.*, 100 FERC 61,287 (2002), *r'hrg*, *New England Power Pool and ISO New England, Inc.*, 100 FERC 61,344 (2002).

that reflect the marginal system cost of serving load at each location on the network. These prices ensure the efficient dispatch of generation in the short run, provide transparent price signals that facilitate efficient forward contracting, and are a primary component of the long-term incentives that guide generation and transmission investment and retirement decisions. Hence, the SMD markets provide substantial benefits in both the short term and long term, and lay the foundation for future market enhancements.

Based on our analysis of the first six months under SMD, this report finds that the SMD markets have operated as designed with the ISO taking actions consistent with its operating rules and procedures. These markets substantially improve the efficiency of congestion management and associated energy pricing in New England. This is particularly true in historically-constrained areas, such as Boston and Connecticut. The report also identifies a number of potential improvements. These improvements can be grouped into two general categories: (1) major enhancements to the SMD markets; and (2) incremental improvements to the existing market rules and operating procedures.

The first category of improvements includes market enhancements that were not part of the initial implementation of the SMD markets, but are currently under development by the ISO. Most notably, the ISO is planning to implement operating reserve markets that are co-optimized with the day-ahead and real-time energy markets. These reserve markets will enable the SMD markets to:

- Reflect the economic relationship between operating reserves and energy that will lead to more efficient price signals for both products, particularly during supply shortages;
- Recognize the economic value of reliability requirements, which have resulted in supplemental commitment and out-of-merit dispatch;
- Create incentives for units that provide operational flexibility to the system; and
- Improve the efficiency of generator commitment and dispatch.

Another important improvement to the current SMD markets is the virtual regional dispatch ("VRD") provisions that would improve the market-to-market coordination between New York and New England. These provisions would create a seamless market in the Northeast, ensuring that power is efficiently transmitted to the highest-value locations and achieving substantial savings for customers in the region. The ISO is working closely with the New York ISO ("NYISO") and the market participants to develop the VRD rules, procedures, and software.

A third improvement is related to increased participation by demand-side resources in the market, which will increase market efficiency and reliability. The ISO has programs and market modifications that are intended to facilitate participation in the New England markets by the demand-side. In particular, we support the ISO's efforts to expand the pricing options and flexibility of its demand response program in the near term, and to allow demand-response resources to participate in the real-time energy market, operating reserves market, and capacity market in the longer-term.

The second category of improvements involves modifications to certain operating procedures and rules that will increase the efficiency of the SMD markets. These recommended modifications are described in the following sections.

***Energy Price Trends***

Energy prices have closely tracked movements in natural gas prices. For example, when the SMD markets opened in March 2003, day-ahead electricity prices were very high by historical standards -- well over \$100 per MWh. The spot price for natural gas at that time ranged from \$10 to \$12 per MMBTU due to tight supply conditions. By mid-March, natural gas prices had decreased to approximately \$6 per MMBTU, resulting in a concomitant decrease in electricity prices to a range of \$50 to \$60 per MWh, a range that generally prevailed throughout the six-month SMD period. This correlation between natural gas prices and electricity prices is consistent with a well-performing market given that: a) fuel costs constitute the vast majority of most generators' marginal costs, and b) natural gas-fired units are frequently on the margin, setting the market price in New England.

In addition to energy prices tracking movements in fuel prices, the energy prices in the day-ahead and real-time markets have converged more closely during the first six months of SMD than have the corresponding prices in either PJM or New York. While all three markets are consistent in exhibiting a slight price premium in the day-ahead market, both the average price difference and the average of the absolute value of the hourly price differences were lower in New England than in the other markets in the Northeast. This indicates consistency in the operation of the day-ahead and real-time markets and demonstrates that participants have effectively utilized their bids, offers, and virtual trades to arbitrage prices between the two markets.

Virtual trading activity in New England has been very active, with the majority of trades taking place at the New England hub or individual nodes. In addition to improving the convergence between the day-ahead and real-time markets, virtual trading provides additional flexibility for participants to manage risk and helps mitigate market power in the day-ahead market by reducing net purchases when day-ahead prices would otherwise be artificially inflated. Hence, the relatively active virtual trading has been a positive feature of the SMD markets and is evidence that participants have a high degree of confidence in the markets.

Finally, the report evaluates congestion experienced in the day-ahead market at the New England hub. The hub is composed of 32 nodes in the geographic center of New England and the hub price is an arithmetic average of the LMPs at these nodes. The New England hub price is calculated and posted by the ISO to facilitate trading in New England. When virtual purchases and sales are made in the day-ahead market at the hub, the injection or withdrawal is evenly distributed over the 32 nodes. In hours with relatively large net virtual purchases, congestion has arisen between these nodes that would not be reasonably expected in real-time. This intra-hub congestion reduces the value of the hub as a facilitator of trade because it can cause the hub price to be a poor reflection of the value of power in New England.

The report shows that the largest congestion-related price differences of this type are concentrated at seven of the 32 nodes. We would expect that over time participants will submit virtual bids or offers at physical nodes to arbitrage these price differences, reducing or eliminating the intra-hub congestion. Nevertheless, redefining the hub over a broader electrical area would distribute virtual sales and purchases at the hub over a larger number of nodes. This change would potentially reduce congestion within the hub in the short-term and would be reasonable to consider as long as it does not delay higher-priority market improvements.

***Congestion and Local Reliability Requirements***

The SMD markets experienced very little congestion during the first six months of operations. This includes low levels of congestion into the Northeast East Massachusetts/Boston area ("NEMA") and Connecticut, despite historical patterns to the contrary. This result is not as surprising for NEMA, given the recent addition of substantial generating resources and the transmission system upgrades over the past few years on facilities serving the area. In addition to finding relatively low congestion levels, the report also shows that day-ahead congestion, real-time congestion, and prices of Financial Transmission Rights ("FTR") have not been well-correlated. However, the correlation of these prices and the liquidity of the FTR markets both improved over the six-month period. Additionally, we find no structural or procedural flaws with the FTR market.

The report identifies operating requirements and procedures that tend to reduce the levels of congestion the SMD markets exhibit in chronically-constrained areas, including NEMA and several areas in Connecticut. To ensure reliability in these areas, the ISO operates with capacity requirements that are comparable to location-specific reserve requirements. But until the ISO implements its spot operating reserve markets, these requirements will not be market requirements. Hence, the initial SMD markets will not generally satisfy these requirements on their own, which causes the ISO to make supplemental commitments and to dispatch generation out-of-merit order to maintain reliability in the constrained areas. These actions can inefficiently mute price signals in the constrained areas.

The analysis in this report shows substantial quantities of supplemental commitment in NEMA and Connecticut. Total supplemental commitment in these areas has averaged almost 500 MW and 600 MW in NEMA and Connecticut, respectively. These quantities tend to increase on the highest-demand days. Approximately two-thirds of these supplemental commitments are made to meet first-contingency or second-contingency reliability requirements in those constrained areas. These commitments are necessary, in part, because these areas do not have a large quantity of quick-start resources that can help meet the capacity requirements of the local area while offline.

Supplemental commitments increase the available supply in the constrained areas, which reduces imports and the associated congestion into these areas. However, supplemental commitments frequently result in a significant quantity of out-of-merit dispatch, i.e., energy produced by resources whose energy offer prices are higher than the market energy price. This occurs because once they are committed, online resources must be dispatched at or above their minimum output parameter ("EcoMin"). These units cannot be shut down since their capacity is needed to satisfy the local capacity requirement. Since out-of-merit resources are treated as must-take resources (equivalent to assigning them a zero offer price) and are not eligible to set LMPs, they displace the marginal source of energy and cause a lower-priced resource to set the energy price in the constrained area. This can depress prices in the constrained area and in the broader New England market as well.

The most important pending improvement to economic signals in constrained areas is promised by the introduction of operating reserve spot markets that are jointly optimized with the energy market. These markets should incorporate the local-reliability capacity requirements, thereby allowing these requirements to be more fully reflected in the SMD market outcomes. Locational operating reserve spot markets would allow energy and reserve prices in constrained areas to more accurately reflect the value of resources in these areas.

***Market Operations and Scheduling***

This section covers a wide variety of areas related to the operation of the SMD markets. Some relate to the ISO's implementation and operation of the markets, while others relate to the market consequences of certain operating procedures and the scheduling actions of participants.

Price corrections are frequently an indicator of implementation problems or software errors. Price corrections remained at very low levels throughout the transition to SMD. Prices were corrected in less than one percent of the five-minute intervals during the six-month period, which is substantially less frequent than the rate of reported corrections during the initial operation of comparable markets.

Day-ahead load forecasting, which is an important determinant of efficient day-ahead commitment, has been very accurate. The average absolute forecast error for the peak load in New England has been 1.8 percent, compared to 2.3 percent in New York and 3.6 percent in PJM. The accuracy of the ISO's forecasts is important because they are a key input to the ISO's reliability assessments and supplemental commitment decisions, and because they provide information to market participants for their day-ahead scheduling and bidding.

Since generation is generally committed day-ahead, the level of load scheduled through the day-ahead market can significantly affect market operations. Approximately 92 percent of the actual load in New England is scheduled in the day-ahead market, although there is a general tendency for this ratio to decrease as actual load increases. This ratio can also vary substantially by zone, with Maine over-scheduled in the initial months of SMD and Connecticut under-scheduled substantially throughout six-month period. The over-scheduling in Maine ceased when certain bilateral contracts that allow the seller to choose the point of delivery (i.e., "seller's choice contracts") were shifted from settling at day-ahead prices to settling at real-time prices. The under-scheduling in Connecticut, which averaged close to 20 percent, is consistent with current incentives provided by the day-ahead and real-time energy markets. Even with the under-scheduling, however, prices in the day-ahead and real-time markets have converged consistently throughout the six-month period. Hence, the markets are not providing an economic incentive to schedule higher quantities of load in the day-ahead market.

Under-scheduling of day-ahead load together with the local capacity requirements in Connecticut and NEMA results in substantial quantities of supplemental commitment in these areas after the day-ahead market closes. This additional supply in the real-time market will reduce real-time prices and reinforce the incentive to under-schedule. This pattern creates three issues in the New England market. First, it creates inefficiencies because supplemental commitments are made with the objective of minimizing commitment costs (i.e., start-up, no-load, and energy costs at EcoMin), rather than minimizing the overall production costs.

Second, it results in a substantial amount of uplift costs that are difficult for participants to hedge, most of which are generated by commitments in Connecticut and NEMA. The uplift costs associated with these commitments are allocated to the real-time market. Because real-time uplift costs are only allocated to the real-time deviations, they can provide an inefficient disincentive to buy or sell energy in the real-time market. This is a particularly important issue for virtual trading because most virtual trades settle entirely as a real-time deviation. In fact, the report shows that the uplift allocations to constrained areas tend to be substantially higher than the profit generally realized from virtual trades in those areas.

Lastly, this supplemental commitment process contributes to substantial over-commitment market-wide since resources that are committed through the day-ahead market are not decommitted when additional resources must be committed in the constrained areas. On average, units committed after the day-ahead market account for more than 1600 MW of surplus commitments each day. Roughly half of this total occurs through self-commitment while the vast majority of the remaining amount is committed by the ISO to meet local reliability requirements. The analysis in this report shows that the ISO's generator commitments have been made consistent with its operating requirements and procedures. Nevertheless, these procedures have contributed to surplus commitments in the New England market. To reduce the surplus commitments, we recommend that the ISO:

- Include the first-contingency transmission constraints and second-contingency reliability requirements in the day-ahead market commitment. This will improve the day-ahead market commitment by allowing the market software to recognize these commitments in its day-ahead schedules and prices, and to commit fewer resources outside of the constrained areas;

- Consider the merits of not allowing suppliers to self-commit units after the Resource Adequacy Assessment ("RAA") process unless they have suffered an outage on another unit or provide comparable justification. This would both reduce the quantities of supplemental commitments, as well as increase suppliers' incentives to offer resources competitively in the RAA since it would be their last opportunity to commit a unit;

- Allocate uplift costs associated with commitments made to satisfy local reliability requirements to all physical loads in the constrained areas. This would remove current disincentives for virtual trading and price-responsive load scheduling in the day-ahead market. Additionally, it would recognize that commitments for local reliability protect all load in the area, regardless of whether it settles in the day-ahead market or real-time market; and

- Include all day-ahead scheduled external transactions and any additional real-time transactions scheduled prior to the RAA in the RAA commitment process. The ISO currently includes transactions that have been scheduled and checked-out with the adjacent control area by 2 p.m. While the ISO's current procedures generally include most external transactions that are ultimately scheduled, that is not always the case. This change should reduce the probability of unneeded commitments resulting from the RAA process.

***Interface Scheduling***

This report evaluates the power scheduled over the three external interfaces with New England: New York, Hydro-Quebec ("HQ"), and New Brunswick. The scheduling activity differs significantly between the Canadian interfaces and the New York interfaces. New York is a competitive market with many participants while in both Quebec and New Brunswick, there is one dominant supplier that accounts for the vast majority of the scheduling power over the interface.

The most significant source of imports to New England is HQ. At night, imports from HQ decrease and become net exports of close to 200 MW. This is consistent with normal hydroelectric operating patterns. Because hydroelectric units are energy-limited, they typically operate during the higher-priced hours and conserve water in the lower-priced hours at night. The pattern of net imports from New Brunswick is similar to imports from HQ, averaging approximately 400 MW in the day and declining to 200 MW at night. The pattern of net imports from New York is opposite that of Hydro-Quebec and New Brunswick – power is imported to

New England at night and exported to New York on net during the day. The consistency of this pattern suggests that most of the external transactions are associated with bilateral power sales and purchases, which are often for the sixteen peak hours of each weekday.

When transmission limits do not bind, trading between neighboring markets should cause prices to converge. In other words, when prices are higher in New England than in New York, imports from New York should increase until the interface is fully scheduled or until prices have converged. Prior analyses have shown that this is generally not the case, indicating that transactions are frequently not scheduled efficiently. In addition to showing that the interface between the markets is not fully utilized when substantial price differences occur, these analyses have shown that power is often scheduled from the higher-priced market to the lower-priced market.

The implementation of the SMD markets was not expected to resolve these concerns, and the analysis in this report confirms that it did not. These results reinforce the importance of the work that is underway between ISO New England and the New York ISO to implement the VRD provisions to coordinate their physical interchange.

***Regulation Market***

Our examination of the regulation market indicates that while participation in the market has been more than sufficient to provide inexpensive regulation service, two aspects of the market's design have prevented it from operating as efficiently as possible. The first aspect relates to suppliers' self-supply of regulation. The regulation market includes an economic evaluation to determine a clearing price the evening prior to the market day. However, participants whose offers were above the clearing price are able to self-schedule regulation in real time without reducing the clearing price. This undermines the incentive for suppliers to offer regulation service at marginal cost and results in inefficient selection of resources for regulation. The ISO has identified this concern and proposed that units not be allowed to self-schedule after the regulation clearing price has been determined. We concur with this proposal and understand that it is currently under consideration in the NEPOOL stakeholder committees.

The second aspect of the regulation market relates to the selection of regulating capability that clears in the regulation auction. Regulation offers are accepted in economic merit order, where the order is determined by the sum of the regulation offer price and an estimate of the unit's opportunity costs of providing regulation. Opportunity costs for a particular unit tend to increase with the quantity of regulation provided. Hence, it can be more efficient to take less than the full amount offered by a particular resource. The regulation market model does not currently optimize the quantity procured from each resource, which leads to inefficiencies in the selection of units for regulation. Our analysis indicates that optimizing the quantities procured from each resource would reduce the regulation price by 40 percent. In addition, it would cause regulation to be held on a larger number of units, which generally should improve the system's regulation performance. Therefore, we recommend the ISO examine the feasibility of enhancing the regulation market model to optimize the quantities procured from each resource.

***Conclusion***

This report concludes that the SMD markets have been implemented successfully and operated well by the ISO. Locational pricing and congestion management under the SMD energy markets are substantial improvements over the prior markets in New England. The report confirms that a number of the market improvements the ISO has under development are needed and will address market issues that arose in the initial six months of the SMD markets' operation.

To supplement these planned enhancements to the SMD markets, the report includes several recommended changes to the commitment procedures and methodologies, and to the current regulation market. These recommendations will improve the efficiency of the SMD markets by addressing several of the market issues identified in the report. Although some of these improvements would be significant, the implementation of operating reserves and regulation markets that are jointly optimized with the energy markets is the most important potential improvement to the current SMD markets and should remain the highest priority.

## II. Prices and Market Outcomes

In this section, we review trends in prices that relate to the performance of the SMD markets during the first six months of operation. This includes analyses of overall price trends, price convergence between the day-ahead and real-time markets, and transmission congestion.

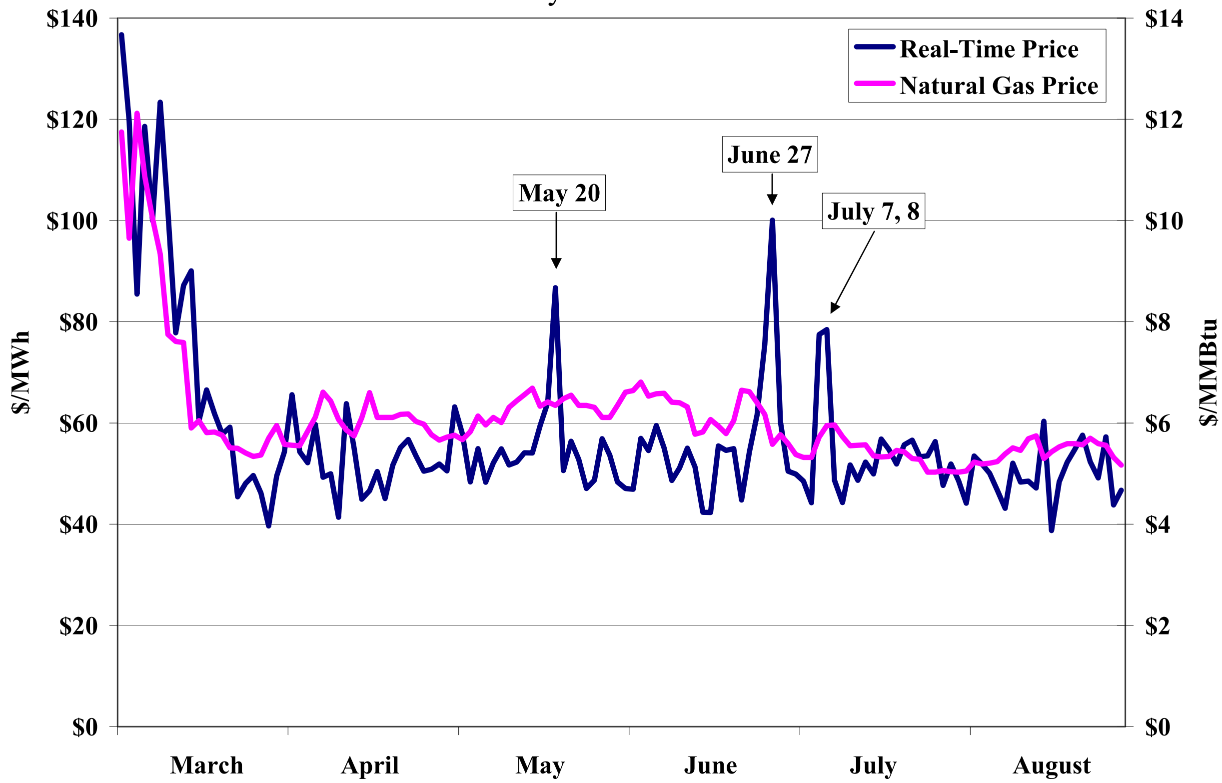
### A. Price Trends

Our first analysis examines trends in day-ahead prices for the first six months of operation of New England's SMD. We examine prices at the New England Hub location. The New England hub represents an average of prices at 32 individual pricing nodes located at the geographic center of New England. This hub price has been developed and published by the ISO to disseminate price information that will facilitate bilateral contracting.

Figure 1 shows the daily average price at the New England Hub in the real-time market. Prices were relatively high when the SMD markets were initially implemented before decreasing substantially in mid-March. To evaluate the general price levels, including the reduction that occurred in mid-March, the figure includes daily natural gas prices. Natural gas prices should be a key driver of electricity prices if the market is operating competitively since natural gas-fired generating units set electricity prices in a large share of the hours. Natural gas-fired generation represents 35 percent of all supply in New England, but is the marginal source of supply in a much higher share of the hours because the natural gas units have marginal costs that are higher than baseload nuclear, coal, and hydroelectric generating units. As expected, electricity prices have been highly correlated with natural gas prices.

This figure also shows that prices did not rise substantially during the summer load conditions, with the exception of prices on May 20, June 27, and July 7 and 8. A number of factors likely contributed to the moderate summer prices, including the relatively high capacity margins resulting from new investment in the region and the mild weather conditions experienced during the summer.

**Figure 1**
**Daily Average Real-Time Prices at New England Hub**
Weekdays 6 AM to 10 PM




### B. Price Convergence

In this subsection, we evaluate the convergence between day-ahead and real-time prices in various locations in New England. Price convergence is important because it indicates whether the market exhibits efficient intertemporal arbitrage. The day-ahead market allows participants to make forward purchases and sales of power for delivery in the real time. The existing multi-settlement markets in the Northeast typically exhibit a small premium in the day-ahead market. This can be explained by the relative risks faced by participants in the day-ahead and real-time markets. Loads can insure against volatility in the real-time market by purchasing power in the day-ahead market. Generators selling in the day-ahead market are exposed to some risk by committing financially day-ahead because an outage after the day-ahead market could compel the generator to purchase replacement power at relatively high prices. If participants are risk-averse, these factors will generate a premium on average in the day-ahead market. Another potentially relevant aspect of the price convergence is whether hourly differences are randomly distributed around the mean difference.

We evaluated weighted average day-ahead and real-time prices at nine locations, including the New England Hub. The analysis is focused on the summer months (June to August) because these are the highest-load months when convergence should be the most difficult to achieve. Two measures of convergence are calculated, the average price difference and the average of the absolute value of the hourly price differences between the two markets. These results are shown below in Table 1.

**Table 1**
**Average Day-Ahead and Real-Time Price Differences**
June to August 2003

| | Average Clearing Price | | | Average of Hourly |
|---|---|---|---|---|
| | **Day-Ahead** | **Real-Time** | **Difference** | **Absolute Price Difference** |
| **New England Hub** | $47.76 | $46.93 | $0.82 | $7.10 |
| **Maine** | $42.71 | $42.20 | $0.50 | $5.65 |
| **New Hampshire** | $46.60 | $45.75 | $0.86 | $6.63 |
| **Vermont** | $48.52 | $47.53 | $0.99 | $7.21 |
| **WC Mass** | $47.72 | $47.09 | $0.63 | $6.71 |
| **Rhode Island** | $47.23 | $45.96 | $1.26 | $7.55 |
| **SE Mass** | $46.43 | $45.88 | $0.55 | $6.75 |
| **NE Mass/Boston** | $47.92 | $46.14 | $1.77 | $7.28 |
| **Connecticut** | $50.80 | $50.50 | $0.30 | $9.38 |

Based on these results, we conclude that the day-ahead to real-time price convergence was very good. In each location, average day-ahead prices were $0.30 to $1.77/MWh higher than average real-time prices. The slight premium in the day-ahead market is consistent with the results of other multi-settlement markets in the Northeast and with expectations based on the discussion of the risk factors above.

Table 1 also shows the absolute average hourly difference between day-ahead and real-time prices, which ranged from $5.65 to $9.38 per MWh. This is lower than comparable results in the New York market.[3] This supports the conclusion that the market participants in New England

3 See *2002 New York ISO State of the Market Report*, May 2003.

have effectively arbitraged the day-ahead and real-time markets. These results also indicate that the day-ahead and real-time market models have been consistent (i.e., consistent transmission limits and other constraints), which has been a significant issue in other markets. However, these conclusions are tempered by the fact that the lack of price spikes in 2003 has made prices in New England less volatile than historical prices. One would expect tighter price convergence under lower volatility.

We further analyzed day-ahead and real-time price convergence by comparing on a more local basis the average price differences and the average absolute hourly price differences in New England to those in New York and PJM. Table 2 shows this comparison for three locations in each market.

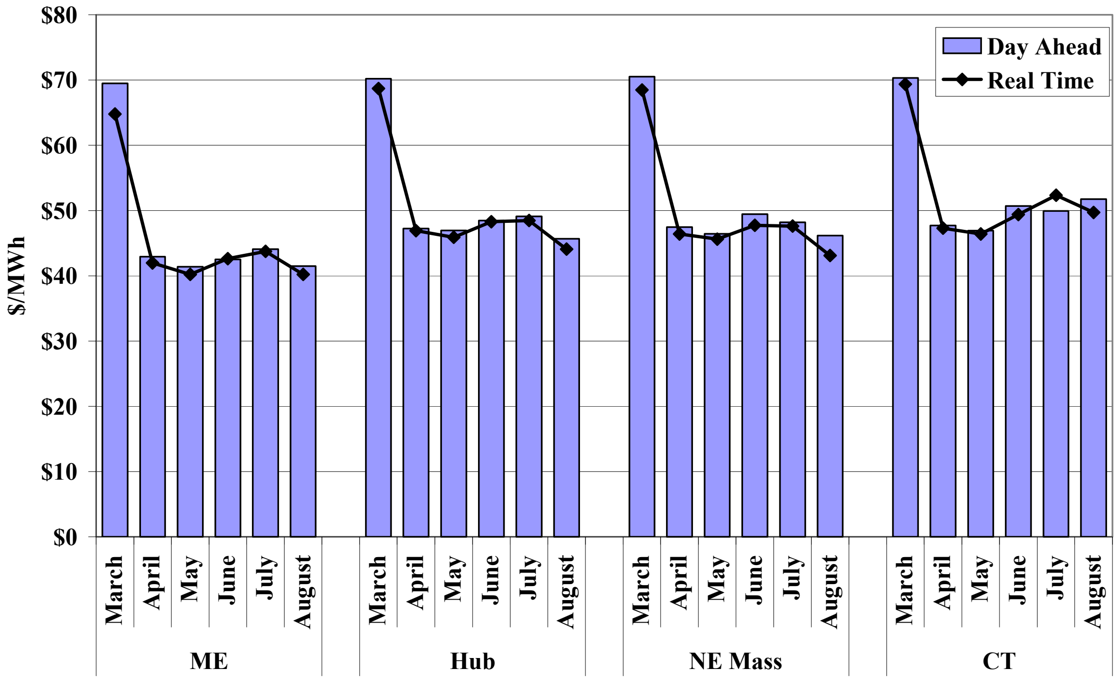
**Table 2**
**Day-Ahead and Real-Time Price Convergence**
New England Compared to Adjacent Regions June to August 2003

| | Average Price Difference - Day Ahead minus Real Time | Average Absolute Hourly Price Difference |
|---|---|---|
| **In New England:** | | |
| **Maine** | $0.27 | $5.52 |
| **New England Hub** | $0.67 | $6.92 |
| **Connecticut** | $0.21 | $8.98 |
| **In New York:** | | |
| **Zone A (West)** | $1.68 | $10.39 |
| **Zone G (Hudson Valley)** | $4.00 | $12.56 |
| **Zone J (New York City)** | -$0.93 | $16.14 |
| **In PJM:** | | |
| **Western Hub** | -$0.43 | $10.31 |
| **New Jersey Hub** | $0.98 | $10.96 |
| **Delmarva Peninsula** | $0.48 | $12.12 |

The three locations shown in Table 2 were intended to include an export-constrained area, an import-constrained area, and a central market location. Based on both of the measures of price convergence, the analysis indicates that New England prices have converged more closely than the prices in either New York or PJM.

Lastly, we analyzed the trend in prices for several key zones over the six-month period studied. In particular, we compared day-ahead and real-time prices for Maine (which tends to be a generation pocket) and NEMA and Connecticut (which tend to be load pockets). This analysis is shown in Figure 2.

**Figure 2**
**Day-Ahead and Real-Time Prices by Location**

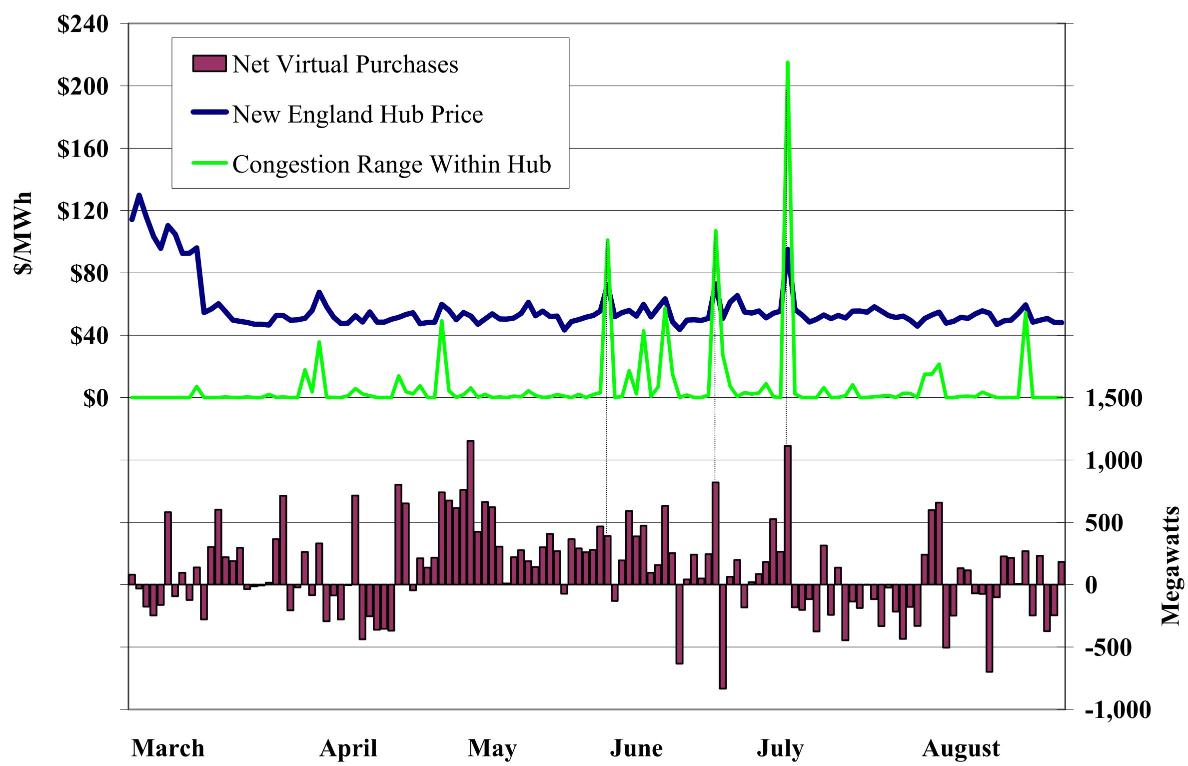



Real-time and day-ahead prices tracked closely in each of the locations. The analysis also shows that prices fell in April from their initial highs in March and stayed relatively flat through the summer. As discussed above, this pattern reflects the fuel price changes that occurred over this timeframe. Finally, the figure reveals the similarity of prices among the zones, which generally reflects the relatively low levels of congestion that have prevailed under the initial six months of SMD operations. The next section evaluates these congestion patterns in detail.

### C. Day-Ahead Pricing at the New England Hub

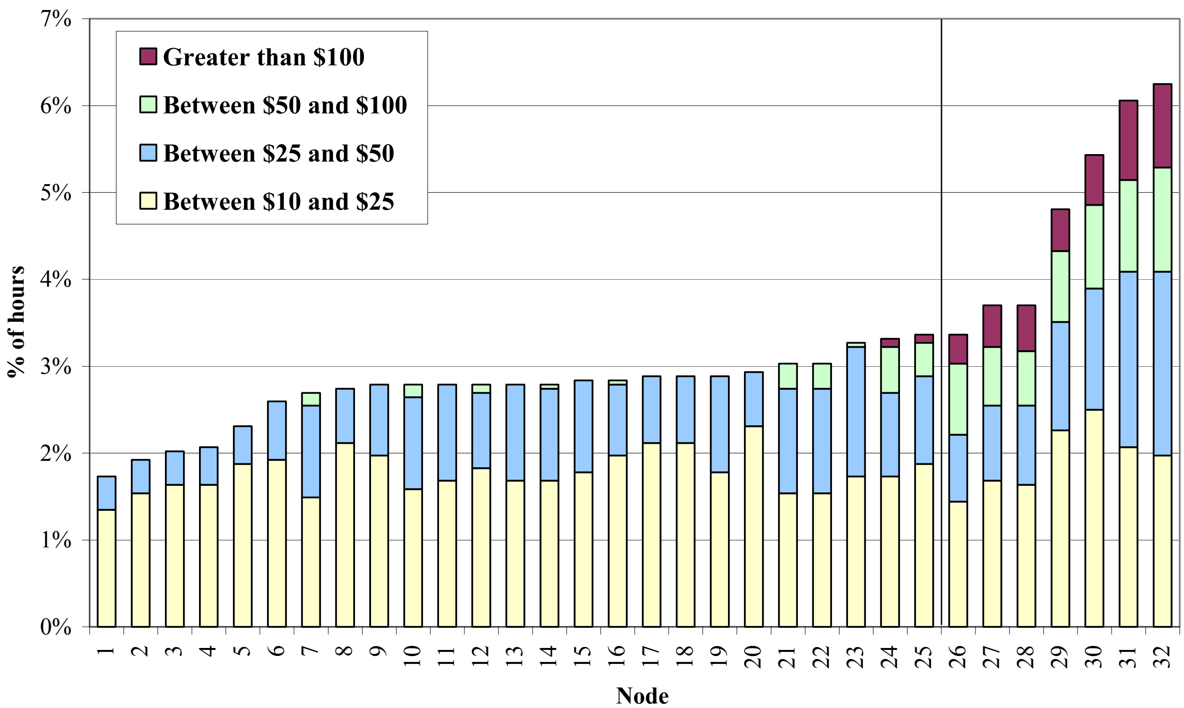
This subsection evaluates congestion experienced in the day-ahead market at the New England hub. When virtual purchases and sales are made in the day-ahead market at the hub, the injection or withdrawal is evenly distributed over the 32 nodes that comprise the hub. In hours with relatively large net virtual purchases or sales, the distribution of these virtual transactions can result in significant network flows on the facilities that interconnect the hub nodes. These flows can create congestion in the day-ahead market that would not occur in real time. To evaluate the extent to which this has occurred, Figure 3 shows the day-ahead market results in peak hours during the six-month period. The figure shows the day-ahead hub price, the volume of net virtual trades, and the difference between the highest and lowest price at the 32 hub nodes.

**Figure 3**
**Day-Ahead Prices and Virtual Schedules at New England Hub**
Peak Hours



This figure shows that the hub price periodically exhibits substantial congestion, generally corresponding to relatively high volumes of virtual purchases. While it would be preferable for the hub to not exhibit congestion, these results do not necessarily indicate a sustained problem with the hub. To the extent that the intra-hub congestion is realized at a limited number of nodes, participants should have the ability to submit virtual bids and offers at physical nodes in order to arbitrage the prices. Virtual bids and offers cannot be placed at hub nodes, however, the majority of hub nodes have a physical node counterpart, and these counterparts may be used by participants to improve convergence of hub nodes. Figure 4 evaluates whether this is the case by showing the distribution of the significant congestion values across the 32 nodes in the hub.

**Figure 4**
**Congestion Between the NE Hub Nodes**
Peak Hours




This figure shows how frequently there are substantial differences between the average congestion price at the hub and the congestion prices at each of the hub nodes. This analysis indicates that the most significant congestion within the hub has been focused on a limited number of nodes. For example, the vast majority of the congestion differences that are greater than $50 have occurred at seven nodes. Six of the seven most congested nodes have physical counterparts. This suggests that participants should be able to submit a limited quantity of virtual bids and offers at these nodes to arbitrage the prices within the hub as they become familiar with these congestion patterns. Hence, redefining the hub should not be a significant improvement in the long term.

We understand that a working group has been formed to evaluate potential modifications to the definitions. While we do not conclude that this is essential, redefining the hub to minimize the intra-hub congestion in the short term could be beneficial. This could include redefining the hub over a broader electrical area to distribute the virtual sales and purchases at the hub over a larger number of nodes to help minimize congestion within the hub in the short term. Hence, we would not discourage such changes unless they would delay other higher-priority market improvements.

## III. Transmission Congestion and Financial Transmission Rights

Transmission congestion can arise in both the day-ahead and real-time markets when transmission capability is not sufficient to allow the lowest-cost resources to be fully dispatched to meet market demand. When congestion arises, the SMD markets establish a spot price for energy at each location on the network that reflects the marginal system cost of meeting load at each location. The marginal system cost can vary substantially over the system, reflecting the fact that higher-cost units must be dispatched in place of lower-cost units to serve incremental load at some locations without overloading any transmission facilities. This will result in higher spot prices at these "constrained locations" than would occur in the absence of congestion.

Setting efficient energy prices that reflect the economic consequences of all binding transmission constraints is one of the most important functions of the SMD markets. These prices guide the short-term dispatch of the generators to manage the congestion as efficiently as possible and establish long-term economic signals that govern investment in new generation and transmission assets. Hence, evaluating the locational marginal prices and associated congestion costs is a primary component of this report.

Congestion costs are incurred in the day-ahead market based on the modeled transmission flows resulting from the day-ahead energy schedules. These costs result from the difference in prices between the points where power is generated and consumed on the network. The price difference indicates the gains in trade between the two locations if additional transmission capability were available. Hence, the difference in prices between the locations represents the marginal value of transmission. The differences in locational prices caused by congestion are embodied in the congestion component of the LMP at each location.[4]

Congestion charges may be hedged by a participant in the day-ahead market by acquiring Firm Transmission Rights (FTRs). FTRs entitle a participant to payments corresponding to a

4 The congestion component of the LMP represents the difference between the marginal cost of meeting load at that location versus the marginal cost of meeting load at a reference location, assuming no transmission losses.

congestion charge between two locations. An FTR consists of a directional pair of points (locations or zones) and a MW quantity. For example, a participant may hold 150 MW of FTRs from point A to zone B. This participant is entitled to 150 times the locational energy price at zone B less the price at location A (a negative value means the participant must pay). A participant can hedge the congestion costs associated with its bilateral contract if it owns an FTR between the same receipt and delivery points as the bilateral contract.

Energy purchased and sold in the real-time market corresponds only to the deviations from the day-ahead schedules. Hence, a participant that purchases more energy in the day-ahead market than it consumes in real time will sell the excess energy into the real-time market. Similarly, a participant that sells more energy in the day-ahead market than it produces in real time will be a purchaser in the real-time market.

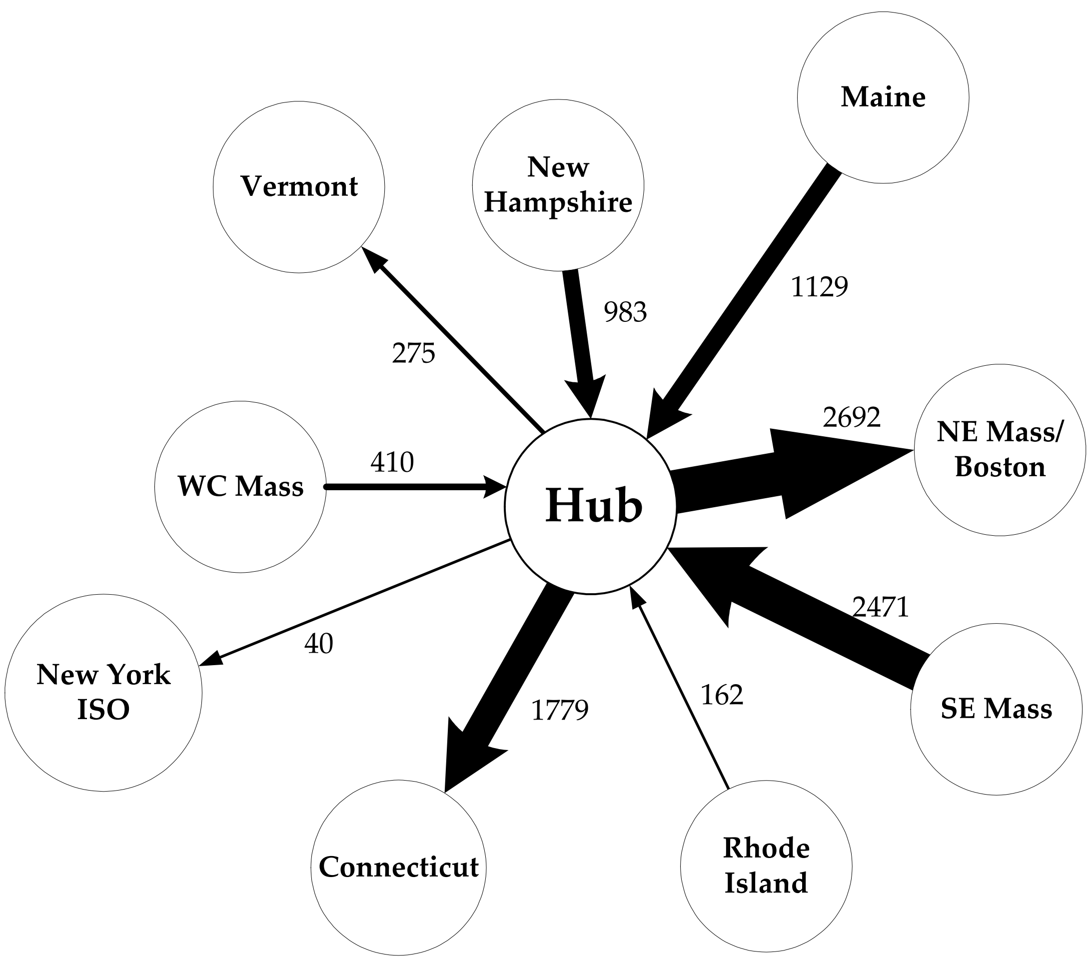
Likewise, settlement of congestion costs in the real-time market is related only to deviations from the day-ahead schedules. Participants with day-ahead schedules do not pay real-time congestion charges related to their scheduled quantities. Because the real-time spot market is a balancing mechanism for day-ahead contracts, net congestion charges should be zero in real time as long as the transmission limits and external loop flows have not changed. In other words, any congestion charge to a real-time purchase would be offset by a payment to real-time sale. This would not be the case if the transmission limits or modeling in the day-ahead market were different than the limits or modeling in the real-time market. Inconsistencies in limits or modeling can compel the ISO to incur substantial costs to reduce the flow on constrained facilities in real time, which would be recovered through uplift charges. This has not been a problem under the ISO's operation of the SMD markets.

### A. FTR Purchases

To begin our evaluation of congestion management in New England, we first assess the pattern of FTR purchases. As discussed above, an FTR is purchased between a designated source and sink. An FTR entitles the purchaser to receive the difference in the prices at the FTR's source and sink points, excluding losses, times the FTR quantity. FTRs can be used to hedge the congestion costs of serving load in congested areas or as speculative investments for purchasers who forecast higher congestion revenues between two points than the cost of the associated FTR. In well-functioning markets, the FTR prices should be highly correlated with the actual congestion on the system. In addition, the pattern of FTR purchases should correspond to the attendant power flows arising from the location of loads and generation.

Our first analysis in this subsection calculates the net purchases of inter-zonal FTR rights in the months from March to August for each of the eight New England Zones. The results of this analysis are shown in Figure 5.

**Figure 5**
**Net FTR Purchases between New England Zones**



To simplify Figure 5, we show all of the FTR purchases relative to the New England Hub rather than showing the actual sources and sinks. Since FTRs have the properties of geometric vectors, an FTR between any two zones is equivalent to an FTR from the first zone to the hub plus an FTR from the Hub to the second zone. If a zone was a net source for FTRs (more FTRs exit the zone than enter the zone), then the arrow in Figure 5 is directed from the zone to the New England Hub (e.g., Maine). If the zone is a net sink, then the arrow points from the New England Hub to the zone (e.g., Connecticut).

The patterns shown in the figure are consistent with expectations. Maine, South East Massachusetts, and New Hampshire zones have been net sources for FTRs, consistent with the fact that these zones tend to exhibit net exports of power. NEMA and Connecticut, and to a lesser extent Vermont, have been net sinks for the FTRs. This is also generally consistent with historical power flows into these areas. The only notable result related to the pattern of FTR purchases is that the FTRs into Connecticut were not fully subscribed. The FTR limit ranged from 2000 MW to 2500 MW while only 1779 MW were sold. While this is unexpected based on historical experience, the actual prices in New England under SMD have not indicated substantial congestion into Connecticut. The following sections evaluate the levels of congestion and FTR pricing into each zone in New England.

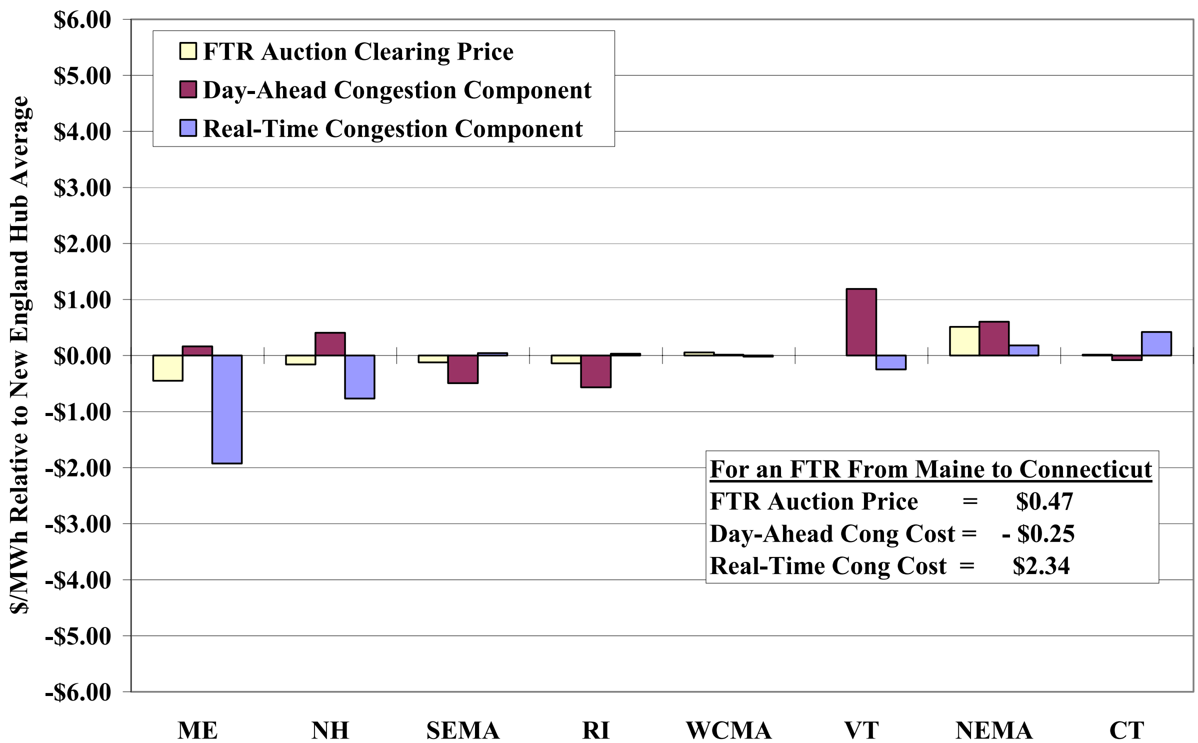
### B. Congestion Patterns and FTR Prices

To evaluate the congestion experienced under SMD, we analyzed day-ahead and real-time congestion costs relative to revenues earned by holders of FTRs in the various zones. In a well-functioning system, these values should be highly correlated. We made this comparison for the ISO's eight zones and the New England Hub.

Figure 6 and Figure 7 show day-ahead and real-time congestion costs and FTR payments for the first six months of SMD for each of the eight New England zones. For both figures, the congestion costs shown are the average for on-peak hours and are calculated relative to the New England hub. Hence, if the congestion component in the figure indicates $4 per MWh, this is interpreted to mean the congestion cost to transfer a MW of power to the New England Hub is

$4. The congestion cost between any two points shown in the figure is the congestion price at the sink location less the congestion price at the source location. The analysis is limited to the on-peak hours since the load and the power flows on the system are greatest in these hours.

**Figure 6**
**FTR Auction Prices vs. Day-Ahead and Real-Time Congestion**
Zonal Averages Shown Relative to New England Hub Price
March-May 2003 -- Weekdays 6 AM to 10 PM




The FTR auction clearing price is the purchase price for monthly FTRs, reported in dollars per MWh by location. Like the congestion costs, the purchase price for an FTR between two locations is the difference between the prices at the destination and origin points for the FTR. For example, a $1.00/MWh FTR price for Maine and $0.50/MWh FTR price for Connecticut would indicate a total price for an FTR from Maine to Connecticut of $1.50/MWh.

The zones listed along the horizontal axis are generally ordered in accordance with their historical congestion patterns relative to the hub. Hence, the zones listed toward the left tend to face congestion as they export power to zones toward the right. This should result in negative congestion and negative FTR values for zones on the left of the horizontal axis and positive values for zones on the right. We generally expect that congestion costs would be correlated with FTR revenues.

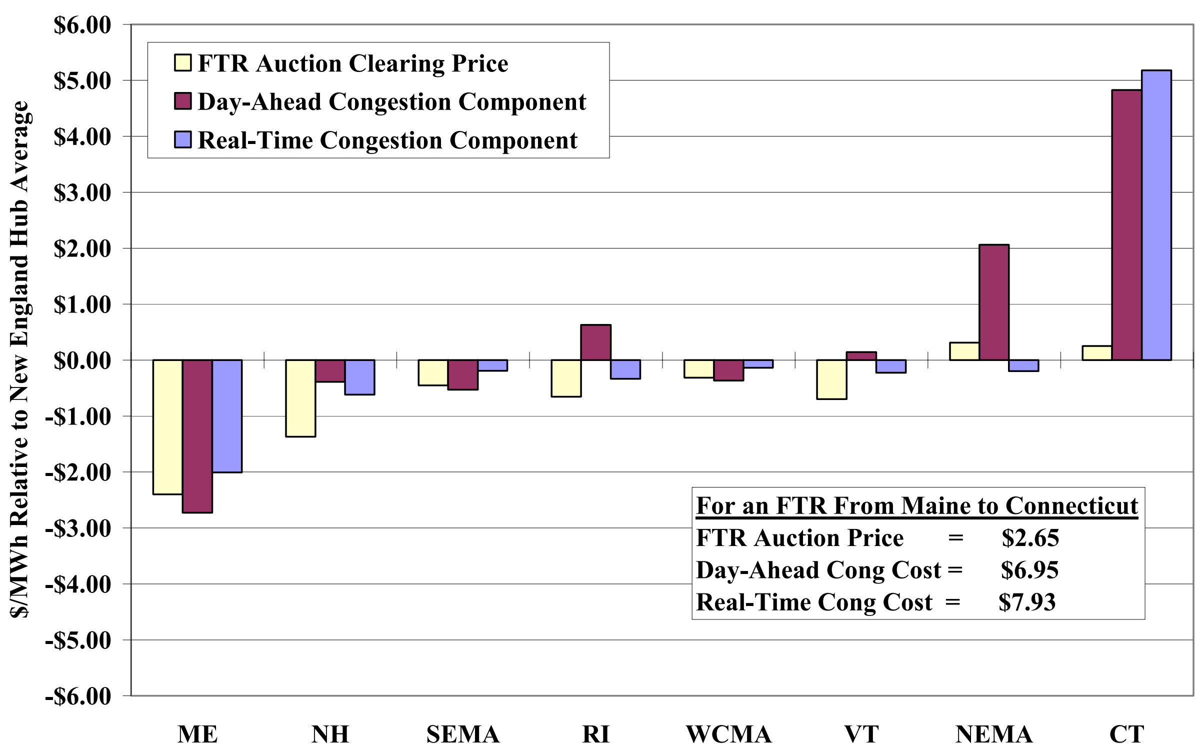
Figure 6 shows results for the first three months of SMD operations (from March to May). During this time period, congestion costs and FTR payments did not correspond well to historical congestion patterns for many of the locations, nor was there a high degree of correlation between the FTR prices, the day-ahead congestion costs, and the real-time congestion costs. As Figure 6 shows, congestion costs were very low and did not reflect historical patterns of congestion in the region. The FTR clearing prices are also quite small in magnitude. We also note that the FTR values are three-month averages and the individual monthly data vary somewhat.

Congestion during the spring months is less likely to be substantial due to the lower load levels. This is particularly true during the initial months of SMD due to the relatively high natural gas prices. These prices cause oil-fired units in the constrained areas to run much more than usual as they became economic relative to many of the natural gas units. To exclude these effects, the analysis shown in Figure 7 focuses on the summer months from June to August. Congestion costs and FTR payments during the summer months are more consistent with expectations to the extent that averages for Maine and Connecticut show FTR prices and congestion costs consistent with historical congestion patterns. For Maine, the FTR prices and the day-ahead and real-time congestion prices correspond well. While the day-ahead and real-time congestion costs are close in magnitude in Connecticut, they are much larger than the FTR prices.

The NEMA zone experienced very low levels of congestion, contrary to historical experience. These low levels of congestion can be attributed to recent transmission improvements into the area, the installation of a considerable quantity of new generation in the NEMA zone, and supplemental commitment and out-of-merit dispatch that occurs in the NEMA zone to address second-contingency reliability requirements. FTR prices, day-ahead congestion, and real-time congestion into New Hampshire have been negative and relatively low, consistent with its historical experience.

Rhode Island experienced positive day-ahead congestion prices, while associated FTR prices and real-time congestion were negative. The positive day-ahead congestion was the result of one episode on August 11 when a binding transmission constraint caused significant day-ahead congestion effects for eight hours. Without this episode, average day-ahead congestion would have been negative as well. The congestion on August 11 was principally the result of a discrepancy in the modeling of the constraint between the day-ahead and real-time models. The ISO has modified the day-ahead model to eliminate the discrepancy, which should ensure consistent day-ahead and real-time results.

**Figure 7**
**FTR Auction Prices vs. Day-Ahead and Real-Time Congestion**
Zonal Average Relative to New England Hub Average Price
June - August 2003 Weekdays 6 AM to 10 PM



NEMA and Connecticut warrant closer examination as they are areas that have been subject to significant constraints historically and represent a substantial share of the total load in New England. Figure 8 and Figure 9 isolate the data for NEMA and Connecticut.

The price data for the NEMA zone do not reveal a consistent pattern with respect to congestion and FTR prices through the six-month period. For example, in those months when day-ahead congestion is the largest, averaging more than $3 per MWh in the day-ahead market, real-time congestion is negative relative to the New England Hub. While the Connecticut zone shows day-ahead and real-time congestion prices moving in tandem to a higher level in the summer compared to the spring, FTR prices remain quite low relative to the value of congestion.

We have reviewed the FTR market processes and do not find any structural or methodological concerns that contributed to the FTR pricing results. To better understand these results, in the next section we analyze generator commitment and dispatch patterns. In particular, we examine commitment and dispatch that occurs outside of the market processes.

**Figure 8**
**FTR Auction Prices vs. Day-Ahead and Real-Time Congestion**
NE Mass Averages Shown Relative to New England Hub Average Price
Daily Peak Hours

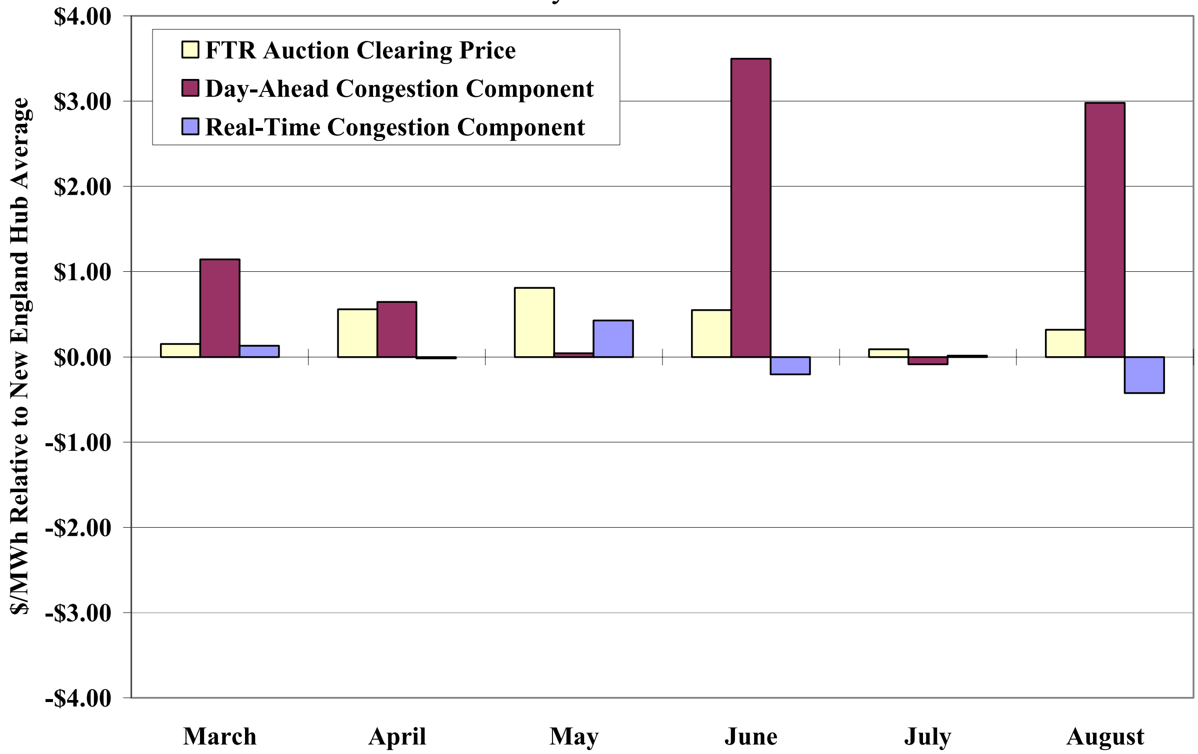
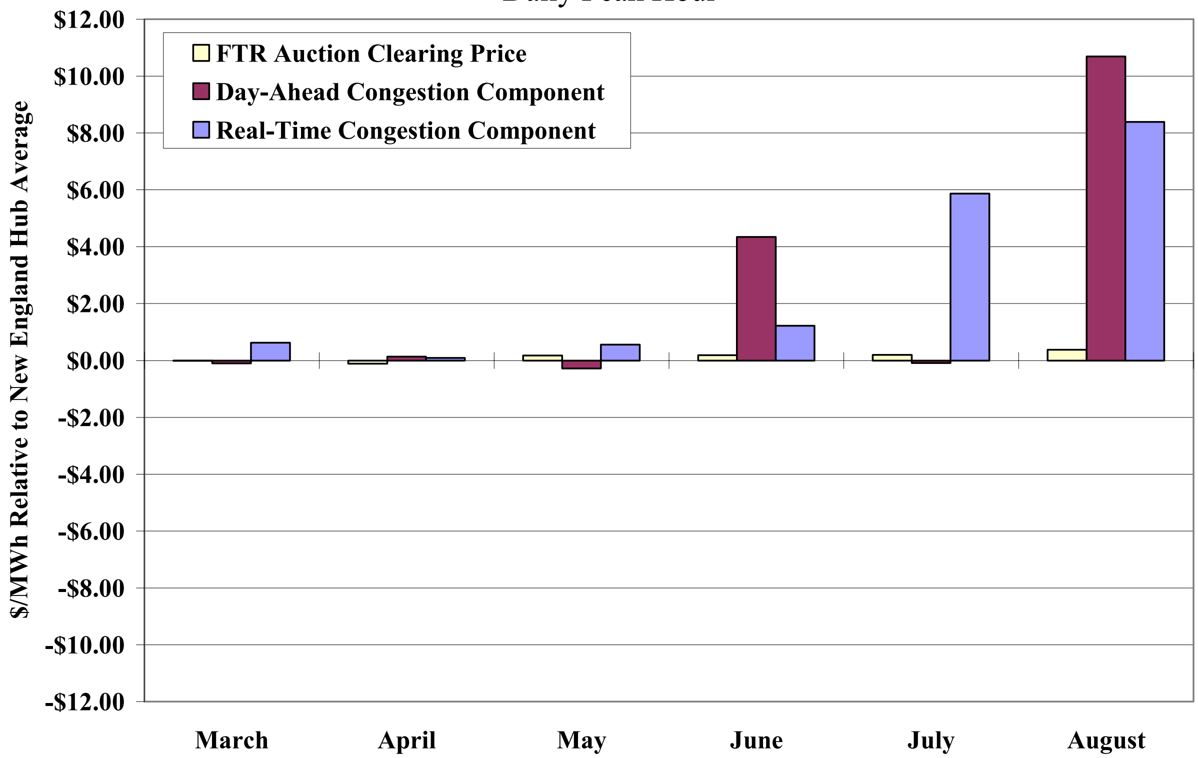


**Figure 9**
**FTR Auction Prices vs. Day-Ahead and Real-Time Congestion**
Connecticut Averages Shown Relative to New England Hub Average
Daily Peak Hour



## IV. Market Operations

The overall implementation of the SMD markets in New England has been very smooth, with little evidence of any type of disruptions during the transition to the markets. This is particularly impressive given the market conditions when the SMD markets began operation. These conditions included tight natural gas markets and unusual weather patterns that led to uncommonly high electricity demand.

In this section, we evaluate a number of issues related to the operation of the SMD markets. These issues include: the accuracy of the ISO's load forecasts, frequency of price corrections, supplemental commitment of generating resources, and out-of-merit dispatch. These issues are important because they can substantially affect the efficiency of the market's price signals.

### A. Accuracy of ISO Load Forecasts

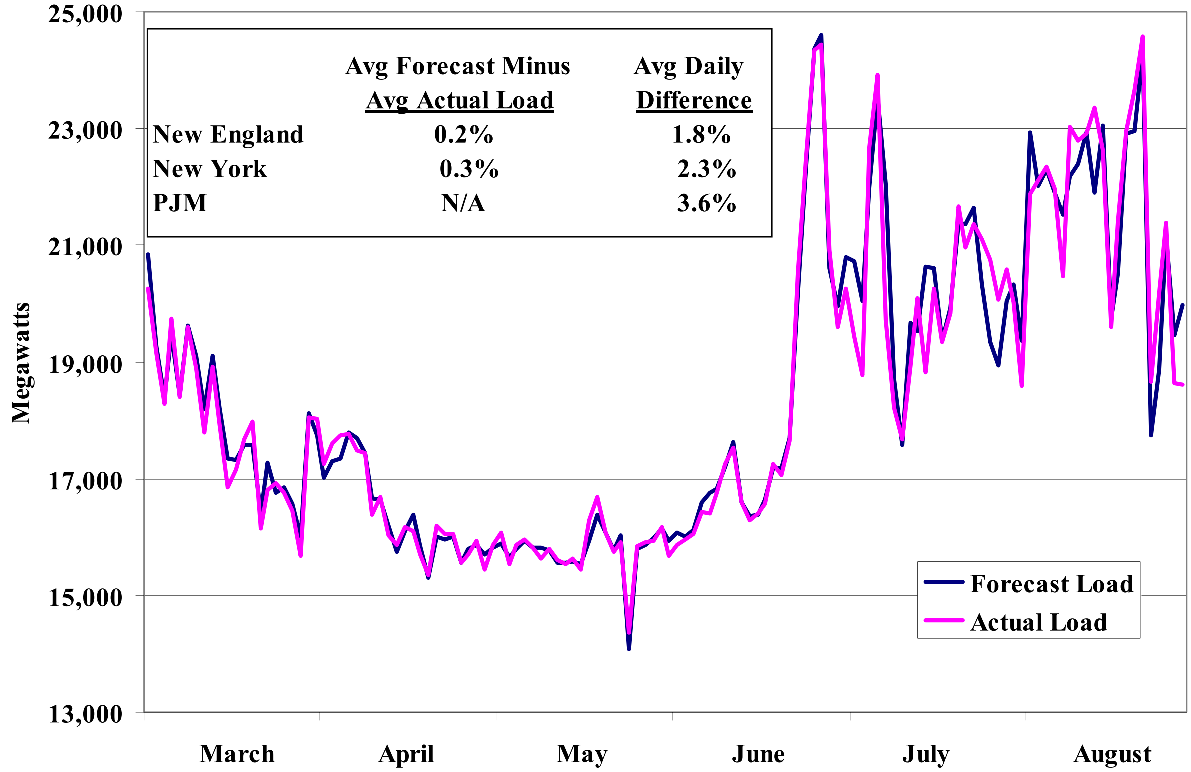
The accuracy of ISO load forecasts is important for efficient market operations. Inaccurate load forecasts can cause the ISO to commit too much or too little capacity. As we explain in more detail below, these "supplemental commitments" can distort real-time prices and increase uplift costs. Therefore, it is desirable that day-ahead forecast loads closely track actual loads.

Figure 10 shows daily peak load forecasts and actual loads on weekdays for the six months ending August 31. Loads were moderate, rising above 24,000 MW on only three days in the summer. Loads were decreasing through March and relatively stable at close to 16,000 MW during most of April and May. As noted above, the summer months exhibited significant increases in load as the warmer weather triggered demand for cooling. Forecasted demand tracked very closely to actual outcomes, as the average difference between the forecast load as a percent of the actual load was only 0.2 percent, with the forecast being slightly lower on average.

To measure the average forecast error associated with the daily peak demand, we also calculated the average of the absolute value of the difference between the forecasted peak demand and the actual peak demand. This difference as a percent of the actual peak demand averaged 1.8

percent. The comparable value for the other operating markets for the same timeframe ranged from 2.3 percent in New York to 3.6 percent in PJM.

**Figure 10**
**Daily Peak Forecast Load and Actual Load**
Weekdays




Because the forecast error levels are small in magnitude and less than values for neighboring markets in the region, we find that the ISO's load forecasting has been accurate. This is important because it provides a foundation for efficient commitment of resources in New England.

## B. Price Corrections

This subsection evaluates the rate of price corrections that have occurred in the first six months of the SMD market operation. Price corrections are necessary to address a variety of issues, including software flaws, operations or data entry errors, system failures, and communications interruptions. A market operator should aim to minimize these corrections since substantial and frequent corrections can harm the integrity of the market.

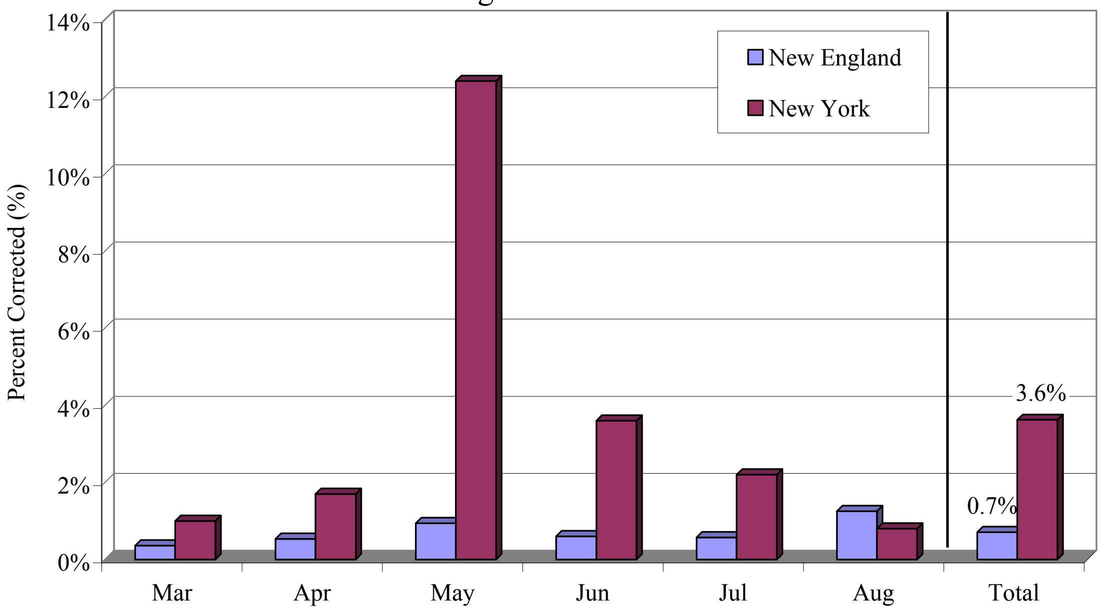
Price corrections tend to be more frequent during the transition to new markets or the implementation of significant software changes. Measuring the frequency of the corrections is one useful metric for evaluating the implementation of a new market. Figure 11 below shows the percent of prices that were corrected in New England during the first six months of SMD compared to the same months in 2000 in New York, which was the NYISO's first year of operation.[5]

The figure shows that the correction rates in New England were lower in each month with the exception of August when the correction rate in New York was at its lowest level. For the six-month period, the average correction rate in New England was 0.7 percent of the hours, less than 20 percent of the 3.6 percent correction rate in New York. The New York ISO made a number of improvements to its market rules and the software in its second year that reduced the corrections to levels comparable to New England's initial levels. Similar data were unavailable for the PJM market.

These results support the conclusion that ISO's implementation of the SMD markets has been competent, resulting in a smooth transition. This can be attributed, in part, to the additional time and resources the ISO devoted to development and testing of the SMD markets to ensure they would perform as designed.

5 The NYISO markets were implemented in November 1999.

**Figure 11**
**Price Corrections in First Year of Market Operations**
2003 for New England and 2000 for New York




Source: ISO-NE and NYISO markets databases. The results shown are the percent of 5-minute intervals corrected.

### C. Supplemental Commitment

The New England market commits resources in the day-ahead market based on multi-part offers. Offers include a cost to start a unit that is offline, a "no-load" cost reflecting the fixed hourly cost of keeping a unit online, and an energy offer curve reflecting the offer price for the unit's incremental output. A supplemental commitment occurs when a unit is not committed in the day-ahead market but is subsequently committed by other means. This can happen in one of two ways. First, a unit without a day-ahead schedule may be committed by its owner (i.e., self-commitment in real time). Second, a unit without a day-ahead schedule may be committed by the ISO or by a transmission operator to satisfy reliability requirements.

The ISO generally makes supplemental commitments when capacity is needed to meet forecast load reliably in the overall market or in a constrained area within the market. The capacity, rather than energy, is often needed because it will provide reserves for the relevant area and be available to produce energy if needed. Specifically, supplemental commitments by the ISO or transmission owners are made to:

- Ensure sufficient capacity is online in real time to meet ISO forecast load for the next day (known as the Resource Adequacy Assessment ("RAA")) -- these commitments include those necessary to meet first-contingency requirements in constrained areas;
- Provide adequate capacity in constrained areas to respond to a second contingency -- these commitments are made pursuant to the Reliability-Must-Run ("RMR") protocols;
- Support the voltage of the system in specific locations; and
- Manage low-voltage constraints on the distribution system that are not modeled in the day-ahead market software (known as Special Constraint Resources ("SCRs")).

Resources committed for these reasons may be economic once committed based on their energy offers. If so, they will be dispatched above their economic minimum generation level ("EcoMin") in merit order and efficiently reduce energy prices by displacing higher-cost resources. Other units committed supplementally are not economic and thus tend to operate at their EcoMin. These resources will inefficiently reduce energy prices by displacing a lower-cost resource, thereby causing an even lower-cost unit to set the energy price. The EcoMin quantity of energy from these resources will be dispatched out of merit order. Hence, units with low EcoMin levels will generally have a smaller effect on prices than those with higher EcoMin levels.

### 1. Supplemental Commitment Quantities

Because the incidence of supplemental commitment actions can distort market outcomes, it is important to monitor the degree to which these actions occur and the locations where they occur. Therefore, we calculate the average peak hour quantity in each of the categories of supplemental commitment for each of the eight zones in New England. Figure 12 shows the supplemental commitments during the six-month time period.

For the purposes of this analysis, the MW commitment level is the entire capacity of the committed unit, regardless of the energy it produced in real time. But the commitments' effect on prices depends on the energy produced from these units, particularly the energy produced out of merit.

**Figure 12**
**Average Supplemental Commitment by Zone**
March to August 2003 Daily Peak Hour

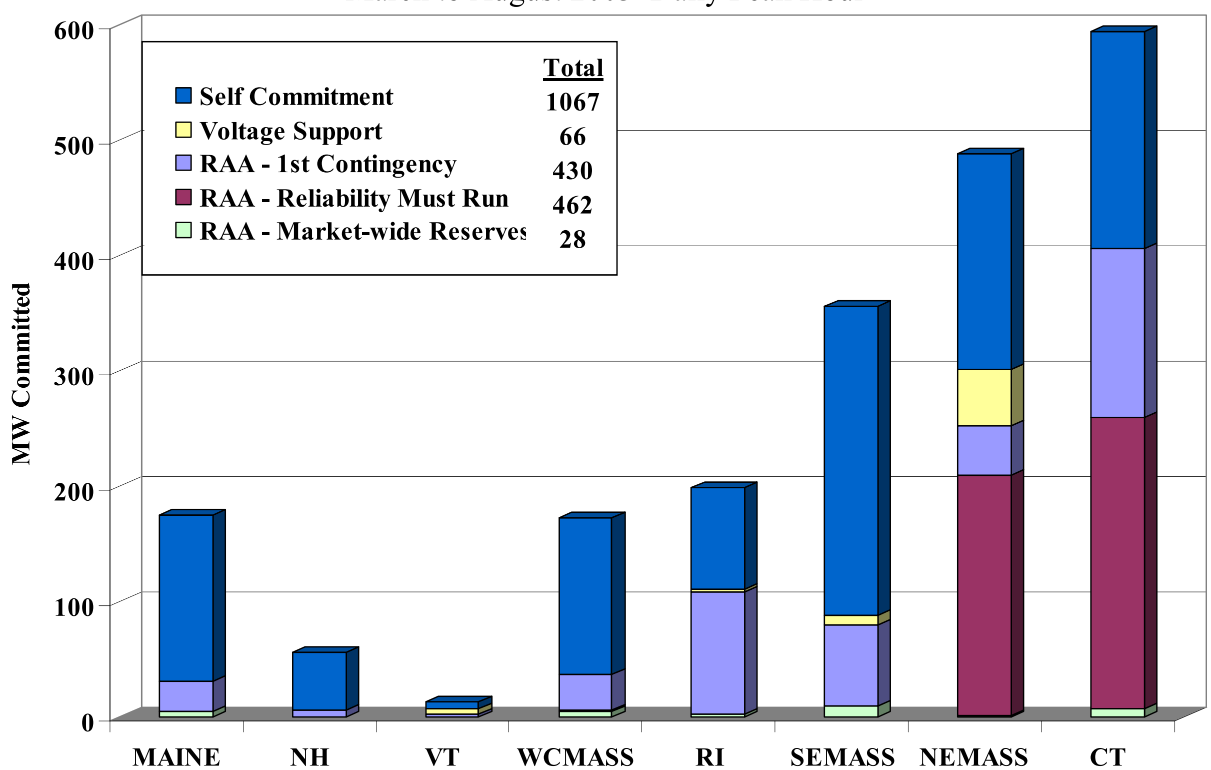
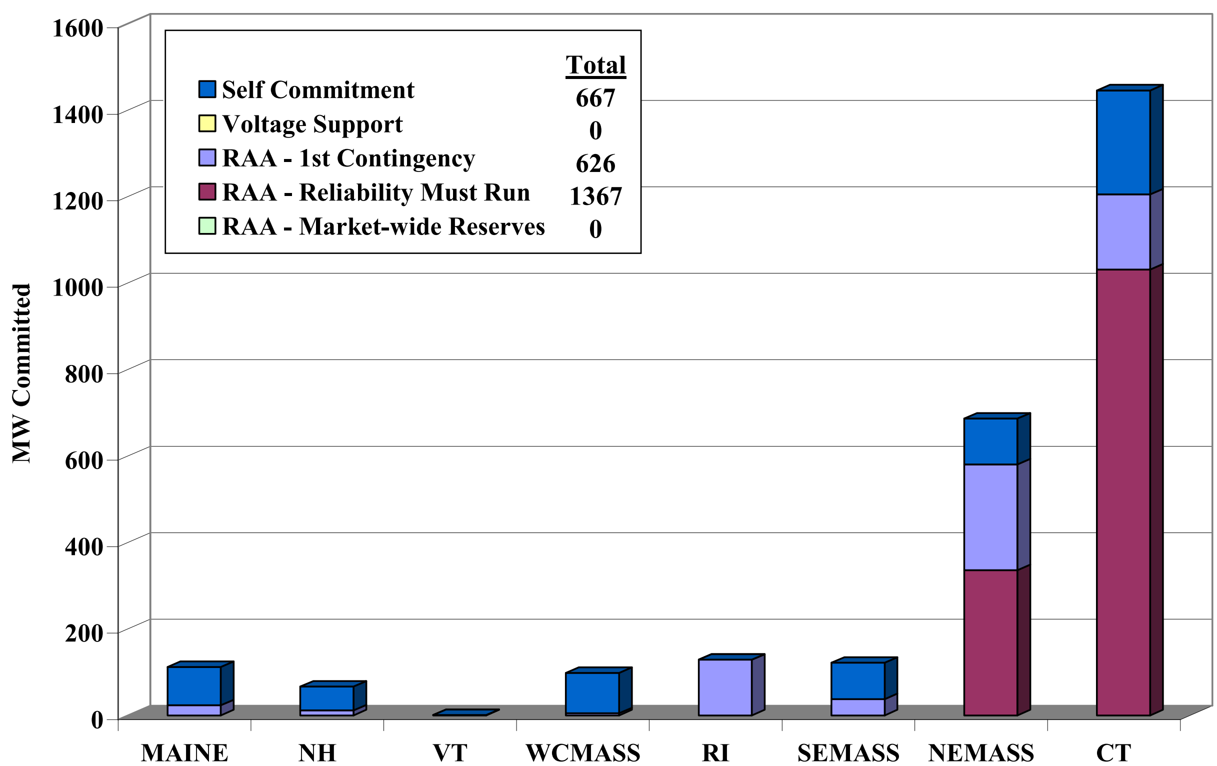



Figure 12 shows that the total supplemental commitments during the period exceeded 2000 MW, of which over 1000 MW is self-committed by participants after the day-ahead market. The majority of the balance of the supplemental commitment is done by the ISO through the RAA process to satisfy RMR and first contingency requirements in NEMA and Connecticut. The RAA also results in supplemental commitments needed to meet forecasted load and reserve requirements in the broader market.

Because the market effects are likely to be the greatest in the highest-load hours, in Figure 13 we show the average supplemental commitment in the peak hours on the five highest-load days during the study period. This figure shows that the supplemental commitments made to meet local reliability requirements were substantially higher while most other categories of these commitments were lower than the average for all days.

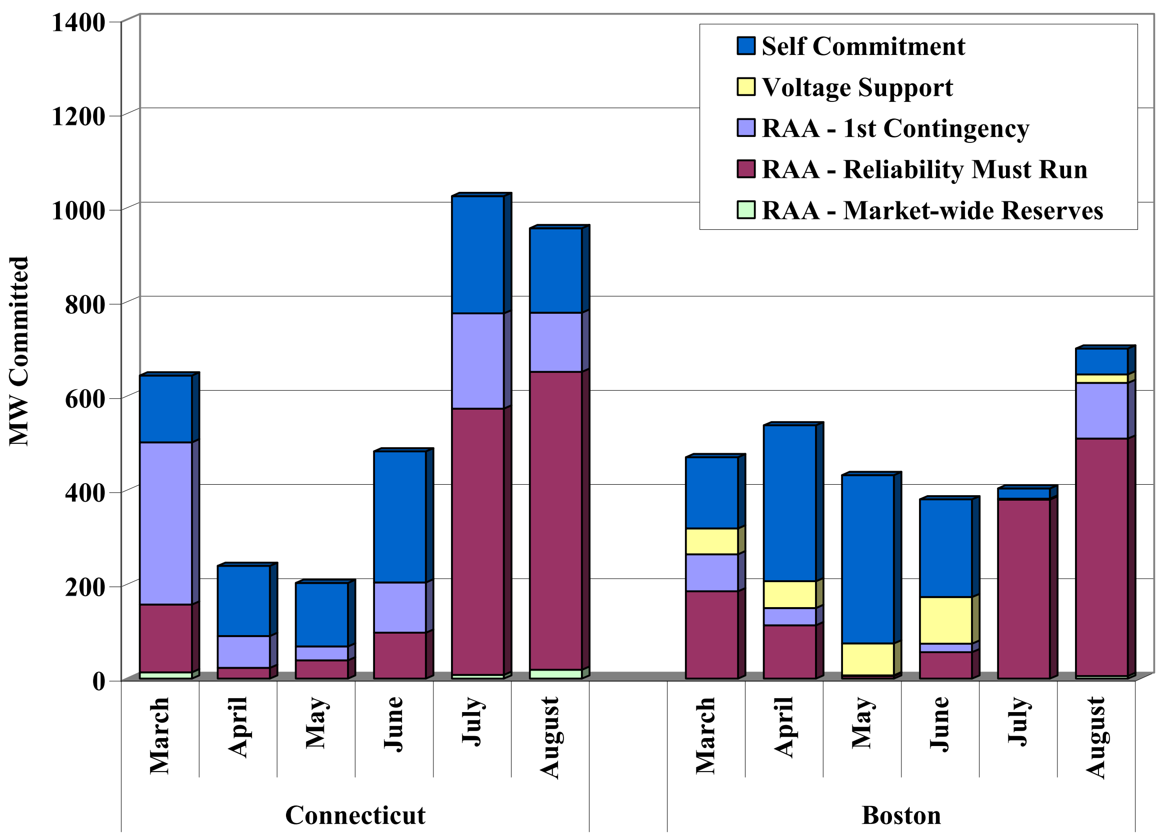
**Figure 13**
**Average Supplemental Commitment by Zone**
**Top 5 Peak Load Days**




Given the predominance of the supplemental commitments in Connecticut and NEMA, we analyzed the patterns in these two zones in each of the six months studied. Figure 14 shows that out-of-merit commitment increased substantially in Connecticut between spring and summer while there was a slight decline in June and July in the NEMA zone. The incidence of supplemental commitment in these two zones, together with the unusually low congestion that has prevailed, suggests that supplemental commitments may be contributing to the unexpected pricing patterns in these zones – particularly in Connecticut.

Figure 14 also shows that a significant amount of supplemental commitment in the NEMA-Boston zone was flagged for voltage support. In general, this commitment is made to address high-voltage problems on the 345 kV system in Boston. We calculated the uplift costs paid to units committed to address this problem, and found these costs totaled $4.2 million during the six-month study timeframe (compared to only $19,000 outside of Boston). We understand from a discussion with ISO staff that the installation of a shunt reactor would virtually eliminate the need for these supplemental commitments. Given both the direct costs and the indirect effects on the market of these commitments, we recommend that the transmission planning process consider the installation of equipment that would be economic to address the high voltage issues in the Boston area and other comparable local reliability issues that result in supplemental commitments.

**Figure  SEQ Figure * ARABIC 14**
**Average Supplemental Commitment in Connecticut and NEMA**
March to August 2003 -- Daily Peak Hour



The RMR commitments in NEMA and Connecticut are made to address second contingency reliability requirements. The ISO must have sufficient reserves available in each area to respond to the largest generation and/or transmission contingency after the first contingency has occurred.

The reserves required in each area vary hourly depending on the availability of quick-start resources, the flow on the interface into the area, the size of the second contingency, and other factors. Due to the limited quantity of quick-start resources in these areas, a large portion of these reserves must be held by on-line resources. If additional quick-start resources are added in these areas over the longer term, the frequency and quantity of supplemental commitment would be substantially reduced.

### 2. Excess Committed Capacity

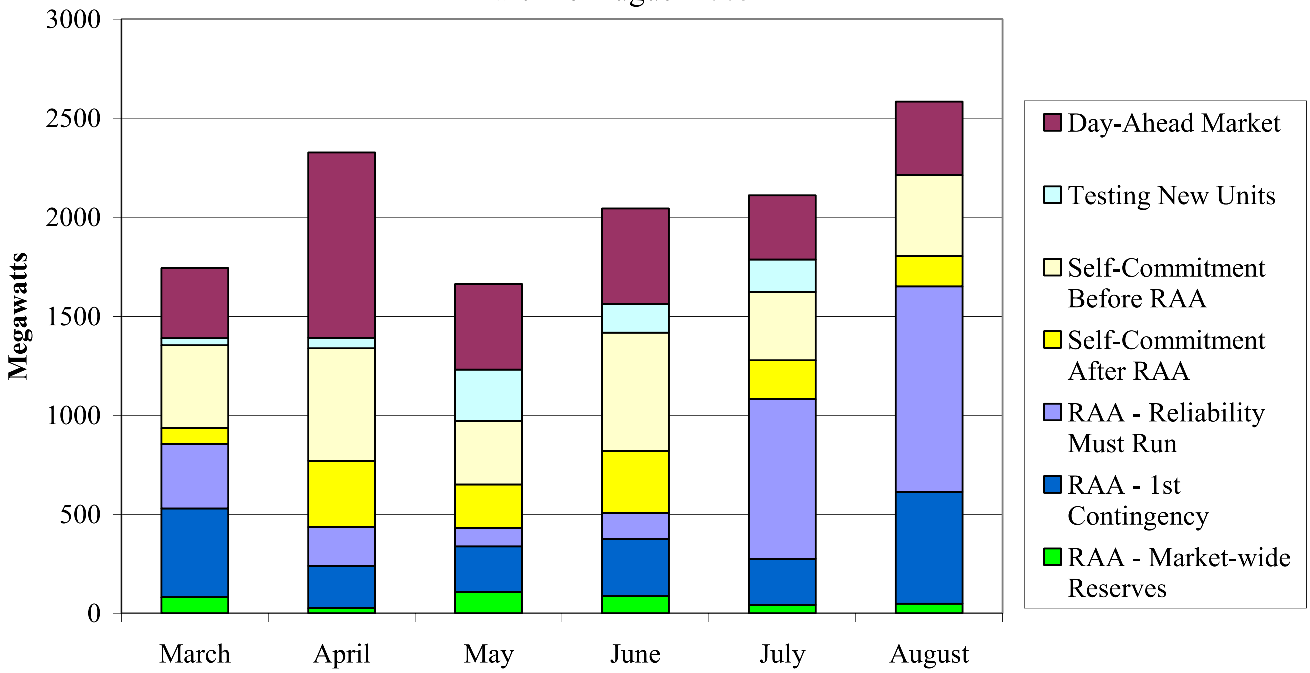
These patterns of supplemental commitments would raise a concern if they resulted in persistent excess committed capacity because they can inefficiently affect energy prices in the real-time market and can result in substantial operating reserve credit payments to ensure that all of the committed units recover their as-bid commitment costs. To evaluate this issue, we calculated the excess capacity committed. Excess capacity is defined as capacity committed (including available offline quick-start resources) in excess of forecast load and reserve requirements.[6] The results are shown in Figure 15. Unlike the prior figure, which shows the total supplemental commitments made by category, this figure shows only commitment quantities that contribute to excess capacity levels. In other words, the supplemental commitments that do not contribute to an excess in a given day are not included in Figure 15.

This figure shows that the excess capacity has been substantial throughout the six-month timeframe of the study, with monthly averages between 1500 MW and 2500 MW. Much of the excess capacity is associated with the results of the day-ahead market. The excess capacity from

6 For purposes of this analysis, we include 10-minute reserves equal to the first largest contingency, 30-minute reserves equal to one-half of the second largest contingency, replacement reserves equal to one-half of the second largest contingency, and an additional quantity corresponding to the ISO's expected potential loss of capacity prior to real-time. These requirements generally total approximately 2600 MW.

the day-ahead market generally occurs for economic reasons. The excess capacity amounts include quick-start resources that typically have relatively high production costs. Therefore, it is frequently economic to commit lower-cost units in the day-ahead market to produce energy, which can result in excess capacity. This is particularly true during lower-load periods when these higher-cost quick-start resources would not otherwise be needed to meet capacity requirements. This outcome is expected from the day-ahead market and, hence, raises no significant efficiency concerns.

**Figure 15**
**Excess Capacity by Type of Commitment***
March to August 2003




* Excess committed capacity is the amount by which the committed capacity exceeds the sum of the peak-hour forecasted load and 2600 MW for reserves.

A second category of commitments shown in Figure 15 consists of new units undergoing testing. Although these units are online, they do not contribute toward satisfying the ISO's capacity requirements because they are not deemed to be reliable resources until after the testing is completed. Therefore, units in testing can contribute to an apparent excess of committed capacity.

A third category of excess commitments reflects self-schedules that occur after the day-ahead market, only some of which occur before the RAA process and are therefore known by the ISO when it makes supplemental commitments to meet its reliability requirements. Excess commitments associated with self-schedules after the day-ahead market average almost 800 MW, of which 75 percent occur before the RAA process and 25 percent occur after the RAA. While all of these excess self-committed resources can distort the market outcomes, the self-commitments that occur after the RAA process are of particular concern. The ISO incurs costs committing additional resources through the RAA process that may not be necessary given the additional units that are self-committed after the RAA. Participants that believe they will be committed through the RAA may have an incentive to increase their start-up or no-load costs to generate an operating-reserve credit payment since they have the option of self-committing their units if they are not selected.

To address this concern, we recommend that the ISO consider not allowing suppliers to self-commit units after the RAA process unless they have suffered an outage on another unit. This would both reduce the quantities of supplemental commitments, as well as increase suppliers' incentives to offer resources competitively in the RAA since it would be their last opportunity to commit a unit.

The fourth and fifth categories of commitments include those made through the RAA process to meet reliability requirements in local areas. The fourth category consists of commitments made to maintain reliability in response to the most substantial contingency in the local area (i.e., the first contingency). The first contingency may be a potential generator outage or a transmission line outage affecting the interface capability into the area. The fifth category of commitments shown in Figure 15, referred to as "reliability must run" commitments in the figure, include commitments required to respond to the second-largest contingency in the local area or to support system voltage.

The total commitments made to meet these locational reliability requirements exceed 750 MW on average, of which 36 percent are made to meet first-contingency requirements and 64 percent are made to satisfy the second-contingency and voltage-support requirements. The second-contingency commitments are defined by the ISO as reliability must-run commitments. The costs of the operating-reserve credits paid to the owners of the units committed after the day-ahead market for second contingencies or voltage support are allocated to the real-time deviations in the local areas while the costs of the first-contingency commitments are allocated to all deviations in New England.

The last category of supplemental commitments represents those made through the RAA process to cover the market-wide forecasted load plus reserve requirements. These include ten-minute reserves equal to the first largest contingency, 30-minute reserves equal to one-half of the second largest contingency, replacement reserves equal to one-half of the second contingency, and 400 MW to 700 MW to cover anticipated losses of generation between the day-ahead market and the real-time market. Some of these commitments may be canceled if generation is not lost over night. Figure 15 shows that the quantities of commitments in this last category have been very small and have not contributed significantly to the capacity surplus.

### 3. Evaluation of RMR Commitments

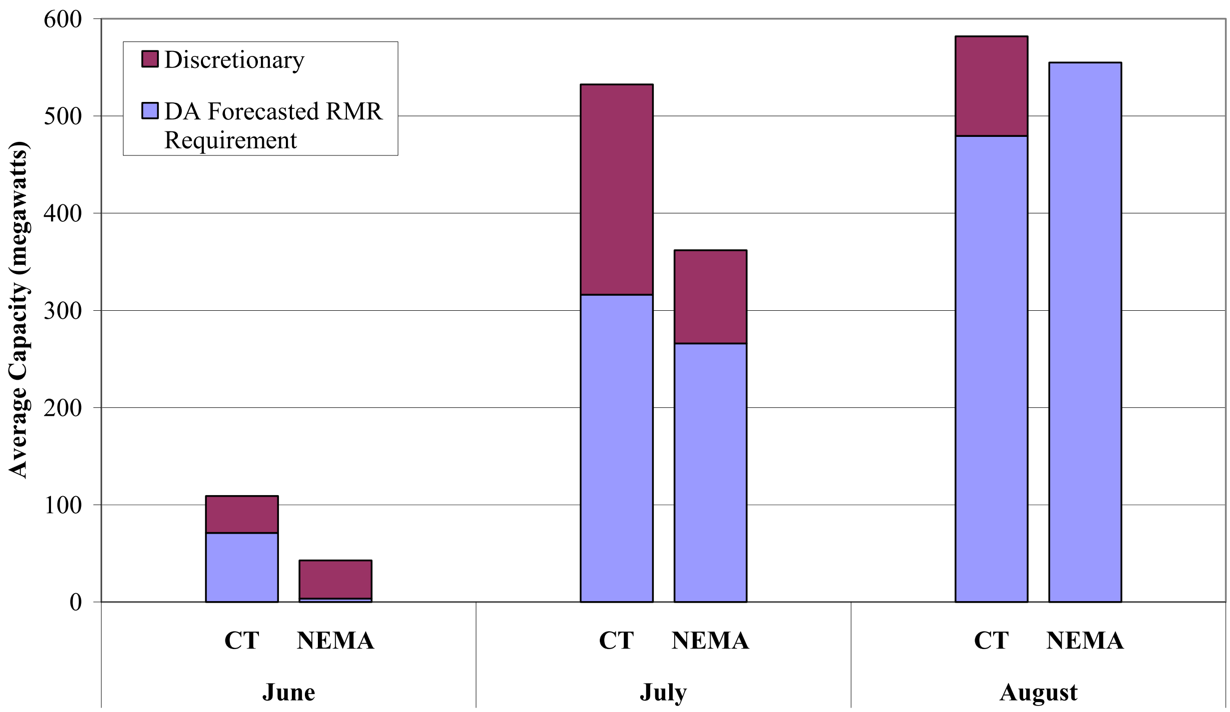
Our final analysis in this subsection evaluates the RMR commitments made by the ISO in NEMA and Connecticut. Based on ISO operations data from June to August, we divided the quantities of RMR commitments made by the ISO operators between those needed to meet the forecasted RMR requirements versus additional discretionary commitments. Discretionary commitments are those that did not appear to be necessary to meet the local reliability requirements in NEMA or Connecticut.[7] Discretionary commitments may be made for a variety of reasons, including concern by the operators regarding the forecasted peak load in the constrained area or the status of a key resource in the area. The results of this analysis are shown in Figure 16.

The results in Figure 16 show that the ISO made limited quantities of discretionary RMR commitments in the months studied. In June, when RMR commitments averaged only 150 MW

7 If only a portion of an RMR resource is needed to meet the forecasted RMR requirements, the entire unit is classified as satisfying the RMR requirement, rather than discretionary.

daily, roughly 50 percent of the commitments were discretionary. In July and August, the share of the RMR commitments that were discretionary was 35 percent and 10 percent, respectively. These results indicate that the level of discretionary commitment in these areas has been moderate and decreasing through the summer. To the extent that they are not necessary to maintain reliability, the ISO should continue to reduce these commitments because they can inefficiently mute the transmission congestion into the constrained areas.

**Figure 16**
**Reliability Must Run Commitments in Constrained Areas**
June to August 2003




### 4. Supplemental Commitment Conclusions

The analysis in this section indicates that the ISO has been committing generating resources consistent with its market-wide and locational reliability requirements under the current market processes and procedures. However, these procedures are resulting in substantial supplemental commitment after the day-ahead market, resulting in capacity surpluses that affect real-time prices and increase uplift costs. To address these concerns, we recommend a number of procedural changes discussed below that should reduce the quantity of supplemental commitment and excess capacity.

### D. Out-of-Merit Dispatch

Out-of-merit dispatch occurs in real time when energy is produced from an output range on a unit whose incremental energy bid is greater than the LMP at its location. In general, resources may be dispatched out of merit because either 1) they would not be economic under the current market conditions, but are needed to meet an operational or reliability requirement; or 2) they are economic under the current market conditions, but are ineligible to set the clearing price. In either case, the out-of-merit generation is treated as "must-take" in the market – equivalent to a resource with an offer price of zero.

Out-of-merit generation tends to reduce energy prices by causing lower-cost resources to set the energy price. In a very simple example, assume the two resources closest to the margin are a $60 per MWh resource and a $65 per MWh resource, with the market clearing price set at $65 in the absence of congestion and losses. When a $100 per MWh resource is dispatched out of merit, it will be treated by the software as a must-take resource with a $0 offer. Assuming the energy produced by the $100 resource displaces all of the energy from the $65 resource, the energy price will decrease to $60 per MWh.

A unit may be dispatched out of merit for three main reasons. First, a unit may run at its EcoMin to satisfy its minimum run time after having run in merit for several previous hours or in anticipation of running in an upcoming hour. Such a unit may also be at its EcoMin when providing reserves. The real-time market software cannot dispatch a unit below its EcoMin so it will dispatch the unit at its EcoMin if the unit must remain online even when its incremental energy bid is above the market price. This is efficient because the software is minimizing cost over the total run-time of the unit. Second, a unit committed for reliability reasons after the day-ahead market may be out of merit at its EcoMin. These units are committed without regard to their incremental energy bid and are, therefore, more likely than units committed in the day-ahead market to have incremental offers higher than the LMP.

Third, a unit may be out of merit in real time to satisfy reliability requirements in real time. Similar to the supplemental commitments, operators may request certain units to be run at higher levels than their energy offers would justify. This can be necessary for a number of reasons, including (a) voltage support on transmission or distribution facilities; (b) managing congestion on local distribution facilities; or (c) providing local reserves to protect against second contingencies. Figure 17 summarizes by zone the average out-of-merit dispatch for weekday hours (6 AM to 10 PM) over the six-month SMD timeframe. As expected, the level of out-of-merit dispatch is much lower than the level of supplemental commitment.

**Figure 17**
**Average Hourly Out-of-Merit Dispatch by Zone**
March to August 2003 Weekdays 6 AM to 10 PM

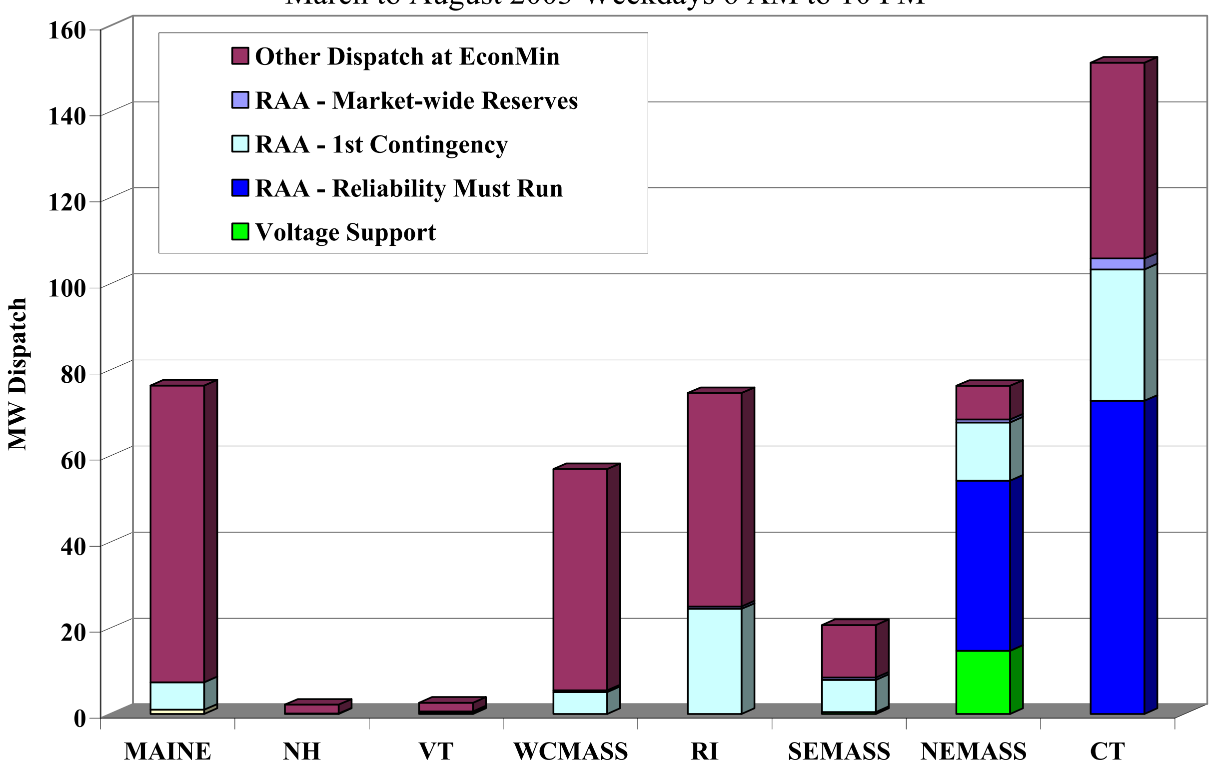


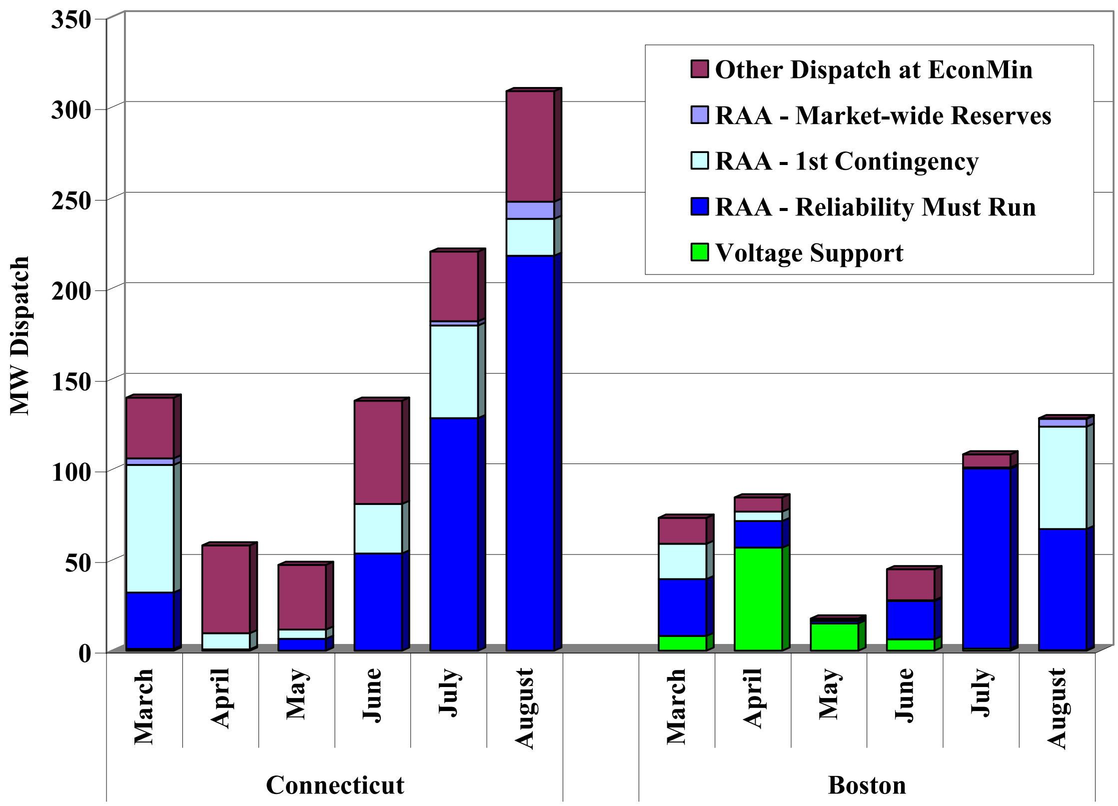
Figure 17 shows that virtually all of the out-of-merit dispatch outside of the constrained areas is attributable to supplemental commitments made for first-contingency reliability requirements in local areas and other units dispatched at EcoMin, both of which are closely related to the commitment process. The out-of-merit dispatch for first-contingencies is related to supplemental commitments that are required because the first-contingency transmission constraints are not yet recognized by the day-ahead market commitment model. There are two factors related to the commitment process that contribute to other resources out of merit at EcoMin. First, the excess commitments shown in the prior section will generally increase the supply on the system and cause higher-cost resources to reduce their output to EcoMin.

Second, because the day-ahead market commitment model does not recognize first-contingency transmission constraints in export-constrained areas or "generation pockets" (e.g., Maine), the commitment process may result in more units being committed than can be dispatched given the network constraints. This can cause the output from units in these areas to be reduced to EcoMin. The recommendations in this report regarding changes to the commitment process would address these factors and reduce the quantity of out-of-merit dispatch.

The primary causes of out-of-merit dispatch in the constrained areas, including NEMA and Connecticut, are resources committed to satisfy first-contingency and second-contingency (RMR resources) requirements and units economically committed that are running at EcoMin. As a percent of the capacity in the area, NEMA had slightly larger quantities of out-of-merit dispatch than Connecticut because NEMA has less internal capacity as a percentage of zonal demand (i.e., it relies more heavily on power from outside the zone) than Connecticut. The out-of-merit dispatch in these areas related to local reliability requirements is consistent with the substantial quantities of supplemental commitments occurring in these areas.

Figure 18 shows the monthly pattern of out-of-merit dispatch quantities in NEMA and Connecticut. This figure shows that the incidence of out-of-merit dispatch increased in the summer. This is not surprising because high load conditions can increase the incidence of system conditions needing to be resolved by out-of-merit dispatch, e.g., voltage support.

**Figure 18**
**Average Hourly Out-of-Merit Dispatch**
March to August 2003 Weekdays 6 AM to 10 PM




Although some resources may need to be dispatched out of merit in any system, this should be minimized because it can undermine the efficiency of the locational energy prices. Furthermore, owners of units that are frequently called out-of-merit order will have an incentive to bid in excess of marginal costs, which can also affect locational price signals when they are taken in merit order.

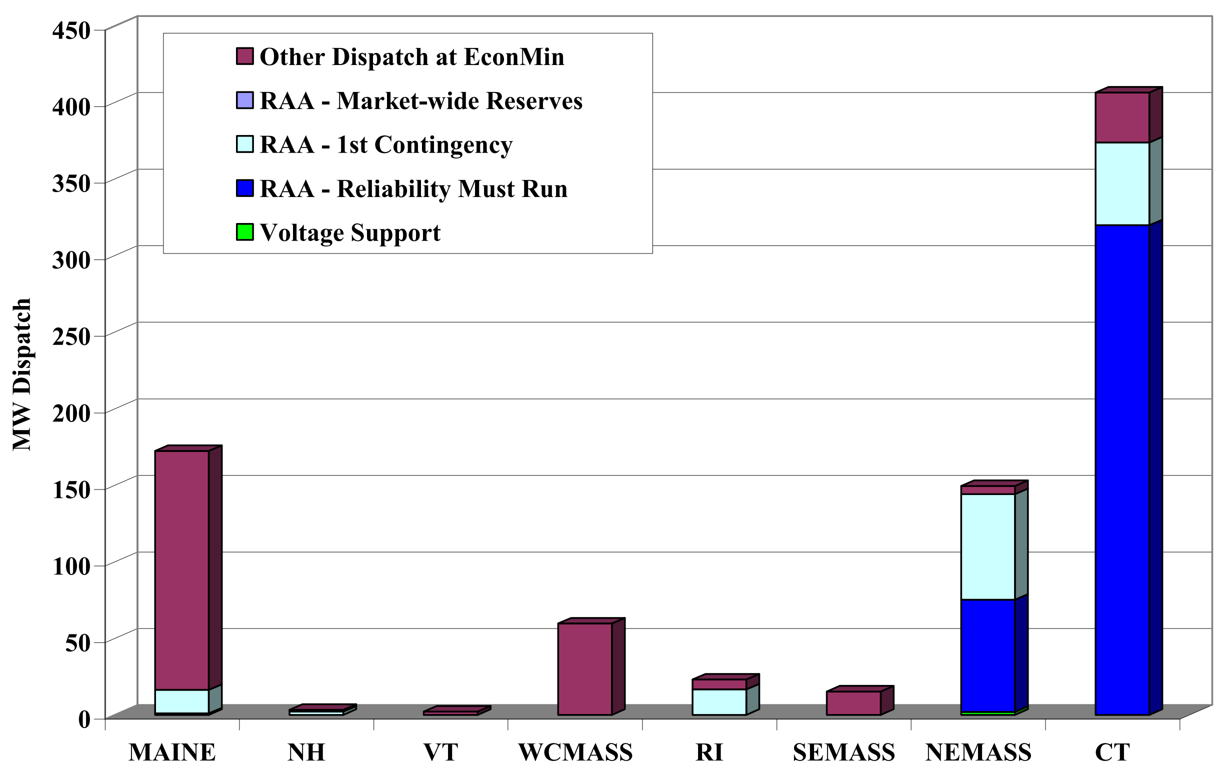
These results are consistent with those reported by ISO-NE in its report reviewing its experience with Peaking Unit Safe Harbor ("PUSH") offer rules that allow "peaking resources" to submit offer prices that would cover the resources' fixed costs.[8] The PUSH report found that although

8 *A Review of PUSH Implementation and Results*, ISO-NE, December 2003 ("PUSH Report"). For purposes of the PUSH provisions, peaking resources were defined as those that have capacity factors less than 10 percent.

one or more peaking units are producing energy in almost two-thirds of the intervals during the summer 2003, these units are generally not in merit. Only 8 percent of the output produced by the PUSH units was in merit.

Prices tend to be more sensitive to out-of-merit dispatch during peak-demand periods when the market is clearing at a steep portion of the supply curve (i.e., where supply is relatively inelastic). Because prices are more sensitive under these conditions, out-of-merit dispatch will have a larger effect on prices. Therefore, we examined the highest-demand days to determine the nature of out-of-merit actions at those times. This analysis is shown in Figure 19.

**Figure 19**
**Average Hourly Out-of-Merit Dispatch by Zone**
Top 5 Peak Days



Like the comparable figure in the prior subsection on supplemental commitment, this figure shows that on the highest-demand days the out-of-merit dispatch for local reliability increases significantly in the constrained areas while most other categories of out-of-merit dispatch decrease. This emphasizes the importance of recognizing these reliability requirements within the SMD market framework, which will allow prices in these areas to reflect these requirements. The most important market improvement in this regard is the implementation of operating reserve markets that include the local reserve requirements in the constrained areas.

### E. Uplift Costs

A unit that is committed after the day-ahead market or dispatched out of merit may receive payments from the ISO to ensure that the unit's bid production costs are recovered. These payments are commonly referred to as "operating reserve credit" payments in New England and are recovered from loads through uplift charges. These payments vary depending on the reason the unit needs the payment (e.g., commitment versus dispatch). Similarly, the costs associated with these payments are allocated differently depending on the reason for the action and whether it occurred before or after the day-ahead market.

The day-ahead operating-reserve credit payments arise during the day-ahead market process (not including the RAA and other processes that occur after the market closes). Units may be designated in the day-ahead market for voltage support, as reliability must-run resources, or as special-case resources. To the extent that these units do not recover their commitment costs in the day-ahead market they will receive Day-Ahead Voltage Support Operating Reserve Credits, Day-Ahead RMR Operating Reserve Credits, and Day-Ahead SCR Operating Reserve Credits, respectively. Units that are committed economically that do not recover their as-bid production costs through the day-ahead energy market receive Day-Ahead Economic Operating Reserve Credits. These units tend to have high commitment costs relative to their incremental energy costs and thus can be economic to commit even when they cannot recover their full commitment costs through the day-ahead energy market.

Units committed after the day-ahead market closes can be committed for RMR, SCR, and voltage support. These units receive Real-Time RMR Operating Reserve Credits, Real-Time SCR Operating Reserve Credits, and Real-Time Voltage Support Operating Reserve Credits, respectively. In addition, payments to units committed pursuant to the RAA to meet market-wide forecasted energy and operating reserve requirements are called Real-Time Economic Operating Reserve Credits.

The total amount of operating reserve credit payments in each of the first six months is shown in Figure 20. These payments are divided between (a) payments to RMR and voltage support resources in Connecticut; (b) payments to RMR and voltage support resources in NEMA; and (c) payments for economic operating reserve credits.

**Figure 20**
**Operating Reserves Credit Charges by Month**
Conn. Reliability, NEMA Reliability, and Economic ORCs
March to August 2003

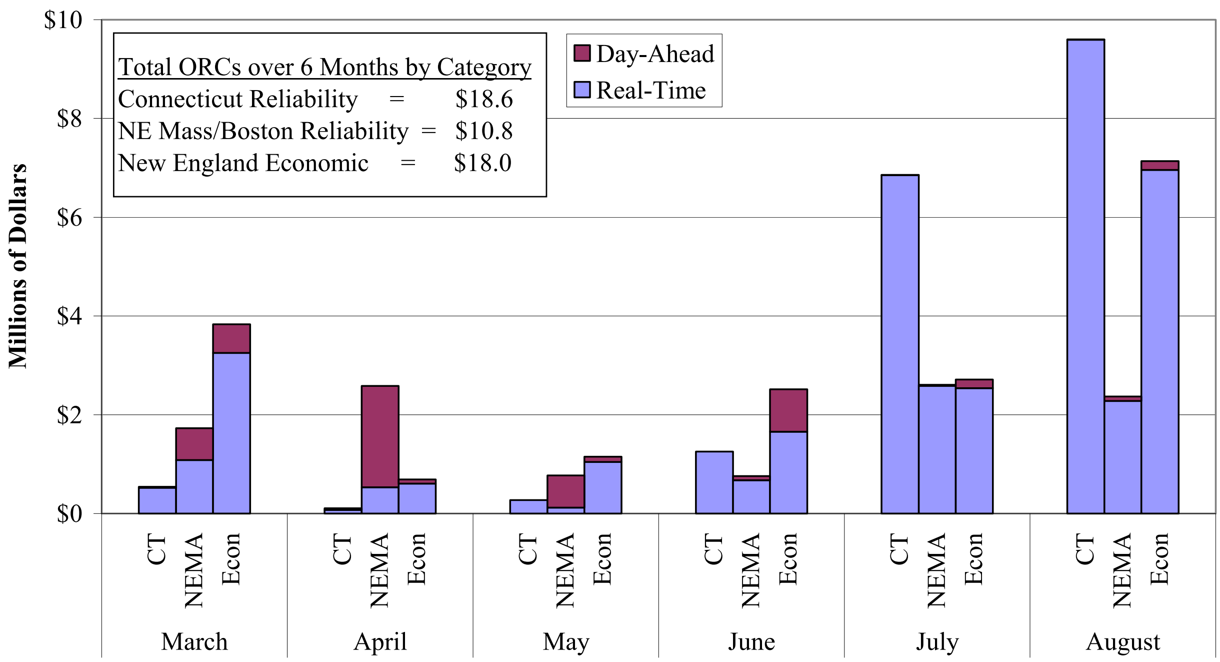


Figure 20 shows that the majority of the operating reserve credit payments were associated with commitments made after the day-ahead market to address local reliability requirements in Connecticut and NEMA/Boston. Since the uplift costs associated with commitments made to satisfy first-contingency requirements in these local areas are allocated to the entire market, a portion of the amounts shown as "New England Economic" operating reserve credits are actually caused by the reliability requirements in the constrained areas.

The uplift costs of operating reserve credits are allocated in different ways. The costs of day-ahead operating reserve credits are allocated to load scheduled in the day-ahead market. For real-time operating reserve credits, which constitute the bulk of the uplift costs, the costs are allocated based on deviations of actual real-time load from day-ahead schedules (including quantities scheduled as virtual load). This allocation methodology can have a substantial effect on certain types of conduct, including virtual trading and price-sensitive day-ahead demand. Virtual trades are sales or purchases of energy in the day-ahead market that are settled in real time because there is no corresponding physical load or generation. Hence, the entire quantity of the virtual load or generation is a real-time deviation. Likewise, load-serving entities (LSEs) that bid price-sensitively in the day-ahead market, opting to purchase in real time if they deem that prices are unjustifiably high in the day-ahead market, will be allocated a large share of the uplift costs because their entire real-time purchase will be a real-time deviation.

For both the day-ahead and real-time markets, uplift costs associated with RMR operating reserve credits and voltage support operating reserve credits are allocated on a zonal basis while economic operating reserve credits are allocated to all loads in New England. The payments to units committed for RMR and voltage support are allocated to the zones where the units are located to recognize that these actions are taken to satisfy local reliability needs. Most of these costs are associated with supplemental commitments after the day-ahead market and are thus considered real-time operating reserve credits. These costs are therefore allocated to only the real-time deviations, which can represent a very small portion of the entire load in the zone. Uplift costs associated with SCR operating reserve credits are allocated to the transmission operator that requested the SCR.

While it is undesirable to generate large operating reserve credit payments, some level is unavoidable at this point in the market's development. However, the current allocation methods can have adverse incentive effects and revisions would serve the interest of economic efficiency. First, and foremost, the practice of allocating the cost of real-time operating-reserve credit payments to real-time deviations from day-ahead schedules creates artificial disincentives for virtual trading and price-sensitive load purchases in the day-ahead market.

Virtual trading and price-sensitive load purchases facilitate price convergence between the day-ahead and real-time markets. To the extent that the allocation methodology creates a disincentive for these actions, larger and more volatile prices differences between the day-ahead and real-time markets will prevail, leading to higher overall costs of serving load. These actions also mitigate market power in the day-ahead market. If a participant attempts to raise day-ahead prices by withholding resources, this will be undermined by virtual sales and loads that choose to buy in the real-time market. However, the effectiveness of this process depends on the real-time market being a viable option for participants without them incurring substantial additional costs.

To address these concerns, we recommend allocating most of these uplift costs to all real-time loads rather than to only deviations from day-ahead schedules. The ISO New England market monitor recognized this issue and made a similar recommendation in the PUSH report. This change is justified not only by the economic efficiency considerations described above, but also by the fact that most of the commitments that result in uplift costs are made to protect the reliability of all load.

The one type of operating reserve credit cost that arguably should not be allocated to real-time deviations is the cost of the Real-time Economic Operating Reserve Credits associated with the RAA. The RAA is used to ensure that sufficient generation is committed to meet forecast load in real time. To the extent loads are under-scheduled in the day-ahead market, these costs may appropriately be allocated to real-time purchases. This differs from allocating the uplift costs to all real-time deviations, which would include loads that were over-scheduled in the day-ahead market.

### F. Economic Minimum Generation Levels

This section analyzes the EcoMin levels set by the suppliers in New England, which can have a significant effect on the performance of the market. Units dispatched by the ISO must be operated at no lower than their EcoMin. When an EcoMin is set at a relatively high level, the ISO's dispatch flexibility is reduced substantially because the dispatchable range of output on the unit is decreased. In the extreme, an EcoMin set at the same level as the EcoMax will provide the ISO no dispatch flexibility. This inflexibility may compel the ISO to dispatch generating units at undesirably high levels to satisfy the EcoMin bid by the owner, particularly during relatively tight market conditions.

Because spinning reserves must be provided from the dispatchable range of the unit, setting a high EcoMin value also reduces the capability of the unit available to provide spinning reserves. Therefore, when the ISO needs additional reserves under relatively high load conditions, it may have to commit more units at their EcoMin than is otherwise required to meet its spinning reserve obligations or to meet the reliability requirements in Connecticut and NEMA.

The analysis in this section evaluates the EcoMin levels of the fossil-fired units in the New England market. The report focuses on fossil-fired units because they constitute the majority of the dispatchable capability in New England. We calculate the average EcoMin level as a percentage of the EcoMax level, and separately show the results for:

- NEMA/Boston and Connecticut since the effects of high EcoMin levels are likely to be the greatest in these areas;
- Gas turbines, combined cycle units, and steam turbines. Gas turbines and combined cycle units are generally operated much closer to full output level for technical reasons while steam turbines typically have a relatively broad dispatchable range (i.e., relatively low EcoMin levels); and

- Self-scheduled versus economically-dispatched generation. Operational flexibility and the quantity of spinning reserves available to the system are provided by the output ranges above the EcoMin level on economically-dispatched units. Suppliers self-scheduling their units set the EcoMin at its self-scheduled level, which is generally significantly higher than the physical minimum generation level.

The results of the analysis are shown in Table 3, which shows that the economically-dispatched steam turbine units had EcoMin levels averaging 29 percent of the EcoMax on a market-wide basis, and averaging 21 and 32 percent in NEMA and Connecticut, respectively.

**Table 3**
**Average Economic Minimum Generation Level for Fossil Units**
March to August 2003

| | **Market** | **NEMass/Boston** | **Connecticut** |
|---|---|---|---|
| Percent of Capacity in Category | | | |
| Economic Dispatch | 49% | 34% | 82% |
| Self Scheduled | 51% | 66% | 18% |
| EcoMin as Percent of EcoMax | | | |
| Economic Dispatch | | | |
| Peaker | 64% | 43% | 78% |
| Combined Cycle | 68% | 51% | 87% |
| Steam Turbine | 29% | 21% | 32% |
| Self Scheduled | | | |
| Peaker | 93% | 74% | 89% |
| Combined Cycle | 86% | 89% | 97% |
| Steam Turbine | 87% | 86% | 99% |

The table also shows that more than half of the generation is economically dispatched in all of New England, 34 percent of the generation is economically dispatched in NEMA, and more than 80 percent of the generation is economically dispatched in Connecticut. These results are substantially improved from similar analysis conducted prior to the implementation of the SMD markets, which showed EcoMin levels were substantially higher in the summer of 2001.[9]

One of the recommendations of the report in 2001 was that generators submit EcoMin levels that can be justified by the physical or economic characteristics of the unit. This requirement was enforced by the ISO, which consulted with suppliers and reviewed these levels. Although some individual units have EcoMin levels that are relatively high, the analysis in this section supports the conclusion that high EcoMin levels have not been a systematic problem under the SMD markets and that the ISO has effectively monitored these levels.

### G. Market Operations -- Conclusions

The SMD markets in New England have been implemented successfully and operated competently. Load forecasting has been accurate and price corrections have been very infrequent. However, the current SMD market software does not recognize and satisfy all of the operational reliability requirements in New England. This causes the ISO to take additional actions through the RAA and other reliability procedures. The ISO's actions have generally been consistent with its reliability requirements and procedures. Nonetheless, these actions result in LMPs that do not accurately reflect these requirements and result in increased uplift costs.

The most significant congestion historically in New England, from both an economic and reliability perspective, has been congestion on the interfaces into NEMA/Boston and into Connecticut. During the first six months of the SMD markets in New England, congestion into these areas has been limited. This has been due, in part, to the supplemental commitment and out-of-merit dispatch patterns that have been necessary to maintain reliability in these areas. These patterns have a number of significant market effects, including reducing prices and associated congestion in the constrained areas and increasing uplift costs.

9 Patton, D., *An Assessment of Peak Energy Pricing in New England During Summer 2001*, Report to ISO-NE Board of Directors, (2001).

This raises substantial concerns because these are the economic signals that are expected to govern new investment and retirement decisions for generation and transmission assets. Hence, it is important to address the underlying causes of the supplemental commitment and out-of-merit dispatch. As discussed above, the supplemental commitment in the constrained areas is most frequently made to protect the system against first and second contingencies in NEMA and Connecticut. These first and second-contingency requirements are essentially local operating reserve requirements.

One way to address this issue is to recognize these local reserve requirements as market requirements when the ISO implements its operating reserve markets. This would have two important effects. First, it would cause the supplemental commitments to be made in the day-ahead market pursuant to well-defined criteria, which would allow these commitments to be reflected in the day-ahead market results. Second, it would allow the implementation of energy-pricing provisions that more accurately reflect the limited transmission capability into these areas, and thereby signal the need for additional generation and transmission facilities. Therefore, we recommend that the ISO consider establishing local operating-reserve requirements in conjunction with the co-optimized operating reserve spot markets it plans to implement.

The operating reserve spot markets will not resolve the energy-pricing concerns since the constrained areas will continue to require the commitment of considerable online resources for reserves that can result in out-of-merit dispatch. Ultimately, additional peaking generation in these areas would provide a lower-cost means of satisfying the local reserves needed to maintain reliability in these areas.

In the shorter term, we recommend that the ISO incorporate its first-contingency limits and forecasted second-contingency capacity requirements in its day-ahead market commitment. This change will allow the SMD market software to decommit resources in other areas when substantial additional resources are needed in the constrained areas and thus reduce the capacity surplus and associated uplift costs. This change will also substantially reduce the incentive for loads in the constrained areas to under-schedule in the day-ahead market.

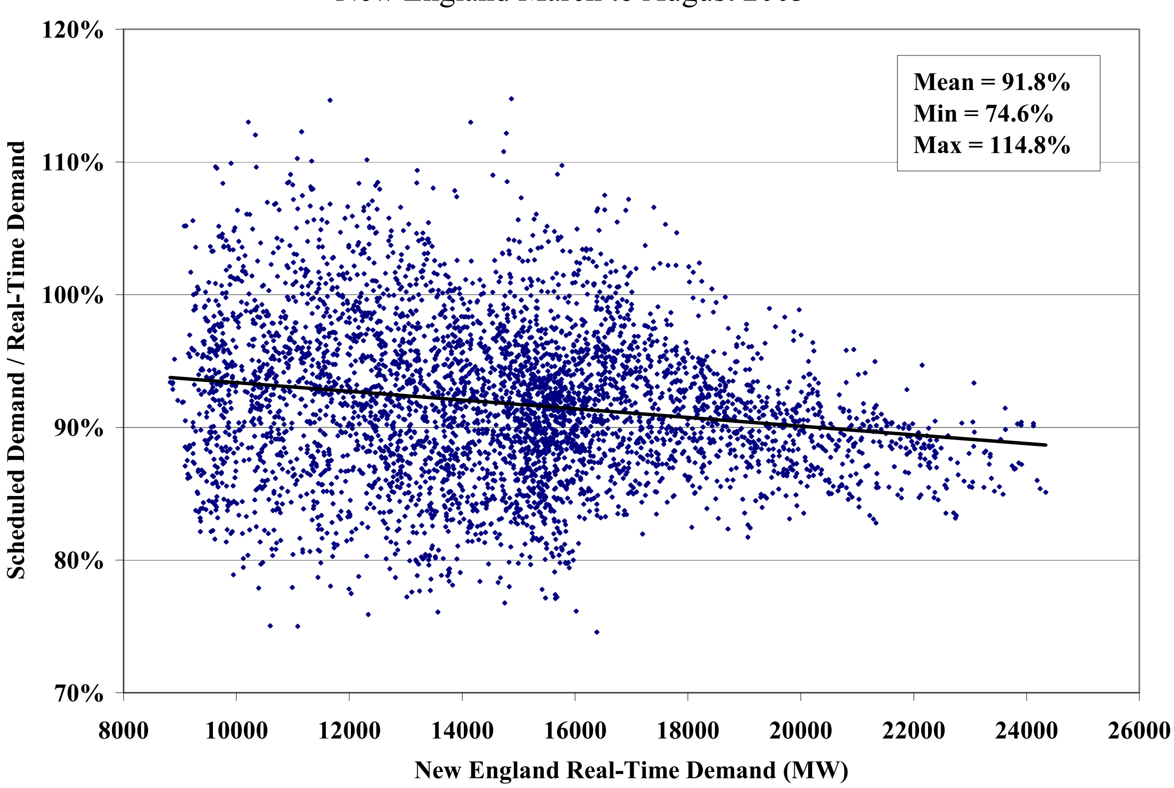
## V. Load Scheduling in the Day-Ahead Market

In this section, we examine the load-scheduling pattern in the day-ahead market to determine whether it has been consistent with efficient market operations. We also analyze virtual trading – both virtual supply and virtual demand.

### A. Load Scheduling

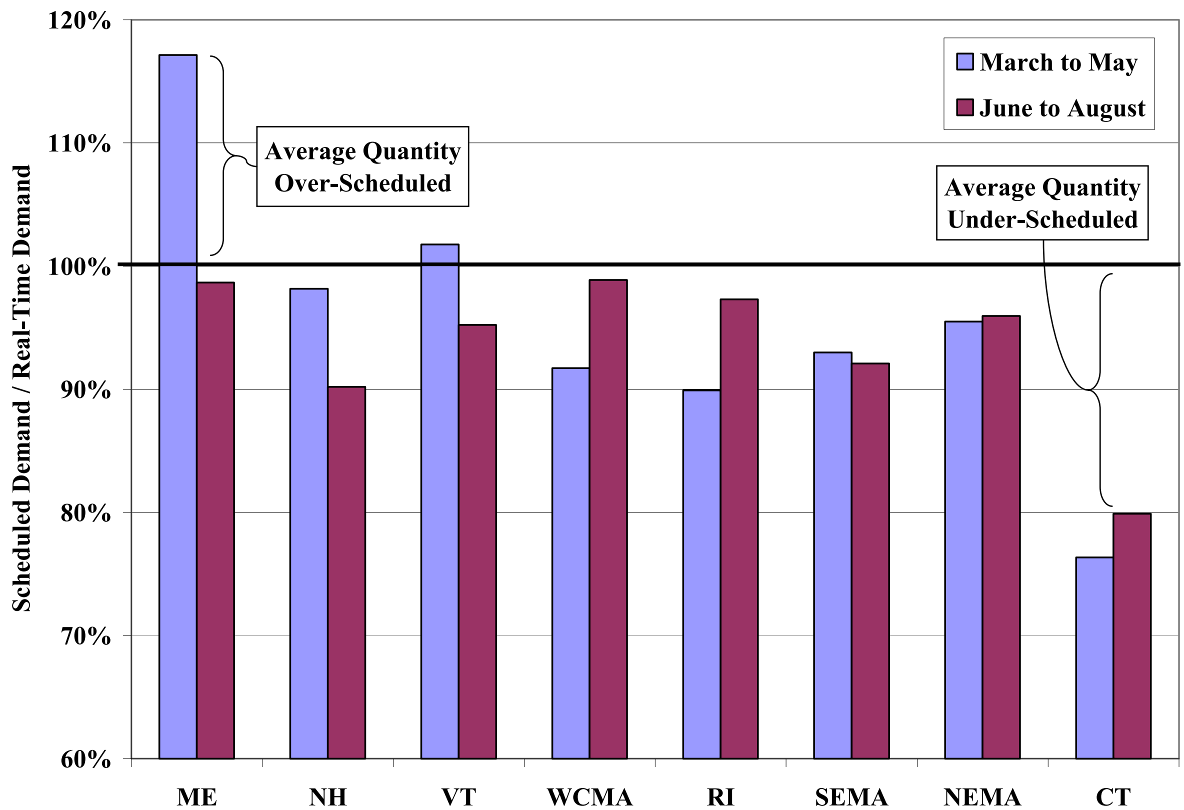
Load bidding can have important effects on market efficiency. Under-scheduling load in the day-ahead market can lower day-ahead prices and contribute to the need to commit supplemental resources, which can distort real-time prices as explained in the prior section. Figure 21 shows the hourly ratio of demand scheduled in the day-ahead market to the actual real-time load in New England. The scheduled day-ahead load includes the physical load scheduled plus the net virtual load scheduled (virtual load minus virtual sales).

**Figure 21**
**Ratio of Scheduled Demand to Real-Time Demand in New England**
New England March to August 2003



This figure shows that the average ratio of the day-ahead load to the real-time load is 91.8 percent -- i.e., demand is under-scheduled by 8.2 percent, on average. While there is a wide range of hourly values, the vast majority of hours are scheduled at between 80 percent and 110 percent of actual load. The figure also reveals that there is a tendency for under-scheduling to increase as the actual level of demand increases. To understand the causes and effects of the under-scheduling, we analyze the load scheduling by zone. Figure 22 shows the weighted average ratio of demand scheduled in the day-ahead market to real-time demand for each zone.

**Figure 22**
**Average Ratio of Scheduled Demand to Real-Time Demand**
March to August 2003




While the average ratio across all zones is 92 percent, the ratios vary substantially by zone. The only significant over-scheduling in the day-ahead market occurred in Maine in the initial months of SMD. This was generally related to very active virtual trading by participants that were parties to seller's choice contracts that settled at day-ahead prices. When these contracts were modified to settle at real-time prices, the virtual trading and resulting over-scheduling in Maine ceased.

All of the other zones, with the exception of Connecticut and Vermont, schedule between 90 and 100 percent of the actual load in the day-ahead market. The load in Connecticut is the most under-scheduled, with an average of only 78 percent of the actual load scheduled in the day-ahead market. Between the spring and summer, the day-ahead load scheduling in WCMA, Rhode Island, and Connecticut increased while the day-ahead scheduling in Maine, New Hampshire, and Vermont decreased. This shift in scheduling patterns from northern areas to southern areas has generally improved the consistency of day-ahead and real-time prices.

This under-scheduling is consistent with the effects of the supplemental commitment and out-of-merit dispatch described in the prior section. These supplemental commitment patterns, which are most prevalent in Connecticut, generally have the effect of depressing the real-time prices in that zone. In the broader market, this is true to a lesser extent. With the premium this creates in the day-ahead market, participants will naturally act on these economic incentives to reduce their day-ahead schedules. This can take the form of reduced schedules by LSEs in the area, reduced virtual loads, or increased virtual supply (all of which reduce the net load scheduled in the area). This under-scheduling pattern is self-reinforcing to some extent since it increases the need for supplemental commitment, which tends to reduce real-time prices and increases the incentive to under-schedule. The most effective way to address this problem is to reduce the need for supplemental commitment and out-of-merit dispatch over time by improving the representation of contingency requirements in the market software.

This section indicates that the overall scheduling patterns are consistent with the economic incentives facing the market participants. A significant portion of these overall scheduling patterns are determined by the virtual load and virtual supply (collectively "virtual trading") that is scheduled in the day-ahead market. These patterns are evaluated in the following subsection.

### B. Virtual Trading

Virtual trading allows participation in the day-ahead market by entities other than Load-Serving Entities and generators that settle in the real-time market. For example, if the day-ahead prices are lower than a participant expects they will be in the real-time market, the participant can make virtual purchases in the day-ahead market and subsequently sell the purchased energy back into the real-time market. Virtual trading plays an important role in a multi-settlement market by:

- Improving the convergence between the day-ahead and real-time prices;
- Providing additional flexibility for participants to manage their positions and associated risk in the ISO markets; and
- Mitigating market power in the day-ahead market by reducing net day-ahead energy purchases when day-ahead prices would otherwise be artificially inflated.

We analyzed virtual trading by comparing the trend over time of scheduled and unscheduled virtual load and virtual supply, which is shown in Figure 23. The solid bars in the figure are scheduled virtual purchases and sales while the transparent portions of the bars are unscheduled virtual supply offers and virtual load bids. The figure shows that virtual bids and offers were substantial in the initial phase of SMD. The total virtual bids and offers taken together averaged close to 8000 MW per hour in the first three months, decreasing to approximately 5000 MW per hour in the summer months. These levels are substantially higher than in New York, which is surprising given that the load in New York is almost 30 percent higher and given the economic disincentives associated with the real-time uplift allocation discussed in the prior section. However, the fact that virtual trading in New York is limited to purchases and sales at the zonal level is likely a significant factor explaining the lower levels in New York.

**Figure 23**
**Average Hourly Virtual Bids, Offers, and Schedules**
Virtual Load and Supply Scheduled and Unscheduled

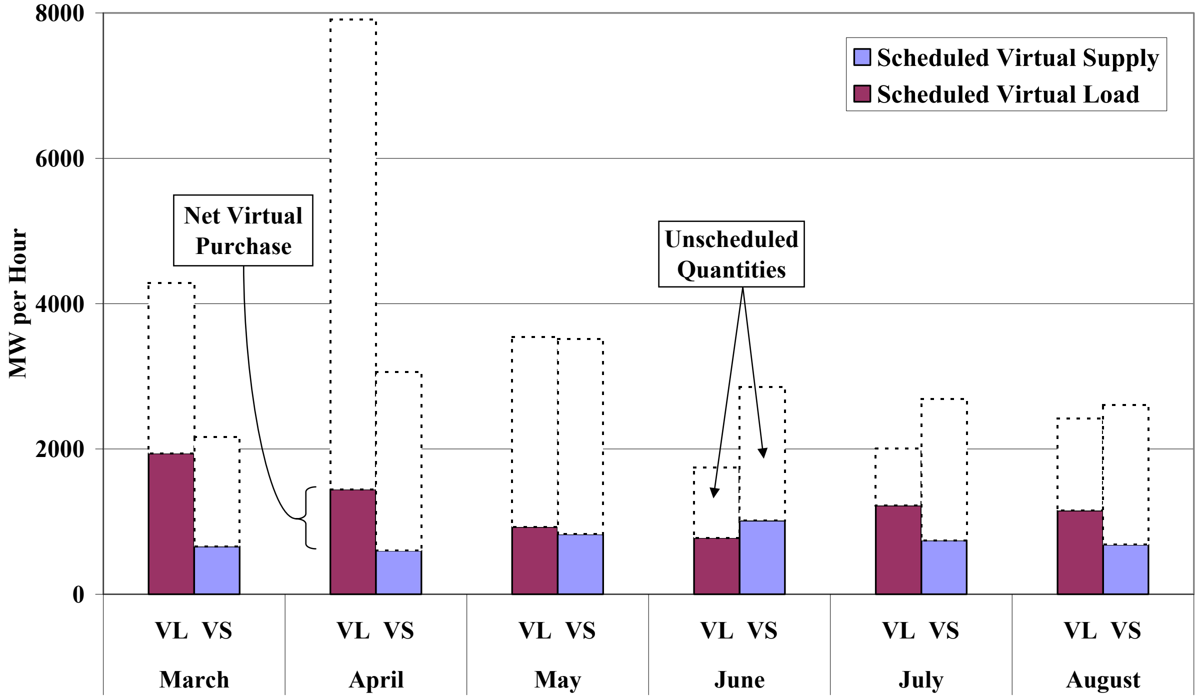
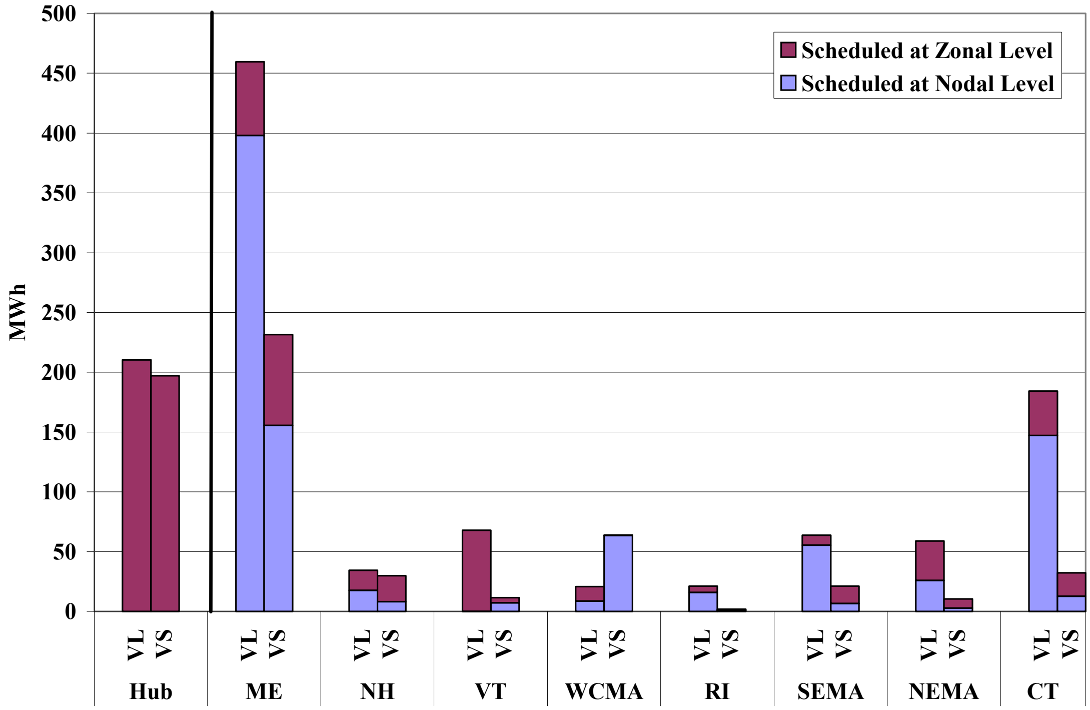



Figure 23 also shows that although the bids and offers have fallen significantly, the scheduled quantities have decreased only slightly over the six-month period. The net virtual load (scheduled virtual load – scheduled virtual supply) has been relatively modest as a percentage of the overall load in New England in most months. It was the highest in the initial month of the SMD markets, exceeding 1000 MW per hour. Much of the virtual trading activity in the initial months occurred in Maine and was related to preexisting seller's choice contracts in that area. This trading activity caused transmission congestion within Maine resulting in a limited number of price spikes in the day-ahead market. These contracts originally settled at day-ahead prices and motivated substantial virtual trading by the participants. The over-scheduling in Maine ceased when the contracts were shifted from settling at day-ahead prices to settling at real-time prices.

In Figure 24, we examine more closely the scheduled virtual trades by zone. Virtual trades can occur at the zonal level or at a particular node. A virtual purchase or sale at the zonal level will result in the purchase or sale quantity being disaggregated over all of the nodes in the zone. Figure 24 shows the total virtual purchases and sales by zone that are made at the zonal or nodal level. It also shows the average virtual trades that occur at the NE Hub, which we have defined as a zone for the purpose of this figure since it corresponds to trades at the multiple nodes comprising the hub.

**Figure 24**
**Average Hourly Scheduled Virtual Load and Supply**
Nodal vs. Zonal Scheduled Offers and Bids




Zonal virtual schedules will generally not cause day-ahead intra-zonal congestion since the energy purchased or sold is distributed throughout the zone. In addition, trading at the zonal level is relatively liquid and, therefore, prices in the zone are less susceptible to volatility as a result of irregular virtual bids or offers. On the other hand, relatively small quantities of virtual purchases and sales at the nodal level can have a large impact on day-ahead congestion patterns in localized areas. This is because trading at some nodes can be quite illiquid, thereby allowing small quantities to have significant price impacts.

The majority of virtual trades have been scheduled at the nodal level, excluding trades at the hub. The most significant activity is in Maine, where net virtual purchases contribute to day-ahead scheduled load that exceeds actual load. Virtual load scheduled in Connecticut is relatively high in comparison to that in other zones (except Maine). This could reflect a competitive reaction by other participants to the persistent under-scheduling in Connecticut, or a preference by participants serving physical load in Connecticut to purchase power virtually in the day-ahead market. Because virtual load can be bid at the nodal level, it allows a participant serving physical load a higher degree of control over the distribution of its day-ahead purchases than is the case for day-ahead load purchases.

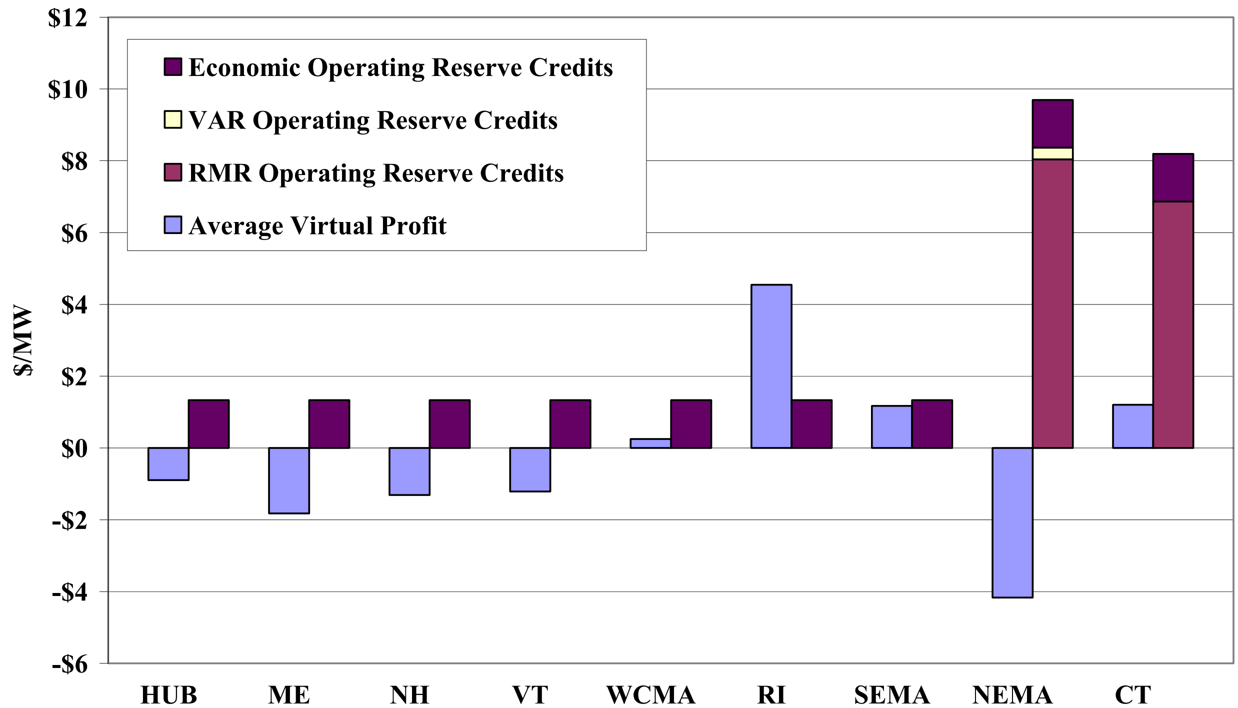
Virtual trading plays an important role in the day-ahead market, improving price convergence with the real-time market, providing flexibility for participants to hedge commitment and scheduling risks, and mitigating potential market power and gaming opportunities in the day-ahead market. Therefore, it is important to minimize inefficient disincentives for participants to engage in virtual trading. In the course of this review, we identified the same issue that was cited by Dr. Ethier in the PUSH Bidding Report regarding the allocation of real-time uplift costs – namely, that these costs are allocated only to real-time deviations from day-ahead schedules.[10] Such deviations include under-scheduled load that will purchase energy in the real-time market, over-scheduled load that will sell the excess energy in the real-time market, and virtual trades that will settle their position in the real-time market.

Because the virtual load and supply can represent a relatively large share of the deviations, they will bear a corresponding large portion of the real-time uplift costs. This raises concerns to the extent that these costs could serve as a disincentive to engage in virtual trading. To evaluate this issue, Figure 25 compares the average gross profits from virtual trading with the average uplift cost allocation per MWh in each zone. In some of the zones, the average profits for virtual trades are negative. Virtual trades are made based on expectations regarding the real-time prices at a location the following day. Because these expectations are subject to substantial uncertainty,

[10] *Op cit.*

virtual trades often result in a loss. The average profits for a zone will be negative when the total losses for virtual trades in a zone are larger than the total revenue for such trades.

**Figure 25**
**Average Virtual Profits vs. Uplift Costs**
June to August 2003




The figure shows that the uplift cost allocation can result in significant costs for virtual trades. In most zones (excluding NEMA and Connecticut), these costs were limited to the economic operating reserve credit that averaged $1.33 per MWh. At this level, the expected uplift costs were higher than the average profit levels for all zones except Rhode Island.

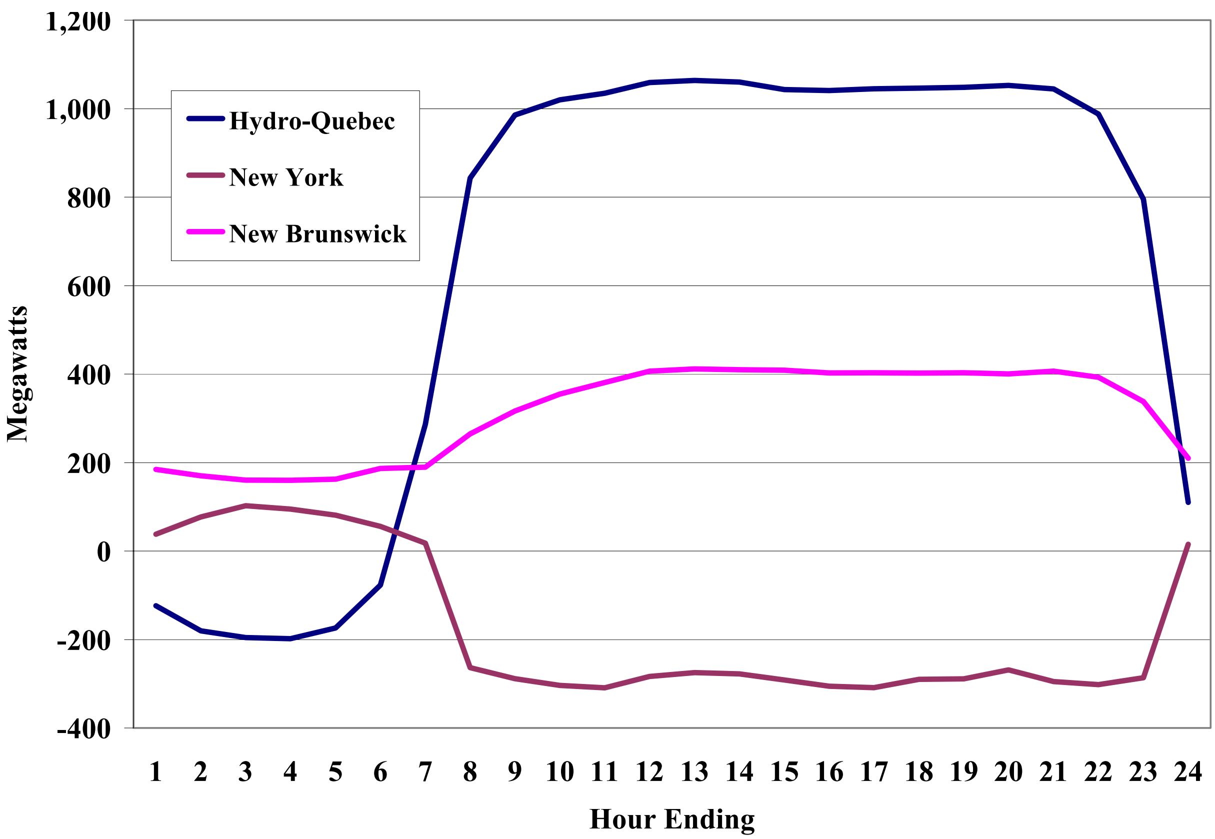
In NEMA and Connecticut, uplift costs associated with RMR and voltage-support operating-reserve credits are allocated directly to the zones so that the costs are higher for real-time deviations in these locations. The uplift costs in NEMA and Connecticut associated with RMR and voltage-support operating reserve credits exceed $8 per MWh, which is substantially larger than the average profits realized on virtual trades in these zones. Because these are relatively constrained areas, the prices will tend to be more volatile and sensitive to over-scheduling or under-scheduling of the physical loads, increasing the importance of virtual trading in maintaining reasonably efficient convergence of the prices in the day-ahead and real-time markets in these areas.

These results indicate the importance of re-evaluating the uplift cost-allocation rules to eliminate this significant disincentive to engage in virtual trading and price-sensitive demand bidding in the day-ahead market.  This could be accomplished by allocating the uplift costs associated with operating reserve credits for RMR and voltage support to all load in the constrained areas.  This is appropriate since all loads in these areas are protected by the local-reliability commitments made after the day-ahead market closes.  Hence, we recommend that the ISO and its market participants modify the allocation rules for the uplift costs.

## VI. Interface Scheduling

This section evaluates the scheduling of external transactions during the first six months of the SMD markets. New England imports power from and exports power to New York and Canada. The trading with Canada is over interfaces with Hydro Quebec and New Brunswick. Figure 26 summarizes the level of net imports from adjacent control areas by showing the average level of net imports for each hour of the day over the first six months of SMD operations.

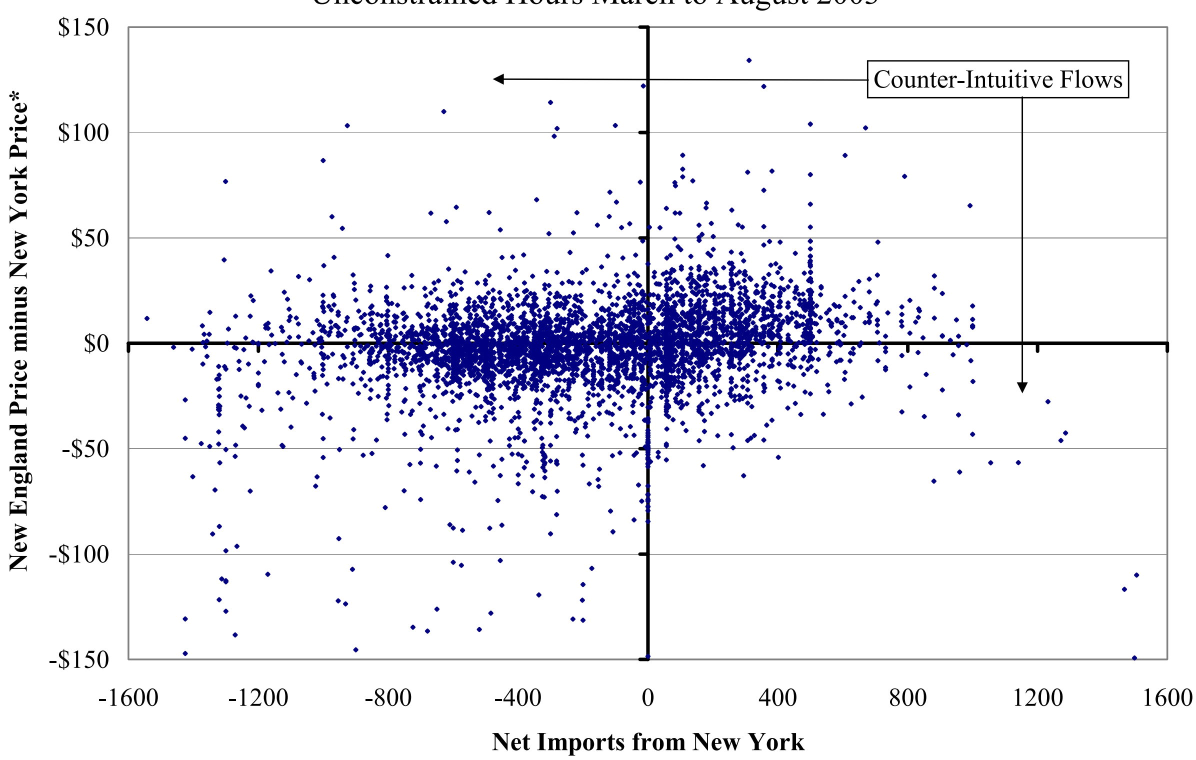
**Figure 26**
**Average Net Imports by Hour of Day and Interface**




The most significant source of imports is from Hydro-Quebec, which accounts for an average of over 1000 MW of net imports during a substantial portion of the day. At night, imports from Hydro-Quebec decrease to a net export of 200 MW. This is consistent with normal hydro operating patterns, which typically exhibit higher output during the higher-priced hours and, to conserve water, lower output in the lower-priced overnight hours. The pattern of net imports from New Brunswick is similar. The average import level during the day is approximately 400 MW, falling to 200 MW at night. The pattern of net imports from New York is opposite that of Hydro-Quebec and New Brunswick – net imports at night become net exports during the day. The consistency of this pattern suggests that most of the external transactions are associated with bilateral power sales and purchases, which are often for the sixteen peak hours of each weekday.

When transmission limits do not bind, trading should occur between neighboring markets to cause prices to converge. For example, when prices are higher in New England than in New York, imports from New York should continue until the interface is fully scheduled or until prices have converged and no economically viable exports remain. We analyzed New England-New York transaction data to determine whether this pattern exists.

**Figure 27**
**Net Imports and Price Difference between New England and New York**
Unconstrained Hours March to August 2003




Source: ISO-NE and NYISO markets databases, Potomac Economics' analysis.
* Prices for New England and New York are the West-Central Mass zone and Capital zone prices, respectively.

The scatter plot in Figure 27 shows the relative differences in prices between New England and New York, as well as the corresponding power flows between the two control areas. The vertical axis shows the difference between the prices at the West-Central Massachusetts zone and New York's Capital zone. These zones are the most directly connected and should converge well during non-transmission-constrained hours. The top half of the figure reflects hours when the price in New England was higher than in New York. The horizontal axis shows the net imports into New England from New York.

The two right quadrants represent net imports while the two left quadrants show net exports. If transactions were scheduled efficiently between the two regions, the points in the chart would be relatively closely clustered around the horizontal line – indicating little or no price difference between New England and New York in the absence of a binding physical transmission constraint. Moreover, one would not expect net exports to occur when the New England price substantially exceeds the price in New York. Likewise, one would not expect net imports to occur when the New England price is substantially less than in New York.

The figure indicates that there remains a substantial dispersion of price differences around zero in hours when the interface between the markets is unconstrained. In addition, a considerable portion of the results are in the two "counter-intuitive" quadrants where power is transmitted from the lower-priced market to the higher-priced market. These results are comparable to prior analyses of geographic arbitrage of prices between New York and New England for periods before SMD.[11]

Although SMD was not expected to resolve these issues, this analysis confirms that the issues persist following the introduction of the SMD markets in New England. Hence, ISO New England and the New York ISO should continue their efforts to implement market provisions to coordinate physical interchange, generally referred to as "Virtual Regional Dispatch". Substantial progress has been made to date by the ISOs and their market participants in developing the details necessary to implement these provisions.

11 See *2001 and 2002 State of the Market Reports for the New York ISO*, Potomac Economics.

We also examined trading over the New Brunswick Interface and the Hydro Quebec Interface. The results are shown in Figure 28 and Figure 29. In these analyses, we show only the price at the New England proxy buses that are used to settle trades with these adjacent control areas. For New Brunswick this is the Keswick Proxy and for Hydro Quebec this is the HQ Proxy. As the figures indicate, the level of imports from these areas is positively correlated with prices in New England, which is generally consistent with expectations.

**Figure 28**
**Real-Time Prices and Net Imports from New Brunswick**
June to August 2003

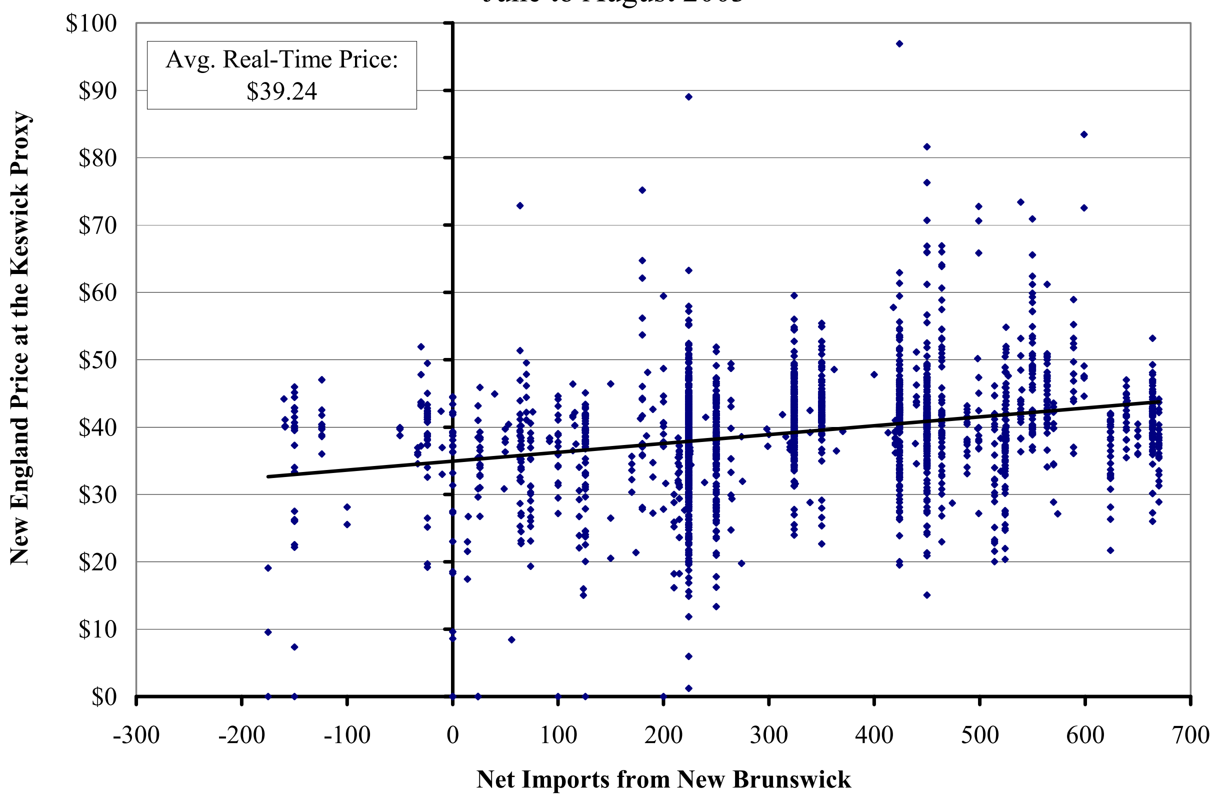
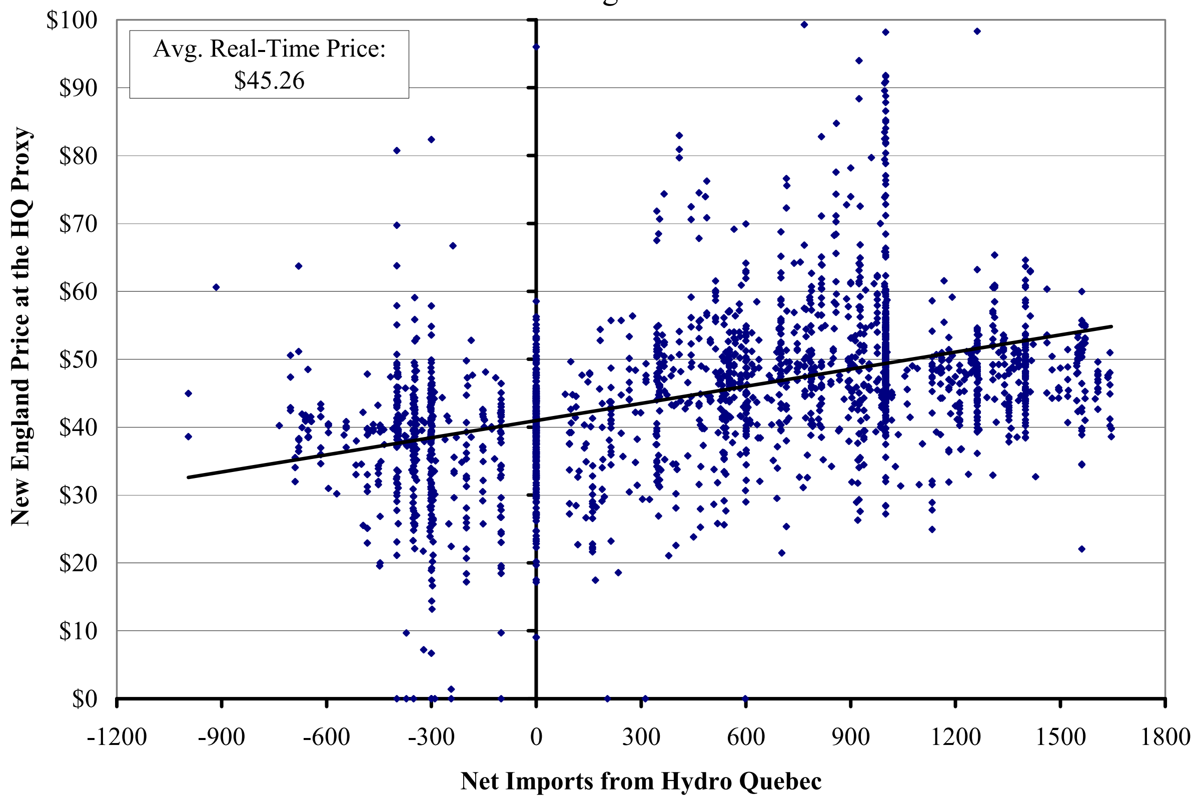


**Figure 29**
**Real-Time Prices and Net Imports from Hydro Quebec**
June to August 2003



## VII. Regulation Market

As part of the introduction of SMD, ISO New England made significant changes to the market for regulation. In this section of the report we evaluate this market. In particular, we evaluate (a) the practice of self-scheduling regulation after the close of the regulation market, (b) the adequacy of resources capable of regulation in New England, and (c) potential enhancements to the regulation market model.

### A. Self-Scheduling by Regulation Providers

Prior to SMD, regulation was cleared in real-time together with energy and other ancillary services. Under SMD, the regulation market is cleared day-ahead after the day-ahead energy market clears. Under this process, owners of regulation-capable resources may submit regulation bids up until 6 PM the day before. An offer to supply regulation consists of a price per megawatt of flexibility and the associated quantity in both the "up" direction" and the "down" direction (required to be equivalent). The offer also must specify the output range within which the unit is capable of providing regulation service.

The regulation optimizing model, known as REGO, clears the regulation market using regulation offers and the anticipated demand for each hour of the next day. The clearing price, the RCP, and the regulation quantities are determined by 10 PM. To arrive at the clearing price and quantities, the ISO establishes an economic merit order of supply offers. The economic merit of each unit is determined by the sum of (a) the unit's regulation offer price and (b) an estimate of the opportunity cost that the unit would incur to ensure it stands ready to provide regulation within its regulating range.[12] After the RCP is determined, participants can self schedule any time prior to real time. These real-time self schedules are queued at the bottom of the economic merit order and effectively "bump" units at the top of the merit order. The new marginal regulation unit is thereby less costly than indicated by the RCP. However, the RCP does not

[12] As discussed further below, the opportunity cost can arise when the unit is dispatched at a lower quantity than specified in its energy bid so that it is within the regulation-capable range. If it is dispatched at the lower level, it loses the opportunity to sell more energy at the energy clearing price.

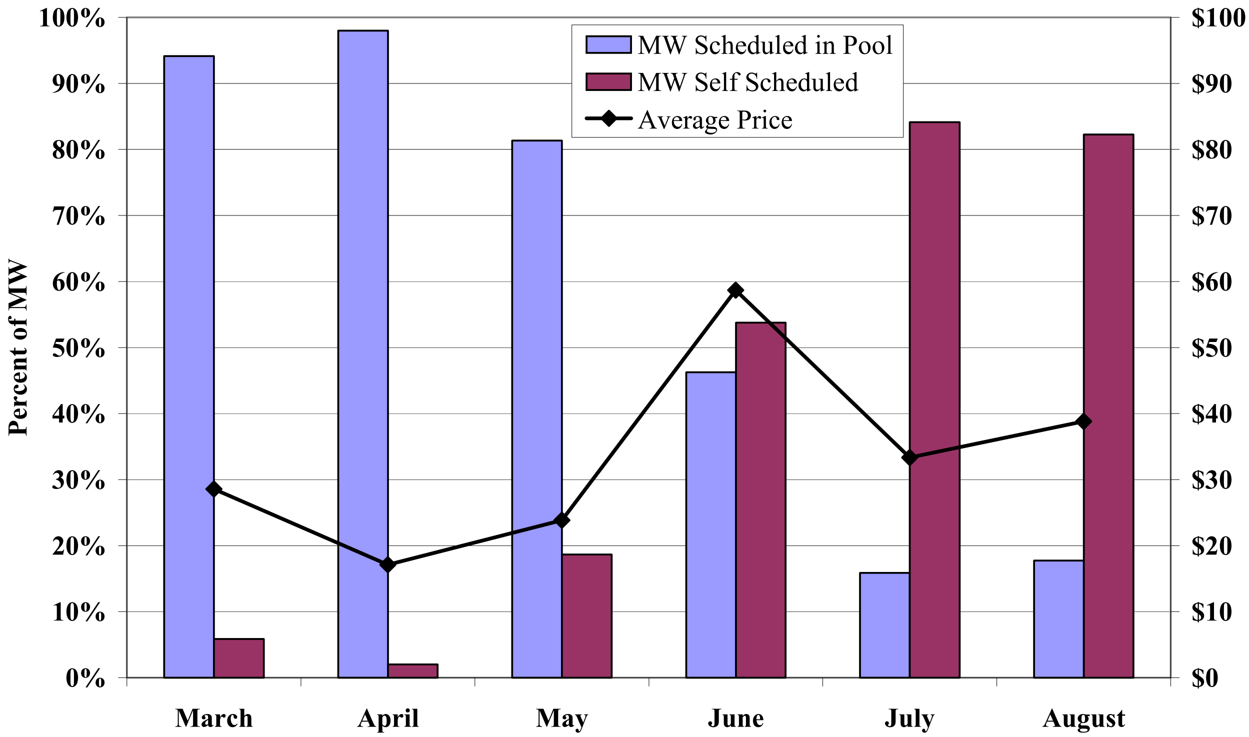
change and units that provide regulation in real-time are paid the RCP. Non-self-scheduled units may earn an additional payment if the RCP is not sufficient to cover losses incurred in the energy market as a result of being dispatched lower than or higher than the unit's optimal energy quantity. Self-scheduled units, because they are supplying regulation voluntarily, do not incur such opportunity costs and are paid only the RCP.

Because the RCP does not change as a result of self schedules, participants have a strong incentive to self-schedule after the market has closed and the price floor has been established. Only participants that expect to incur significant opportunity costs have the incentive to provide regulation through the market rather than via a self schedule. All other suppliers can costlessly induce a higher regulation floor price by withholding resources from the regulation market and then self-scheduling after the market closes.

Figure 30 shows the quantity of regulation that is provided via the market versus the quantity that is self-scheduled for each of the first six months of the SMD market operations. The figure also shows the average RCP during this period. In March and April, less than ten percent of regulation was provided by real-time self schedules. However, this percentage rose rapidly so that by the summer, more than 80 percent of regulation was provided by real-time self schedules.

When large quantities of regulation are self-scheduled in real-time, it leads units that were taken in economic merit order in the day-ahead regulation market to also self schedule in order to avoid being "bumped". While this engenders a sort of competition, it is not efficient because it does not lead to an optimal selection of regulation supply and inflates the RCP. When suppliers are willing to provide more regulation at a given RCP than the ISO is willing to purchase, the RCP is higher than the competitive level.

**Figure 30**
**Average Regulation Schedules and Prices**
March to August 2003



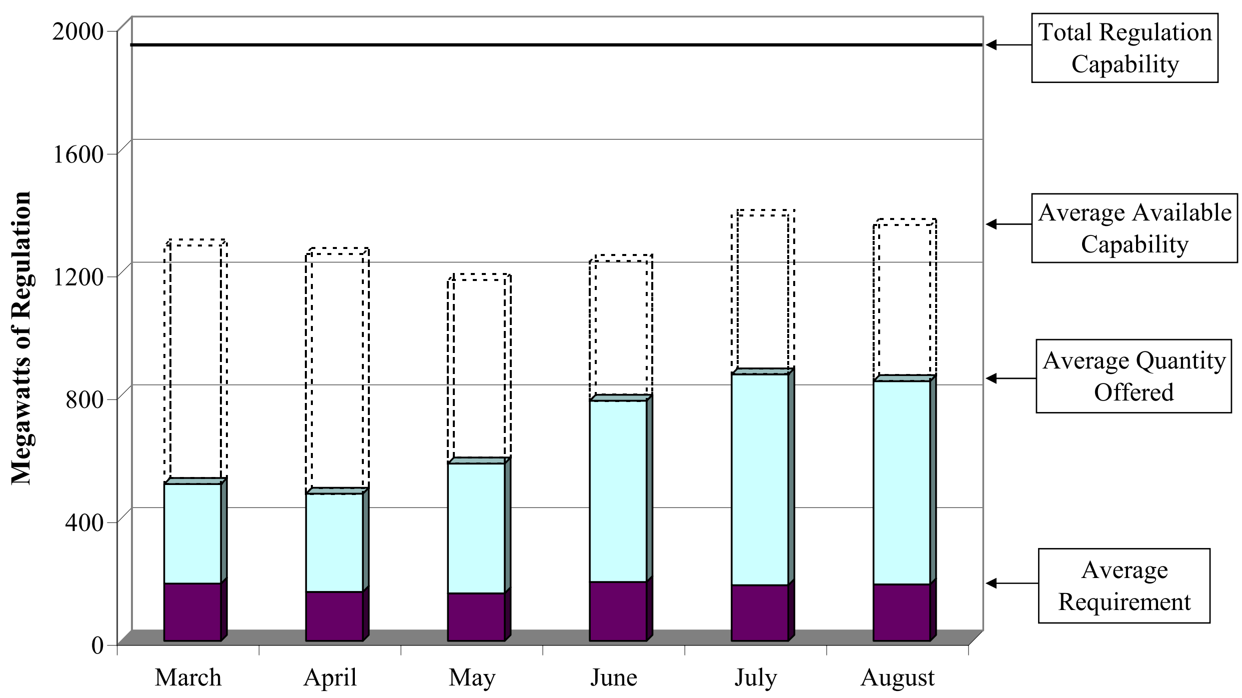

We attribute the rise in self-scheduling that occurred over the six month SMD period to a gradual recognition by the participants of the incentives provided by the current regulation market rules. The current rules provide suppliers with the incentive to withhold capacity from the regulation market and lead to inefficient selection of regulating units. To address these concerns, we recommend that regulation suppliers not be permitted to self schedule after the RCP is established. PJM, who operates a substantially comparable market, has already implemented a similar rule change.

We have discussed this recommendation with the ISO-NE market monitor who had independently reached the same conclusion. We concur with this proposal, which is currently under consideration in the NEPOOL stakeholder committees.

### B. Regulation Market Participation

Competition should be robust in New England's regulation market because in most hours the amount of regulation capability in New England far exceeds the amount required by the ISO. Figure 31 below shows monthly averages of the total quantity of regulation-capable capacity, the available regulation-capable capacity, the regulation-capable capacity offered into the market, and the amount of regulation procured by the ISO. On average, 30 percent of regulation-capable capacity is effectively unavailable to the market. Regulation-capable capacity can be unavailable in a given hour for at least two reasons: (a) the capacity is on a resource that is not quick-start and was not committed in the day-ahead energy market, or (b) the capacity is held on a portion of a resource that was self-scheduled for energy.

**Figure 31**
**Regulation Capability, Offers, and Requirements**
March to August 2003




Naturally, more regulation capacity tends to be available during the high-load portion of the day because more units have been committed and are on-line. This is partly mitigated by the fact that energy self schedules tend to increase during high-load hours and, therefore, the output ranges that are self-scheduled for energy are not available for regulation service. During the summer, approximately 65 percent of available regulation capacity was offered into the market on average, including self-schedules. This was a substantial improvement over March and April when less than half of available regulation capability was offered. At the same time, prices increased from an average of $24 in March through May to an average of $44 in June through August. As higher-cost regulation-capable resources became economically viable, the quantities offered into the market increased.

In the summer of 2003, an average of four times more regulation was offered into the market than was actually procured by the ISO. This limits concerns about market power in the regulation market because demand can easily be supplied without the largest regulation supplier. However, supply may be tight in the regulation market when energy demand is high and the regulation market must compete with the energy market for resources. High energy prices during peak-demand periods can lead resources to incur large opportunity costs when providing regulation service, thereby increasing prices for regulation.

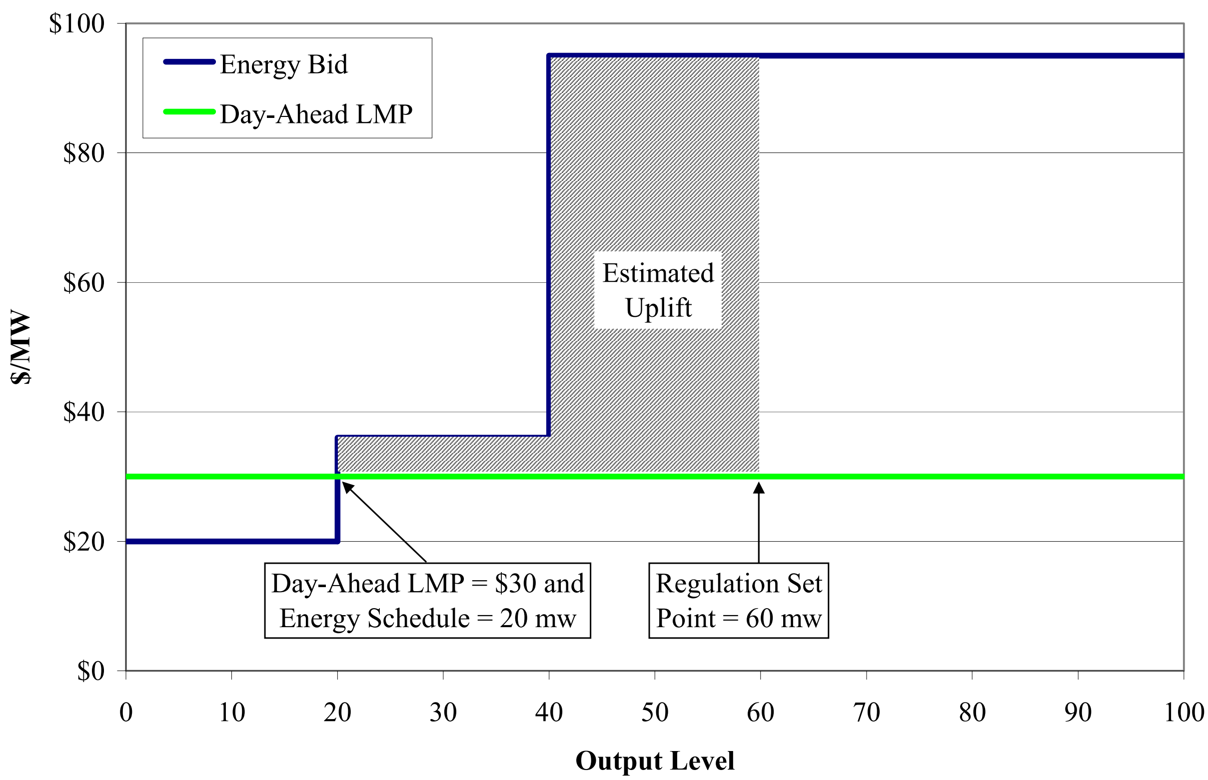
Competition between the regulation market and energy market for capacity is reflected in the opportunity cost segment of a unit's regulation bid. As noted above, the regulation market software, REGO, calculates opportunity costs by estimating the lost revenues or out-of-merit dispatch costs arising from the need to change a unit's energy dispatch level in order for it to provide regulation. Currently, REGO can only accept the entire quantity of regulation offered from a unit. Hence, the adjusted energy schedule, *set point*, must be located so that the resource can regulate up or down (on a symmetric basis) without going outside its operating range. This process prevents REGO from selecting the lowest-cost regulation resources that would minimize the cost of satisfying the ISO's regulation requirements.

An example is helpful in illustrating this point. Consider a unit with an operating range of 20 MW to 100 MW that receives a day-ahead energy schedule of 20 MW as shown in Figure 32. In order to provide any regulation down, the set point must be raised above 20 MW. Suppose the unit offered and was selected to supply 40 MW of regulation. Its set point must be at least 60

MW to enable provision of 40 MW of regulation down without having its output drop below the minimum dispatchable level of 20 MW. Likewise, its set point must also be at most 60 MW in order to enable provision of 40 MW of regulation up without having its output rise above the maximum dispatchable level of 100 MW. In this case, the unit's set point must be set equal to 60 MW.

Because this hypothetical unit has a day-ahead energy schedule of 20 MW, it is forced to produce at 60 MW and can incur costs in the energy market in instances when the energy clearing price is less than the energy bid curve of the unit at its set point of 60 MW. The energy clearing price is assumed to be $30 and the energy bid curve of the unit at 60 MW is assumed to be $95. The area between the energy bid and the day-ahead LMP in the chart below is equal to the uplift that would be incurred if the unit's set point is adjusted up to 60 MW.

**Figure 32**
**Example Calculation of Estimated Opportunity Costs**

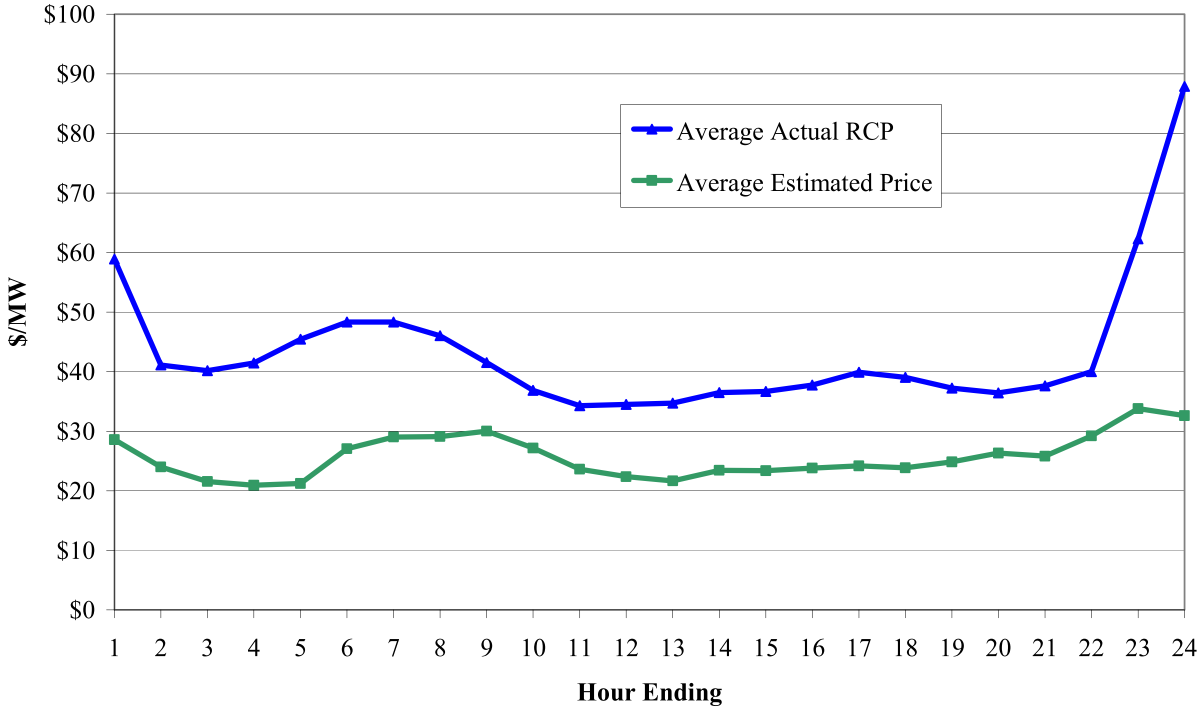


In this case, the uplift is quite moderate up to the 40 MW point of the bid curve. From 20 MW to 40 MW the offer price is $36 ($6 above the clearing price), and therefore creates $120 in uplift ($6 per MW * 20 MW). However, the uplift becomes significantly larger between 40 MW and 60 MW when the bid curve exceeds the energy clearing price by $65 -- total uplift in this range is $1300 ($65 per MW * 20 MW). In this case, it would be far less costly per megawatt for the ISO to accept only 20 MW of regulation for an average of $6 per MW from this unit than to accept the full 40 MW (provided that other units are available to provide regulation at less than $65 per MW). Because, REGO can only accept the full amount of the regulation offer, it is prevented from accepting the lowest-cost quantities of regulation from each resource.

In the same way that the energy markets optimize the energy dispatch levels of all units, the regulation market should optimize the quantities of regulation taken from each resource. Figure 33 below shows an estimate of the price impact from optimizing the use of resources for providing regulation at various hours of the day. To arrive at the estimate of an optimized regulation supply, we used the energy bid curves of each of the regulation units that actually supplied regulation over the summer of 2003. Instead of requiring the entire regulation bid quantity to be accepted, we allowed only a portion of the quantity to be selected when doing so minimized overall cost of providing regulation.

On average, the estimated price is 40 percent lower than the actual price, with the largest impact in high-priced hours. Thus, hour ending 24 showed the largest average benefit, which had the largest number of regulation price spikes (15 hours over $100). This is because price spikes can typically be avoided with a small amount of additional flexibility. Another benefit of optimizing regulation supply is that it will tend to spread the allocation of regulation to a larger number of resources. Because units are limited in how fast they can increase or decrease their output, allocating regulation to a broader array of units will tend to increase the regulation response rates system-wide. Additionally, the effect on the system of any individual regulating unit that is not responding to the regulation signal will be diminished.

**Figure 33**
**Estimated Price Impact from Optimizing Regulation Quantities**
Average Prices by Hour of Day – Summer 2003




## C. Conclusions

While participation in the market for regulation has been more than sufficient to provide inexpensive regulation service, two market design features have led to inefficient procurement and higher prices than would have otherwise prevailed. On the basis of the results in this section, we make two recommendations for changes to the regulation market in the short-term. First, we recommend eliminating the practice of self scheduling after the determination of the RCP because this undermines the competitive incentives of suppliers. Second, we recommend that the ISO examine the feasibility of making enhancements to REGO that would allow it to optimize the quantity of regulation taken from each resource. In the longer term, we recommend the ISO co-optimize the dispatch of resources for energy, reserves, and regulation when it implements its operating reserve markets.