2005 Assessment of the Electricity Markets in New England

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I. Executive Summary

This report assesses the efficiency and competitiveness of New England's wholesale electricity markets during 2005. The current locational wholesale electricity markets began operation on March 1, 2003 and include day-ahead and real-time energy markets, a regulation market, and a forward reserve market. These markets are referred to as Standard Market Design ("SMD"). In addition to these markets, the ISO operates an installed capacity market. The ISO has proposed other ancillary services markets ("ASM"), including real-time operating reserve markets, and other enhancements to the initial SMD markets.

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") that reflect the marginal system cost of serving load at each location on the network. When the market is functioning well, these prices 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.

A. Introduction and Summary of Findings

In addition to providing a summary of market outcomes in 2005, this report includes findings in two primary areas: the competitive performance of the market and the operational efficiency of the markets. The findings in each of these areas are discussed below.

Competitive Performance of the Market

We analyzed the competitive performance of the overall market in New England, as well as a number of constrained areas within the market. Based on the results of these analyses, we find that the markets have performed competitively in 2005. We found little evidence that any suppliers were either economically or physically withholding resources to raise prices in the transmission-constrained areas or in the broader market. However, this report does raise concerns regarding conduct by a supplier in the Boston area that began in late 2004 and was initially identified in last year's report.[1] The local reliability requirements for Boston compel the ISO to commit generation outside of the day-ahead market process. To ensure that these generators receive revenue at least equal to their offer, they may receive Net Commitment Period Compensation payments ("NCPC") in addition to the revenue earned from the market. The supplier's conduct resulted in considerable increases in its NCPC payments and to other suppliers in Boston.

We consulted with the ISO's market monitor regarding this behavior and its proposal to modify the mitigation measure to more effectively address this issue. This proposal was approved by FERC and substantially reduced the impact of this conduct on the market outcomes in 2005. Nonetheless, the conduct still led to substantially increased costs for local reliability commitment in Boston during 2005. These costs have decreased in 2006.

Operational Efficiency of the Markets

In general, the day-ahead and real-time markets have operated efficiently in 2005 with prices that reflected underlying market fundamentals. For example, electricity prices in New England have been strongly correlated with changes in underlying fuel prices as one would expect in a well-functioning market. To maintain reliability in the constrained areas, however, the ISO has continued to commit substantial quantities of additional resources to supplement the market-based commitments in the day-ahead market. This is an issue that is common to all electricity markets and arises when the market requirements do not fully reflect the reliability needs of the system. Additionally, the limited quantities of quick-starting resources in these areas increase the need for these commitments. Therefore, the ISO must commit larger, slower-starting steam and combined-cycle generation to ensure reliability and manage voltage in constrained areas.

This additional online supply in constrained areas substantially reduces the congestion into these areas and generates significant supplemental charges to New England loads that are difficult for

[1] See *2005 Assessment of the Electricity Markets in New England*, Potomac Economics, June 2005. ("2004 Annual Report").

them to hedge (we refer to these charges as "uplift charges"). Therefore, reducing the need for these supplemental commitments should remain a high priority for the ISO. To that end, the ISO has made a number of changes in its market rules and worked with market participants to address the underlying reasons for the supplemental commitments. For example, in late 2004 and early 2005, the ISO worked with participants to install equipment and make other operational changes to improve the ISO's ability to manage voltage in the NEMA/Boston area. These improvements contributed to a sharp reduction in supplemental commitments for voltage support in 2005.

The ISO has also implemented a number of other significant changes, some of which were recommended in our prior assessments of the SMD markets.[2] For example, the commitment process in the day-ahead market was substantially improved in early 2005 to recognize certain transmission constraints in local areas. This enhancement has contributed to improved consistency of congestion management in the day-ahead and real-time market models. However, substantial additional improvement in operation of the market should occur when Phase II of the ASM project is implemented. Phase II will include local reserve requirements in the real-time and forward reserve markets. The introduction of these market requirements will improve the consistency between the market requirements and the system's operating requirements, reducing the need for manual actions by the system operators and improving the market's price signals.

These changes will address the most significant issue regarding the long-run economic signals in the New England markets – the lack of economic signals that fully reflect the local reliability requirements in transmission-constrained areas. These requirements compel the ISO to make supplemental commitments in the constrained areas, which are not reflected in the market prices in New England. These supplemental commitments tend to reduce congestion into the constrained areas and prevent the market prices from fully reflecting the economic value of energy produced and consumed in these areas. The fact that significant reliability requirements are not priced within the New England market framework causes the long-term economic signal in the key constrained areas to be understated, which limits the entry of new resources that are

2 *Six-Month Review of SMD Electricity Markets in New England*, Potomac Economics, February 2004, and 2004 Assessment of the New England Energy Market, Potomac Economics, June, 2005.

needed. These understated price signals have also resulted in a heavy reliance on reliability agreements to ensure that existing generation needed for reliability in these areas remains in operation. Reliability agreements are poor substitutes for efficient, transparent market prices.

In addition to the market enhancements contained in the Phase II ASM project, scheduled to be implemented in the Fall 2006, we continue to recommend that the ISO develop provisions to better coordinate the physical interchange between New York and New England. We have been recommending the development of these provisions for the past four years in both New York and New England. These provisions would facilitate a more seamless market in the Northeast, which would ensure that power is efficiently transmitted to the highest-value locations, achieve substantial economic savings for customers in the region, and improve reliability. They also hold the promise of efficiently utilizing the controllable transmission lines between Connecticut and Long Island, two of the most congested locations in the Northeast.

Other potential improvements to the SMD markets involve 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 along with a summary of the report's findings and conclusions in each area.

B. Energy Prices and Congestion

Energy prices have closely tracked movements in natural gas prices, which were extraordinarily volatile throughout 2005. In January, natural gas prices averaged more than $12 per MMbtu, decreasing during the spring and early summer to $7 per MMbtu. Natural Gas prices rose sharply in the late summer due to the hurricanes that decreased the productive capability in the Gulf Coast region. Prices from September to December ranged from $10 to $15 per MMbtu. The 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.

Prices rose during June, July and August of 2005 as a result of hot summer weather and high demand associated with air conditioning. This is in sharp contrast to 2004 which experienced no substantial seasonal rise in electricity prices due to the particularly mild summer weather.

Energy prices in New England continue to exhibit relatively low levels of congestion, due in part to the continued need to commit supplemental generation in constrained areas. The additional supply online in the constrained areas associated with these commitments serves to reduce imports and congestion into these areas.

Congestion and Financial Transmission Rights

Under SMD, New England has experienced relatively little congestion in historically-constrained areas, including the NEMA/Boston area and Connecticut. In fact, a large portion of the price separation between net exporting regions and net importing regions has been due to transmission losses rather than transmission congestion. For instance, 40 percent of the difference between prices in Maine and NEMA/Boston was due to losses and 60 percent was due to congestion in 2005.

While the overall level of congestion in the New England markets was low, there was a substantial increase in congestion into the Norwalk-Stamford load pocket during 2005. Day-ahead market prices in the Norwalk-Stamford load pocket averaged approximately $20/MWh more than the surrounding areas in Southwest Connecticut. Imports to the Norwalk-Stamford load pocket accounted for approximately one-half of the congestion rents from the day-ahead market throughout New England.

The ISO operates annual and monthly markets for Financial Transmission Rights (FTR). These markets generally functioned well during 2005. The FTR prices determined in the annual auction, which took place prior to 2005, significantly under-estimated the value of congestion in the day-ahead market. However, the monthly auction prices were considerably more accurate than the annual auction prices, likely because they occur closer to the spot markets. This pattern suggests that as market participants observed higher levels of congestion during 2005, particularly in Norwalk-Stamford, they updated their expectations in the monthly auctions. This improvement between the long-term auction and the shorter-term auctions is a positive indicator regarding the liquidity and overall efficiency of the FTR market.

The ISO sold fewer FTRs into the Norwalk-Stamford load pocket than the import-capability of the interface would have allowed during 2005. During peak hours, the average amount of FTRs into Norwalk-Stamford was 536 MW, while the average imports during periods of day-ahead congestion was almost 700 MW. This helps explains why congestion rents from the ISO's spot markets exceeded the payments to FTR holders by $56 million (28 percent) in 2005.

Day-Ahead to Real-Time Price Convergence and Virtual Trading

The energy prices in the day-ahead and real-time markets have converged more closely under SMD in most areas of New England than have the corresponding prices in PJM, the Midwest, or New York. Measured at the New England Hub, New England exhibited a price premium in the day-ahead market of 2.5 percent in 2005. These results are generally consistent with historical patterns in other multi-settlement markets. Buyers can reduce their risk by purchasing power at less volatile day-ahead prices, while some sellers may have additional outage risks when scheduled day-ahead. These factors tend to raise the day-ahead price relative to the expected real-time price, although this is generally mitigated by virtual traders who seek to arbitrage predictable price differences between the two markets. In addition, the cost allocation rules for NCPC costs that allocate significant costs to real-time purchases provide an incentive for loads to pay a premium to buy in the day-ahead market. On a monthly average basis, these costs were as high as $2.75 per MWh during the summer of 2005.

Although day-ahead and real-time prices have generally converged well in New England, the Norwalk-Stamford area exhibited poor convergence in 2005. Norwalk-Stamford consistently exhibited a large day-ahead price premium, which averaged more than 10 percent during 2005. We attribute this outcome primarily to the inconsistencies between the pattern of commitments in the day-ahead and real-time markets. Typically, the generators in the Norwalk-Stamford area are not committed in the day-ahead market, but they are frequently committed by the operators after the day-ahead market for local reliability reasons. This inconsistency has led to substantially more day-ahead congestion than appears in real-time. Several market participants have helped alleviate the day-ahead congestion by scheduling virtual supply, which reduces day-ahead prices in the load pocket. However, they have scheduled insufficient volumes to cause the day-ahead and real-time prices to converge in the Norwalk-Stamford area.

Prior to 2005, virtual schedules were assessed charges for supplemental generator commitments made for local reliability that frequently averaged more than $10 per MWh in Connecticut and NEMA/Boston. These charges reduce the incentive of virtual traders to arbitrage day-ahead and real-time prices, which is particularly important in areas such as Norwalk-Stamford. The ISO's Tariff was changed in March 2005 to allocate the costs of satisfying local 2nd contingency reliability requirements to the network load in the constrained area, rather than to energy traded in the real-time market (including virtual trades). As described above, however, other types of commitment expenses are still allocated to real-time deviations from day-ahead schedules (which includes virtual transactions). These charges create disincentives for virtual trading and hinder day-ahead to real-time price convergence. We make two recommendations in the following sub-section to address these cost allocation issues.

C. Market Operations

This section covers a wide variety of areas related to the operation of the SMD markets, including the market consequences of certain operating procedures and the scheduling actions of participants.

Price Corrections

Price corrections are frequently an indicator of implementation problems or software errors. Considering that SMD was implemented in 2003, the rate of price corrections was relatively low in that year. In 2004 and 2005, the rate of price correction decreased to very low levels. In most months, prices are corrected in less than 0.3 percent of the five-minute intervals.

Load Forecasting

Day-ahead load forecasting is an important determinant of efficient day-ahead commitment. The accuracy of the ISO's forecasts is important because the forecasts are a key input to the ISO's reliability assessments, forecasted transmission limits, and supplemental commitment decisions. They also provide information to market participants for their day-ahead scheduling and bidding.

Although the ISO's load forecasts during the summer of 2005 were less accurate than in previous years, New England still had more accurate day-ahead forecasts than other wholesale markets. The average forecast error for the daily peak load in New England was 2.2 percent in 2005, compared to 1.8 percent in 2004. The forecasted load was higher on average than actual load by 0.7 percent in 2005 versus no significant difference in the previous year. The modest increase in forecast error is likely attributable to the higher weather-related loads in New England in 2005.

Day-ahead Transmission Limits

Imports into a given area are generally limited by the capacity of the transmission interfaces into the area. Any load that cannot be served by imports must be served by local resources within the transmission-constrained area. The forecasted transmission limits used in the day-ahead market help determine the commitment of resources in these areas. We find that the transfer limits used in the day-ahead market are systematically lower than the ones used in the real-time for the transmission interfaces into four key load pockets in New England. Under-forecasting the transfer capability into a load pocket can result in two types of market inefficiency.

- Under-forecasting the transfer limits can lead to excessive day-ahead prices and over-commitment within the load pocket if demand and virtual transactions do not reduce their net purchases in the load pockets. Based on our analysis of day-ahead to real-time price convergence, this has not been a significant issue outside Norwalk-Stamford. Even in the case of Norwalk-Stamford where price convergence was poor, the inconsistencies in transmission limits had a small impact relative to other more significant factors.

- The forecasted transfer limits are used to determine when it is necessary to make supplemental commitments for local reliability in the day-ahead market and the RAA process. Under-forecasting transfer limits will generally lead to over-commitment of resources in the load pockets for local reliability, which tends to distort market outcomes and mute real-time price signals in congested areas.

However, reliability concerns related to unknown factors in the day-ahead timeframe may justify conservative assumptions that would cause the day-ahead limit to be lower than the real-time limit. Therefore, we recommend that the ISO investigate the factors that lead to systematic differences between the day-ahead and real-time transmission limits to identify and eliminate any unjustified differences in the limits.

Supplemental Commitment and Out-of Merit Dispatch

We find substantial quantities of supplemental commitment in both NEMA/Boston and Connecticut. Supplemental commitment for local reliability has increased 44 percent in NEMA/Boston from a daily average of 610 MW in 2004 to a daily average of 880 MW in 2005. Although there were significant reductions in the need for voltage support commitments, there was a dramatic rise in commitments for local 1st and 2nd contingencies. Supplemental commitment for local reliability has increased more than 120 percent outside NEMA/Boston from a daily average of 275 MW in 2004 to 614 MW in 2005. Under peak demand conditions, commitments for local capacity requirements increase substantially, particularly in the NEMA/Boston area. These commitments are necessary, in part, because these areas do not have a large quantity of fast-start resources that can help meet the capacity requirements of the local area while offline.

Supplemental commitments also 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 when running at their EcoMin, they displace the marginal source of energy. This results in lower prices in constrained areas and in the broader New England market as well. Since most of the out-of-merit energy is produced from resources committed supplementally, the changes in out-of-merit energy generally mirror changes in supplemental commitments. Hence, the report finds that out-of-merit energy increased in NEMA/Boston from an average of 233 MW per hour in 2004 to 314 MW per hour in 2005. Out-of-merit dispatch increased outside NEMA/Boston from an average of 217 MW per hour in 2004 to 285 MW per hour in 2005.[3]

Supplemental commitments and out-of-merit energy dispatch create four issues in the New England market.

- They can create inefficiencies in the commitment 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.
- They tend to mute market signals to invest in areas that would benefit the most from additional generation and transmission investment. They also diminish incentives to develop demand response capability.
- They can create incentives for generators frequently committed for reliability to avoid market-based commitment when they would be economic at the day-ahead LMP. This can induce the ISO to commit the resource in the Resource Adequacy Assessment ("RAA") process for local reliability where the generator is paid its bid price in the form of uplift.
- They cause a substantial amount of uplift costs that is difficult for participants to hedge and can be quite volatile, most of which are generated by commitments in Connecticut and NEMA/Boston. The uplift costs associated with these commitments are allocated in a variety of ways based on Tariff requirements. Some of these allocations create inefficient incentives. The report discusses these allocations and recommends improvements.

The ISO has already implemented several changes that should reduce the need for supplemental commitments and improve the economic signals in the constrained areas. The most important change is the improvement in the commitment software and process to recognize transmission limits in the day-ahead market commitment. These limits include the first contingency limits and "proxy 2^{nd} contingency" limits that recognize the 2^{nd} contingency reliability requirements in Connecticut and NEMA/Boston. Day-ahead market operators had previously accounted for these limits by manually adjusting the day-ahead market commitment. Other measures being pursued to minimize reliance on supplemental commitments in load pockets include:

[3] Peak hours

- Enhanced combined cycle unit dispatch process to gain additional unit flexibility and non-spin capability in load pockets;
- New ASM markets to provide better incentives for resources in the load pockets, particularly for new fast-start units.

Additional Recommendations to Improve Market Operations

In order to further reduce the inefficiencies associated with supplemental commitments, we recommend that the ISO:

- Reconsider how NCPC costs associated with supplemental commitments for local 1st contingencies and voltage support commitments are allocated. In particular, we recommend that the ISO consider allocating the costs of voltage support commitments to the network load in the affected area and the costs of 1st contingency transmission constraint commitments (if they can be distinguished from market-wide capacity commitments) to the real-time load in the constrained area. These changes would improve incentives for virtual trading and price-responsive load scheduling in the day-ahead market.
- Evaluate the underlying assumptions in the calculation of the import limits to constrained areas to eliminate any unjustified differences between the day-ahead and real-time limits. This would improve the efficiency of the day-ahead commitment and tighten convergence between day-ahead and real-time market outcomes; and
- Incorporate local reliability commitment criteria currently used in the RAA process into the day-ahead market model. This should improve price convergence and reduce incentives to under-schedule load in the day-ahead market (since the additional supply will be scheduled in the day-ahead market).

D. Regulation Market

In this section of the report, we evaluate the market for regulation. In particular, we evaluate (a) the overall costs of procuring regulation, (b) the market design changes that occurred during 2005 under Phase 1 of the Ancillary Services Market ("ASM"), and (c) the competitiveness of supply offers from regulation providers. Based on this evaluation, we provide several recommendations to improve the performance of the market.

Regulation market expenses averaged $3.5 million during the first nine months of 2005, but rose substantially from October through the end of 2005. Capacity payments were the most consistent portion of total expenses, but rose 84 percent from November to December. The rapid rise in overall costs included increases in:

- Capacity payments as a result of higher regulation clearing prices ("RCPs");
- Lost opportunity payments ("LOC"), which grew by 151 percent from September to October; and
- Mileage payments, which did not exist until October 2005.

Regulation Market Design Changes

Significant changes were made to the regulation market under Phase 1 of the ASM re-design that was implemented on October 1, 2005. Understanding these changes is important for accurately evaluating the increase in regulation costs that occurred in late 2005. One of the most significant changes was that the previous design used a model that minimized system cost, while the new design uses a model that minimizes consumer payments. A main feature of the system cost minimizing approach is that it sets a clearing price based on an *ex ante* estimate of the marginal cost to the system of providing regulation. Lost opportunity cost payments augment the payment of the clearing price to the extent that the clearing price does not cover the ex post calculation of as-bid costs (including lost opportunity costs) of the units selected to provide regulation.

The consumer payment minimizing objective compensates generators based on the regulation price, the actual mileage of the unit, and the opportunity cost of not selling energy. The energy opportunity cost in this case is not reduced to account for net revenues the supplier received from the regulation market. In theory, this approach selects the set of regulation offers that are expected to earn the lowest total payments. In addition to the change in the objective of the market model, two other changes were made in the new regulation market.

First, a mileage payment was added to pay regulation suppliers based on the amount they move when regulating. The payment is equal to 10 percent of the mileage (i.e. the up and down distance measured in MW) times the RCP. Based on historic patterns of regulation deployment, this formula is expected to generate mileage payments that are equal to the capacity payments on average. Second, the RCP is now based on the highest accepted offer price, while it was previously based on the ex ante estimate of the marginal cost of the highest-cost unit accepted.

To minimize the expected payments for regulation, the regulation selector chooses those units with the lowest "rank price". The selection process is iterative with one of the components of the rank price changing from the first to the second iteration as described below. The rank price is comprised of the following five quantities:

(i) *Estimated capacity payment* – In the first iteration of the model, this is the offer price of each unit. The subsequent iterations set this equal to the higher of the offer price and the previous iteration's highest priced accepted offer. Given that each generator's capacity payment is equal to the RCP, this iterative approach is designed to cause each generator's rank price to equal the estimated payment to the generator.

(ii) *Estimated mileage payment* – This is equal to the estimated capacity payment.

(iii) *Estimated lost opportunity cost payment* – This is the estimated opportunity cost from operating at the set point rather than at the most economic dispatch level (given the unit's offer prices and the prevailing LMP).

(iv) *Estimated production cost change* – This is similar to the estimated opportunity cost, but ramp rate limitations are considered in estimating the units' most economic dispatch level.

(v) *The look ahead penalty* – This measures the maximum possible change in the energy offer price within the regulating range relative to the set point. This is included in order to avoid selecting units that would earn large opportunity cost payments if they were to regulate into a range of their energy offer priced at extreme levels.

We have evaluated the period in late 2005 corresponding to the initial operation of the new regulation market, which included analyses of the factors that may have contributed to the increased costs that occurred in this time frame. The results of this evaluation are described below.

Regulation Market Performance and Recommendations

The new regulation market was introduced on October 1, 2005 as part of the Phase 1 Ancillary Services Market project. Regulation costs rose substantially after the introduction of the new regulation market, particularly in December 2005.

We attribute the increase in costs to the following combination of factors. Because these factors were all occurring at the same time, it is difficult to determine the relative contribution of each factor to the increased regulation that occurred in the fourth quarter of 2005.

- Natural gas prices increased substantially and contributed to higher regulation cost. Natural gas prices can contribute increased regulation costs because: a) it may account for some of the increase in regulation offers by the large suppliers, b) it increased some of the estimated LOCs in the regulation selector causing resources with higher offer prices to be selected, and c) it reduced the supply of regulation capable resources in some hours by reducing the commitment of natural gas-fired generation.[4]

- The mileage payment was added, but there was no corresponding adjustment in the offer prices of regulation suppliers. Adding the mileage payment should have roughly doubled the expected stream of payments associated with the RCP (not including LOC payments).[5] This change should have caused suppliers reduce their offer prices. Because this did not occur, regulation market expenses increased. One plausible explanation for the fact that the offer prices did not decrease is inexperience of the suppliers with the new market design.

- There is a bias in the regulation selector that over-weights lost opportunity costs. The source of this bias is that the *estimated production cost* component of the rank price is

4 Higher natural gas prices will increase the estimated lost opportunity costs of a natural gas-fired unit whenever a lower-efficiency gas-fired unit (i.e., a unit with a higher heat rate) is setting energy prices assuming both units are offering energy at their marginal cost.

5 The formula for the mileage payment was designed to cause a typical unit moving an average amount when providing regulation to receive a payment that is equal to its capacity payment.

very similar to the *estimated LOC* component (i.e., it is a redundant component). The only difference between the two is that the estimated production cost component incorporates units' ramp rate limitations in calculating the estimated LOC. The effect of this redundant component is that the market will not always select the offers that will lead to the lowest estimated payments by consumers (the objective of the new market), which can result in higher RCPs. Additionally, we believe the *Look Ahead Penalty* component for some resources is not a good estimate of the potential payments it is intended to represent.

- There was a substantial reduction in the quantities of regulation offers associated with the withdrawal of one of the large regulation suppliers late in the year, which reduced the contestability of the market (i.e., the supply available to enter the market it response to higher regulation prices). We believe the reduced contestability of the market and the incentive effects of the market design issue described above account for some of the increase in offer prices by the large regulation suppliers. These higher offer prices contributed to the higher RCPs and market costs.

Based on our review of the regulation market, we do not believe the market has any fatal design flaws or structural issues that would warrant wholesale changes in the market design or introduction of additional market power mitigation measures in the short-term. However, we have developed the following short-term recommendations to improve the incentives to submit competitive offers and improve the efficiency of the selection of regulation resources.

- We recommend that the *Estimated Production Cost* component be eliminated from the rank price, and

- We also recommend that the ISO evaluate modifications to the calculation of the *Look Ahead Penalty* to allow it to better reflect the ISO's actual LOC cost exposure.

These changes would improve the estimated payments to individual suppliers that are the basis for the selection of the regulating units. The efficiency of the regulation market depends, in large part, on the accuracy of these estimates.

In the long-term, we recommend that the ISO continue to evaluate potential market design changes that would enhance the performance of the regulation market. This may take the form of incremental changes to the current design, or fundamental changes in the design. For example, the ISO should consider day-ahead and real-time regulation markets that are co-optimized with the energy market.

E. Competitive Assessment

This section of the report evaluates the market concentration and competitive performance of the markets operated by the ISO–New England in 2005. Under locational marginal pricing, there may be greater potential for certain participants to exercise market power in geographic markets that are smaller load pockets within the entire ISO-New England region. This evaluation identifies the geographic areas and market conditions that are most susceptible to the exercise of market power by at least one large supplier. We analyze the following areas:

- All of New England;
- All of Connecticut;
- Norwalk-Stamford, which is in Connecticut; and
- NEMA/Boston.

The first part of our assessment evaluates each geographic market using a pivotal supplier analysis to determine the demand conditions under which a supplier may have market power. We find that the largest suppliers in Norwalk-Stamford, Middletown, and NEMA/Boston are pivotal in a large number of hours. However, these areas contain large amounts of nuclear capacity and capacity covered under reliability agreements that significantly mitigate the incentives to exercise market power. After taking the effects on incentives of nuclear capacity and reliability agreements into account, the areas where market power was the greatest concern were: (i) Norwalk-Stamford, where the only supplier is pivotal in 28 percent of all hours and whose resources are not covered by reliability agreements, (ii) NEMA/Boston, where the largest supplier is pivotal in 14 percent of all hours and (iii) all of New England, where a supplier is pivotal in 8 percent of all hours. However, our analysis suggests that once the reliability agreements expire, market power will be a more significant concern in other areas in Connecticut outside Norwalk-Stamford.

The second part of this assessment examines market participant behavior to determine whether it was consistent with the profitable exercise of market power. We analyze the market for potential economic and physical withholding and find little evidence of behavior that is consistent with the exercise of market power. Congestion was relatively mild outside Norwalk-Stamford during 2005 due to substantial amounts of supplemental commitment. Strategic withholding is likely to be a bigger concern in the future if there is less excess commitment in local areas. Thus, we recommend that the ISO continue to monitor structural and behavioral market power indicators.

While there is no substantial evidence that suppliers exercised market power by raising clearing prices, suppliers can also exercise market power by inflating the guarantee payments (i.e., NCPC payments). This is generally a concern when there is only one supplier that has the resources needed to satisfy specific local reliability requirements. Such a supplier faces pay-as-bid incentives and if they increase their offer prices by more than they would in a competitive market, one may conclude that they are exercising local market power.

Based on our review of the commitment patterns, offers, and uplift payments made in the NEMA/Boston area, we conclude that an exercise of local market power began in late 2004 that continued through most of 2005. This was detected when it began occurring. To improve the effectiveness of the market power mitigation measures, the ISO filed for a change in the reference price calculation methodology that was approved by FERC and helped reduce the exposure of the market to the costs of this conduct. Even after this improvement, the conduct resulted in more supplemental commitments for local reliability and correspondingly higher uplift costs through the end of 2005. Expanded application of reliability agreements for resources in the area has substantially eliminated this conduct in 2006.

Conclusion

This report concludes that the SMD markets have performed competitively in 2005. The report identifies some major changes to the SMD markets that will increase their efficiency and improve the long-term economic signals they provide to govern investment and retirement decisions. The most important changes in the near-term involve the introduction of real-time locational operating reserve markets that will be jointly-optimized with the energy markets and the implementation of locational forward reserve requirements. Both of these changes are components of the Phase II ASM project.

The report also recommends a number of additional changes to market rules and procedures, including the development of a market-based process to optimize the net interchange between New England and New York, as well as other changes related to supplemental generator commitments. Although these recommendations are important, the implementation of the Phase II ASM markets should remain the highest priority.

II. Prices and Market Outcomes

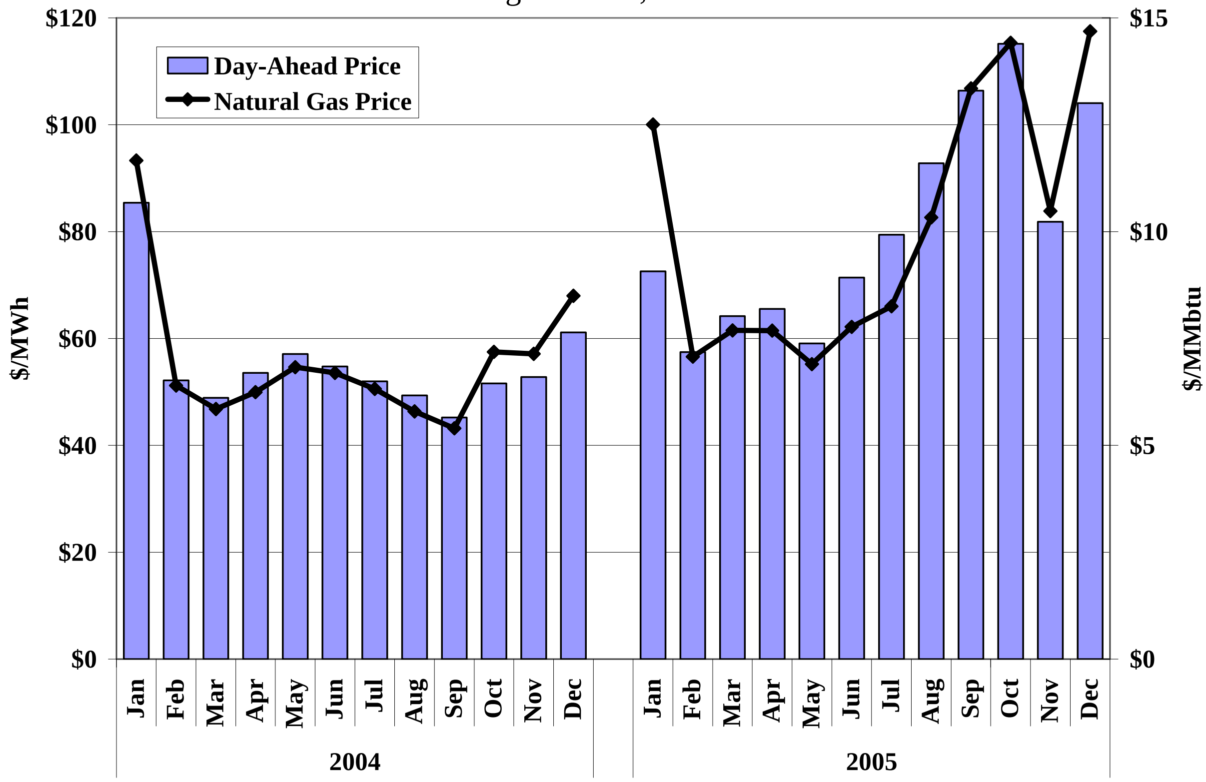
In this section, we review trends in prices that relate to the performance of the New England wholesale market during 2005. This includes analyses of overall price trends, price convergence between the day-ahead and real-time markets, and transmission congestion.

A. Price Trends

Our first analysis examines trends in day-ahead prices at the New England Hub during 2004 and 2005. The New England Hub is located at the geographic center of New England and is an average of prices at 32 individual pricing nodes. This hub price has been developed and published by the ISO to disseminate price information that will facilitate bilateral contracting.

Figure 1 shows the load-weighted average price at the New England Hub in the day-ahead market for each month in 2004 and 2005. The figure also shows the average price of natural gas which should be a key driver of electricity prices if the market is operating competitively. This is true because natural gas-fired generating units set electricity prices in a large share of the hours and fuel costs constitute a large share of most generators' marginal production cost. Natural gas-fired generation represents 38 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 base load nuclear, coal, and hydroelectric generating units. These lower cost resources are frequently fully utilized, causing natural gas-fired resources to be dispatched and set the market clearing price. Therefore, electricity prices should be highly correlated with natural gas prices, which is confirmed by the results in Figure 1.

Figure 1
Monthly Average Day-Ahead Prices and Natural Gas Prices
New England Hub, 2004 & 2005

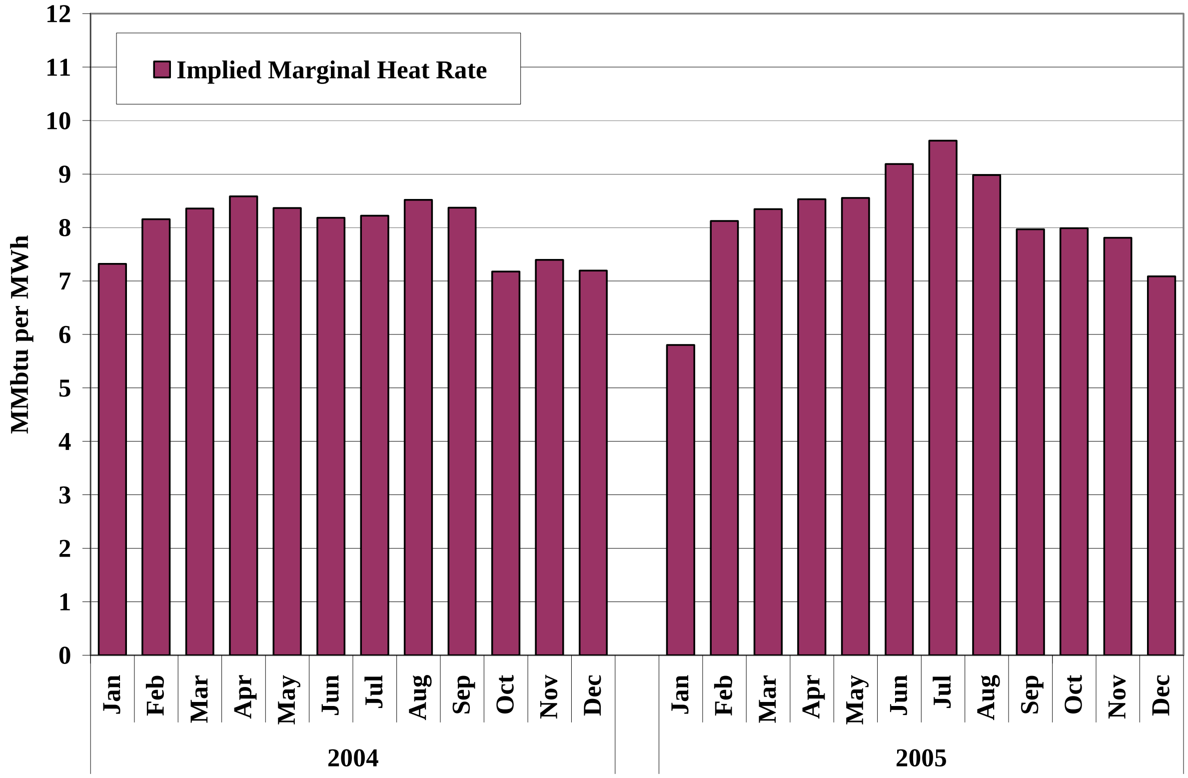


Note: Monthly average prices are load-weighted.

Natural gas price fluctuations were the primary driver of fluctuations in electricity prices in 2004 and 2005. Natural gas price spikes led to elevated electricity prices in January 2004, January 2005, and during the second half of 2005 after the loss of production in the Gulf Coast region due to the hurricanes. Electricity prices rose more sharply than natural gas prices during the summer 2005. Hotter weather conditions than normal led to higher peak load levels in 2005 than in 2004 when summer weather conditions were relatively mild.

To identify changes in electricity prices that are not related to the fluctuations in natural gas prices, Figure 2 shows the marginal heat rate that would be implied if natural gas resources were always on the margin. The *Implied Marginal Heat Rate* is equal to the electricity price divided by the natural gas price as measured in MMbtu/MWh. Thus, if the electricity price is $63/MWh and the natural gas price is $7/MMbtu, this would imply that a 9.0 MMbtu/MWh generator is on the margin. Figure 2 shows the monthly average implied marginal heat rate for the New England Hub in each month during 2004 and 2005.

Figure 2
Monthly Average Implied Marginal Heat Rate
Based on Day-ahead Prices at New England Hub
2004 & 2005



Note: Monthly average prices are load-weighted.

With the exception of January and the summer months, the implied heat rates were comparable between 2004 and 2005. Implied heat rates dropped significantly during January 2005 when natural gas prices were at extreme levels, indicating that there were a large number of hours when either natural gas-fired units were not on the margin, or they were running but not setting energy prices. This figure also shows that the implied marginal heat rates were higher during the summer months in 2005, revealing the effect of the hotter weather and higher load conditions that occurred during the summer. Although it is also possible that economic or physical withholding could contribute to the higher prices the competitive assessment presented later in this report does not reveal evidence of physical or economic withholding.

B. Prices in Transmission Constrained Areas

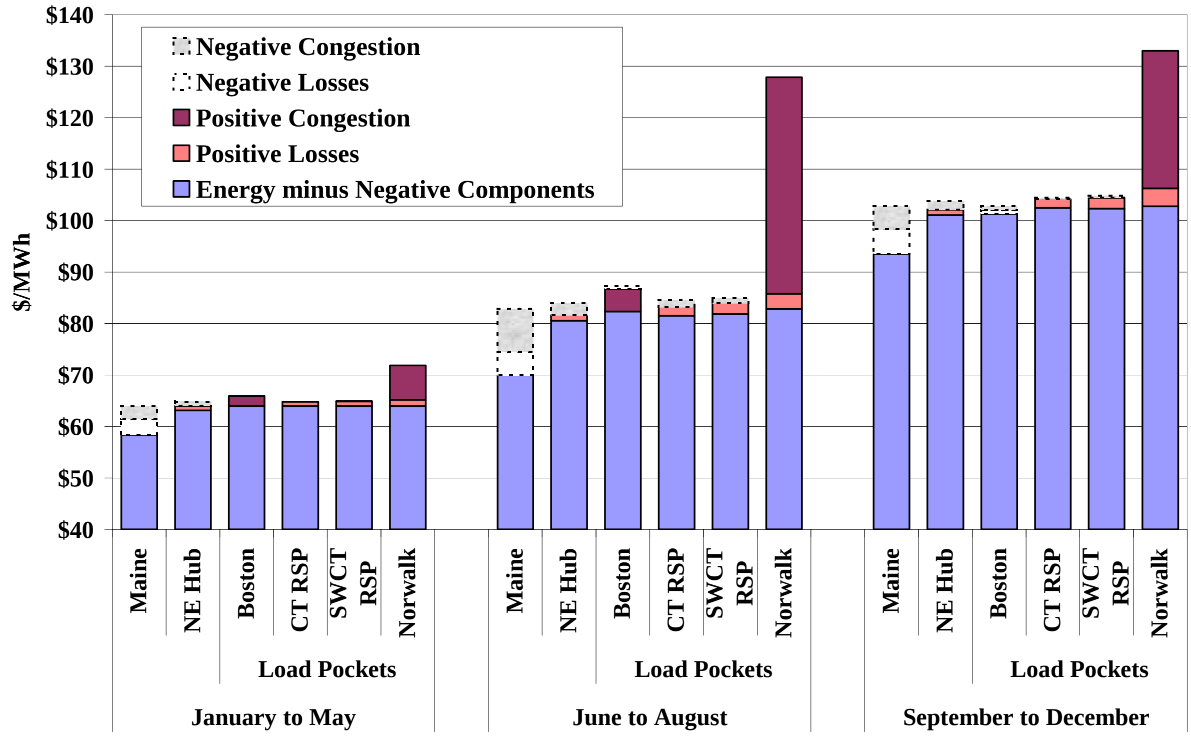
Historically, there have been significant transmission limitations between net-exporting and net-importing regions in New England. For instance, exports from Maine to the south are frequently limited by transmission constraints. Likewise, Connecticut and NEMA/Boston are sometimes unable to import enough to satisfy demand without dispatching expensive local generation. Standard Market Design ("SMD") was implemented in 2003 to help manage these transmission constraints in an efficient manner through energy markets that produce locational marginal prices ("LMPs"). In LMP markets, variation in prices between locations reflects the marginal value of transmission losses and congestion.

Losses occur whenever power flows across the transmission network. Losses are greater when power is transferred over long distances and at lower voltages. The rate of transmission losses increases as flows increase across a particular transmission facility. Transmission congestion arises 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 and their output transmitted to the locations where it should be consumed. When congestion arises, LMP markets establishes 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 load at some locations to avoid overloading transmission facilities. This will result in higher spot prices at these "constrained locations" than would occur in the absence of congestion.

Just as the transmission capacity is limited, requiring higher cost generation to operate in constrained areas, there are certain areas that require additional operating reserves to maintain reliability. After the implementation of real-time reserves markets under Phase II of the ASM project, LMPs will reflect the interaction between reserve and energy when conditions are tight. We analyzed the differences in energy prices between several important locations during the study period. Figure 3 shows the components of average day-ahead LMPs. The effects of congestion and losses are shown for (i) the Maine load zone, (ii) New England Hub, (iii) NEMA/Boston, (iv) the Connecticut regional system planning ("RSP") sub-area, which excludes

Southwest Connecticut, (v) Southwest Connecticut RSP, which excludes Norwalk-Stamford, and (vi) Norwalk-Stamford. For each location, the average LMP is broken into the energy, losses, and congestion components.

Figure 3
Average Day-ahead Prices by Location



Note: Monthly average prices are load-weighted.

The average congestion and loss components shown in Figure 3 are measured relative to an hourly reference price, which is the load-weighted average price in New England. When congestion and/or losses reduce the price relative to the reference, the impact is shown with an empty bar. Alternatively, increases associated with congestion and losses are shown with solid bars. Thus, in Maine, prices are lower than the New England average due to losses and congestion. In the Connecticut RSP sub-area and Southwest Connecticut RSP the price associated with losses has been larger in magnitude than the price of congestion. This reflects the low levels of congestion that have prevailed since the implementation of SMD.

The export limits from northern New England and the import limit into Norwalk-Stamford accounted for most of the congestion in New England during 2005. The average congestion component of Norwalk-Stamford prices was significant in the day-ahead market throughout 2005, rising as high as $42.08/MWh during the summer of 2005. The Norwalk-Stamford transmission limit accounted for approximately one-half of the net congestion revenue in 2005, while the export limits from northern New England accounted for approximately one-fourth of the congestion revenue.

C. 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 markets exhibit efficient arbitrage between the day-ahead and real-time markets. Such arbitrage is essential for ensuring that the commitment of generation through the day-ahead market is efficient. For example, if prices are consistently lower in the day-ahead market than the market fundamentals would dictate, generation will be less willing to be scheduled in the day-ahead market.

The day-ahead market allows participants to make forward purchases and sales of power for delivery in the real time. Small day-ahead price premiums occur frequently in multi-settlement markets (i.e., markets with centralized day-ahead and real-time settlements), because of 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 in the day-ahead market. However, a predictable day-ahead price premium encourages virtual traders to schedule virtual supply (i.e. to sell short at the day-ahead price and buy back at the real-time price). This response puts downward pressure on day-ahead prices and should limit the size of the average day-ahead premium.[6]

6 Under some conditions, rational traders can cause the real-time price to be higher than the day-ahead price. See Bessembinder, H., and Lemmon, M, *Equilibrium Pricing and Optimal Hedging in Electricity Forward Markets*. Journal of Finance 57 (June 2002): 1347-82.

We evaluated average day-ahead and real-time prices at twelve locations, including the New England Hub, the eight load zones, and three sub-areas within Connecticut. 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. The average price difference shows whether prices over the entire period were higher in the day-ahead or real-time market. The average of the absolute value of the hourly price differences shows the size of the hourly differences between the day-ahead and real-time prices. This can be an important aspect of the price convergence between the two markets. For example, if the day-ahead price is $100 higher in half of the hours and $100 lower in the other half of the hours, the average difference would be zero while the average of the absolute value of the hourly difference would be $100 per MWh. One could conclude that the markets exhibit poor convergence in this example, notwithstanding the simple average difference of zero. These values for these two measures are shown in Table 1.

Table 1
Average Day-Ahead and Real-Time Price Differences
January to December, 2005

	Average Clearing Price			Average of Hourly
	Day-Ahead	Real-Time	Difference	Absolute Price Difference
New England Hub	$81.36	$79.70	$1.65	$13.36
Load Zones:				
Maine	$73.03	$72.86	$0.18	$11.85
New Hampshire	$77.85	$77.42	$0.43	$12.41
Vermont	$81.70	$80.73	$0.97	$13.48
WC Mass	$81.54	$80.22	$1.32	$13.36
Rhode Island	$78.73	$77.32	$1.41	$12.93
SE Mass	$78.62	$77.24	$1.39	$12.91
NE Mass/Boston	$83.26	$80.58	$2.67	$16.93
Connecticut	$86.80	$84.15	$2.65	$15.52
Connecticut SubAreas:				
CT (outside SWCT)	$82.76	$81.18	$1.58	$14.26
SWCT (outside Norwalk)	$83.10	$82.26	$0.85	$14.83
Norwalk-Stamford	$107.46	$97.31	$10.15	$27.74

Note: Monthly average prices are load-weighted.

Based on these results, we conclude that there was relatively efficient convergence between the day-ahead and real-time price in most regions of New England. Outside of the load pockets of All Connecticut and NEMA/Boston, the average day-ahead prices were $0.18 to $1.65/MWh higher than average real-time prices. A slight premium in the day-ahead market is generally consistent with the results of other multi-settlement markets in the Northeast and with expectations based on the discussion of the risk factors above. However, the table shows that day-ahead prices exceeded real-time prices by a modest amount in NEMA/Boston and by a large margin in Norwalk-Stamford. A number of factors explain why this unusual pattern began in 2005 in the Norwalk-Stamford load pocket. These are analyzed in detail in Section IV.C.

Table 1 also shows the average absolute hourly difference between day-ahead and real-time prices, which ranged from $11.85 to $16.93 per MWh outside Norwalk-Stamford. As shown later in this section, this is on the lower end of comparable statistics for the New York, PJM, and Midwest markets. Thus, market participants in New England have effectively arbitraged the day-ahead and real-time markets in most areas. However, this conclusion is tempered by the fact there have been few price spikes outside of Norwalk-Stamford, which has made prices in New England less volatile than historic prices. Tighter price convergence is generally expected under conditions of low price volatility.

ISO New England instituted day-ahead and real-time LMP markets in March 2003. Over time, market participants gain experience that should improve their ability to forecast real-time conditions. Improved foresight should lead to better convergence between day-ahead and real-time prices. Table 2 compares day-ahead and real-time price statistics during 2004 and 2005 to assess whether price convergence has improved.

Table 2
Average Day-Ahead and Real-Time Price Differences
January to December, 2004 & 2005

	Real-Time Clearing Price		Day-Ahead - Real-Time Price Difference				Hourly Absolute Price Difference			
	2004	2005	2004		2005		2004		2005	
New England Hub	$54.29	$79.70	$1.42	2.6%	$1.65	2.1%	$8.72	16.1%	$13.36	16.8%
Load Zones:										
Maine	$49.53	$72.86	$0.71	1.4%	$0.18	0.2%	$7.48	15.1%	$11.85	16.3%
New Hampshire	$52.80	$77.42	$1.17	2.2%	$0.43	0.6%	$8.25	15.6%	$12.41	16.0%
Vermont	$54.44	$80.73	$1.46	2.7%	$0.97	1.2%	$8.70	16.0%	$13.48	16.7%
WC Mass	$54.53	$80.22	$1.33	2.4%	$1.32	1.6%	$8.73	16.0%	$13.36	16.7%
Rhode Island	$53.30	$77.32	$1.45	2.7%	$1.41	1.8%	$8.54	16.0%	$12.93	16.7%
SE Mass	$52.80	$77.24	$1.45	2.7%	$1.39	1.8%	$8.42	15.9%	$12.91	16.7%
NE Mass/Boston	$53.62	$80.58	$1.84	3.4%	$2.67	3.3%	$9.10	17.0%	$16.93	21.0%
All Connecticut	$55.14	$84.15	$1.61	2.9%	$2.65	3.2%	$9.49	17.2%	$15.52	18.4%
Connecticut SubAreas:										
CT RSP (excl. SWCT)	$54.64	$81.18	$1.17	2.1%	$1.58	1.9%	$8.92	16.3%	$14.26	17.6%
SWCT RSP (excl. Norwalk)	$54.65	$82.26	$1.57	2.9%	$0.85	1.0%	$9.11	16.7%	$14.83	18.0%
Norwalk-Stamford	$57.81	$97.31	$3.11	5.4%	$10.15	10.4%	$13.97	24.2%	$27.74	28.5%

Note: Monthly average prices are load-weighted.

For the New England Hub, Table 2 shows that real-time prices were approximately 47 percent higher in 2005 than in 2004. Outside NEMA/Boston and Norwalk-Stamford, day-ahead premiums actually decreased as a percentage of real-time prices. In NEMA/Boston, the day-ahead premium remained close to three percent the real-time price in 2005, while the premium in Norwalk-Stamford nearly doubled from 5.4 to 10.4 percent in 2004. The reasons for this dramatic increase in the day-ahead premium are related to the substantial quantities of supplemental commitments made in the load pocket after the day-ahead market, which reduces real-time prices. These issues are evaluated in detail in Section V.C.

Although a day-ahead price premium can be expected under most conditions, the size of the premium is likely affected by certain aspects of settlement rules. There are several types of costs incurred by the ISO–New England in the process of operating the system that are “uplifted” to load. Since allocations of these “uplift costs” to day-ahead scheduled load are smaller than allocations to load that is not scheduled day-ahead, uplift charges are higher for load served in the real-time market. Thus, the day-ahead price premium is at least partly the result of charging less uplift to energy purchased at the day-ahead price. These uplift charges are addressed in greater detail in Section IV.F. of this report.

Table 2 shows that the average hourly absolute price difference was comparable between 2004 and 2005 as a percentage of real-time prices for most areas of New England. For instance, at the New England Hub, this average hourly absolute price difference was 16 percent of the real-time price in 2004 and 17 percent in 2005. Norwalk-Stamford had a considerably larger absolute difference in 2005 than other areas, primarily due to the large systematic differences between day-ahead and real-time prices in that area.

We further evaluated day-ahead and real-time price convergence by comparing the average price differences and the average absolute hourly price differences in New England to those in New York, PJM, and the Midwest ISO. Table 3 shows this comparison for several locations within each market.

Table 3
Day-Ahead and Real-Time Price Convergence
New England Compared to Adjacent Regions, 2005

	Average Price Difference - Day-Ahead minus Real-Time	**Average of Hourly Absolute Price Difference**
New England ISO:		
Maine	$0.18	$11.85
New England Hub	$1.65	$13.36
Norwalk SubArea	$10.15	$27.74
New York ISO:		
West Zone	$1.61	$16.08
Hudson Valley	-$0.36	$22.07
New York City	-$4.90	$28.20
PJM:		
N. Illinois Hub	$0.40	$12.68
AEP	$0.48	$12.68
Eastern Hub	$0.72	$20.31
Midwest RTO:		
Minnesota Hub	$3.19	$20.98
Cinergy Hub	$1.59	$15.35
WUMS Area	$2.36	$21.91

Note: Monthly average prices are load-weighted. The two-settlement LMP market began in the Midwest on April 1, 2005. Therefore, Midwest price statistics are shown for April to December, 2005.

The locations shown in Table 3 were intended to include a variety of export-constrained areas, import-constrained areas, and central market locations. As discussed above, areas in New England outside Norwalk-Stamford exhibited small day-ahead premiums and good hourly convergence, although this is partly attributable to the lack of price volatility. Convergence was very poor in the Norwalk sub-area. The reasons for this poor convergence are discussed in detail in Section V.C. In summary, it is primarily due to the fact that most physical supply in Norwalk-Stamford is committed after the day-ahead market closes, leading to inconsistencies between day-ahead and real-time supplies during periods of congestion.

The table shows that New York City, the most transmission constrained area in New York, also exhibited poor average price convergence and relatively high average absolute price differences, although the reasons are different than those that explain the divergence in Norwalk-Stamford. The New York wholesale market experienced high levels of real-time transmission congestion and real-time price volatility during shortage conditions in 2005. Participants in New York did not accurately anticipate the real-time price spikes during shortages, perhaps due to the fact that the New York ISO introduced new real-time markets in February 2005 that included a new methodology for pricing energy and ancillary services during shortages.

PJM exhibited good price convergence with average day-ahead and real-time prices being relatively close. The average hourly price difference was low throughout PJM. The Eastern Hub, the most import-constrained location shown for PJM, did not converge as well as other PJM areas.

In the Midwest, the Cinergy Hub (a well recognized and liquid trading hub), exhibited good convergence while the transmission-constrained areas did not converge as well. The Minnesota Hub experienced a significant number of *negative* real-time price spikes due to a lack of dispatch flexibility available to manage congestion from Minnesota into the Wisconsin area ("WUMS"). The difficulty of predicting negative price events led to poorer convergence and a significant day-ahead premium. Price convergence in the import-constrained WUMS area was comparable to the import-constrained areas in other markets.

III. Transmission Congestion and Financial Transmission Rights

Setting efficient energy prices that reflect the economic consequences of all binding transmission constraints is one of the most important functions of LMP markets. These prices guide the short-term dispatch of generation 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 focus 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. A price difference due to congestion 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.[7]

A participant may hedge congestion charges in the day-ahead market by holding Financial Transmission Rights ("FTRs"). An FTR entitles a participant to payments corresponding to the congestion-induced difference in prices between two locations in a defined direction. For example, a participant that holds 150 MW of FTRs from point A to zone B is entitled to 150 times the locational energy price at zone B less the price at point A (a negative value means the participant must pay) assuming no losses. Hence, 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 includes only 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

7 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.

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.

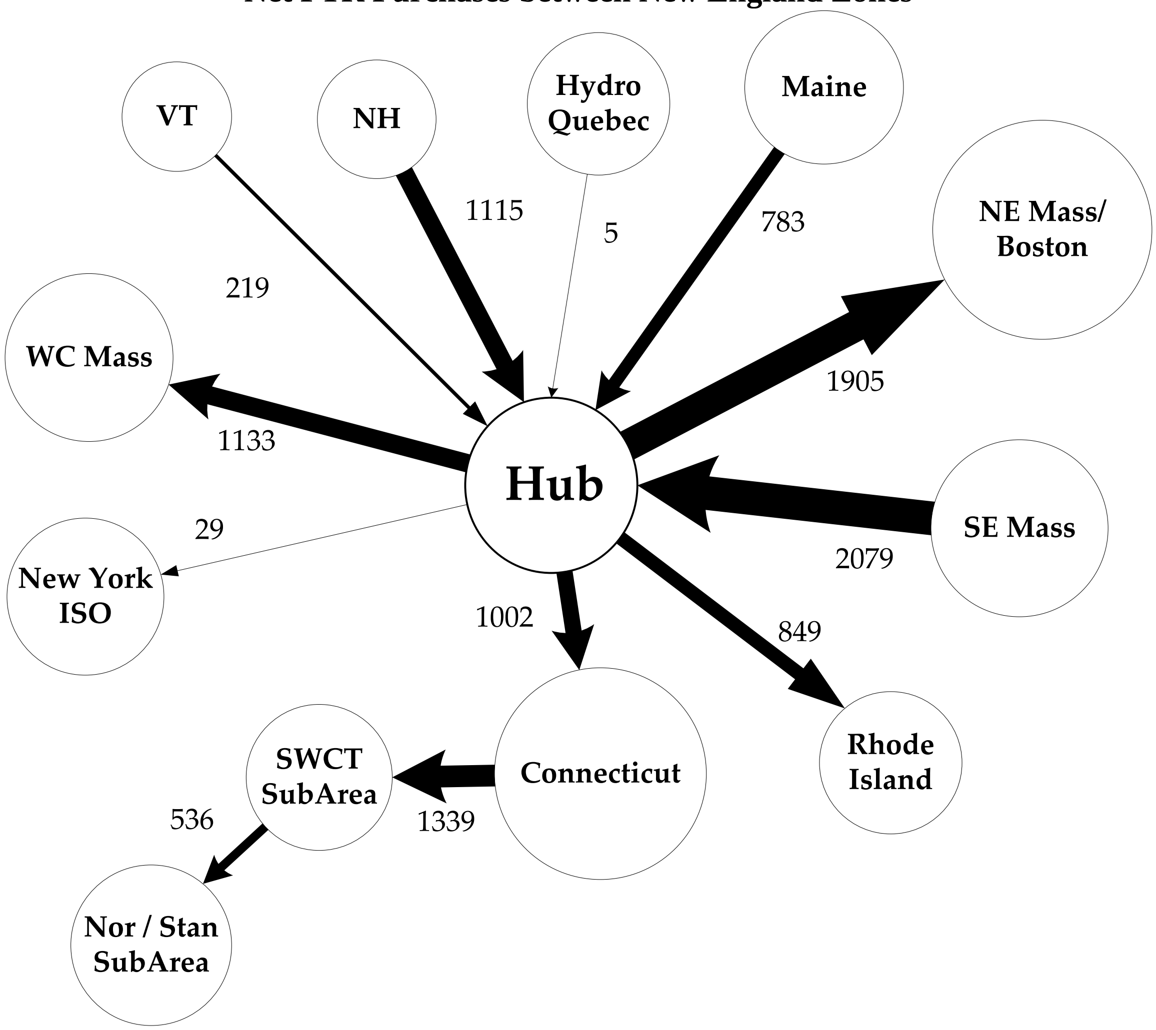
Likewise, settlement of congestion costs in the real-time market is related only to deviations from the day-ahead schedules. Participants with day-ahead schedules do not pay real-time congestion charges related to their scheduled quantities. Because the real-time spot market is a balancing mechanism for day-ahead schedules, net congestion charges should be zero in real time as long as the transmission limits and external loop flows have not changed from those assumed in the day-ahead market. In other words, any congestion charge to a real-time purchase would be offset by a payment to a real-time sale. This would not be the case if the transmission limits or other modeling inputs in the day-ahead market were different than the inputs to the real-time market. Inconsistencies in limits or other modeling inputs 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 associated with the location of loads and generation.

In 2005, the ISO auctioned FTRs with one-month and twelve-month terms. The longer-term FTRs allow market participants greater certainty by locking-in congestion hedges further in advance. Currently, the ISO releases 50 percent of the transmission capability of the system in the long term auction. All but 5 percent of the capability is made available in the one-month auction. Our first analysis in this subsection calculates the net purchases of inter-zonal FTRs for each of the eight New England Zones, Southwest Connecticut, and Norwalk-Stamford and is shown in Figure 4. The net purchases from the twelve-month auction are combined with the quantities from the one-month auction in the figure.

Figure 4
Net FTR Purchases between New England Zones

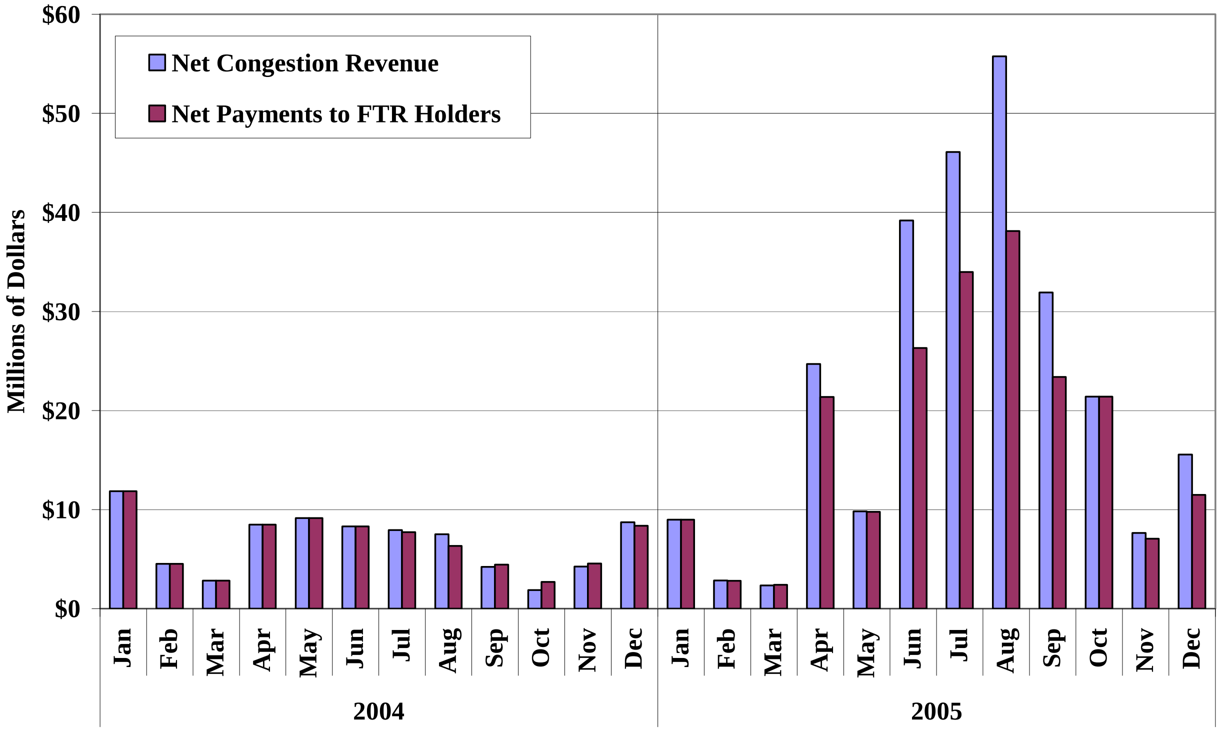


To simplify Figure 4, we show all of the FTR purchases for each zone (except the two sub-zones) relative to the New England Hub rather than showing the actual sources and sinks. Since FTRs have the properties of geometric vectors, an FTR between any two zones is equivalent to the FTR from the first zone to the hub plus the 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 4 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). Sub-areas nested within larger regions are shown relative to the larger region. Hence, Norwalk-Stamford is shown relative to Southwest Connecticut where it is wholly contained and Southwest Connecticut is shown relative to Connecticut. Thus, an FTR from Maine to Norwalk-Stamford would be broken into four pieces in the figure above: from Maine to the Hub, from the Hub to Connecticut, from Connecticut through Southwest Connecticut, and from Southwest Connecticut to Norwalk-Stamford.

The patterns shown in Figure 4 are generally consistent with expectations. Maine and 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/Boston and Connecticut have been net sinks for the FTRs. This is also generally consistent with historic power flows into these areas.

The next analysis shows the total obligations to FTR holders and the day-ahead congestion revenue collected by ISO-NE to satisfy those obligations. Figure 5 summarizes the total payment to FTRs and the net congestion revenue during 2004 and 2005. As discussed above, the value of an FTR from point A to point B in a particular hour is based on the size of the FTR in megawatts times the difference in congestion prices between the two points. Congestion revenue is generated in the day-ahead market whenever there is a binding transmission constraint. The congestion revenue generated from the constraint is equal to the megawatts of power flow across the interface times the shadow price (i.e., the marginal economic value) of the interface.

Figure 5
Summary of Congestion Revenue and Payments to FTR Holders
January to December, 2004 & 2005



The first conclusion that can be drawn from the analysis is that net congestion revenue and net payments to FTR holders were much greater in 2005 than in 2004, particularly during the summer months. Net congestion revenue increased from $80 million in 2004 to $266 million in 2005. Likewise, net payments to FTR holders increased from $79 million in 2004 to $207 million in 2005. Because there have not been significant increases in the capability of the transmission system, the increases in congestion are attributable to the increased frequency and value of the congestion over particular paths in 2005. The patterns of congestion in 2005 are evaluated in greater detail in the following subsection.

While net payments to FTR holders were relatively consistent with net congestion revenues in 2004, congestion revenues were considerably higher than FTR payments in 2005. In general, this occurs when the capability of the transmission system exceeds the capability defined by the total portfolio of FTRs held by participants. For example, if the transmissions system could accommodate 800 MW of flows between two points and a net amount of only 600 MW of FTRs were sold from one to the other, we would expect net congestion revenues to exceed payments to FTR holders by approximately 200 MW times the difference in congestion components between the two points. In this case, a substantial portion of this excess can be attributed to the FTR quantities sold into the Norwalk-Stamford area. As shown above, 536 MW of FTRs were sold into this area while the average limit on the interface into this area in the day-ahead market was 770 MW. Because this was the most congested interface in 2005, it resulted in significant excess day-ahead congestion revenue.

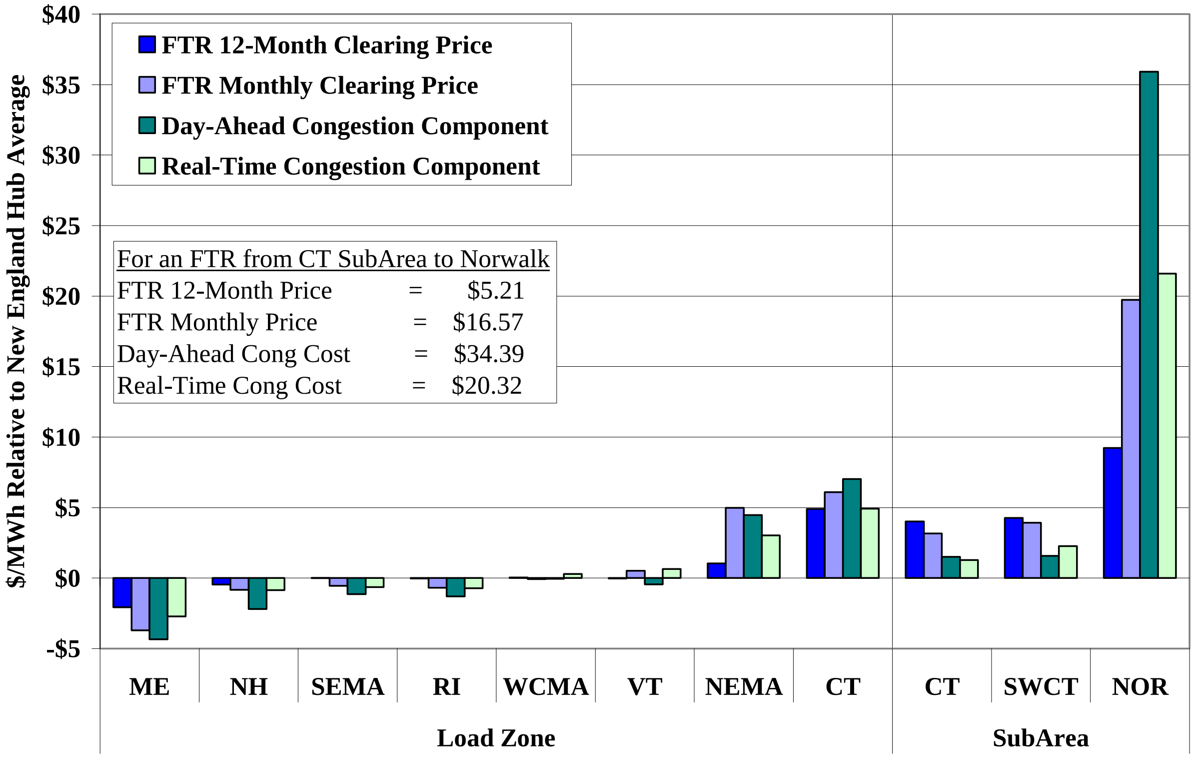
In contrast, FTRs were slightly under-funded in 2004 (i.e., less day ahead congestion revenue was collected than the obligations to the FTR holders). When this occurs, the payments to FTR holders are reduced such that the payments will equal the net congestion revenues. This explains why the payments on net congestion revenues were exactly equal in many months in 2004.

B. Congestion Patterns and FTR Prices

This subsection evaluates the efficiency of the FTR auctions by comparing the levels of congestion and the FTR prices into each zone in New England. This evaluation is based on a comparison of the day-ahead and real-time congestion costs to FTR prices in the various zones. In a well-functioning system, these values should be highly correlated.

Figure 6 shows day-ahead and real-time congestion costs compared to FTR prices during 2005 for each of the eight New England load zones and three Connecticut sub-areas. 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
Locational Averages Shown Relative to New England Hub Price
2005 -- Weekdays 6 AM to 10 PM



The monthly FTR auction clearing price is the average purchase price from the twelve monthly auctions, 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 load zones and sub-areas listed along the horizontal axis are generally ordered in accordance with their historical congestion patterns relative to the hub. Hence, the locations 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 locations on the left of the horizontal axis and positive values for locations on the right. We generally expect that congestion costs would be correlated with FTR revenues.

During 2005, congestion costs and FTR payments were generally well-correlated, although the magnitudes of FTR prices and congestion costs differed. As Figure 6 shows, the monthly FTR prices were higher than the annual FTR prices (more negative in the exporting areas), while day-ahead congestion was larger in magnitude than monthly FTR prices in most areas. The fact that the annual FTR prices were consistently lower than the monthly FTR prices in the import-constrained areas suggests that market participants forecasted lower levels of congestion, but revised their expectations upward as it became apparent that more congestion was occurring. One reason that congestion may have been more than expected is the high load conditions that prevailed during the summer of 2005 and the escalation of gas prices through the latter half of 2005, both of which generally increased congestion.

Figure 6 also reveals substantially more congestion *within* the Connecticut than on the interfaces *into* Connecticut. The Connecticut load zone is an aggregation of many smaller nodes and the price is a load-weighted average of the smaller nodes. In 2005, approximately one-sixth of the Connecticut load was in the Norwalk-Stamford sub-area, one-third was in the Southwest Connecticut RSP (which does not include Norwalk-Stamford), and one-half was in the Connecticut RSP (which does not include Southwest Connecticut).[8] Although FTRs into the Connecticut load zone were under-valued relative to the day-ahead congestion, a review of the sub-area prices reveals that FTRs into Connecticut and Southwest Connecticut were actually slightly over-valued. The table in Figure 6 shows that market participants revised their expectations of *intra*-zonal congestion between the annual and monthly auctions. The price of an FTR from the Connecticut RSP to Norwalk-Stamford tripled from $5.21/MWh in the annual auction to an average of $16.57/MWh in the monthly auctions as market participants observed large amounts of congestion into Norwalk Stamford. Even with this increase, however, the payments to FTRs held into Norwalk-Stamford (which are based on day-ahead congestion) were significantly higher than the FTR prices.

8 There are a handful of nodes inside the Connecticut load zone that are outside the Connecticut sub-area. This is because the Connecticut load pocket does not include all of the areas within the political boundaries of Connecticut.

The next analysis compares the same results for 2004 and 2005. Because the greatest stress on the transmission system typically occurs during the summer when cooling demand is at its peak, Figure 7 shows the FTR clearing prices, day-ahead congestion, and real-time congestion for the peak hours during the summer season. The higher summer loads generally result in higher congestion costs and greater financial risks for market participants, making FTRs most valuable during the summer. Figure 7 shows FTR prices and congestion costs for the three most congested zones during the summers of 2004 and 2005.

Figure 7
FTR Auction Prices vs. Day-Ahead and Real-Time Congestion
Locations Shown Relative to New England Hub Average Price
June to August, 2004 & 2005 – Weekdays 6 AM to 10 PM

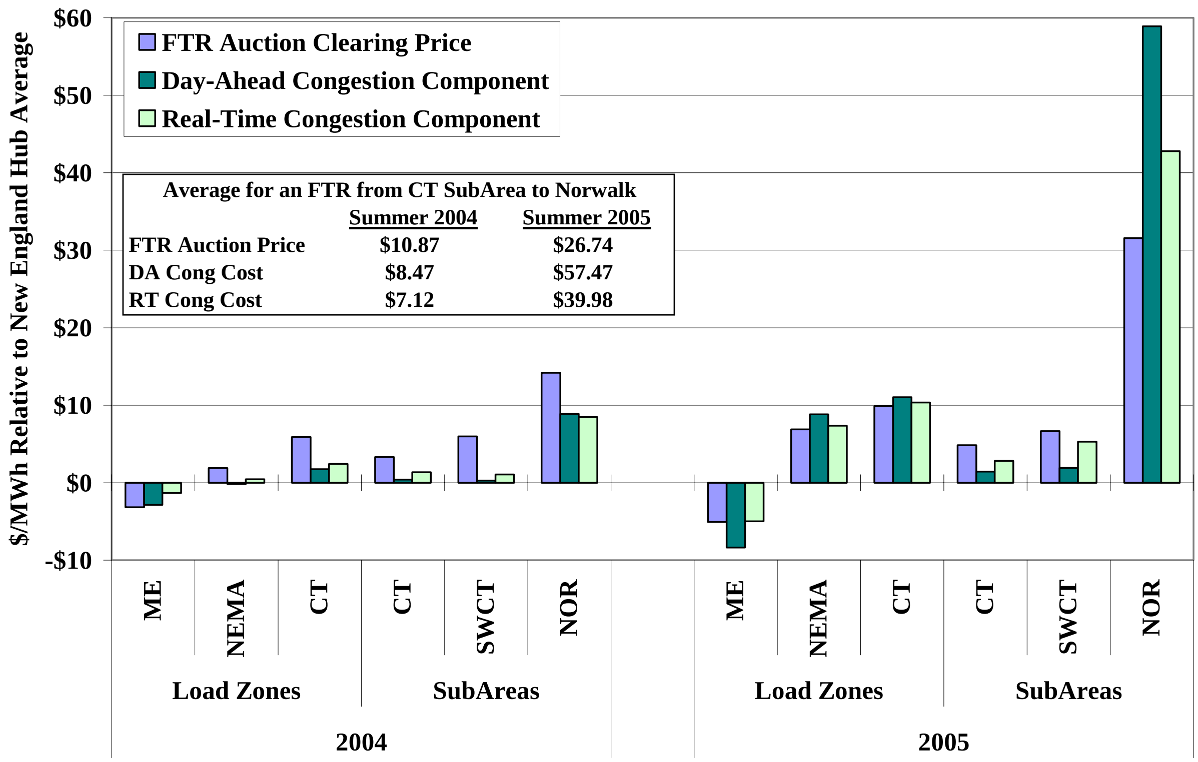


Figure 7 averages prices for the months of June, July, and August. Therefore, the FTR prices include only results from the monthly auctions. The figure shows that the average prices of FTRs into NEMA/Boston and Connecticut were significantly higher than actual day-ahead congestion costs in the summer of 2004, while FTR prices were more consistent with congestion costs in 2005. In general, the day-ahead and real-time congestion costs were higher during the summer of 2005 because of higher peak loads, higher natural gas prices, and increased congestion within Connecticut.

During the summers of 2004 and 2005, there was very little congestion *into* Connecticut while congestion *within* Connecticut increased substantially. The figure shows that the average cost of day-ahead congestion from the Connecticut RSP (which does not include Southwest Connecticut) to Norwalk-Stamford increased from $8.47/MWh in 2004 to $57.47/MWh in 2005. The average monthly FTR price for this path was $26.74/MWh in the summer of 2005. Hence, the monthly FTR market did not fully anticipate the increased congestion into Norwalk-Stamford.

In 2005, we found that while FTRs were generally under-valued in the FTR auctions, the monthly auctions exhibited more accurate valuations than the 12-month auction. Thus, the FTR market showed signs of adapting to changes in patterns of day-ahead congestion during the study period. We have also reviewed the FTR market processes and did not find any structural or methodological impediments to efficient FTR pricing. To better understand the congestion patterns in New England, we analyze generator commitment and dispatch patterns in the next section. In particular, we examine commitment and dispatch that occur outside of the market processes.

IV. Market Operations

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 and transmission limits, 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 New England market's price signals.

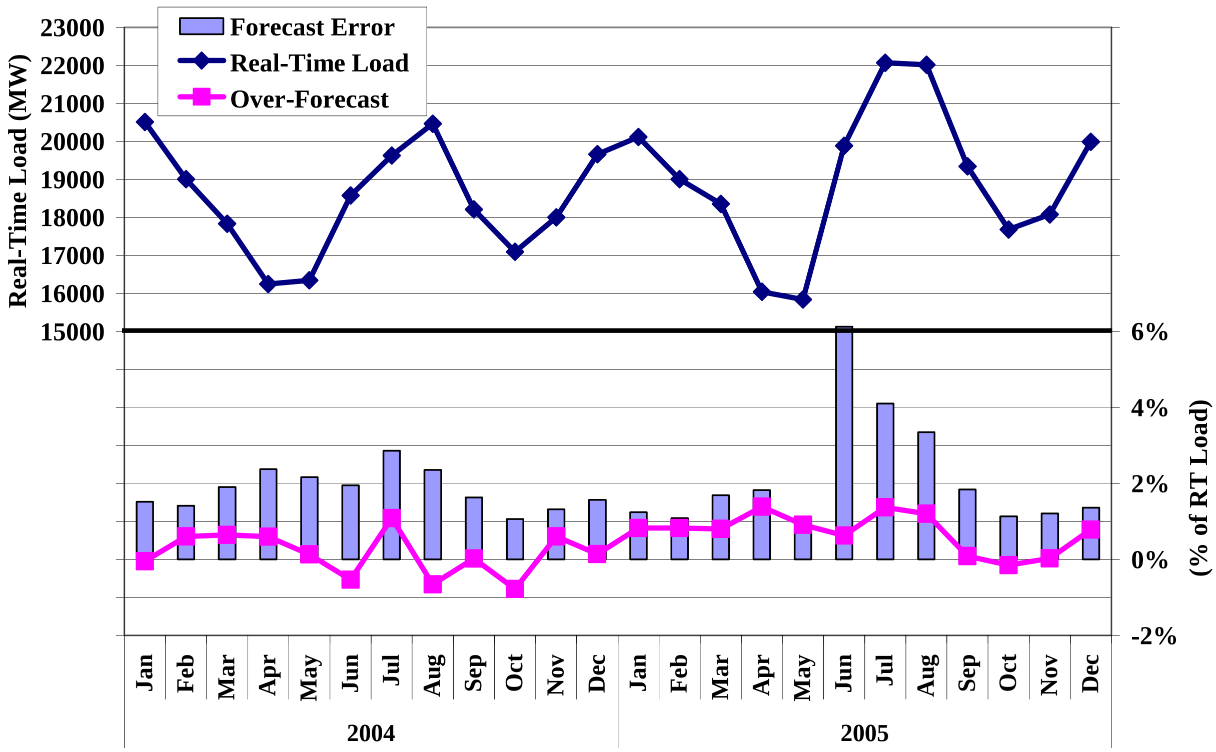
A. Accuracy of ISO Load Forecasts

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. Over-forecasting can lead to excess generator commitments, resulting in uplift costs and understated real-time prices. Alternatively, under-forecasting can lead to insufficient supply in real-time and result in overstated real-time prices. Therefore, it is desirable that day-ahead forecasts accurately predict actual loads. Figure 8 shows daily peak load on weekdays, as well as two measures of forecast error averaged on a monthly basis during 2004 and 2005.

The figure shows a characteristic pattern of high loads during the winter and summer and mild load during the spring and fall. The 2005 annual peak load of over 26 GW occurred during July, and the figure shows that the average daily peak was highest in July. Forecasted demand tracked actual load closely in most months. The average difference between the forecast load and actual load in 2005 was 0.7 percent, with the forecast being higher on average. On a monthly basis, this average over-forecast was generally close to zero, but ranged as high as 1.4 percent in April and as low as -0.2 percent in October. Given the small size of these average differences, the only potential issue raised by this analysis is the fact that the average difference is consistently positive in 2005 – fluctuating around 1 percent in each month from January to August. The ISO should evaluate the load forecasting algorithm to ensure there are no elements of the model that would bias the forecasts unjustifiably.[9]

[9] A small bias may be justifiable because the costs of under-forecasting (i.e., under-commitment and potential for shortages) are likely larger than the costs of over-forecasting.

Figure 8
Average Daily Peak Forecast Load and Actual Load
Weekdays, 2004-2005



Note: Over-forecast is the percentage by which the day-ahead forecasted load exceeded real-time load on average -- a negative percentage value indicates an under-forecast. Forecast error is the average of the absolute difference between the day-ahead forecasted peak load and the actual peak load.

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. For example, a one percent over-forecast on one day and a one percent under-forecast on the next day would result in an average forecast error of one percent, even though the simple average would be zero. Our analysis shows that the forecast error as a percent of the actual peak demand averaged 2.2 percent in 2005. On a monthly basis, the average forecast error for the daily peak ranged from as high as 6.1 percent in June to 1.1 percent in February. The forecast error was considerably higher during the summer when load fluctuates the most and uncertainty associated with the weather is the highest.

Overall, we find that the load forecasting performance of the ISO remains good. Outside the summer of months, the load forecast was more accurate in 2005 than in the previous year.

However, the forecast was less accurate in the summer months. This may be attributable, in part, to the hotter weather and higher loads that prevailed in 2005. Higher weather-dependant loads are inherently more uncertain and should lead to higher average forecast errors. Hence, these increases do not raise substantial concerns.

B. Forecasted Transmission Interface Limits

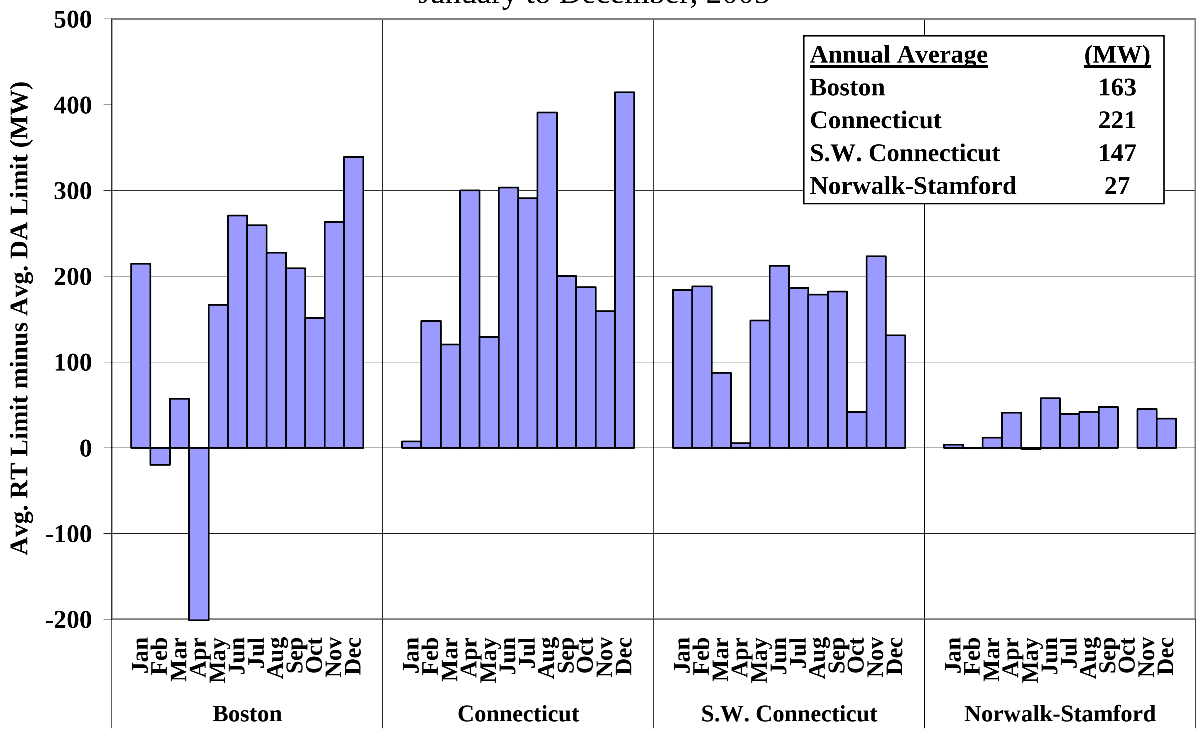
Load pockets such as Connecticut and NEMA/Boston have historically imported a large share of their power because supply resources in these areas are generally more expensive than in outlying areas. However, imports are limited by the capacity of the transmission system, and whatever cannot be imported must be provided from local resources. Like the forecast of load, the forecasted transmission limits into these areas helps to determine the commitment of resources in these areas. While over-forecasting load can cause over-commitment, over-forecasting the transfer limit of an interface can cause under-commitment inside the load pocket. Conversely, under-forecasting the transfer limit leads to over-commitment within the load pocket. Thus, it is important to accurately forecast factors that affect the capability of the transmission system.

The limits into the load pockets in Connecticut and NEMA/Boston are calculated to reflect the second-contingency requirements in the area (known as the proxy second-contingency limits). The methodology is the same for calculating the day-ahead and real-time limits. However, the real-time limit is based on actual operating conditions, while the day-ahead limit is based on a forecast of the next day's operating conditions. Many of the factors used to calculate the limit can change between the day-ahead forecast and real-time including:

- The thermal limits of individual elements that make up the interface and reactive power flows;
- Outages of key transmission lines and generators;
- The size of the largest generator contingency;
- The quantity of 30-minute reserves available on units on-line and available on off-line quick start resources in the load pocket; and
- The amount of load that can be shed in the event of a contingency.

Naturally, there will always be differences between forecasted and actual conditions, which will lead to some differences between day-ahead and real-time limits. In general, most of these differences should be random and result in a relatively small difference in the limits between the day-ahead and real-time market. However, reliability concerns related to unknown factors in the day-ahead timeframe may justify conservative assumptions that would cause the day-ahead limit to be lower than the real-time limit. To evaluate the differences, Figure 9 shows the monthly average real-time transmission limit minus the average day-ahead limit for four key interfaces during 2005.

Figure 9
Systematic Differences between Real-Time and Day-Ahead Transmission Limits
Average RT Limit minus Average DA Limit
January to December, 2005



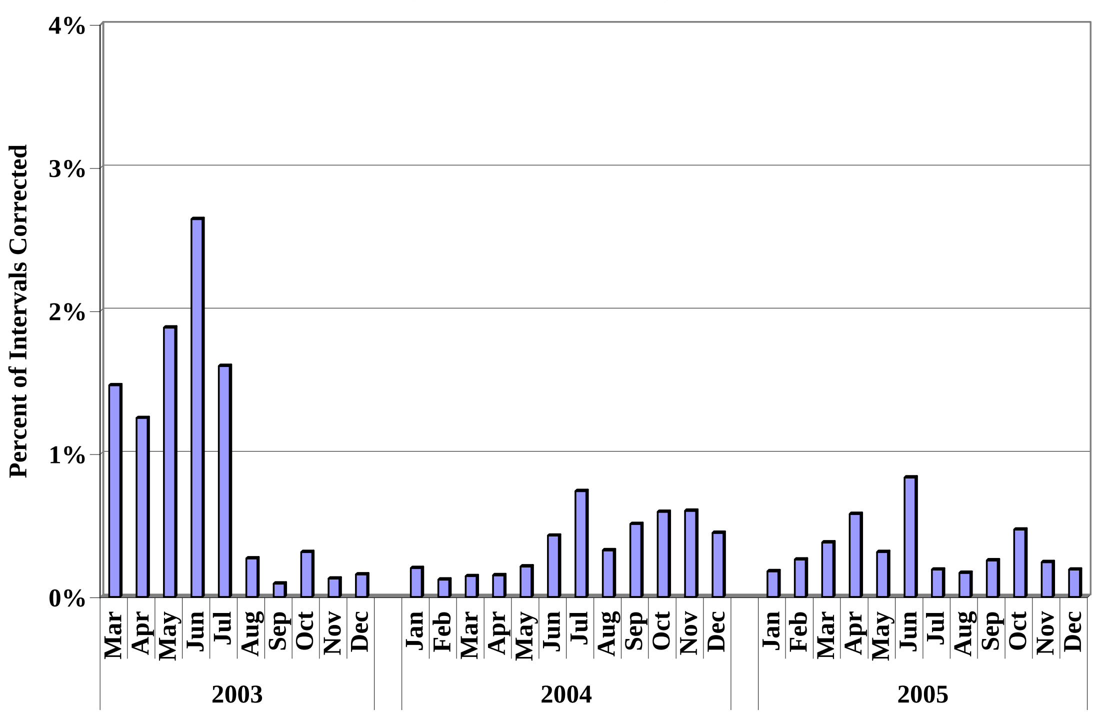
The figure shows that the day-ahead limit has been usually been lower than the real-time limit for these four interfaces. This indicates that there have been systematic differences between the assumptions used in the day-ahead market and in the real-time market. To improve the consistency of these limits, we recommend that the ISO investigate the factors that may have caused these differences to determine whether improvements can be made to reduce or eliminate any unjustifiable differences between day-ahead and real-time limits.

C. Price Corrections

This subsection evaluates the rate of price corrections that have occurred during 2005. Price corrections are necessary to address a variety of issues, including software flaws, operations or data entry errors, system failures, and communications interruptions. Although they cannot be completely eliminated because data and communications errors are an inherent issue in electricity markets, 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. Therefore, the rate of price corrections dropped significantly after the initial introduction of SMD in March, 2003. Figure 10 below shows the rate of real-time price corrections in New England from March 2003 through December 2005.

Figure 10
Rate of Real-Time Price Corrections
March, 2003 to December, 2005



The figure shows that New England required a significant number of price corrections in the first five months under SMD. However, since August 2003, the rate has been less than one percent in each month and less to 0.3 percent in most months. These results support the conclusion that the SMD markets are operating reliably.

D. Commitment for Local Congestion and Reliability

In New England, there are several load pockets that import a significant portion of their total consumption. In order to ensure that these areas can be served reliably, additional capacity within the load pocket must be committed. Specifically, additional capacity may be required to:

- Make certain that sufficient capacity is on-line to meet forecasted load in the load pockets without violating any first contingency transmission limits (i.e., ensure the ISO can manage congestion on all of its transmission interfaces).
- Ensure that reserves are sufficient in local constrained areas to respond to a second contingency;
- Support the voltage of the transmission system in specific locations; and
- Manage constraints on the distribution system that are not modeled in the market software (known as Special Constraint Resources ("SCRs")).

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. In order for a unit to be committed in the day-ahead market, demand bids from load serving entities and virtual traders must express a willingness to pay enough for the energy from the unit that it is economic to incur the start-up, no-load, and incremental offer of the unit. However, demand bidders should not be willing to pay substantially higher prices day-ahead than they anticipate in the real-time market the following day. Thus, day-ahead market-based commitment is always affected by expectations of real-time prices.

As described above, there is a requirement to ensure sufficient capacity is on-line in load pockets to manage voltage and provide reserves. However, New England does not currently operate spot markets for reserves or voltage support. Thus, the real-time LMPs will not fully reflect the value of on-line capacity in certain locations when trade-offs are necessary between reserves and energy. As in any forward financial market, the day-ahead market prices will tend to converge with the real-time prices. Hence, the day-ahead LMPs also will not reflect the value of additional capacity in local areas.

Because local reliability requirements are not explicitly included in the day-ahead market, market-based commitment will generally not be sufficient to meet local reliability requirements. However, the ISO has attempted to increase the extent to which the market-based commitments will satisfy the local reliability requirements by modeling a lower transfer limit into the constrained area to reflect the 2nd contingency reliability requirements. This lower limit is referred to as the "proxy 2nd contingency limit". Nonetheless, "supplemental commitments" are still frequently needed to meet local requirements. Supplemental commitments may occur in either the day-ahead market process or later in the Reliability Adequacy Assessment ("RAA") process. There are two ways in which supplemental commitments are made:

- The commitment software recognizes a need for capacity (but not energy) in a local area and commits the resources with the lowest commitment costs that satisfy the need.
- The operator recognizes a constraint that is not modeled in the software and manually commits resources to manage the constraint. This may not be the lowest-cost method to manage the constraint.

Although it is preferable for the commitment software to make supplemental commitments rather than to do so manually, neither method adequately reflects the cost of maintaining reliability in the LMPs. Furthermore, since these units must be dispatched at or above their economic minimum generation level ("EcoMin"), these commitments will generally reduce LMPs by displacing energy that would have been produced by other units committed through the market.

Thus, supplemental commitment tends to mute locational price signals associated with resolving transmission congestion. Because congestion price signals can be muted in the real-time, day-ahead demand bidders may not bid enough to commit the minimum set of resources necessary to manage normal transmission constraints. These are called "1st Contingency" commitments, because normal transmission flows must be maintained at levels that would allow the network to withstand the single largest contingency. Hence, supplemental commitment may be required simply to manage normal transmission congestion. This section gives a detailed summary of supplemental commitment during 2005 for voltage support, 2nd contingency requirements, and 1st contingency transmission limits.

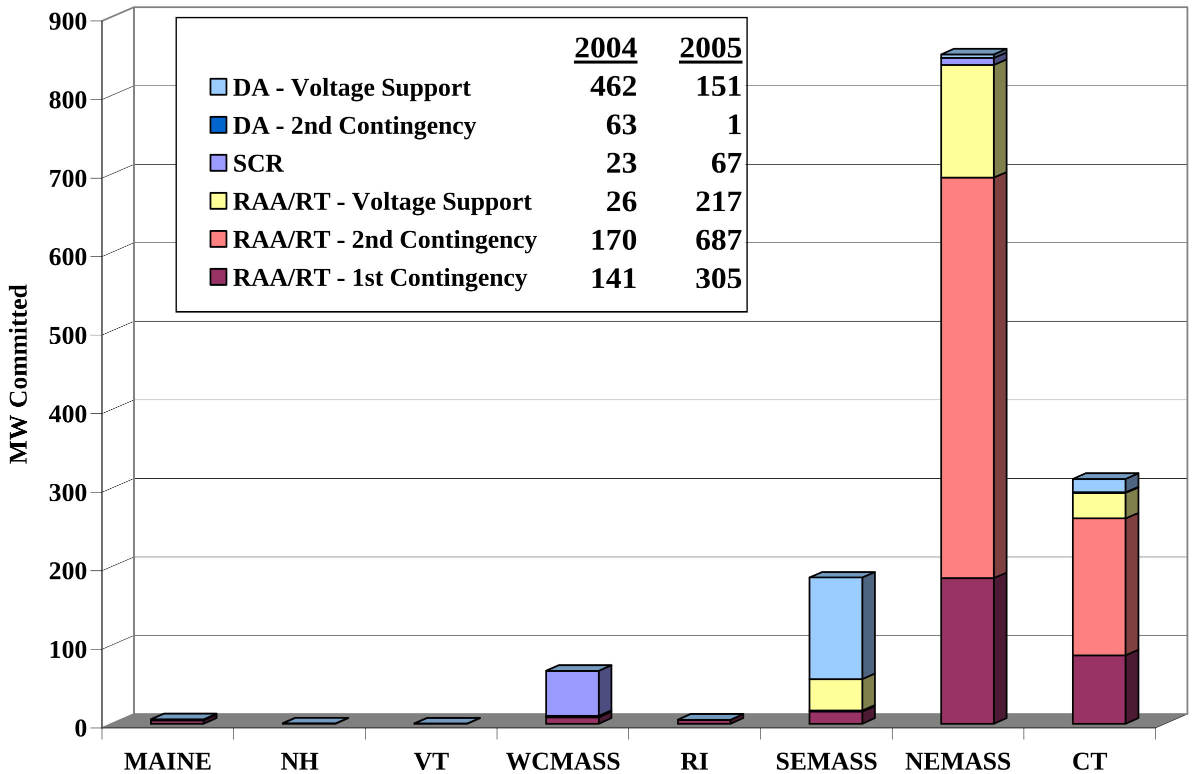
1. Generation Committed for Local Needs

Because committing units to provide reserves and/or voltage support in a local area increases the on-line supply in the congested area, it can diminish locational price signals in the areas. Hence, it is important to monitor the extent to which these actions occur, and the locations where they occur. Therefore, we calculate the average quantity of commitments made to satisfy local requirements at the daily peak load in each zone in New England. These commitments during 2005 are shown in Figure 11. The commitments that are made to withstand the 2nd largest contingency in a local area are referred to as local 2nd contingency protection resources, commonly referred to as "RMR commitments". These are distinct from the reliability agreements discussed earlier in this report. Reliability agreements provide capacity payments to units that must remain in operation over a specified timeframe (e.g., the next year) to maintain reliability. 2nd contingency commitments are made as part of the operation of the system on a given day to ensure that sufficient resources are online in an area to withstand the first and second largest contingencies.[10] 2nd contingency commitments can occur for units that do or do not have a reliability agreement with the ISO.

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. However, the commitments' effects on prices depend on the energy produced from these units, particularly the energy produced out of merit order.

10 In accordance with its Tariff, the ISO-NE classifies certain day-ahead commitments as RMR commitments even though they occur as the result of market-based scheduling activity. Since these are not out-of-market commitments, we exclude them from our analyses of supplemental commitment in this section.

Figure 11
Commitment for Local Reliability by Zone
2005 – Daily Peak Hour



Note: Capacity committed day-ahead for voltage support that would have been economically committed in the day-ahead market is excluded. Capacity committed day-ahead and flagged for 2nd contingency protection is only included if it resulted from a non-market local capacity requirement.

Figure 11 shows an average of 1429 MW committed for local reliability in 2005, an increase of 62 percent from 2004. In 2004, nearly half of this capacity was committed in the day-ahead market to maintain voltage in the NEMA/Boston area. However, this need was significantly reduced in 2005 by a series of transmission upgrades (discussed in more detail below) and because some of the commitments for voltage support were shifted to the real time (including the RAA process). In 2005, there was a significant rise in the quantities committed to satisfy local 2nd contingency and first contingency requirements in NEMA/Boston and Connecticut, primarily during the RAA process. Since commitment for voltage support also provides local reserves and congestion relief, the reduced commitment for voltage support in the NEMA/Boston area contributed to the rise in 2nd contingency and 1st contingency commitments in NEMA/Boston. However, the shift of commitments from voltage support to the 2nd contingency and 1st contingency category is only part of the change in 2005. Changes in the scheduling and offering patterns of key resources in the NEMA/Boston area compelled the ISO to substantially increase its commitments to maintain local reliability and resulted in significant uplift costs. There was also a notable rise in day-ahead and real-time commitments for voltage support in SE MASS.

In general, the increase in supplemental commitments after the day-ahead market has led to a less efficient overall commitment. The day-ahead commitment software is designed to commit the set of resources that minimizes overall production costs. To the extent that the commitment of units to satisfy a local requirement is known, it is most efficient to commit the units in the day-ahead market software runs. This allows the software to determine the lowest-cost solution, taking into account the commitments needed for local requirements. When an additional resource is committed supplementally, it may no longer be efficient to commit one or more units that were committed in the day-ahead market. This tends to make some units committed economically through the day-ahead market run out of economic merit in real-time. Therefore, it is most efficient for the day-ahead software to determine the lowest-cost set of offers taking into account units that must run for local reliability to the extent that they are known when the day-ahead market runs.

Because the market effects of local reliability commitments are likely to be the greatest in the highest-load hours, Figure 12 shows the average quantities 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 2nd contingency and first contingency requirements were substantially higher while commitments for voltage were considerably lower than the average for all days.

Figure 12
Average Supplemental Commitment by Zone
Top 5 Peak Load Days in 2005

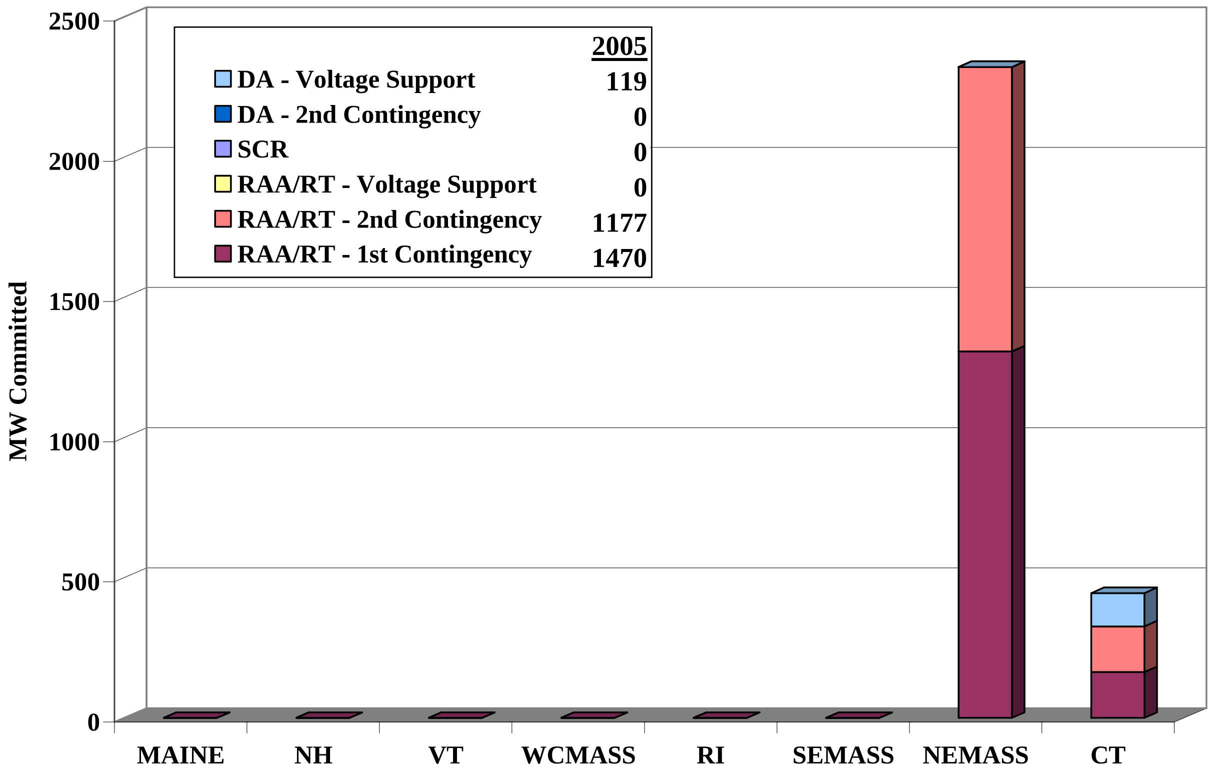


Figure 12 shows that commitments for local reliability averaged more than 2700 MW on these five days. More than 95 percent of this capacity was committed to satisfy 2nd contingency requirements (i.e., local reserves needed to respond to 2nd contingencies) and local congestion management (i.e. 1st contingencies). While approximately 400 MW was committed for local reliability in Connecticut, nearly 2300 MW was committed in NEMA/Boston. This latter value is particularly noteworthy given that it constitutes 68 percent of the non-quick starting capacity installed in NEMA/Boston.

Given the predominance of the supplemental commitments in Connecticut and NEMA/Boston during 2005, we analyzed the patterns in these two zones. Figure 13 shows supplemental commitments for local needs in NEMA/Boston on a monthly basis during 2005.

Figure 13
Commitment for Local Reliability in NEMA/Boston
Daily Peak Hours

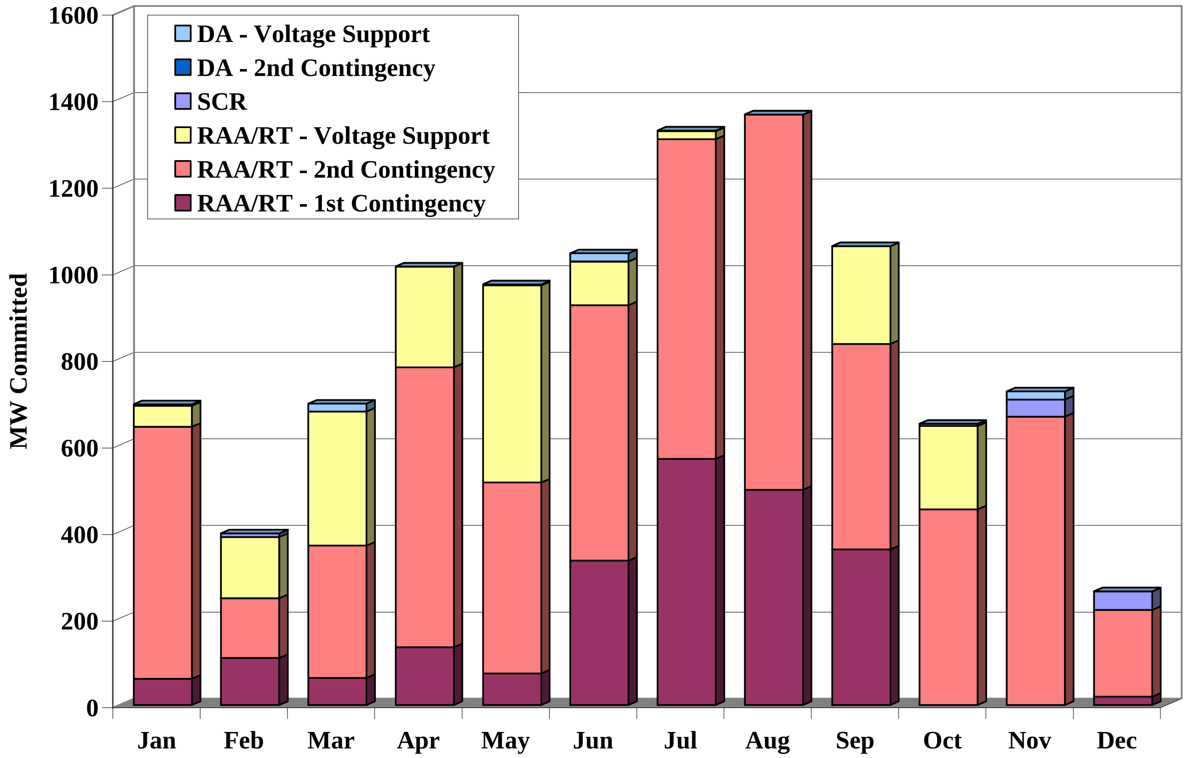


Figure 13 shows that a significant amount of supplemental commitments in the NEMA/Boston zone was made during the real time and RAA process to satisfy the system's 1st contingency and 2nd contingency requirements. Real-time commitments for 2nd contingency and 1st contingency reasons were most frequent during the spring and summer. Most of the voltage support commitments occurred during the low demand months, March to May and September and October. Generally, less commitment is necessary for voltage during high load periods when substantial quantities of capacity are already on-line to serve demand.

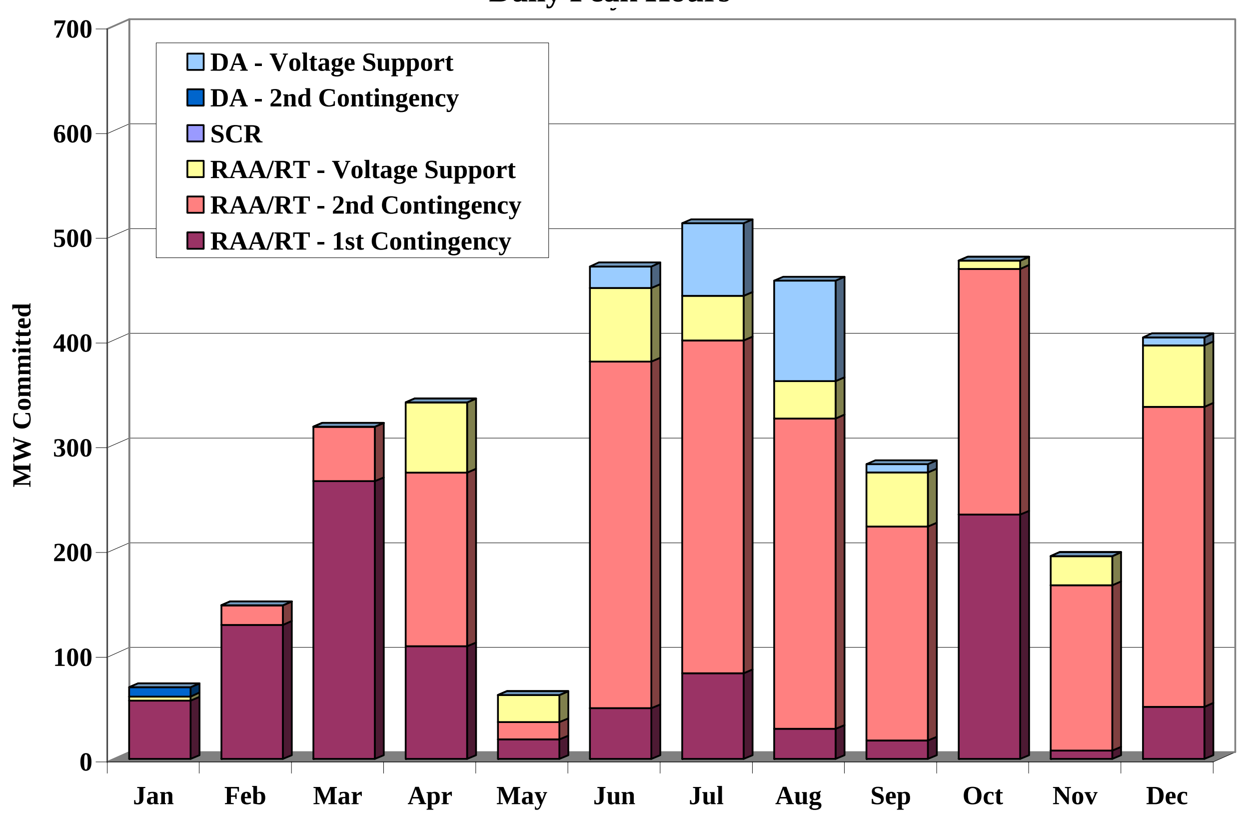
During 2004 and 2005, the ISO carried out several initiatives to reduce the need for supplemental commitments for voltage support. These initiatives were responsible for the sizable reduction in supplemental commitments for voltage support in NEMA/Boston in 2005 and included:

- Working with the owners of Mystic 8 and Mystic 9 to increase their ability to produce reactive power by a total of 100 MVar – Completed 4th quarter 2004;
- Working with NSTAR to return a shunt reactor to service with the capability of absorbing 80 MVar – Completed 4th quarter 2004;

- NSTAR to quickly repairing a load tap changer in the Woburn 345/115 kV transformer that enables three shunt reactors to be more effective in absorbing reactive power – Completed 4th quarter 2004;
- Revising the ISO's NEMA/Boston area operating guide based on these three upgrades and train operations staff on new procedures – Completed 2nd quarter 2005; and
- NSTAR installing a new 150 MVar shunt reactor to absorb reactive power – Completed 2nd quarter 2005.

Even with the substantial reductions in supplemental commitment for voltage support, there was still a substantial increase in reliability commitments overall. This increase was necessitated by a significant reduction in the NEMA/Boston-area supply available to the day-ahead market. The reduced supply compelled the operators to use out-of-market actions to commit generation, resulting in additional uplift. The reduction in supply was due to the conduct of a particular supplier, which is discussed in greater detail later in the next sub-section. Figure 14 shows supplemental commitments for local needs in Connecticut on a monthly basis during 2005.

Figure 14
Commitment for Local Reliability in Connecticut
Daily Peak Hours



The figure shows that out-of-merit commitment in Connecticut increased and decreased with load over the year, peaking during the summer and winter. This is because local 1st contingency and 2nd contingency requirements rise with demand levels. Relatively few units were committed for voltage support, and SCR commitments occurred rarely. The figure also shows that most of the 2nd contingency commitments during June, July, and August were made through the RAA process.

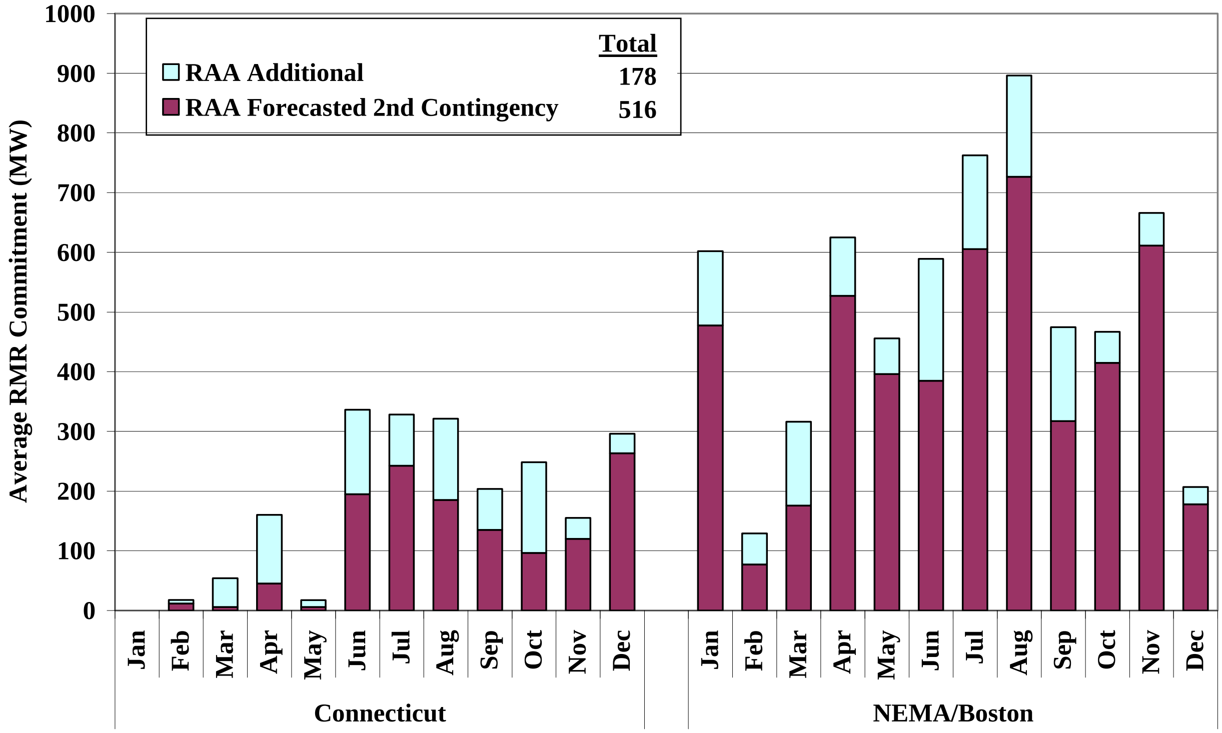
The 2nd contingency commitments in Connecticut are made to address second contingency reliability requirements. The ISO must have sufficient reserves available in each area to respond to the largest generation and/or transmission contingency after the first contingency has occurred. The reserves required in each area vary hourly depending on the availability of fast-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 fast-start resources in these areas, a large portion of these reserves must be held by on-line resources. If additional fast-start resources are added in these areas over the longer term, the frequency and quantity of supplemental commitment would be substantially reduced. This underscores the potential resource adequacy benefits associated with the ISO's project to introduce locational reserves in the real-time market and the forward reserves market, which will provide more efficient economic signals to guide new investment in resources needed to provide operating reserves.

The incidence of supplemental commitment in NEMA/Boston and Connecticut, together with the unusually low congestion that has prevailed outside Norwalk-Stamford, suggests that supplemental commitments have contributed to the lack of congestion into these zones. In a subsequent section, we will examine how much energy runs out-of-merit as a result of these supplemental commitments.

2. Evaluation of 2nd Contingency Commitments

Because supplemental commitments in constrained areas can significantly affect the market outcomes, it is important that they only be made when truly needed. This subsection evaluates the performance of the ISO in making 2nd contingency commitments for NEMA/Boston and Connecticut through RAA process. Based on the information the ISO uses to establish the 2nd contingency commitment requirements in the RAA process, we divided the quantities of 2nd contingency commitments made by the ISO operators between those needed to meet the forecasted 2nd contingency requirements versus additional commitments made in excess of the forecasted 2nd contingency requirements ("additional commitments"). Additional commitments are those that did not appear to be necessary to meet the local reliability requirements in NEMA/Boston or Connecticut.[11] Additional 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. Figure 15 shows this analysis.

Figure 15
Reliability Commitments in Constrained Areas
Reliability Adequacy Assessment – 2005



The analysis shows that during 2005, 2nd contingency commitments averaged almost 700 MW in the RAA process. Generally, the ISO made significant quantities of additional 2nd contingency commitments in the months studied, which averaged 70 MW in Connecticut and 108 MW in NEMA/Boston. In 2005, roughly 39 percent of RAA commitments in Connecticut

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11 If only a portion of a 2nd contingency resource is needed to meet the forecasted 2nd contingency requirements, the entire unit is classified as satisfying the 2nd contingency requirement.

were additional commitments, while 21 percent of RAA commitments in NEMA/Boston were additional commitments. If these commitments are not necessary to maintain reliability, the ISO should seek to minimize these commitments because they can inefficiently mute the transmission congestion into the constrained areas.

In addition to any unnecessary additional 2nd contingency commitments that may have occurred, there are several other factors that contribute to over-commitment in these constrained areas. First, commitment is naturally lumpy because most generators have significant minimum operating levels and minimum run-times. Hence, operators may have to commit substantially more than is actually required to satisfy the 2nd contingency limit in a particular hour. Second, Figure 9 above showed that the day-ahead transfer limits are generally lower than the real-time transmission limits for the four interfaces that require the majority of 2nd contingency commitments. Since the transmission limits are largely based on the same criteria as the 2nd contingency commitment requirements, this suggests that the local capacity requirements in the day-ahead and RAA process may be greater than the real-time requirements. Therefore, some of the required 2nd contingency commitments shown in Figure 15 were unnecessary based on the real-time requirement. Third, resources sometimes self-commit after the RAA process, making some of the 2nd contingency commitments no longer necessary to satisfy the 2nd contingency requirement. In NEMA/Boston, this phenomenon became common in 2005 and is analyzed in greater detail in the following sub-section.

The ISO has undertaken the several projects that are designed to reduce the need for 2nd contingency commitments and rely more on the market to reflect the value of resources in load pockets. First, the commitment software used by the ISO was modified in early 2005 to minimize the total commitment and dispatch costs associated with satisfying the day-ahead load, subject to the transmission constraints that limit the flow into and out of various areas in New England. Prior to 2005, the commitment software did not recognize these import constraints. However, the day-ahead market operators would make manual adjustments to the commitment to resolve clear inefficiencies in the commitment related to transmission constraints (e.g., insufficient commitments in NEMA/Boston or excess commitments in Maine). This software enhancement has allowed the day-ahead market to more efficiently commit resources for local reliability, thereby reducing the need for supplemental commitments. However, this will only occur if the day-ahead price in load pockets is bid up to levels that reflect efficient levels of congestion in real-time. When generation is over-committed in these load pockets, prices will be reduced below efficient levels, making the generation needed for local reliability uneconomic at the real-time price. Expecting these lower prices in the real-time markets, market participants will bid and offer in the day-ahead to cause the day-ahead market to converge with the real-time prices. This reduction in day-ahead prices will cause them to not be high enough to induce the necessary commitments in the day-ahead market. Ultimately, this pattern results in net load schedules in the day-ahead market that are persistently lower than actual real-time load, contributing to a significant quantity of supplemental commitments.

The other measures proposed by the ISO to minimize reliance on 2nd contingency commitments in load pockets include:

- Enhanced combined cycle unit dispatch process to gain additional unit flexibility and non-spin capability in load pockets;
- Develop new ASM markets to provide better incentives for resources in the load pockets, particularly for new fast-start units.

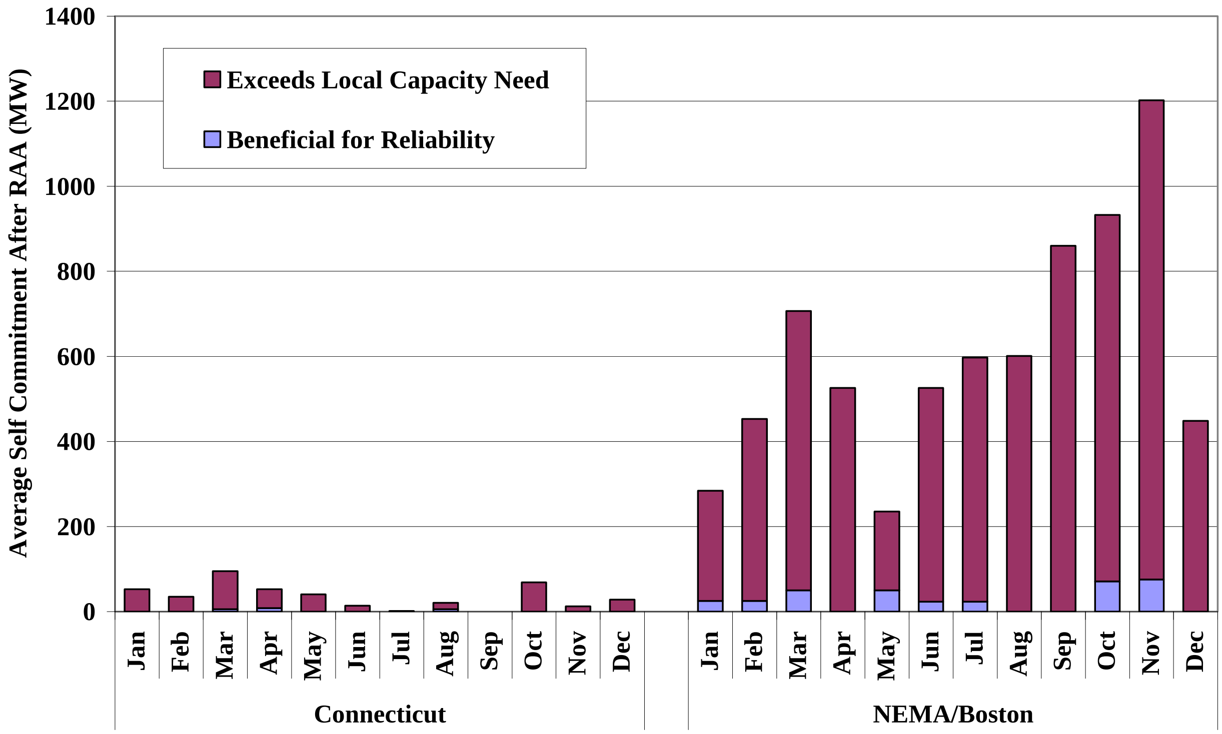
3. Self-Commitment after the RAA

In local areas that are frequently constrained, market-based commitments are not sufficient to ensure reliability. Hence, the ISO regularly supplements market-based commitments with additional commitments. We showed above that commitments are made for local 2nd contingency coverage in NEMA/Boston/Boston and Connecticut regularly. In the RAA, this is done by forecasting the minimum necessary on-line capacity and then committing additional generators as needed to meet the requirement.

Before making a supplemental commitment, the ISO counts capacity committed prior to this evaluation in the following categories: (i) day-ahead, (ii) after the day-ahead for voltage support, (iii) after the day-ahead for SCR, (iv) self committed in the re-offer period, and (v) committed in the RAA for local 1st contingencies. If the ISO is still short of the local capacity requirement after these commitments, it will commit additional resources. However, if a supplier commits a generator after the RAA, it can lead to surplus capacity in the load pocket. Moreover, the ISO may need to pay uplift for a 2nd contingency-committed unit that would not have been necessary if the ISO had been aware of all self-commitments when it conducted the RAA.

Figure 16 summarizes the extent to which self-commitment after the RAA has helped meet any remaining local 2nd contingency requirement versus how often it has led to excess capacity in local areas.

Figure 16
Self Commitment after the Resource Adequacy Assessment
Connecticut and NEMA/Boston – 2005



In Connecticut, an average of 35 MW was self committed after the RAA. In NEMA/Boston, the average self commitment after the RAA was significant and generally rose during 2005. Only a small quantity of the self commitments was necessary to meet the local capacity requirement. While it can be efficient to have more than the minimum capacity required in each local area, most of the self commitments in NEMA/Boston during November and December occurred after the ISO had already committed units for 2nd contingency coverage. If the ISO had known that these units would be self scheduled, it would have needed to commit fewer units for 2nd contingency coverage.

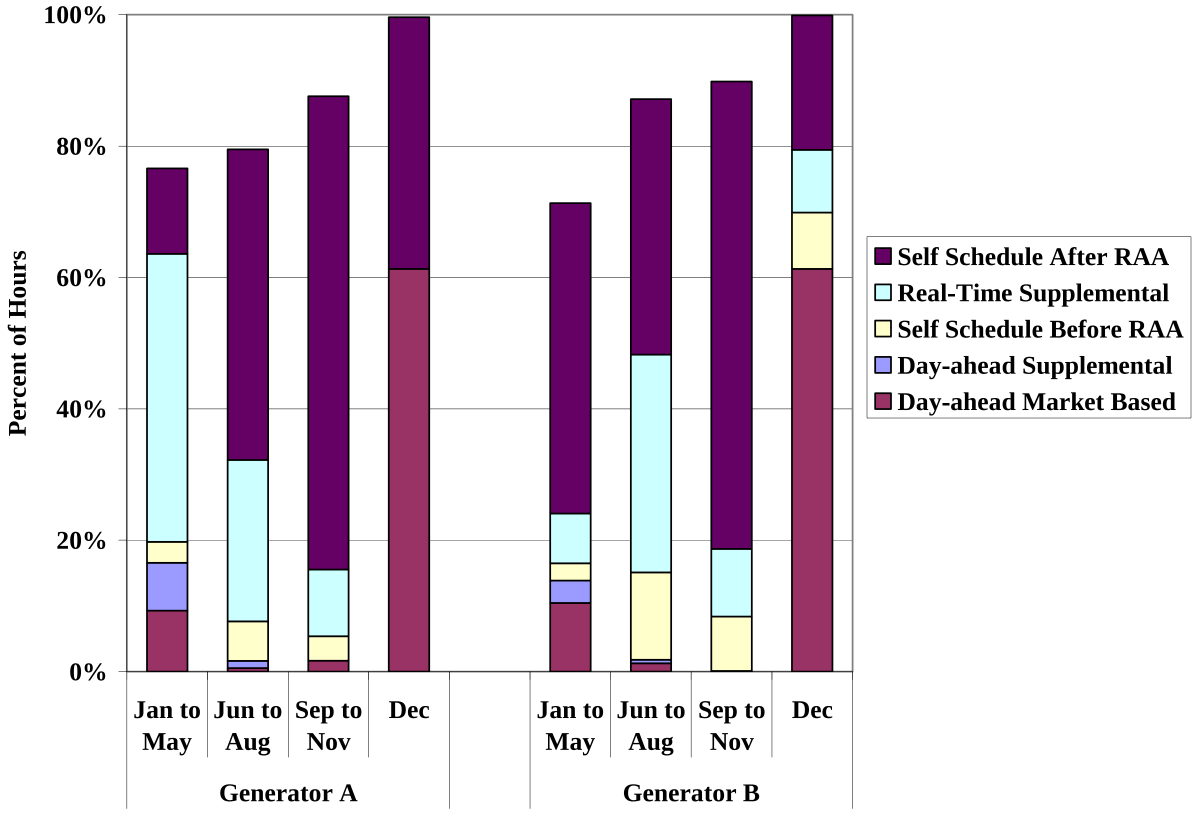
In some cases, the ISO can de-commit a resource that had been committed in the RAA if a self-schedule occurs later that eliminates the need for the commitment. However, the figure shows that this has not been fully effective and the de-commitment is not without cost. The committed generator may have incurred cost to procure fuel in response to the commitment instruction and can, therefore, be harmed if the commitment instructions are not reliable. These costs can affect generators' incentives to offer their resources in the RAA process.

Self commitment after the RAA can lead to inefficient market outcomes in the constrained areas. When excess capacity is committed in the load pockets because the ISO has committed units in the RAA for 2nd contingencies prior to a self-commitment, the real-time prices will generally be depressed, congestion into the area will be muted, and uplift charges will increase. Because it is difficult for load serving entities to predict when units will choose to self schedule, the result will likely be worse convergence between day-ahead and real-time prices. Indeed, NEMA/Boston has exhibited worse price convergence than any part of New England outside Norwalk-Stamford.

While there are some legitimate reasons for self commitment after the RAA (e.g., suffering a forced outage on a unit that had been scheduled in the day-ahead market), the rise in this activity is also consistent with incentive problems that result from frequent supplemental commitment. In NEMA/Boston, local reliability requirements are generally satisfied outside the market process, and these units are paid their offer when the clearing price is not sufficient for them to recover their as-bid cost. Even under perfect competition, units with pay-as-bid incentives rationally offer above costs. Generators frequently committed for local reliability usually have some degree of local market power, and thereby have a greater incentive to offer above marginal cost. If such units submit high-priced offers in the RAA process and are not committed, they would potentially forego the profitable opportunity to sell energy in the real-time market because they will be offline. However, they do not incur this cost because they have flexibility to self-commit the units after the RAA process if they are not selected. Hence, the market rules make this a low-risk strategy.

If the rise in self commitment after the RAA is caused by inefficient incentives, the units that were frequently self-committed in 2005 should be the same units that are frequently committed for local reliability (because they should self-schedule when not selected in the RAA process). Figure 17 shows the pattern of commitment of the two units that frequently self schedule after the RAA. The two units account for 92 percent of the unit-hours and 99 percent of the MWh self committed after the RAA in Boston in 2005.

Figure 17
Two Units Most Frequently Self Committed After RAA
Frequency and Reason for Commitment
January to December, 2005



The figure shows that both generators were committed 80 to 90 percent of the time, which is generally economic based on their operating costs. Prior to December, these two generators received market-based commitments and schedules in the day-ahead market less than 10 percent of the time. In addition, each of these two generators was committed for reliability reasons 15 to 25 percent of the time prior to December. The figure shows that in cases where these units were not committed day-ahead or in the RAA process, they were usually self-scheduled after the RAA. This indicates that the owner deemed them to be economic at the expected real-time prices. In December, there was a significant rise in the frequency of day-ahead market-based commitments for these two generators.

The RAA ensures that sufficient capacity is on-line to meet the local 2nd contingency requirements by committing additional generation. However, some of these 2nd contingency commitments made in the RAA process become unnecessary after additional units self commit. This excess capacity depresses real-time prices and results in additional uplift costs. Furthermore, it is evident that generators frequently committed for local reliability have an incentive to wait until after the RAA process to inform the ISO of their decision. In the short-term, the provisions of the reliability agreements that apply to many of the generating resources in the load pockets mitigate this incentive problem. In the longer-term, after many of the reliability agreements expire, the ISO should consider prohibiting generators in load pockets from self-committing resources after the RAA unless they make a justifiable request to the ISO (e.g., replacing a unit that is forced out of service). However, this is not a high priority recommendation for the short-term.

In addition to the reliability agreements, we consulted with the Internal Market Monitor on a modification of the methodology for calculating reference levels for units that are frequently committed for local reliability.[12] Units that are frequently committed for local reliability generally receive a large share of their compensation through guarantee payments corresponding to their offer (rather than through a clearing price). Hence, these suppliers are faced with "pay-as-bid" incentives and do not have an incentive to offer their units at marginal cost. This violates an assumption underlying the reference level calculation methodology, which relies principally on past accepted offers under the assumption that generators have the incentive to offer at marginal cost. Units with pay-as-bid incentives will offer at higher prices, which will result in higher reference levels. This, in turn, reduces the effectiveness of the market power mitigation

12 Reference prices are used to monitor and, when warranted, to mitigate attempts to exercise market power. A reference price serves as a competitive benchmark for performing the tests that determine whether mitigation may be warranted. The reference price is intended to reflect a generator's marginal cost, including legitimate risk and opportunity costs. This is an appropriate benchmark because, absent market power, a supplier will maximize its profit by continuing to increase its output until the cost of producing additional output (i.e., its marginal cost) is higher than the market clearing price.

measures at mitigating market power associated with local reliability requirements that compel the ISO to commit these resources. To address this problem, the ISO–New England made a filing to FERC proposing to change its reference level methodology for units frequently committed and dispatched out of merit order. The change was approved by FERC in April 2005, resulting in a significant drop in the uplift payments to these generators.

In December, the two generators shown in Figure 17 were frequently committed in the day-ahead market through the normal market process as a result of a change in their offer patterns. They lowered their offer prices to levels more consistent with competitive expectations during December. This led them to be committed through the day-ahead market, thereby reducing the need for local 1st contingency and 2nd contingency commitments in the NEMA/Boston area.

4. Local Commitment Conclusions

The analysis in this section indicates that most of the ISO's commitments for reliability were 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, which can affect real-time prices and increase uplift costs. Work is underway that will address these concerns, including:

- Introducing locational requirements in the forward reserve market;
- Developing real-time operating reserves markets with locational requirements;

In addition, we recommend the ISO:

- Consider prohibiting suppliers in constrained areas from self-committing generation after the RAA process, although this may not be a critical change until many of the reliability agreements in the transmission-constrained areas expire;
- Identify and eliminate any unjustified differences in the transmission limits in the day-ahead and real-time market into areas that frequently require reliability commitment; and
- Consider integrating local reliability requirements currently used in the RAA process into the day-ahead market commitment model;

The final recommendation will help limit the over-commitment of generation in New England, improve the convergence of prices in the constrained areas between the day-ahead and real-time market, and restore the incentive for loads to be fully scheduled in the day-ahead market. However, we recognize that some of the units committed to satisfy these requirements are de-listed (i.e., not sold in the capacity market) and, therefore, may not have the obligation or incentive to be available for commitment in the day-ahead market. The ISO should consider this in evaluating this recommendation.

E. Out-of-Merit Dispatch

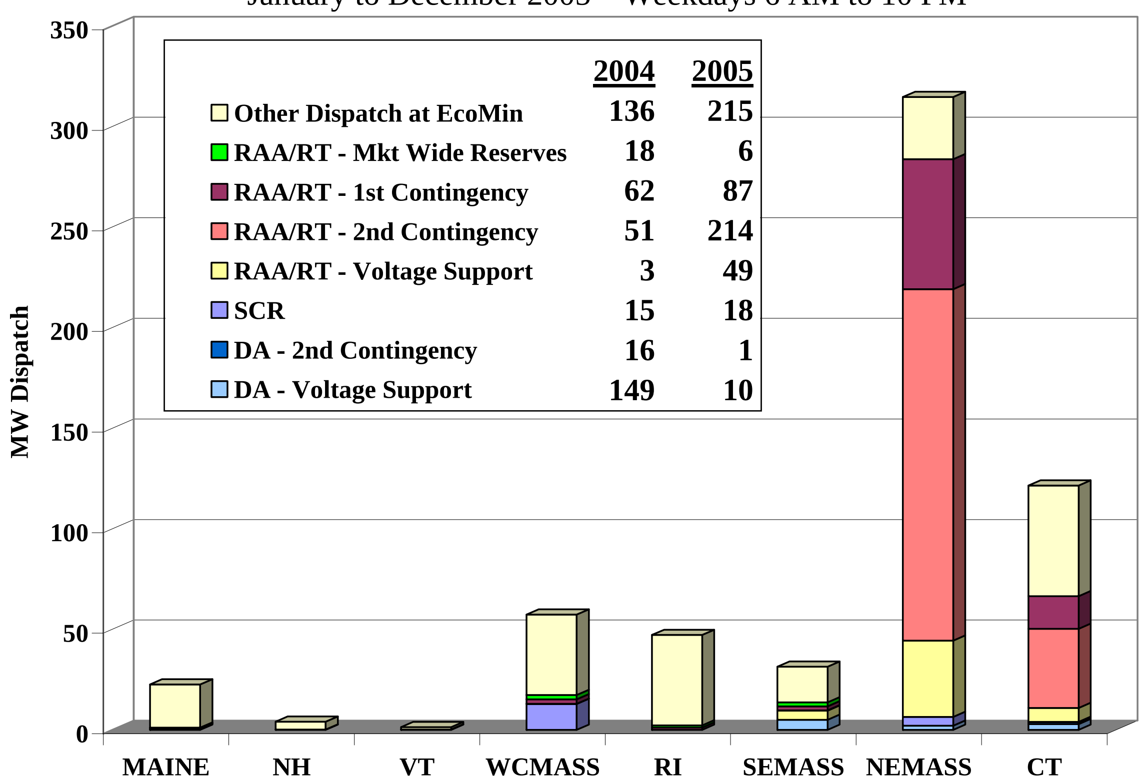
Out-of-merit dispatch occurs in real time when energy is produced from an output range on a unit whose incremental energy offer is greater than the LMP at its location. In general, resources may be dispatched out of merit because either 1) they would not be economic under the current market conditions, 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/MWh resource and a $65/MWh resource, with the market clearing price set at $65/MWh in the absence of congestion and losses. When a $100/MWh resource is dispatched out of merit, it will be treated by the software as a must-take resource with a $0/MWh offer. Assuming the energy produced by the $100/MWh resource displaces all of the energy from the $65/MWh resource, the energy price will decrease to $60/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 when its incremental energy offer 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 during or after the day-ahead market may be out of merit at its EcoMin. Units committed for reliability after the day-ahead market are committed without regard to their incremental energy offer and are, therefore, more likely than units committed competitively 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 18 summarizes the average out-of-merit dispatch by zone for weekday hours (6 AM to 10 PM) during 2005.

Figure 18
Average Hourly Out-of-Merit Dispatch by Zone
January to December 2005 – Weekdays 6 AM to 10 PM



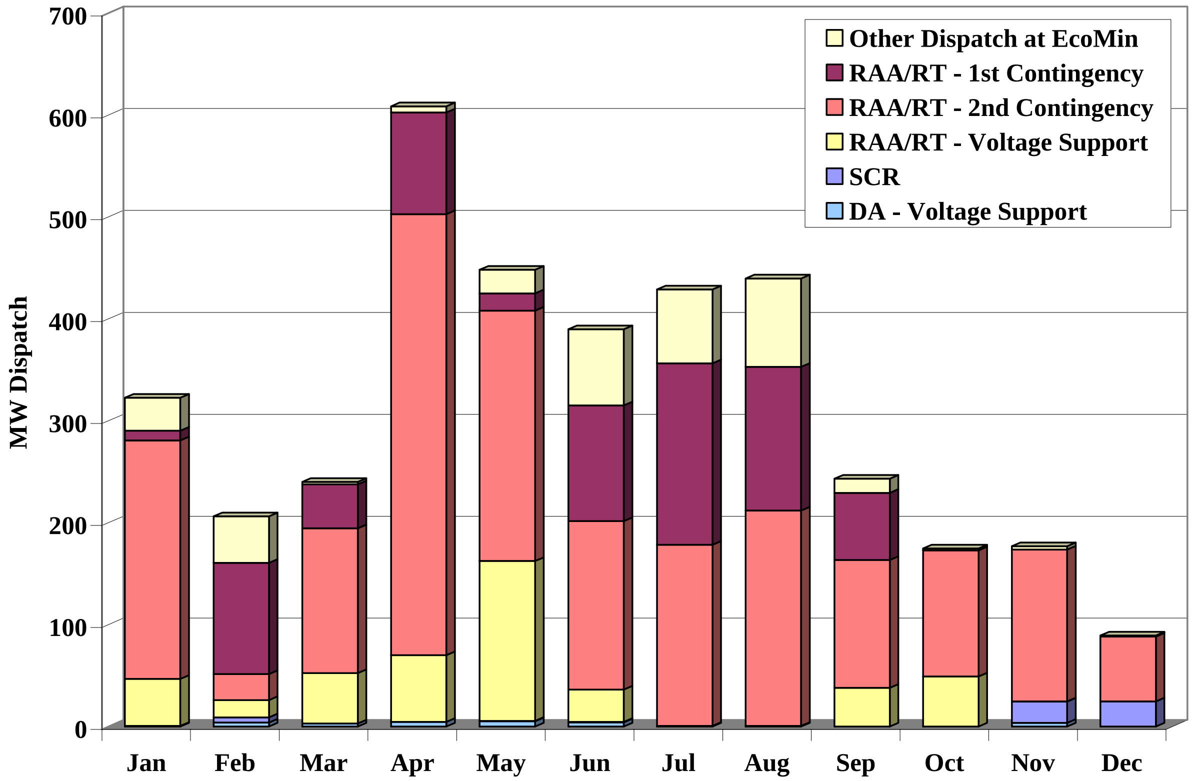
Note: Capacity committed day-ahead for voltage support that would have been economically committed in the day-ahead market is included in the 'Other Dispatch at EcoMin' category. Capacity committed day-ahead and flagged for local 2nd contingency protection is also included in the 'Other Dispatch at EcoMin' category if it did not result from a non-market local capacity requirement.

As expected, the level of out-of-merit dispatch is much lower than the level of supplemental commitment. In addition, Figure 18 shows that virtually all of the out-of-merit dispatch outside of the constrained areas is attributable to economically committed units dispatched at EcoMin. However in NEMA/Boston and Connecticut, most of the out-of-merit dispatch is from units committed in the RAA process for local reliability. The average quantity of out-of-merit dispatch from units committed for local reliability (including 1st contingency, 2nd contingency, and voltage support) in both the day-ahead and real-time market increased 22 percent from 2004 to 2005. Out-of-merit energy from non-local reliability units (i.e. Other Dispatch at EcoMin and Market-Wide Reserves) increased 44 percent in 2005. The "Other Dispatch at EcoMin" category is partly due to the excess commitments discussed in the prior sub-section, which generally increase the supply on the system and cause higher-cost resources to reduce their output to EcoMin.

The primary causes of out-of-merit dispatch in the constrained areas, including NEMA/Boston and Connecticut, are resources committed to satisfy first-contingency, second-contingency, and voltage requirements. Although there was a significant reduction in voltage support commitments in NEMA/Boston due to improvements in operation by the ISO, the commitments for first-contingencies and second-contingencies increased substantially. Supplementally-committed units typically run at EcoMin, displacing energy from more economic resources. Furthermore, two generating units in NEMA/Boston began to self commit after the RAA process, contributing an additional 600 MW to the overall amount of excess capacity in NEMA/Boston in real-time.

Figure 19 shows the monthly pattern of out-of-merit dispatch quantities in NEMA/Boston. This figure shows that the incidence of out-of-merit dispatch has been highly correlated with the pattern of supplemental commitments shown in Figure 13.

Figure 19
Average Hourly Out-of-Merit Dispatch in NEMA/Boston
January to December, 2005 – Weekdays 6 AM to 10 PM



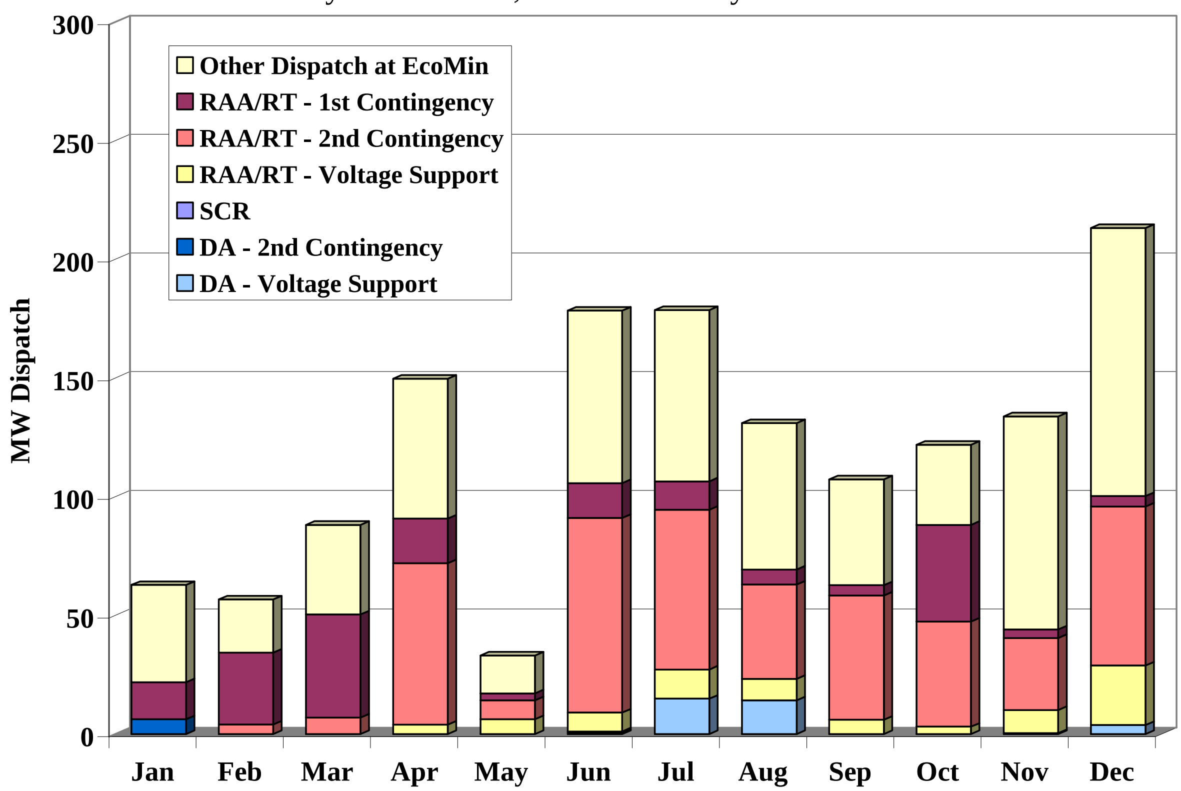
Out-of-merit dispatch from units committed for local reliability averaged 341 MW during the summer months and rose to more than 600 MW in April. These quantities are very large relative to the amount of energy generated in NEMA/Boston, which was 1,533 MW in 2005.

The large self commitments after the RAA process generally displaced more expensive energy from units committed during the RAA process, thereby increasing the portion of their output that was out-of-merit in real-time. Indeed, there was a substantial drop in out-of-merit energy in December due to a change in behavior from the two frequently self-committed units in NEMA/Boston.

The quantity of out-of-merit energy spiked in April due, in part, to the fact that the methodology for calculating reference prices allowed references prices to rise for units that are frequently dispatched out-of-merit. The issue is described in Section IV.D., but it enabled certain market participants with resources frequently committed for reliability to raise their offer prices substantially above competitive levels. Although these units were economic to run based on their actual costs and real-time prices, they were able to raise their offers above the real-time clearing prices without being mitigated, thereby increasing the portion of their output that was out-of-merit in the figure above.

Figure 20 shows the monthly pattern of out-of-merit dispatch quantities in Connecticut during 2005.

Figure 20
Average Hourly Out-of-Merit Dispatch in Connecticut
January to December, 2005 – Weekdays 6 AM to 10 PM

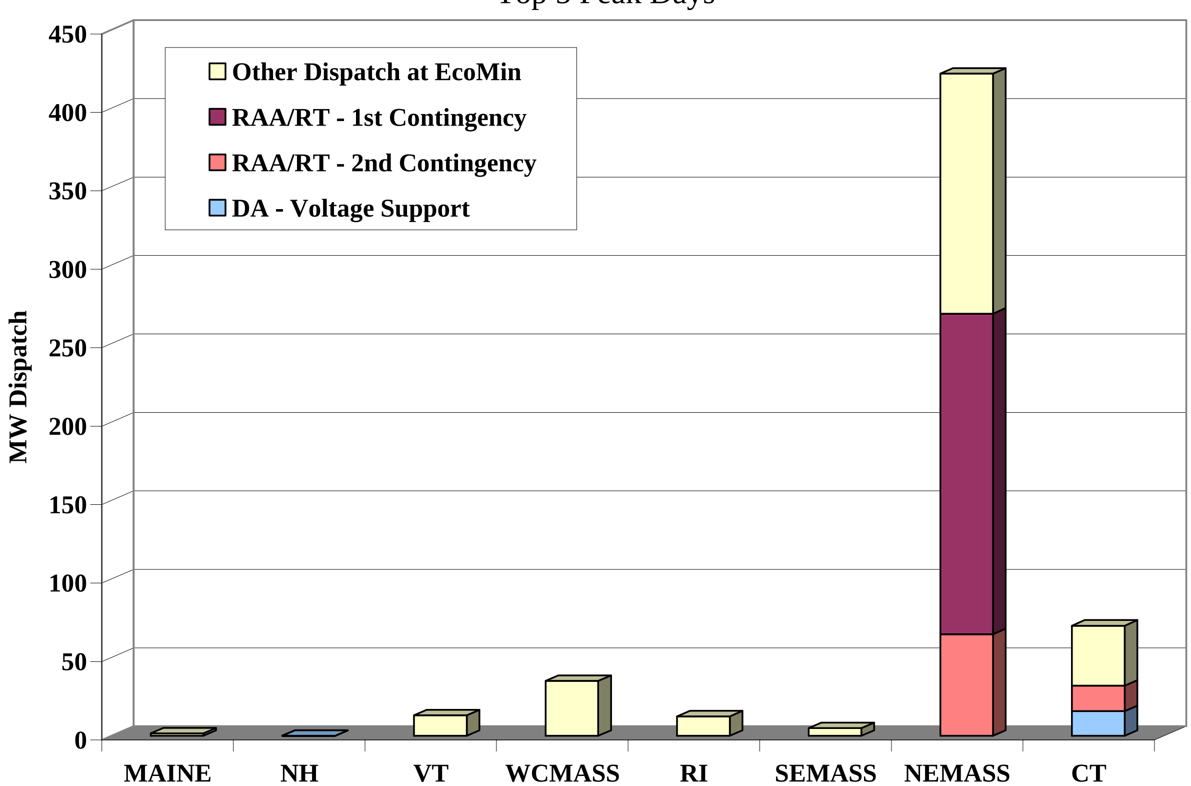


This figure shows that OOM quantities fluctuated within normal ranges for this area historically. Late in the year, there was an increase in the "Other Dispatch at EcoMin" category of OOM generation. We attribute this increase primarily to the sharp increase in natural gas prices that more frequently caused natural gas-fired generators to be dispatched down to their EcoMin.

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 offer in excess of marginal costs, which can also affect locational price signals when they are taken in merit order. When units are offered above marginal costs, it reduces the likelihood that they will be committed economically through the day-ahead market, thereby contributing to the need for supplemental commitments. Hence, it is a pattern that can be self-reinforcing.

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 magnitude and nature of out-of-merit actions at those times. This analysis is shown in Figure 21.

Figure 21
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 the out-of-merit dispatch for local 1st and 2nd contingencies increases significantly in the constrained areas on the highest-demand days, while most other categories of out-of-merit dispatch decrease. This emphasizes the importance of recognizing these reliability requirements within the SMD market framework. This will allow prices in these areas to reflect these requirements. To address this issue, the ISO is currently working to implement operating reserve markets that include the local reserve requirements in the constrained areas (i.e., Phase II Ancillary Services Markets ("ASM"). The Phase II ASM is planned for implementation in the fall of 2006.

F. Uplift Costs

In some cases, locational prices are not sufficient to cover the as-offered costs of resources required to serve load and meet all applicable reliability requirements. In these cases, the suppliers receive supplemental payments referred to as "Net Commitment Period Compensation" ("NCPCs"). The costs associated with these payments are recovered from loads through uplift charges. These charges are allocated differently depending on the reason for the action and whether it occurred before or after the day-ahead market.

To the extent that units committed in the day-ahead market process do not recover their commitment costs in the day-ahead market, they will receive NCPC payments. Some of these units are designated for voltage support, indicating that they are committed based on voltage reliability criteria rather than economic criteria in the day-ahead market. The remaining units are committed economically in the day-ahead market, but tend to have high commitment costs relative to their incremental energy costs. Economically committed units in load pockets that are committed due to the 2nd contingency proxy import limits are flagged by the ISO as "Local 2nd Contingency Protection Resources" resources, while the remainder is referred to as "Economic" resources. This designation determines how the NCPC charges are allocated, with Local 2nd Contingency Protection NCPCs are charged to the local zone, while the charges for "Economic" resources are allocated to all of New England.

Units committed after the day-ahead market closes can be designated as Local 2nd Contingency Protection Resources, Special Constraint Resources, or voltage support resources.

Units committed in the RAA process for any other reason are referred to as "Economic" resources. While some of the units receiving RT Economic NCPCs are committed to meet market-wide forecasted energy and operating reserve requirements, most are committed to meet forecasted load in local areas without violating any 1st contingency transmission limits. Special Constraint Resources ("SCRs") are requested by the local transmission owner to manage local constraints not modeled by the ISO.

There are several units in highly congested areas that are needed to satisfy local reliability requirements that do not receive enough revenue from the energy and capacity markets to cover their fixed costs of remaining in operation. Given trends in market revenues no new investment is expected to replace these resources. To maintain local reliability, therefore, these resources are covered under reliability agreements that provide supplemental payments to ensure that they recover their fixed costs. The costs of the various sources of uplift are allocated in different ways. Table 4 describes how the different types of uplift costs are allocated.

Table 4
Allocation of Uplift Costs

	Day-Ahead Market	RAA and Real-Time Dispatch
Voltage Support NCPCs:	**Allocated to network load in New England and Through or Out Reservations**	
Local 2nd Contingency Protection NCPCs:	**Allocated to load scheduled in the day-ahead market in the zone where the unit is located.**	**Prior to March 1, 2005: Allocated to real-time deviations in the zone where the unit is located.** **Since March 1, 2005: Allocated to real-time load and emergency purchases in the zone where the unit is located.**
Economic NCPCs (mostly local 1st contingencies):	**Allocated to load scheduled in the day-ahead market in all of New England.**	**Allocated to real-time deviations in all of New England.**
SCR NCPCs (called by TO):		**Allocated to transmission operator that requested the SCR**
Reliability Agreement Costs	**The charges are assessed to the physical load in the zone where the RMR unit is located.**	

In March 2005, the allocation of real-time Local 2nd Contingency Protection NCPCs was modified to be allocated to real-time load in the relevant zone. This change was made to address disincentives that the prior allocation created for engaging in virtual trading in the constrained areas. Prior to March 1, 2005, real-time NCPCs for 2nd contingencies were allocated to real-time deviations. For load serving entities and virtual loads, real-time deviations are the difference between day-ahead scheduled load and real-time consumption. For generators and virtual supply, real-time deviations are the differences between day-ahead scheduled generation and real-time actual production. Because there is generally no corresponding physical load or generation for virtual transactions, the entire virtual transaction would be a real-time deviation.

This change in the cost allocation was made because the 2nd contingency commitments protect the reliability of all the load in the area and allocating these costs to deviations often resulted in substantial charges that inefficiently discouraged virtual trading and price-sensitive demand bidding in these areas. Uplift costs for voltage support are allocated to all network loads throughout New England. Costs associated with payments under reliability agreements are allocated to network load on a zonal basis.

The following table summarizes the total costs of uplift associated with reliability agreements and supplemental commitment that are allocated to various areas within New England.

Table 5
Allocation of Uplift for Out-of-Market Energy and Reserves Costs
2004 & 2005

	Millions of Dollars	
Category of Uplift	**2004**	**2005**
2nd Contingencies (Local)		
Connecticut	**$27**	**$41**
Boston	**$15**	**$91**
Other Areas	**$2**	**$1**
1st Contingencies (Mostly Local)	**$45**	**$69**
Voltage Support	**$68**	**$75**
SCR	**$12**	**$10**
Reliability Agreement		
Connecticut	**$111**	**$190**
Boston	**$40**	**$26**
Other Areas	**$0**	**$25**
Total	**$320**	**$527**

Note: Since information is not publicly available on the breakdown of payments under reliability agreements by load zone, this analysis assumes that the ratio of payments to fixed cost guarantees is the same for NEMA/Boston, Connecticut, and other areas.

The total uplift costs incurred were $527 million in 2005, a 65 percent increase from 2004. This rise in uplift costs was driven primarily by a 200 percent rise in uplift from local 2nd contingencies and a 60 percent increase in reliability agreement costs. In 2005, approximately $117 million was assessed to NEMA/Boston and $231 million was assessed to Connecticut for reliability agreement costs and 2nd contingency commitments in those areas. However, $144 million of uplift was charged to all of New England for local 1st contingencies and voltage support requirements in local areas.

While it is undesirable to generate large NCPC payments, some level is unavoidable at this point in the market's development. However, certain allocation methods can have adverse incentive effects and revisions would serve the interest of economic efficiency. For example, the practice of allocating the cost of real-time NCPC payments to real-time deviations from day-ahead schedules can create inefficient disincentives for virtual trading and price-sensitive load purchases in the day-ahead market. This is important because virtual trading and price sensitive load facilitate price convergence between the markets and mitigate market power in the day-ahead market. As described above, the ISO modified its Tariff effective March 1, 2005 to assess NCPCs for local 2nd contingency commitments to real-time load in the zone. This change has reduced barriers to virtual trading in Connecticut and NEMA/Boston, which are the only zones with significant NCPCs for local 2nd contingency commitments. However, other costs associated with commitments that are needed to meet local reliability needs of the system continue to be allocated to real-time deviations. These include the costs associated with 1st contingency commitments and voltage support. Like the commitments for local 2nd contingencies, these commitments are made to protect physical load in specific areas. We recommend that the ISO reconsider how NCPC costs associated with supplemental commitments for local 1st contingencies and voltage support commitments are allocated. In particular, we recommend that the ISO consider allocating the costs of voltage support commitments to the network load in the affected areas, and allocating the costs of 1st contingency transmission constraint commitments (if they can be distinguished from market-wide capacity commitments) to the real-time load in the constrained area. These changes would improve incentives for virtual trading and price-responsive load scheduling in the day-ahead market.

NCPC costs associated with satisfying market-wide capacity needs are appropriate to allocate to real-time purchases (i.e., positive real-time load deviations) because they are generally necessary when load is under-scheduled in the day-ahead market. This allocation provides efficient incentives for participants to fully schedule load in the day-ahead market. This allocation differs from allocating the NCPC costs to *all* real-time deviations, which would include loads that were *over-scheduled* in the day-ahead market. Over-scheduling load does not contribute to the need to commit additional generation after the day-ahead market.

G. Market Operations -- Conclusions

In general, we conclude that the markets operated well during 2005. Price corrections have been rare, and load forecasting has been relatively accurate. However, substantial quantities of supplemental commitments continue to occur in both NEMA/Boston and Connecticut. These commitments are necessary, in part, because these areas do not have a large quantity of fast-start resources that can help meet the capacity requirements of the local area while offline.

Supplemental commitments and out-of-merit energy dispatch create four issues in the New England market.

- They create 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.
- They tend to mute signals to invest in areas that would benefit the most from additional generation and transmission investment. They also stifle incentives to develop demand response.
- They cause a substantial amount of uplift costs that is difficult for participants to hedge and can be quite volatile, most of which is generated by commitments in Connecticut and NEMA/Boston. The uplift costs associated with these commitments are allocated in a variety of ways based on Tariff requirements. Some of these allocations may be improved to create more efficient incentives.
- They can create incentives for generators frequently committed for reliability to avoid market-based commitment to seek additional payments through the reliability commitment process.

With regard to the last issue, the report finds that a very small number of generators in the NEMA/Boston area engaged in this conduct regularly until December 2005, which led to substantially more supplemental commitment in 2005 than in previous years. This conduct resulted in sizable NCPC payments to the supplier, as well as to other Boston area suppliers that were also committed more frequently for local reliability due to the conduct of the supplier in question.

The ISO is pursuing several additional measures to minimize reliance on supplemental commitments in load pockets include:

- Developing a new Combined Cycle unit dispatch process to gain additional unit flexibility and non-spin capability in load pockets;
- Developing new ancillary services markets to provide better incentives for resources in the load pockets, particularly for new fast-start units; and

In addition to these measures, we recommend the following changes to further reduce the inefficiencies associated with supplemental commitments. We recommend that the ISO:

- Re-evaluate the allocation of uplift costs associated with supplemental commitments for local 1st contingencies and voltage support commitments.

- To improve the incentives associated with the costs of voltage support commitments, we recommend the ISO consider allocating these costs to all network loads in the affected area rather than allocating the costs market-wide as is done currently.
- The ISO should consider allocating the costs of commitments made in load pockets to meet forecasted load in the area without violating any 1st contingency limits more narrowly. Currently, these costs are allocated throughout New England.

- Evaluate the underlying assumptions in the calculation of the import limits to constrained areas to minimize any unjustified inconsistencies between the day-ahead and real-time limits. This would improve the efficiency of the day-ahead commitment and tighten convergence between day-ahead and real-time market outcomes; and

- Consider incorporating local reliability commitment criteria currently used in the RAA process into the day-ahead market model.
  - To the extent that the commitment of a particular unit to satisfy a local requirement is known, it is most efficient to commit the unit as part of the overall cost minimization that occurs in the day-ahead market software.
  - This should improve price convergence and reduce incentives to under-schedule load in the day-ahead market (since the additional supply will be scheduled in the day-ahead market).
  - However, we recognize that issues related to the de-listing of units needed to meet these requirements would need to be evaluated and resolved.

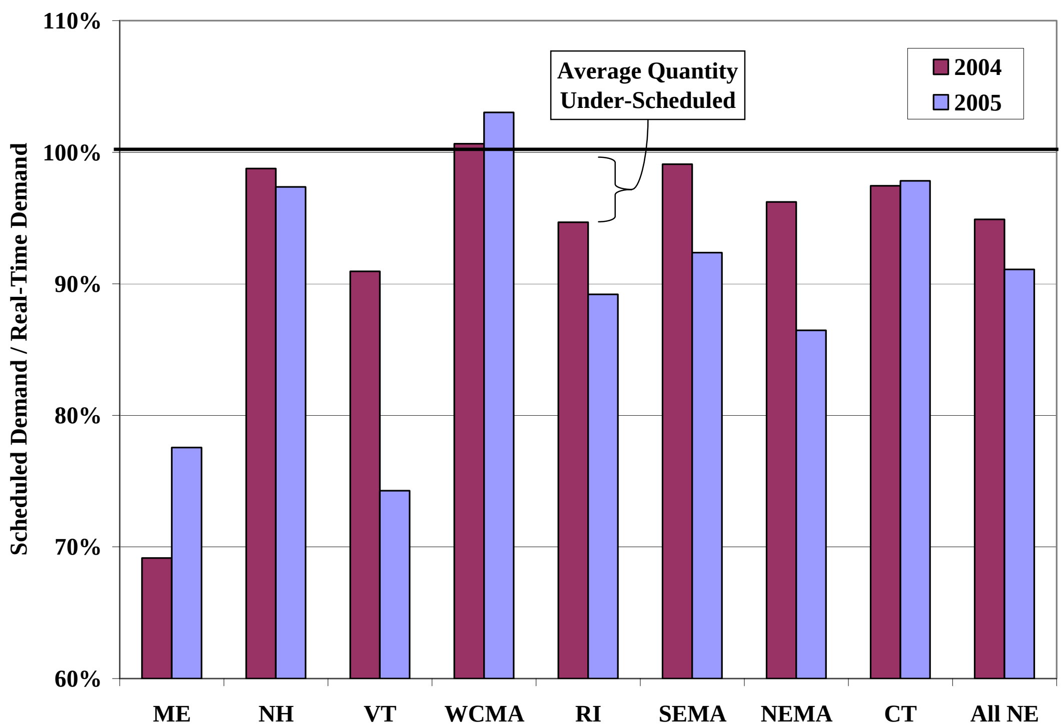
V. Load Scheduling in the Day-Ahead Market

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. Scheduling less net load (physical and virtual load net of virtual supply) than actual load ("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. Figure 22 shows the weighted average ratio of demand scheduled in the day-ahead market to real-time demand for each zone in 2004 and 2005. The scheduled day-ahead load includes the physical demand scheduled plus the net virtual load scheduled (virtual load minus virtual sales).

Figure 22
Average Ratio of Scheduled Demand to Real-Time Demand
2004 - 2005



The figure shows that the percentage of demand scheduled in the day-ahead market decreased from 95 percent in 2004 to 91 percent in 2005. While this is a small percentage change, it implies that the quantity of under-scheduling has increased substantially, from 5 percent to 9 percent. This change was driven primarily by the reduced scheduling of load in NEMA/Boston. However, the portion of demand scheduled day-ahead also decreased in Vermont, Rhode Island, and SEMA, but increased in Maine and WCMA.

The increase in under-scheduling in NEMA/Boston was consistent with the effects of the supplemental commitment after the day-ahead market and out-of-merit dispatch described in the prior section. Commitment after the day-ahead market, both in the RAA process and through self commitment, tends to depress real-time prices relative to day-ahead prices. This creates a premium in the day-ahead market and 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 because it increases the need for supplemental commitment, which in turn tends to reduce real-time prices and increases the incentive to under-schedule.

The most effective way to address under-scheduling is to reduce the need for supplemental commitment and out-of-merit dispatch by improving the representation of contingency requirements in the market software. This will cause the LMPs in the constrained areas to better reflect the value of energy and reserves. This improvement can be achieved in three ways:

- Implementing the real-time ancillary services markets under development as part of the Phase II ASM project will improve the consistency by including local reserve requirements. The Phase II AS markets are scheduled for implementation in the Fall of 2006.

- Identifying and minimizing any unjustified differences between the transmission limits (including the 2nd contingency proxy limits) used in the day-ahead and real-time market software; and

- Adding the local commitment requirements that are currently satisfied in the RAA to the day-ahead market. We have recommended that the ISO consider this change.

In summary, this section indicates that the overall scheduling patterns are consistent with the economic incentives facing the market participants. A key component of overall scheduling patterns has to do with the quantities of virtual load and virtual supply (collectively "virtual trading") scheduled in the day-ahead market. These patterns are evaluated in the following subsection.

B. Virtual Trading

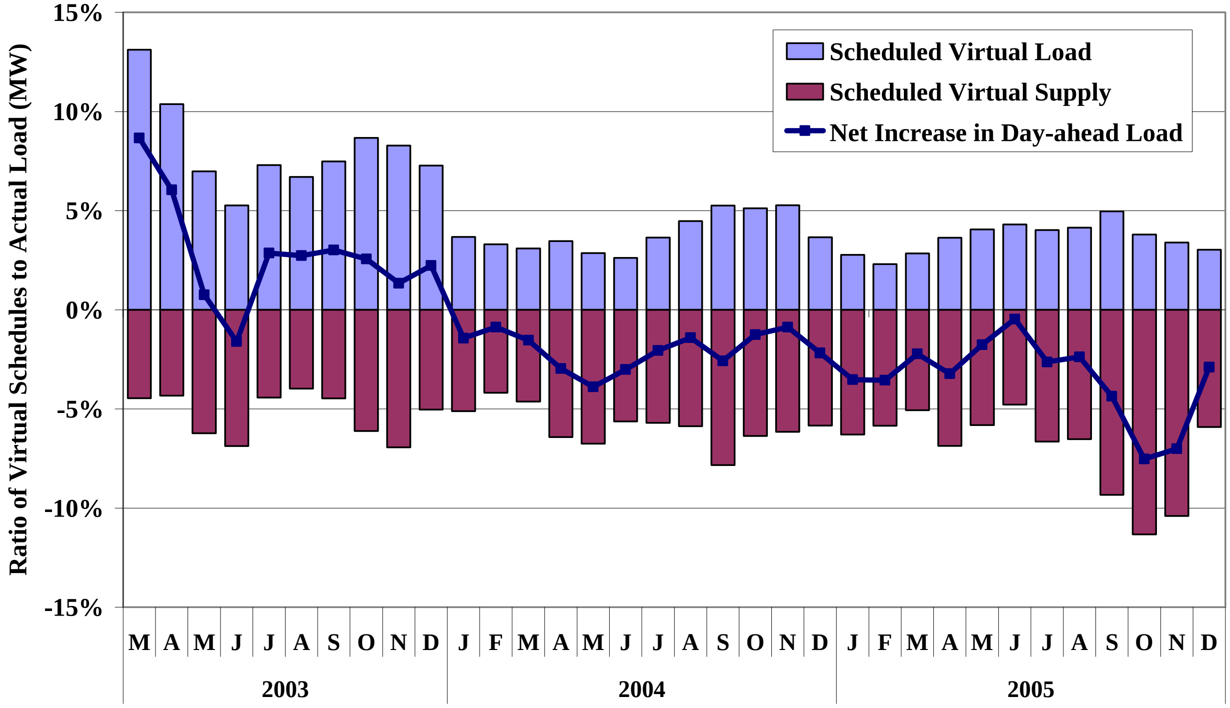
Virtual trading allows participation in the day-ahead market by entities other than LSEs and generators. Virtual trades settle in the real-time market. For example, if the day-ahead prices are lower than a participant expects they will be in the real-time market, the participant can make virtual purchases 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.

The following analysis evaluates the trends in virtual load and virtual supply in New England since the start of SMD. Figure 23 shows the quantities of scheduled virtual transactions as a percent of actual load in New England from 2003 to 2005.

The figure shows that the volumes of virtual purchases and sales as a percentage of actual load were highest during the first few months of SMD. The average quantity scheduled in the first month of SMD was 2,600 MW, but it ranged between 1 GW and 2 GW during 2004 and most of 2005. For several months during the fall of 2005, the quantity of virtual supply grew significantly. This was driven primarily by additional virtual supply scheduling in the NEMA/Boston load zone. The increase in virtual supply and slight decrease in virtual load were components of the overall reduction in net load scheduled in the day-ahead market that was discussed in prior sub-section.

Figure 23
Average Volume of Virtual Transactions per Hour
March 2003 to December 2005



Virtual trading can play an important role in the day-ahead market by 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 incentives that discourage virtual trading. In particular, the allocation of certain types of uplift costs to real-time deviations from day-ahead schedules provides disincentives to schedule virtual transactions. 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 24 shows the average uplift cost allocation per MWh resulting from uplift for NCPC costs in three areas of New England in 2004 and 2005.

Figure 24
Allocation of Operating Reserve Credits for 1st and 2nd Contingencies
January to December 2004 & 2005

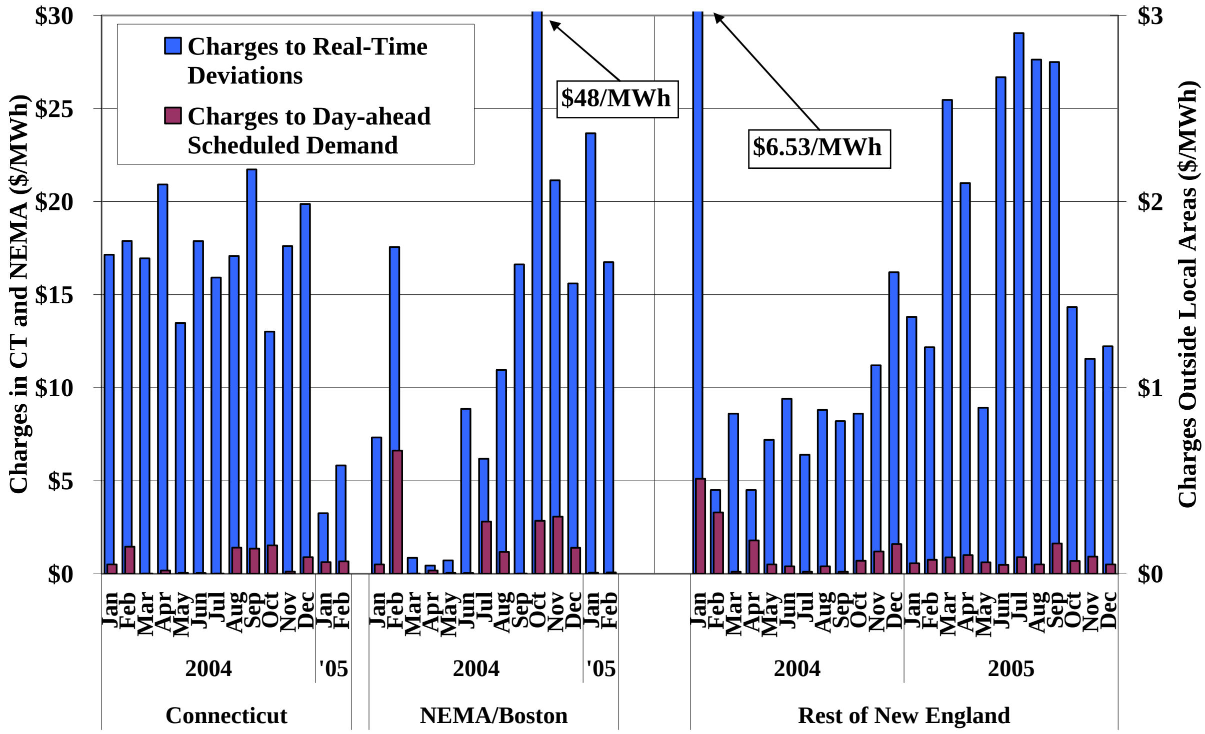


Figure 24 shows the average allocations to day-ahead scheduled demand and real-time deviations in Connecticut, NEMA/Boston, and the rest of New England. The uplift cost allocation method employed prior to March 2005 resulted in much larger charges to real-time deviations than to physical demand scheduled day-ahead. This imposed significant costs on virtual trades that are, by definition, real-time deviations. In NEMA/Boston and Connecticut, the real-time charges were quite high due to frequent supplemental commitment of units for local 2nd contingencies. Uplift costs associated with local 2nd contingency units were allocated directly to zones so that the costs were higher for real-time deviations in these locations. However, the allocation mechanism for 2nd contingencies was changed in March, 2005, and these costs are now assessed to real-time load in the zone. Since March 2005, day-ahead schedules and real-time deviations in NEMA/Boston and Connecticut have been assessed the same charges per MWh as the rest of New England for uplift costs that arise from 1st contingency commitments. This change substantially improved the incentives of virtual traders in the constrained areas by reducing a significant economic barrier to the efficient arbitrage of prices in these areas.

In order to arbitrage between day-ahead to real-time prices, virtual traders form expectations regarding the real-time prices at a location the following day. They will try to schedule virtual load when they expect the day-ahead price to be lower than the real-time price and virtual supply when they expect the day-ahead price to be higher. Because these expectations are subject to substantial uncertainty, virtual trades can result in a loss. Virtual traders will submit offers if they expect profits to exceed what they expect the allocation to be for real-time deviations. In August 2005, for example, virtual traders would have had to expect to earn at least $2.76 per MWh in order for their trades to be profitable. Real-time deviation charges create disincentives for virtual trading and this is reflected in the relatively low volume of trades shown in Figure 23.

Table 1 in Section II of this report shows the average day-ahead price premium ranged from $0.45 to $2.99 per MWh for different load zones in 2005. While risk aversion helps explain the day-ahead premium, it is likely that the difference between charges to day-ahead scheduled load and real-time deviations has contributed to the premium as well. According to Figure 24, load-serving entities paid only $0.05 per MWh on average during August 2005 in uplift charges by scheduling day-ahead. Thus, they would pay less on average by scheduling load at a slightly higher day-ahead price. Although the change in the allocation of 2nd contingency costs made in March 2005 was a substantial improvement, the continued allocation of real-time reliability commitment costs to real-time deviations continues to be an impediment to virtual trading. Since a large share of this allocation results from supplemental commitment to resolve local 1st contingency limits in local areas, we recommend that the ISO re-evaluate the allocation of these costs to assign the more directly to the affected areas.

C. Day-ahead Scheduling in Norwalk-Stamford

In 2005, day-ahead and real-time prices in the Norwalk-Stamford sub-area exhibited particularly poor convergence, as average day-ahead prices exceeded average real-time prices by $10.15/MWh. We generally expect participants in the day-ahead market to arbitrage predictable differences between day-ahead and real-time prices. Thus, the pattern of poor convergence is unusual, given that there are few barriers to virtual trading in the day-ahead market. In this sub-section, we examine the causes of poor price convergence in Norwalk-Stamford and identify factors that have helped to reduce the size of the day-ahead price premium. Table 6 summarizes the pattern of day-ahead and real-time prices in Norwalk-Stamford:

Table 6
Summary of Price Convergence in Norwalk-Stamford
2004 & 2005

Statistic	2004	2005
Average Day-Ahead Price	**$60.92**	**$107.46**
Average Real-Time Price	**$57.81**	**$97.31**
Average Day-Ahead Premium	**$3.11**	**$10.15**
Median Day-Ahead Premium	**$2.64**	**$4.04**
Number of Outliers > $100 DA Premium	**102**	**283**
Number of Outliers > $100 RT Premium	**90**	**93**

Note: Average prices are load-weighted.

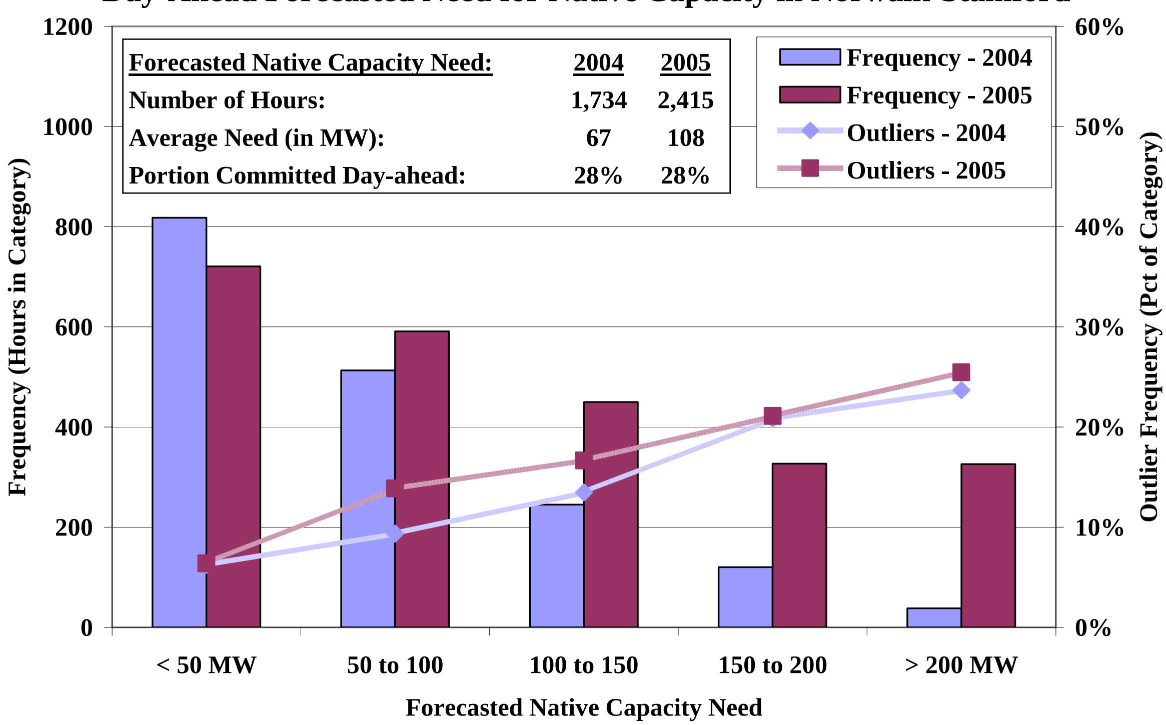
While a day-ahead premium existed in 2004, it grew considerably larger in 2005. The amount of real-time congestion also increased substantially in 2005. In both years, the median day-ahead premium was smaller than the average premium, suggesting that large positive outliers had a significant impact on the average, particularly in 2005. A significant difference between 2004 and 2005 is that these positive outliers (i.e., day-ahead premium) became much more frequent, while the negative outliers (i.e., real-time premium) did not increase.

There are a number of factors that may have contributed to the poorer price convergence in Norwalk-Stamford in 2005. There was significantly more congestion into Norwalk-Stamford in the day-ahead than in the real-time. This suggests either that demand was over-scheduled day-ahead relative to actual load, or that additional supplies became available after the day-ahead market and reduced congestion. Additional supply can become available if the import capability of the interface increases after the day-ahead market but before real-time. Supply also increases when supplemental commitments and self-commitments occur after the day-ahead market.

In the majority of hours, Norwalk-Stamford load can be served entirely by imports. When real-time demand rises above the import limit, generation inside Norwalk-Stamford must come on-line to serve the excess demand in real-time. When the day-ahead forecasted load in Norwalk-Stamford exceeds the import capability, the excess is not necessarily satisfied by scheduling internal generation. It is also possible for load serving entities to under-purchase in the day-ahead relative to their forecasted real-time consumption, and for virtual suppliers to schedule transactions that have the same impact as reducing day-ahead load. Generally, load serving entities schedule day-ahead load that is not very sensitive to the Norwalk-Stamford price and relatively close to what they expect to consume in real-time. Their incentive to bid in a price-sensitive manner is diminished by the fact that load serving entities settle at the load-weighted average price for the Connecticut zone, even if their customers are in Norwalk.

The following analysis examines the forecasted need for generation within the Norwalk-Stamford area based on the day-ahead load forecast and the import limit used in the day-ahead market. The bars in the figure below show how frequently the amount of required Norwalk generation was in various ranges in 2004 and 2005. No bars are shown for the hours when the forecasted need is 0 MW, which is more than 70 percent of the hours. The lines show the portion of each group of hour that experienced poor price convergence (i.e. the difference between day-ahead and real-time prices exceeded $100/MWh). These outliers, which account for less than 2 percent of all hours in 2004 and less than 4 percent in 2005, occurred frequently during periods when the forecasted need for Norwalk capacity was greater than 0 MW.

Figure 25
Day-Ahead Forecasted Need for Native Capacity in Norwalk-Stamford



Several conclusions can be derived from the figure above. First, there were substantially more hours in 2005 that required internal Norwalk-Stamford capacity to satisfy the energy needs of Norwalk-Stamford customers. This is consistent with higher overall load levels and the increased congestion in 2005. Second, only 28 percent of the anticipated internal capacity need was committed in the day-ahead market in both years, indicating that the remaining need were satisfied by a combination of under-scheduling by loads and net virtual supply. Third, the hours when the day-ahead to real-time price difference was greater than $100/MWh (i.e. outliers) occurred much more frequently during periods when there was an anticipated need for internal Norwalk-Stamford capacity. Additionally, the probability of large price differences increase as the anticipated need for internal capacity increases. In hours where the forecasted internal capacity need exceeded 200 MW, outlier events occurred roughly 25 percent of the time in 2004 and 2005.

The response by market participants to these patterns is also an important factor. As a response to persistent day-ahead price premiums, one would expect a change in day-ahead scheduling behavior. Load serving entities should reduce their day-ahead purchases, while virtual traders have strong incentives to increase their net virtual sales. Conversely, when the day-ahead price is consistently low, scheduling additional net virtual load puts upward pressure on day-ahead prices. To the extent that virtual schedules help prices converge, they are also profitable.

To examine whether virtual trading has generally improved convergence, Table 7 below summarizes the net profits for virtual trades placed in Norwalk-Stamford. It indicates that market participants have made substantial profits from virtual trading in this area, thereby helping improve day-ahead to real-time price convergence. Overall profits were greater in 2005, not because the volumes scheduled were larger, but because the day-ahead to real-time price differences were larger in 2005. During the hours with very poor price convergence (i.e. outlier hours), the average virtual supply quantity scheduled was 70 MW in 2004 and 63 MW in 2005. Even in the outlier hours, the virtual scheduling volumes were small relative to the total load in Norwalk-Stamford which rises above 1 GW in higher load hours.

Table 7
Profits from Virtual Scheduling in Norwalk-Stamford

	2004	2005
Virtual Supply		
All Hours		
Average Quantity Scheduled (MW)	**17**	**14**
Net Profits (in $000s)	**$1,113**	**$4,530**
Outlier Hours		
Average Quantity Scheduled (MW)	**70**	**63**
Net Profits (in $000s)	**$263**	**$2,474**
Virtual Load		
All Hours		
Average Quantity Scheduled (MW)	**3**	**6**
Net Profits (in $000s)	**-$103**	**$72**
Outlier Hours		
Average Quantity Scheduled (MW)	**2**	**4**
Net Profits (in $000s)	**$38**	**$128**

On the basis of these analyses, we attribute poor price convergence in the Norwalk-Stamford load pocket in 2005 to three factors:

- Generators in Norwalk-Stamford are usually not scheduled until after the day-ahead market so large amounts of supply routinely becomes available after the day-ahead market.
- There was a lack of price-responsive demand bidding in the day-ahead market, most likely because load serving entities settle at the Connecticut load-weighted average price and are not directly exposed to the Norwalk-Stamford price.
- The response of virtual suppliers improved convergence, but the volume of virtual supply was not sufficient to bring about close convergence.

We find that most of the factors that caused poor price convergence in 2005 were also present in 2004. However, the rise in Norwalk load relative to import capability increased the frequency of local capacity commitments and hours with poor price convergence. Overall, 84 percent of the capacity committed in Norwalk-Stamford is committed for local reliability by the operators, most of which occurs after the day-ahead market. The frequent inconsistency between day-ahead and real-time commitment generally decreases price convergence in Norwalk-Stamford. This underscores the potential benefit of using the same local reliability criteria in the day-ahead commitment model that are imposed in the RAA process.

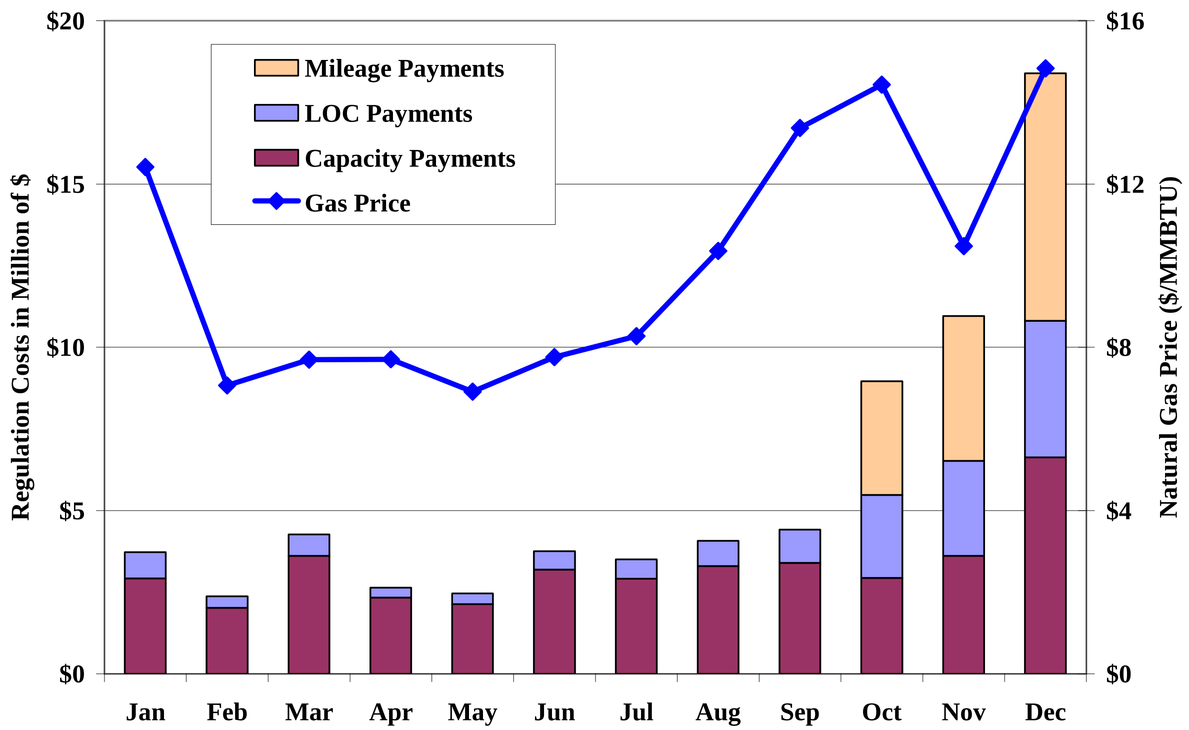
VI. Regulation Market

In this section of the report we evaluate the market for regulation. In particular, we evaluate (a) the overall costs of procuring regulation, (b) the market design changes that occurred during 2005 under Phase 1 of the Ancillary Services Market ("ASM"), and (c) the competitiveness of supply offers from regulation providers. Based on this evaluation, we provide several recommendations to improve the performance of the market.

A. Regulation Market Expenses

The Figure 26 summarizes of regulation market costs during 2005 from the three categories of expenses: 1) capacity payments, 2) lost opportunity cost payments ("LOC"), and 3) mileage payments. The figure also shows the monthly average natural gas prices.

Figure 26
Regulation Market Expenses
January to December, 2005



Capacity payments are paid to resources selected to provide regulation capability according to the regulation clearing price. Lost opportunity cost ("LOC") payments compensate regulating generators for over- and under-producing relative to their optimal energy dispatch level. Mileage payments, which were added on October 1 under the new market design, are given to regulation providers according to how much they move up and down in response to the regulation signal. The mileage payment equals 10 percent of the actual mileage (i.e. the movement in the generator's output up and down measured in MW) times the RCP.

Regulation market expenses averaged $3.5 million during the first nine months of 2005, but rose substantially from October through the end of 2005. Capacity payments were the most consistent portion of total expenses, but rose 84 percent from November to December. The rapid rise in overall costs included increases in: (i) LOC payments which grew by 151 percent from September to October and (ii) mileage payments, which did not exist until October 2005.

Input fuel prices can affect regulation market expenses, so Figure 26 is shows the monthly average natural gas prices. There are four potential reasons why natural gas prices affect regulation market expenses. First, providing regulation can reduce the operational efficiency of generators. These generators may consume more fuel to produce a given amount of electricity when they provide regulation. This portion of the costs of providing regulation is proportional to the price of fuel (because it is equal to the incremental increase in the unit's heat rate times the natural gas price). We expect market participants to reflect these costs in their regulation offer prices leading to higher RCPs. Since capacity payments and mileage payments are both a function of the RCP, they are both directly affected by increased RCPs.

Second, rising natural gas prices can lead to larger opportunity costs for regulation providers. Opportunity costs arise when a regulation provider is instructed to produce above or below the optimal energy output level. As fuel prices and electricity prices rise, the differences between the marginal costs of regulation providers and LMPs grow, leading to larger opportunity costs for some resources. The effect of higher natural gas prices on opportunity costs should be most directly reflected in LOC payments.

Third, higher fuel prices can affect the RCPs by leading to the selection of a different set of resources to provide regulation. As described below, the estimated LOC is heavily-weighted in the selection of the resources. To the extent that higher fuel prices raise some units' estimated LOCs,[13] it will tend to cause the market to select units with relatively low estimate LOCs (even though they may have higher regulation offers), resulting in an increase in the RCPs. Finally, when natural gas prices rise significantly, natural gas-fired units are committed less frequently, leading to fewer available offers from these units.

Hence, some of the variation in regulation costs may be explained by fluctuations in natural gas prices. Some of the increased regulation costs are also due to other factors, which is evident from the monthly average regulation costs shown in Figure 27. Later in this section, we discuss some of the other factors that contributed to the rise in regulation expenses.

B. Regulation Market Design Changes

Significant changes were made to the regulation market under Phase 1 of the ASM re-design that was implemented on October 1, 2005. Understanding these changes is important for accurately evaluating the fluctuations in regulation costs that occurred in 2005. One of the most significant changes was that the previous design used a system cost minimizing objective, while the new design uses a consumer payment minimizing objective. The main feature of the cost minimizing approach is that it sets a clearing price based on an *ex ante* estimate of the marginal cost to the system of providing regulation. Lost opportunity cost payments augment the payment of the clearing price to the extent that the clearing price does not cover the ex post calculation of as-bid costs of the units selected to provide regulation.

The consumer payment minimizing objective compensates generators based on the capacity set aside to provide regulation, the actual mileage of the unit, as well as the opportunity cost of not selling energy. The energy opportunity cost in this case is not reduced to account for the net

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13 Higher natural gas prices will increase the estimated lost opportunity costs of a natural gas-fired unit whenever a lower-efficiency gas-fired unit (i.e., a unit with a higher heat rate) is setting energy prices assuming both units are offering energy at their marginal cost.

revenues the supplier received from the regulation market. This approach selects the set of regulation offers that are expected to earn the lowest total payments from these three categories. This sub-section discusses the specific design changes and summarizes them in Table 8.

First, a mileage payment was added to pay generators based on the amount they move when regulating. The payment is equal to 10 percent of the mileage (i.e. the up and down distance measured in MW) times the RCP. Based on historic patterns of regulation deployment, this formula is expected to generate mileage payments and capacity payments of similar magnitude in the long term. Second, the RCP is now based on the highest accepted offer price. It was previously based on the ex ante estimate of the marginal cost of the highest-cost unit accepted.

Third, the method for selecting the resources to provide regulation has changed. While the model selects the resources with the lowest rank price to provide regulation under both designs, the formula for determining the rank price has changed under the new market design. Additionally, the selection process is iterative with one of the components of the rank price changing from the first to the second iteration as described below. Under the new design, the rank price is the sum of the following five quantities:

(i) *Estimated capacity payment* – In the first iteration of the model, this is the offer price of each unit. The subsequent iterations set this equal to the higher of the offer price and the previous iteration's highest priced accepted offer. Given that each generator's capacity payment is equal to the RCP, this iterative approach is designed to cause each generator's rank price to equal the estimated payment to the generator.

(ii) *Estimated mileage payment* – This is equal to the estimated capacity payment.

(iii) *Estimated lost opportunity cost payment* – This is the estimated opportunity cost from operating at the set point rather than at the most economic dispatch level (given the unit's offer prices and the prevailing LMP).

(iv) *Estimated production cost change* – This is similar to the estimated opportunity cost, but ramp rate limitations are considered in estimating the units' most economic dispatch level.

(v) *The look ahead penalty* – This measures the maximum possible change in the energy offer price within the regulating range relative to the set point. This is included in order to avoid selecting units that would earn large opportunity cost payments if they were to regulate into a range of their energy offer priced at extreme levels.

The following table summarizes the market design of the new regulation market implemented under Phase 1 of ASM in comparison to the prior market.

Table 8
Summary of Regulation Market Design Changes
Under Phase 1 of ASM

	REGO Market	ASM Phase 1 Market
Payments to Regulation Units:		
Components of Payment	Capacity Pymt + LOC Pymt	Capacity Pymt + LOC Pymt + Mileage Pymt
Determination of RCP	Marginal Rank Price	Highest Accepted Offer Price
Capacity Payment	Regulation Capability MWh * RCP	
Mileage Payment	None	10% * Mileage MW * RCP
LOC Payment	Energy LOC minus (RCP - Offer Price)	Energy LOC
Selection of Regulation Units:		
Components of Rank Price	= Offer Price	= Est. Capacity Pymt (= Offer price in first iteration)
		+ Est. Mileage Pymt (= Offer price in first iteration)
	+ Est. Energy LOC (based on DA LMP)	+ Est. Energy LOC (based on RT LMP)
		+ Est. Production Cost Change
		+ Look Ahead Penalty
Iterations	None	After the first iteration, offer prices are replaced with MAX{offer price , last iteration RCP}

Under the new design, the ranking process iterates until the set of units selected to provide regulation does not change for two consecutive iterations. However, the iteration process is subject to the constraint that if the RCP rises from one iteration to the next, the model will use the previous iteration to rank units. The timing of the selection process has changed under the new market design. Previously, the regulation market model would rank units and perform its selection after 6 PM on the evening before the operating day. The estimated lost opportunity costs were derived from day-ahead market LMPs and energy offers submitted for the real-time market. Under the new market, the ranking process is performed at the beginning of each hour of the operating day, and sometimes within the hour. The estimated lost opportunity costs, production cost change, and look-ahead penalty are derived from the latest available real-time LMPs. Within the operating hour, units are selected to provide regulation according to the rank determined at the top of the hour.

C. Effects of the Regulation Market Changes on Regulation Costs

We have evaluated the period in late 2005 corresponding to the initial operation of the new regulation market and the extent to which the new market design may have contributed to the increased costs that occurred in this time frame. There are two aspects of the market and how participants responded to the new design that likely contributed to the increase in costs.

First, the addition of the mileage payment creates a new source of revenue for regulation providers. The mileage payment is a function of the RCP and is designed to be roughly equal in magnitude to the capacity payment. Thus, market participants can expect to receive approximately twice the revenue for a given RCP under the new market design. The implication of this is that a competitive supplier should be willing to lower its offer price by roughly 50 percent. Similarly, the fact that net revenue from the regulation market are not subtracted from a supplier's lost opportunity cost should cause suppliers that expect to earn incremental net revenue in the regulation market to reduce their offer price. However, suppliers did not reduce their offer prices. The largest suppliers increased their offers. Other suppliers continued to submit offers that were comparably priced to offers in the old regulation market. One plausible explanation for this is the lack of experience with the new market design. This caused the sum of the capacity and mileage payments in the new market to be significantly higher than the capacity payment in the older market.

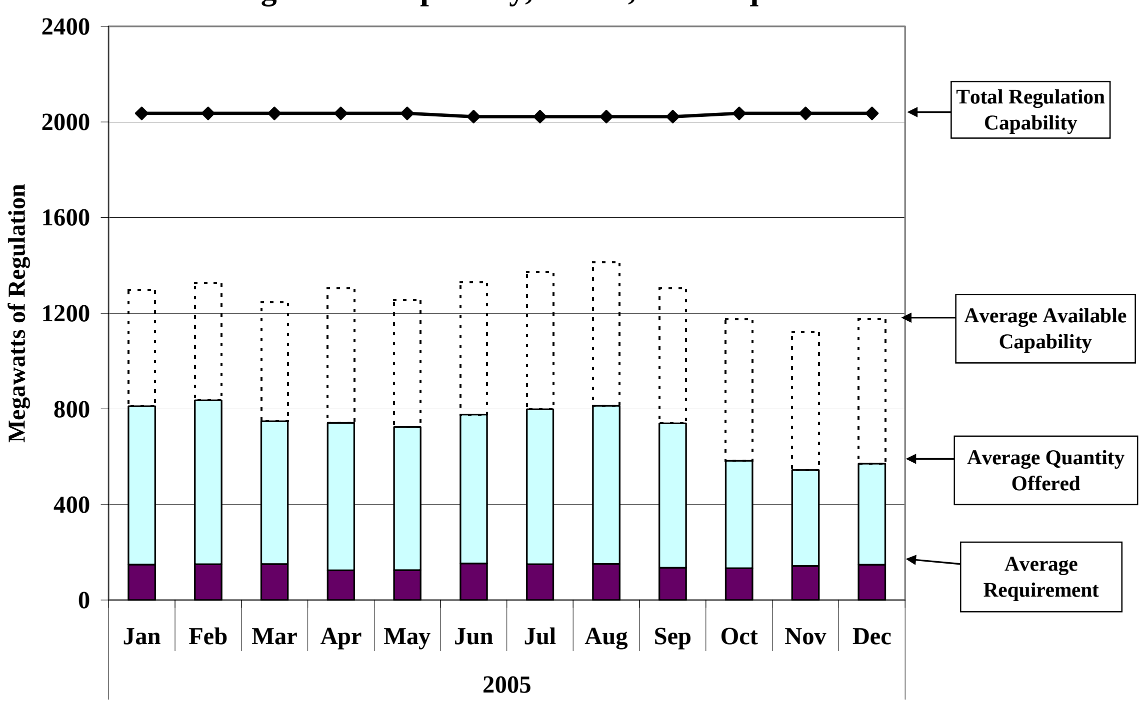
The second factor relates to how regulation resources are selected. As described above, regulation resources are selected based on the overall rank price, which includes estimates of the resources' opportunity costs and its offer price. However, the price is set by the highest accepted offer. We have concluded that the rank price includes a bias that over-weights the estimated lost opportunity costs. The source of this bias is that the *estimated production cost* component of the rank price is very similar to the *estimated LOC* component (i.e., it is a redundant component).

The only difference between the two is that the estimated production cost component incorporates units' ramp rate limitations in calculating the LOC. The effect of this redundant component is that the market will not always select the offers that will lead to the lowest estimated payments by consumers (the objective of the new market), which can result in higher RCPs. Additionally, we believe the *Look Ahead Penalty* component for some resources is not a good estimate of the potential payments it is intended to represent. This report includes recommendations to address these issues that are described in the conclusion sub-section below.

D. Regulation Offer Patterns

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 27 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.

Figure 27
Regulation Capability, Offers, and Requirements



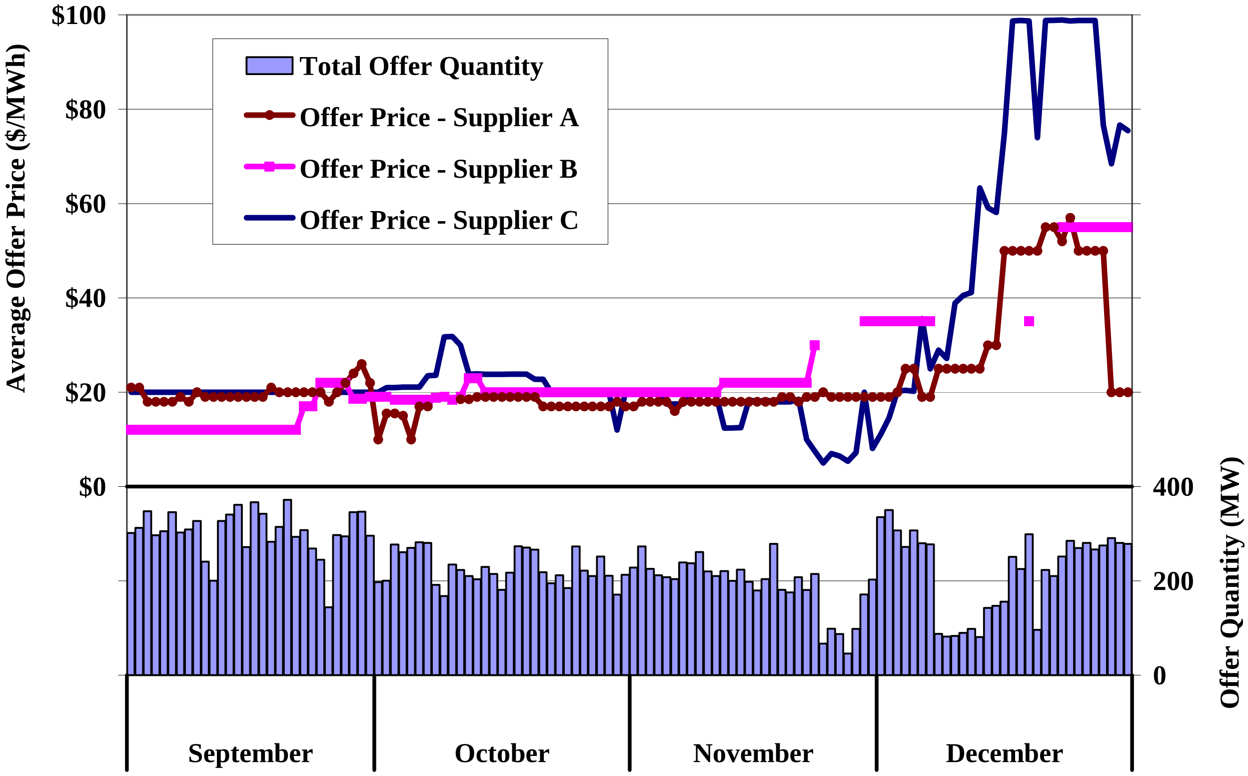
On average, 37 percent of regulation-capable capacity is effectively unavailable to the market. Regulation-capable capacity can be unavailable in a given hour for at least two reasons: (a) the capacity is on a non-quick start resource that was not committed prior to the regulation auction, or (b) the capacity is held on a portion of a resource that was self-scheduled for energy. Naturally, more regulation capacity tends to be available during the high-load portion of the day because more units have been committed and is 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 2005, an average of five times more regulation was offered into the market than was actually procured by the ISO. This would generally limit concerns about the exercise of 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. Likewise, supplies may be tight in low-demand hours when many regulation-capable resources are off-line. Indeed, Figure 27 shows that the more regulation capable resources are available during the summer and winter months than during the shoulder months in the spring and fall.

While it is typical for the available capacity to be reduced from September to October, the 130 MW drop shown in Figure 27 is larger than normal. May is comparable to October in terms of the overall demand level and the typical pattern of unit commitment, and yet May had an average of 80 MW more available capacity in 2005. The high natural gas prices in the fall likely resulted in fewer natural gas-fired resources being on-line in the fall than the spring. The volume of offers from on-line and quick start units also decreased substantially from September to October because one large supplier reduced its offer quantities by 65 percent.

We examined regulation offer patterns to better understand the reduced quantity of offers and rising expenses in the regulation market during the last three months of 2005. We found that much of the variation in available capacity and offer prices could be explained by changes in offers by the three largest suppliers of regulation in New England. The offer quantities and offer prices of the other regulation suppliers were relatively stable. The following figure summarizes offer prices and quantities from available capacity held by the three suppliers on a daily basis from September to December. It shows that there were significant fluctuations in offer prices and quantities from available resources of these three suppliers during the period.

Figure 28
Regulation Market Expenses
September to December, 2005



While Supplier B raised its offers from $12/MW to around $20/MW in late September, offer prices through late November were relatively stable for the three suppliers. Beginning at the end of November, the available quantity offered by Supplier B decreased markedly, and there were many days when Supplier B offered no regulation. We investigated the circumstances surround Supplier B's reduced offer quantities and did not find that Supplier B was attempting to exercise market power by withholding resources.

The other two suppliers also raised their offer prices substantial in this timeframe, with Supplier C raising its offers close to the offer cap for the regulation market of $100/MW. We have evaluated the offer patterns for these large suppliers and believe that the increases by these suppliers can be attributed to the following factors:

- The increase in natural gas prices that increased the marginal costs of regulating and may also have increased the gas contract penalties that can be caused by regulating.
- The reduced contestability of the market caused by the reduction in supply that occurred after late November.
- The bias in the selection of regulation resources described in the prior sub-section that allowed high-priced offers to be accepted more frequently.

Due to the simultaneous increases in natural gas prices and reduction in the supply of regulation, it is impossible to determine the relative contribution of each of these factors to the higher offer prices. In early 2006, the natural gas prices decreased substantially and regulation supply increased, which has improved the contestability of the market, lowered the cost of providing regulation, and moderated the regulation prices. Nonetheless, we recommend some incremental changes in the next sub-section that will address the third factor above that likely contributed to the increased regulation costs.

E. Conclusions and Recommendations

On October 1, 2005, a new regulation market was introduced as part of the Phase 1 Ancillary Services Market project. Regulation costs rose substantially after the introduction of the new regulation market, particularly in December 2005. We attribute the increase in costs to:

- The substantial increase in natural gas prices that occurred in the fourth quarter of 2005 contributed to higher regulation costs because it may account for some of the increase in regulation offers by the large suppliers, it increased the estimated LOCs in the regulation selector causing resources with higher offer prices to be selected, and it reduced the supply of regulation capable resources in some hours by reducing the commitment of natural gas-fired generation.

- The offer prices for regulation did not decrease as we would have expected due to the addition of the mileage payment and the change in the calculation of the lost opportunity cost payment. One plausible explanation for the fact that the offer prices did not decrease is inexperience of the suppliers with the new market design.

- The bias in the regulation selector described in the prior sub-section led to the selection of resources with higher offer prices and, therefore, increased the RCP in some hours. This issue also reduced the incentive for the large regulation suppliers to submit competitive regulation offers.

- The substantial reduction in supply that occurred late in the year reduced the contestability of the market (i.e., the supply available to enter the market in response to higher regulation prices). We believe the reduced contestability of the market and the incentive effects of the market design issue described above account for some of the increase in offer prices by the large regulation suppliers, which contributed to the higher RCPs and market costs.

Based on our review of the regulation market, we do not believe the market has any fatal design flaws or structural issues that would warrant wholesale changes in the market design or introduction of additional market power mitigation measures in the short-term. However, we have developed the following short-term recommendations to strengthen the incentives to submit competitive offers and improve the efficiency of the selection of regulation resources.

- We recommend that the *Estimated Production Cost* component be eliminated from the rank price, and

- We also recommend that the ISO evaluate modifications to the calculation of the *Look Ahead Penalty* to allow it to better reflect the ISO's actual LOC cost exposure.

These changes would improve the estimates of the payments to individual suppliers that are the basis for the selection of the regulating units. The efficiency of the regulation market depends, in large part, on the accuracy of these estimates.

In the long-term, we recommend that the ISO continue to evaluate potential market design changes that would enhance the performance of the regulation market. This may take the form of both incremental changes to the current design, as well as a fundamentally different market design. For example, the ISO should consider day-ahead and real-time regulation markets that are co-optimized with the energy market.

VII. Competitive Assessment

This section evaluates the competitive performance of the New England wholesale markets in 2005. This type of assessment is particularly important now that LMP markets are in operation. We identify geographic areas and market conditions that present the greatest potential for market power abuse. We use a methodology for measuring and analyzing potential withholding that was developed in prior assessments of the competitive performance in the New England markets.[14] In this section we address four main areas:

- Mechanisms by which sellers exercise market power in LMP markets;
- Structural market power indicators to assess competitive market conditions;
- Potential economic withholding; and
- Potential physical withholding.

A. Market Power and Withholding

Supplier market power can be defined as the ability to profitably raise prices above competitive levels. In electricity markets, this is generally done by economically or physically withholding generating resources. Economic withholding occurs when a resource is offered at prices above competitive levels to reduce its output or otherwise raise the market price. Physical withholding occurs when the output of a resource is not offered to the market when it is economic, and is accomplished practically by "derating" a generating unit (i.e., reducing the operating maximum).

Many suppliers may have the ability to increase prices, buy not every supplier can actually profit from doing so. The benefit of withholding is that the supplier will sell output at clearing prices above the competitive level, while the cost is that it will lose profits on the withheld output. Thus, withholding is generally only profitable when the price impact exceeds the opportunity cost of lost sales for the supplier.[15]

14 See, *e.g.*, *2004 Assessment of the Electricity Markets in New England*, *2002 Competitive Assessment of the Energy Market in New England*, and *2001 Competitive Assessment of the Energy Market in New England*.

15 This section evaluates whether market participants have exercised market power by withholding supply in order to raise market clearing prices for energy. It is also possible for market participants to exercise

Other than the size of the market participant, there are several additional factors that affect whether a market participant has market power. First, if a supplier has already sold power in a forward market, then it will not be able to sell that power at an inflated clearing price in the spot market. Thus, forward power sales by large suppliers effectively reduce their incentive to raise price in the spot market. Second, the incentive to withhold partly depends on the impact the withholding is expected to have on clearing prices. When demand levels are high in wholesale electric markets, a given quantity of withholding has a larger price impact than when demand levels are lower. Thus, large suppliers are more likely to possess market power during high demand periods than at other times.

Third, in order to exercise market power, a large supplier must have sufficient information about the physical conditions of the power system and actions of other suppliers to know that the market may be vulnerable to withholding. Since no supplier has perfect information, the conditions that give rise to market power (e.g., transmission constraints and high demand) must be reasonably predictable. The next section defines market conditions where certain suppliers possess market power.

B. Structural Market Power Indicators

The first step in a market power analysis is to define the relevant market, which includes the definition of a relevant product and the relevant geographic market where the product is traded. Once this is established, it is possible to assess conditions under which one or more large suppliers could profitably raise prices. This sub-section examines structural aspects of supply and demand in the relevant market in order to focus the behavioral analyses in later sections.

1. Defining the Relevant Market

Electricity is physically homogeneous (i.e., each megawatt of electricity is physically interchangeable) even though the characteristics of the generating units that produce the

market power in the provision of reliability services to ISO New England. The value of these reliability services is generally not reflected in market clearing prices and this issue is evaluated in Section IV.D.

electricity vary substantially (*e.g.*, electricity from a coal-fired plant is substitutable with electricity from a nuclear power plant). Despite this physical homogeneity, the definition of the relevant product market is affected by the unique characteristics of electricity. For example, it is not generally economic to store electricity, so the market operator must continuously adjust suppliers' output to satisfy the demand in real time. This limits inter-temporal substitution between spot and forward electricity markets.

In defining the relevant product market, we must identify the generating capacity that can produce the relevant product. In this regard, we consider two categories of capacity: (i) on-line and quick start capacity available for deployment in the real-time spot market, and (ii) off-line non-quick start capacity available for commitment in the next 24-hour timeframe. While only the former category is available to compete in the real-time spot market, both of these categories compete in the day-ahead market, making the day-ahead market less susceptible to market power. In general, forward markets are less vulnerable to market power because buyers can defer purchases if they expect prices to be lower in the spot market. The timeframe in which the market is most vulnerable to the exercise of market power is the real-time spot market when only on-line and fast-start capacity is available for deployment. Hence, we define the relevant product as energy produced in real time. This is appropriate because the value of energy in all other forward markets, including the day-ahead market, is derived from the value of energy in the real-time market.

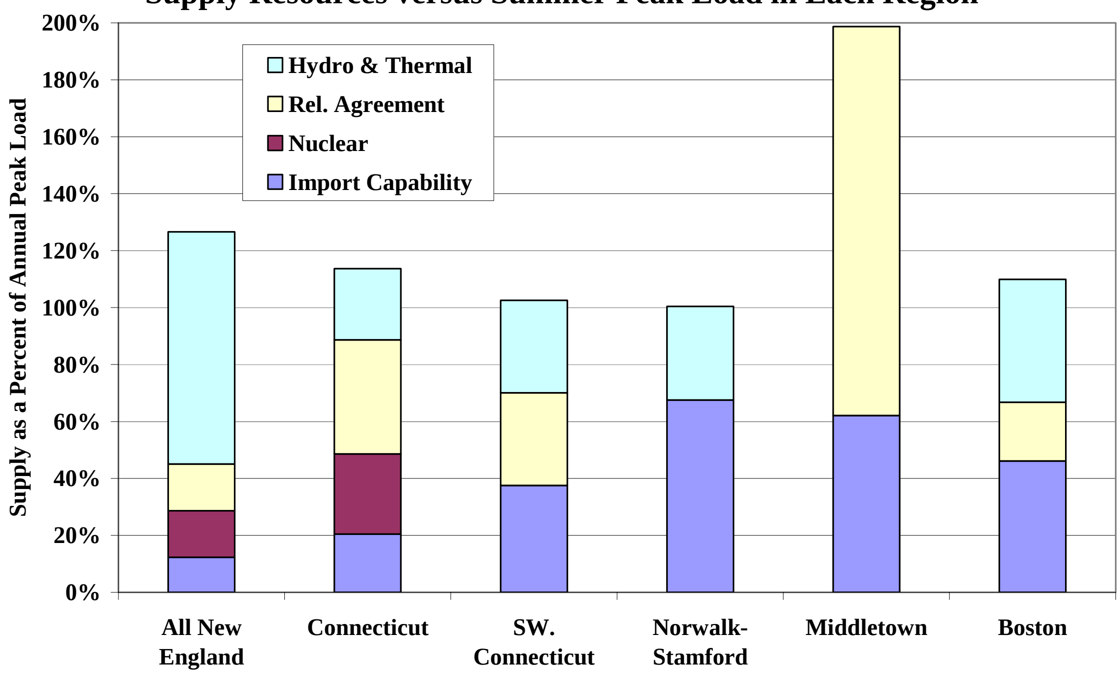
The second dimension of the market that must be defined is the geographic area in which suppliers compete to sell the relevant product, referred to as the relevant geographic market. In electricity markets, the relevant geographic market is generally defined by the transmission network constraints. When a transmission constraint is binding, there are limits on the extent to which power can flow between regions. In these situations, a supplier within the geographic area faces competition from fewer suppliers. There are a small number of geographic areas in New England that are generally recognized as being persistently constrained and, therefore, restricted at times from importing power from the rest of New England. When these areas are transmission-constrained they constitute distinct geographic markets that should be analyzed separately. These geographic markets are:

- All of New England;
- All of Connecticut;
- The southwest portion of Connecticut;
- Norwalk-Stamford which is contained in southwest Connecticut;
- The Middletown portion of Connecticut; and
- The NEMA/Boston.

2. Installed Capacity in Geographic Markets

This section provides a summary of supply resources and market shares in the geographic submarkets identified above. Each market can be served by a combination of native resources and imports. Native resources are limited by the physical characteristics of the generators in the area while imports are limited by the transfer capability of the transmission grid. Figure 29 shows several categories of supply relative to the load in each of the six regions of interest.

Figure 29
Supply Resources versus Summer Peak Load in Each Region



For each region under summer peak load conditions, Figure 29 shows import capability and three categories of installed summer capability: (i) nuclear units, (ii) units with reliability agreements, and (iii) all other generators. These resources are shown as a percentage of demand, although a substantial quantity of additional capacity is also necessary for reserves in New England. The figure shows that while the New England control area can import no more than 12 percent of its load, the five load pockets can serve larger shares of their load with imports into the constrained area. In particular, Norwalk-Stamford and Middletown can rely on imports to serve more than 60 percent of their load under peak conditions. Alternatively, imports can supply only 46 percent of the load in NEMA/Boston, 38 percent of the load in Southwest Connecticut, and 20 percent of the load in all of Connecticut.

The figure also shows the margin between the total available supply, including both imports and native resources, and the peak load. Areas with lower margins may be more susceptible to withholding than other areas. For example, the total supply able to serve Norwalk-Stamford exceeds the annual peak load by only one percent. Thus, even a small reduction in supply or import capability to Norwalk-Stamford can cause a shortage under peak conditions.

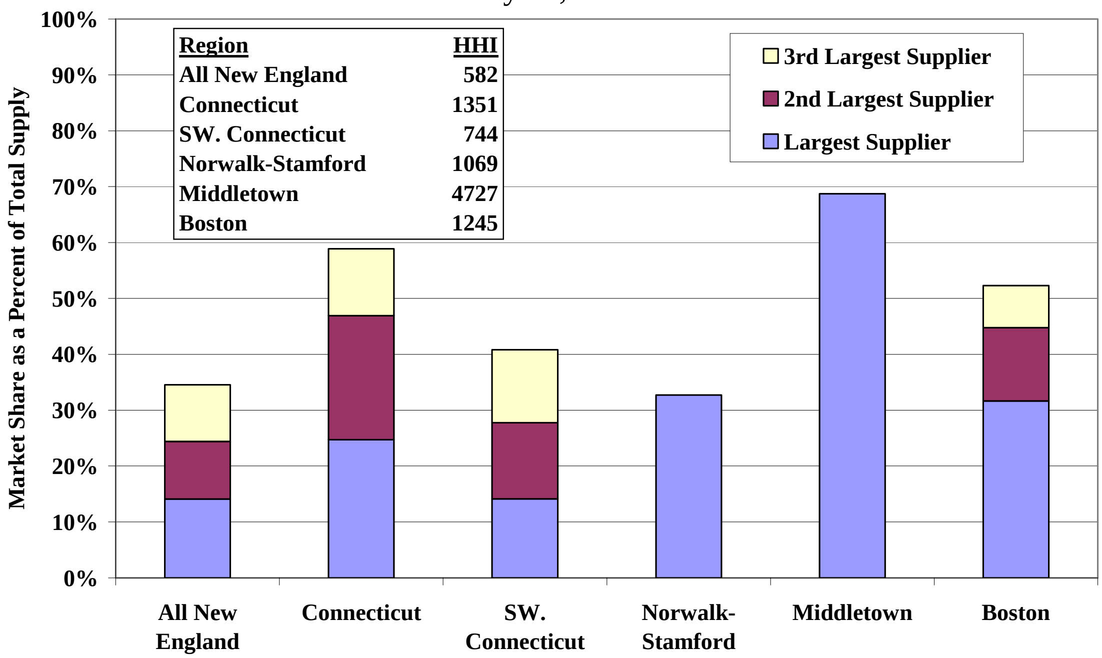
Internal generation is shown separately for nuclear capacity and capacity under reliability agreements because these resources are likely to pose fewer market power concerns. In order to exercise market power successfully in an electricity market, it can be important to be able to withhold capacity only at times when it will be profitable because the lost revenue on withheld units can be very costly. Nuclear generators cannot be dispatched down significantly to allow the owner of the unit to profitably withhold. Thus, the owner of nuclear generation would have to also own significant amounts of non-nuclear capacity that could be withheld from the market.

Units with reliability agreements are obligated to offer their units at short-run marginal costs on a daily basis, which makes it unlikely that such units could be used to economically withhold. The short-run marginal costs are reviewed by the ISO's internal Market Monitoring department and are the offers of these units are monitored on an on-going basis. While it is possible for a market participant to physically withhold capacity from a unit that is under a reliability agreement, the units will incur a reduction in the fixed cost payments if they fail to meet their target available hours as specified in the reliability agreement. Hence, units thus may have an incentive to report themselves as available when they are not in order to avoid a reduction to their target available hours. If the units are called upon during such a period, however, the supplier will incur a significant non-performance penalty. The target availability hours provisions of a reliability agreement, in conjunction with the non-performance penalties set out in those agreements, provide a substantial disincentive to inaccurately report the unit's availability status. This also provides a substantial disincentive to withhold a unit with a reliability agreement.

The areas within Connecticut rely heavily on nuclear and units under reliability agreements, particularly Middletown. This significantly reduces the portion of the capacity in those areas that could be withheld to exercise market power.

The previous figure shows that the capacity margins are as low as one percent in some areas. Market power is generally of greater concern in areas where capacity margins are small. However, the extent of market power also depends on the market shares of the largest suppliers. For each region, Figure 30 shows the market shares of the largest three suppliers as of the time of the annual peak load on July 27, 2005. The remainder of supply to each region comes from smaller suppliers and import capability. We also show the Herfindahl-Hirschman Index ("HHI") for each region. The HHI is a standard measure of market concentration calculated by summing the square of each participant's market share. In our analysis, we assume imports are highly competitive and so treat the imports as having zero market share. For example, in a market with two suppliers and import capability all of equal size, the HHI would be close to 2200 [$(33\%)^2 + (33\%)^2 + (0\%)^2$]. This assumption will tend to understate the true level of concentration because, in reality, the market outside of the area that is the source of the imports is not perfectly competitive.

Figure 30
Installed Capacity Market Shares for Three Largest Suppliers
July 27, 2005



The figure indicates a substantial variation in market structure across New England. The largest suppliers have market shares ranging from 14 percent in all New England and Southwest Connecticut to 69 percent in Middletown. Likewise, there is variation in the number of suppliers that have significant market shares. For instance, Norwalk-Stamford and Middletown have only one native supplier, while the top three suppliers in Southwest Connecticut have virtually the same market shares. While Middletown has only a single supplier, the market power is substantially mitigated by the fact that all of the capacity in this area is under reliability agreements.

Of the regions with more than one supplier, NEMA/Boston is the area with the largest single supplier; although Connecticut's largest two suppliers both have market shares close to 25 percent. Based on market shares, all of New England and Southwest Connecticut appear to be of less concern since the largest supplier in each area accounts for 14 percent of total resources. The HHI results suggest that only Middletown is highly concentrated; this can raise potential market power concerns.[16] The HHI for Norwalk-Stamford is very low, which is counter-intuitive since there is only one supplier in the area. Of the remaining four areas, Connecticut and NEMA/Boston have the highest HHI statistics with 1351 and 1245, respectively.

While HHI statistics can be instructive in generally indicating the concentration of the market, it does not allow one to draw reliable conclusions regarding potential market power in wholesale electricity markets due to the special nature of the electricity markets. In particular, it does not consider demand conditions, load obligations, or the heterogeneous effects of generation on transmission constraints based on their location. In the next sub-section, we introduce a pivotal supplier analysis which is more appropriate for evaluating market power in electricity markets.

3. Pivotal Supplier Analysis

While HHI statistics can provide reliable competitive inferences for many types of products, this is not generally the case in electricity spot markets.[17,18] The HHI's usefulness is limited by the fact that it reflects only the supply-side of the market, ignoring demand-side factors that affect the competitiveness of the market. The most important demand-side factor is the level of load. Since electricity cannot be stored economically, production must match demand on a real-time basis. When demand rises, an increasing quantity of generating capacity is utilized to satisfy the demand, leaving less capacity that can respond by increasing output if a large supplier withholds resources. Hence, markets with higher resource margins tend to be more competitive, which is not recognized by the HHI statistics.

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16 The antitrust agencies and the FERC consider markets with HHI levels above 1800 as highly concentrated for purposes of evaluating the competitive effects of mergers.

17 It is true that the DOJ and FTC evaluate the *change* in HHI as part of its merger analysis. However, this is only a preliminary analysis that would typically be followed by a more rigorous simulation of the likely price effects of the merger. It is also important to note the HHI analysis employed by the antitrust agencies is not intended to determine whether a supplier has market power.

18 For example, see Severin Borenstein, James B. Bushnell, and Christopher R. Knittel, "Market Power in Electricity Markets: Beyond Concentration Measures," *Energy Journal* 20(4), 1999, pp. 65-88.

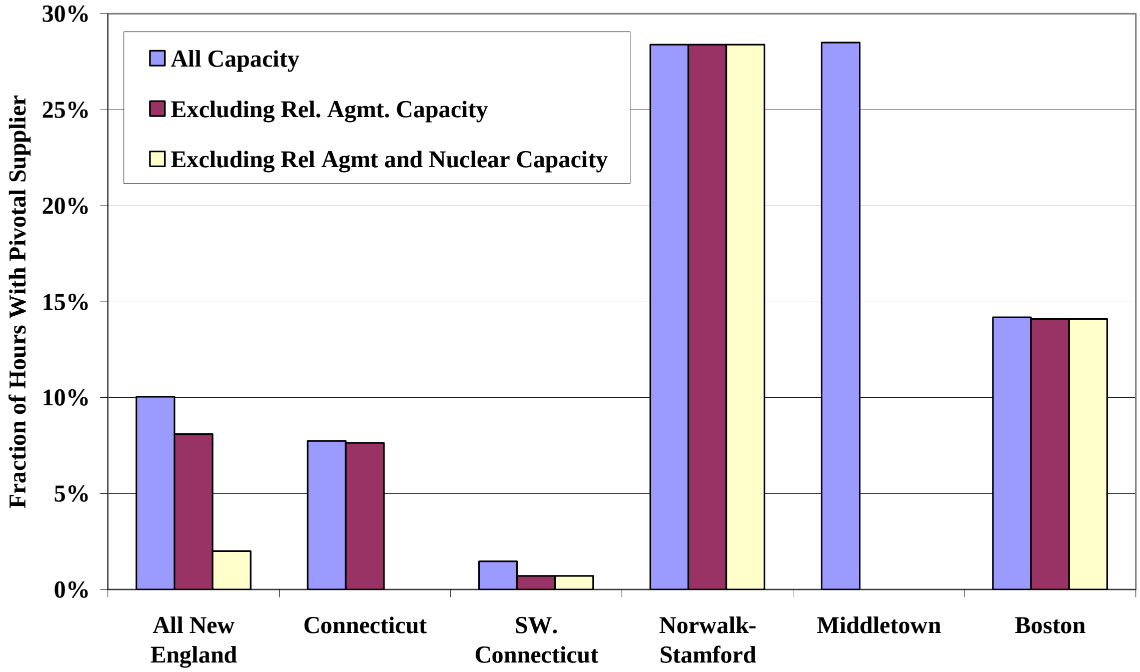
A more reliable means to evaluate the competitiveness of spot electricity markets and recognize the dynamic nature of market power in these markets is to identify when one or more suppliers are "pivotal". A supplier is pivotal when the output of some of its resources is needed to meet demand in the market. A pivotal supplier has the ability to unilaterally raise the spot market prices to arbitrarily high levels by offering its energy at a very high price level. Hence, the market may be subject to substantial market power abuse when one or more suppliers are pivotal and they have the incentive to raise prices. The Federal Energy Regulatory Commission has adopted a form of pivotal supplier test as an initial screen for market power in granting market-based rates.[19] This section of the report assesses which suppliers were pivotal in the real-time energy market during the study period.

Even small suppliers can be pivotal for brief periods. For example, all suppliers are pivotal during periods of shortage. This does not mean that all suppliers should be deemed to have market power. As described above, suppliers must have both the *ability* and *incentive* to raise prices to be deemed to have market power. For a supplier to have the ability to substantially raise the balancing energy prices, it must be able to foresee that it will likely be pivotal. In general, the more frequently a supplier is pivotal, the easier it will be for it to foresee circumstances when it can raise the clearing price.

To assess which areas have the most frequent conditions when market power might be a concern, Figure 31 shows the portion of hours when at least one supplier was pivotal in each region during 2005. The figure also shows the impact of excluding nuclear units and units under reliability agreements from the analysis. This is shown because withholding these classes of capacity is unlikely as discussed earlier in this section.

19 The FERC test is called the "Supply Margin Assessment". For a description, see: Order On Rehearing And Modifying Interim Generation Market Power Analysis And Mitigation Policy, 107 FERC ¶ 61,018, April 14, 2004.

Figure 31
Frequency of One or More Pivotal Suppliers Based on Type of Withheld Capacity
All Hours – 2005



There are three load pockets inside Connecticut that have historically been heavily concentrated. The figure indicates that if all capacity could be withheld, Norwalk-Stamford and Middletown would each have had at least one pivotal supplier in about 28 percent of hours. While the concerns about the exercise of market power in Middletown are virtually eliminated by the fact that all of the capacity there was under reliability agreements, Norwalk-Stamford had a high degree of concentration that warrants further review. Southwest Connecticut had a pivotal supplier in less than two percent of all hours, and this would drop below one percent if reliability agreement capacity were excluded from the analysis. Hence, market power is of less concern there. The conclusions that Middletown and Southwest Connecticut do not warrant further review are supported by the fact that the interfaces into these areas experienced almost no real-time congestion during 2005, while congestion into Norwalk-Stamford was significant.

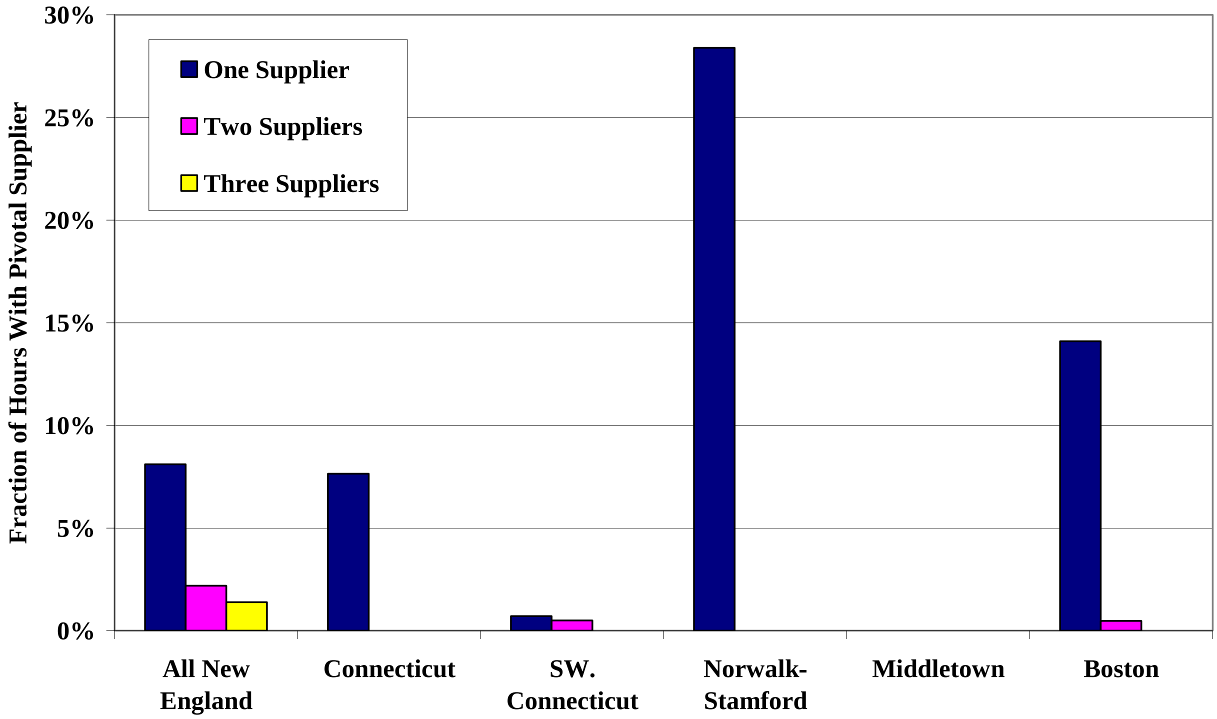
Connecticut had a pivotal supplier 8 percent of the time in 2005 (in nearly 700 hours). However, the largest supplier in Connecticut owns only nuclear capacity. In order to exercise market power, the largest supplier would need to withhold from non-nuclear resources in order to raise the clearing prices paid for its nuclear production. Therefore, it is appropriate to exclude the nuclear capacity from the pivotal supplier frequency for Connecticut. Similarly, the second largest supplier in Connecticut has a substantial amount of capacity under reliability agreements, which reduces its incentives to withhold. Excluding capacity covered under reliability agreements and from nuclear units, we found no hours with pivotal suppliers in Connecticut. Furthermore, the transmission interface into Connecticut experienced very little congestion during 2005.

Outside of Connecticut, the largest supplier in NEMA/Boston is pivotal in 14 percent of hours. Excluding nuclear units and units under reliability agreements does not change this result significantly. These results raise potential market power concerns for NEMA/Boston.

The largest supplier in all of New England is pivotal in 10 percent of the hours. The extent of potential market power for the entire New England region depends on how reliability agreements and nuclear capacity affect the incentives of large suppliers. Excluding reliability agreement capacity from the pivotal supplier analysis reduces the pivotal frequency to 8 percent of the hours. Further, excluding nuclear capacity would reduce the pivotal frequency to just two percent of hours. However, the reasons for excluding nuclear capacity from the analysis do not apply to the largest suppliers in New England. These suppliers have large portfolios with a combination of nuclear and non-nuclear capacity, and while they are not expected to physically withhold their nuclear capacity from the market, their nuclear capacity would earn more revenue if they withheld their non-nuclear capacity. Accordingly, NEMA/Boston and all of New England warrant further review.

The pivotal supplier summary indicates significant market power potential in Norwalk-Stamford, NEMA/Boston, and all of New England. Additionally, Figure 30 indicates that there are areas with several dominant suppliers, suggesting that several suppliers might be pivotal in these areas under certain conditions. Figure 32 shows the number of pivotal suppliers during hours where one or more supplier is pivotal in each region.

Figure 32
Frequency of One or More Pivotal Suppliers
Excluding Capacity Under Reliability Agreements -- All Hours in 2005



The frequency shown in this figure is the same as in the previous figure (Figure 31), excluding capacity under reliability agreements. This figure also shows the frequency with which two and three suppliers are pivotal in an hour. In the five load pockets, it is very uncommon for more than one supplier to be pivotal at the same time. In the case of Connecticut, the only pivotal supplier owns exclusively nuclear capacity, which is not likely to provide that supplier with an incentive to withhold. In All New England, while the second and third-largest suppliers were pivotal far less than the largest, they were still pivotal in more than 100 hours.

Since the relevant market includes capacity able to serve demand in the real-time market, it excludes non-fast-start capacity that is off line. There is some variation in the market shares on a daily basis due to differences in the commitments, but little variation in the identity of the largest supplier under most conditions in 2005. Therefore, each area had a single supplier that was most likely to have market power. Accordingly, the next sub-section will compare the behavior of the largest single supplier with that of other suppliers under various market conditions.

As described above, market power tends to be more prevalent as the level of demand grows. In order to strategically withhold, a dominant supplier must be able to reasonably foresee its opportunities to raise prices. Since load levels are relatively predictable, a supplier with market power could focus its withholding strategy on periods of high demand.

To assess when withholding is most likely to be profitable, Figure 33 shows the fraction of hours when a supplier is pivotal by load level. The left most bar in each load range shows the fraction of hours when a supplier is pivotal in Norwalk-Stamford. The next bar shows the results for NEMA/Boston, and the last bar shows All New England. Middletown, Southwest Connecticut, and Connecticut are not shown because congestion on the interfaces into these areas and instances when a supplier was pivotal was infrequent during 2005.

Figure 33
Frequency of One or More Pivotal Suppliers by Load Level
Excluding Capacity Under Reliability Agreements – All Hours in 2005

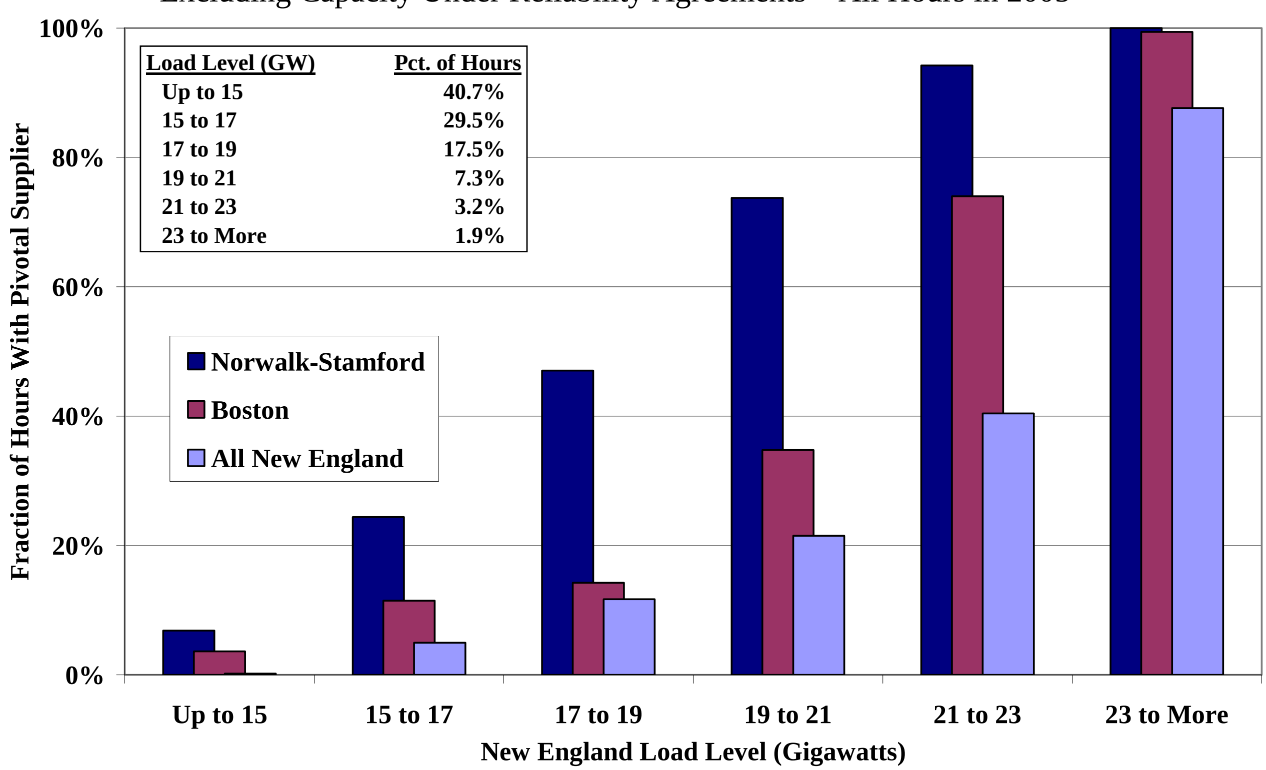


Figure 33 indicates that the single supplier in Norwalk-Stamford was pivotal in nearly half the hours when the load in New England was between 17 and 19 GW, and in the most of hours when load was greater than 19 GW in New England. Load was above 17 GW in approximately 30 percent of the hours during 2005. In NEMA/Boston, the largest supplier was pivotal in more than 70 percent of the hours when load exceeded 21 GW. The largest supplier was pivotal in more than 10 percent of the hours in NEMA/Boston when load was higher than 15 GW (60 percent of the hours during the year). In All of New England, the largest supplier was pivotal in 88 percent of the hours when load exceeded 23 GW, although this represents only 1.9 percent of the hours. The largest supplier was pivotal in more than 10 percent of the hours all of New England when load was higher than 17 GW (47 percent of the hours during the year).

Based on the pivotal supplier analysis in this sub-section, market power is most likely to be a concern in Norwalk-Stamford when New England load is greater than 17 GW, in NEMA/Boston when load rises above 19 GW, and in All of New England when load is above 21 GW. The following sections examine the behavior of pivotal suppliers under various load conditions to assess whether the behavior has been consistent with competitive expectations.

C. Economic Withholding

Economic withholding occurs when a supplier raises its offer prices substantially above competitive levels to raise the market price. Therefore, an analysis of economic withholding requires a comparison of actual offers to competitive offers.

Suppliers lacking market power maximize profits by offering resources at marginal costs. A generator's marginal cost is the incremental cost of producing additional output, including inter-temporal opportunity costs, incremental risks associated with unit outages, fuel, additional O&M, and other incremental costs attributable to the incremental output. For most fossil-fuel resources, marginal costs are closely approximated by their variable production costs (primarily fuel inputs, labor, and variable operating and maintenance costs). However, at high output levels or after having run long periods without routine maintenance, outage risks and expected increases in O&M costs can create substantial additional incremental costs. Generating resources with energy limitations, such as hydroelectric units or fossil-fuel units with output restrictions as a result of environmental considerations, must forego revenue in a future period when they produce in the current period. These units incur an inter-temporal opportunity cost associated with producing that can cause their marginal costs to be much larger than their variable production costs.

Establishing a proxy for units' marginal costs as a competitive benchmark is a key component of our analysis. This is necessary to determine the quantity of output that is potentially economically withheld. The ISO's Internal Market Monitoring Unit calculates generator cost reference levels pursuant to Attachment A of Section III of the ISO's Tariff. The Internal Market Monitoring Unit has provided us with cost reference levels, which can be used as one competitive benchmark for our analysis of economic withholding.[20]

1. Measuring Economic Withholding

We measure economic withholding by estimating an output gap for units that fail a conduct test for their start-up, no-load, and incremental energy offer parameters indicating that they are submitting offers in excess of competitive levels. The output gap is the difference between the unit's capacity that is economic at the prevailing clearing price and the amount that is actually produced by the unit. In essence, the output gap shows the quantity of generation that is withheld from the market as a result of having submitted offers above competitive levels. Therefore, the output gap for any unit would generally equal:

$Q_i^{econ} - Q_i^{prod}$ when greater than zero, where:

Q_i^{econ} = Economic level of output for unit i; and

Q_i^{prod} = Actual production of unit i.

To estimate Q_i^{econ}, the economic level of output for a particular unit, it is necessary to evaluate all parts of the unit's three-part reference level: start-up cost reference, no-load cost reference,

20 In the case of one unit, variable cost estimates were used instead of the reference level because the reference level substantially understated the unit's marginal costs.

and incremental energy cost reference. These costs jointly determine whether a unit would have been economic at the clearing price for at least the unit's minimum run time. We employ a three-stage process to determine the economic output level for a unit in a particular hour. In the first stage we examine whether the unit would have been economic *for commitment* on that day if it had offered its at marginal costs – i.e., whether the unit would have recovered its actual start-up, no-load, and incremental costs running at the dispatch point dictated by the prevailing LMP (constrained by its EcoMin and EcoMax) for its minimum run time. If a unit was economic for commitment, we then identify the set of contiguous hours during which the unit was economic to have online. Finally, we determine the economic level of incremental output in hours when the unit was economic to run. In all three cases, the marginal costs assumed for the generator are the reference levels for the unit used in the ISO's mitigation measures plus a threshold.[21]

In hours when the unit was not economic to run and on days when the unit was not economic for commitment, the economic level of output was considered to be zero. To reflect the timeframe in which commitment decisions are actually made, this assessment is based on day-ahead market outcomes for non-quick start units, and for quick start units this assessment is based on real-time market outcomes.

Q_i^{prod} is the actual observed production of the unit. The difference between Q_i^{econ} and Q_i^{prod} represents how much the unit fell short of its economic production level. However, some adjustments are necessary to estimate the actual output gap because some units are dispatched at levels lower than their three-part offers would indicate. This can be due either to transmission constraints, reserve considerations, or changes in market conditions between the time when unit commitment is performed and real-time. Therefore, we adjust Q_i^{prod} upward to reflect three-part offers that would have made a unit economic to run, even though the unit may not have been fully dispatched. For example, if the ISO manually reduces the dispatch of an economic unit, the

21 For incremental energy offers, a unit fails if the offer exceeds (i) the reference level plus $25/MWh or (ii) 150 percent of the reference level. For an offer at the minimum generation level, a unit fails if the offer exceeds 150 percent of the reference level. For the start-up parameter, a unit fails if the offer exceeds 150 percent of the reference level.

reduction in output is excluded from the output gap. Hence the output gap formula used for this report is:

$Q_i^{econ} - \max(Q_i^{prod}, Q_i^{offer})$ when greater than zero, where:

Q_i^{offer} = offer output level of i.

By using the greater of actual production or the output level offered at the clearing price, units that are subject to ramp limitations are excluded from the output gap. In addition, portions of resources that are offered above marginal costs due to a forward reserve market obligation are not included in the output gap.

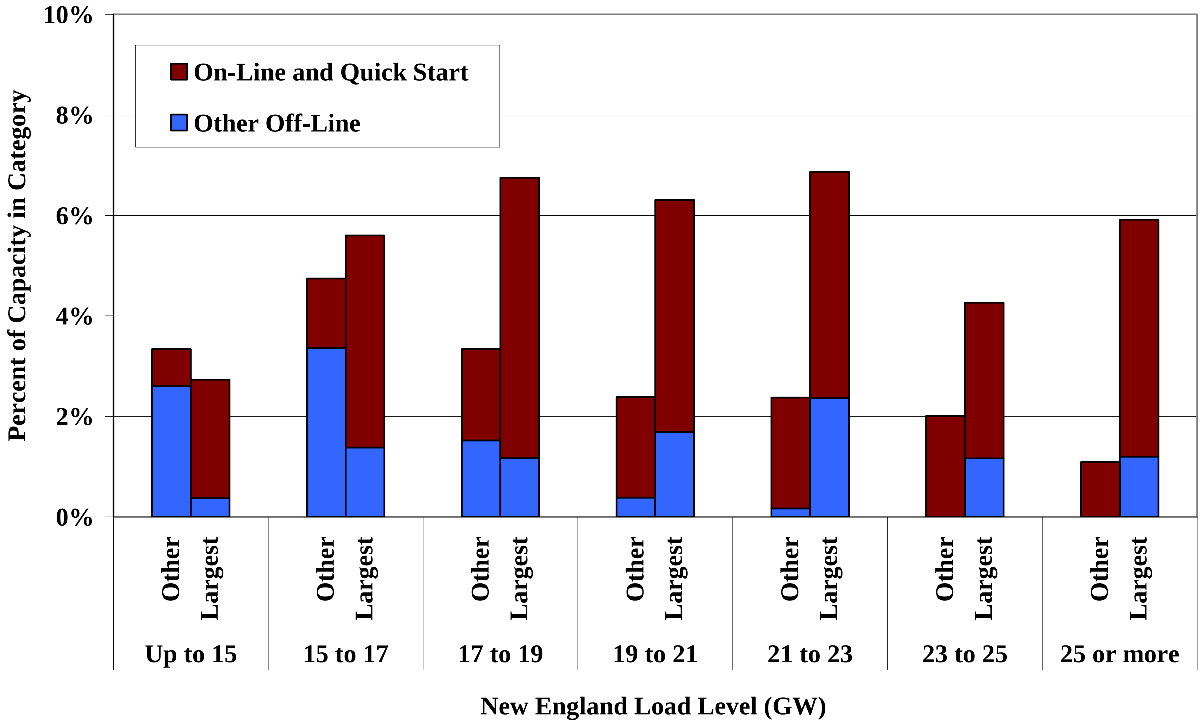
In this section we evaluate the output gap results relative to various market conditions and participant characteristics. The objective is to determine whether the output gap increases when those factors prevail that can create the ability and incentive for a pivotal supplier to exercise market power. This allows us to test whether the output gap varies in a manner consistent with attempts to exercise market power. Based on the pivotal supplier analysis from the previous sub-section, the level of market demand is a key factor in determining when a dominant supplier is most likely to possess market power in some geographic market. In this section, we examine output gap results for the following four geographic markets:

- All of New England;
- Connecticut;
- Norwalk-Stamford; and
- NEMA/Boston.

2. Output Gap in NEMA/Boston

Figure 34 shows output gap results for the NEMA/Boston area for various load levels. Based on the pivotal supplier analysis in the previous sub-section, the dominant supplier can expect to be pivotal in most hours when load exceeds 21 GW and a significant share of the hours when load is between 19 GW and 21 GW. Output gap statistics are shown for the dominant supplier compared with all other suppliers in the area.

Figure 34
Average Output Gap by Load Level and Type of Supplier
NEMA/Boston – 2005



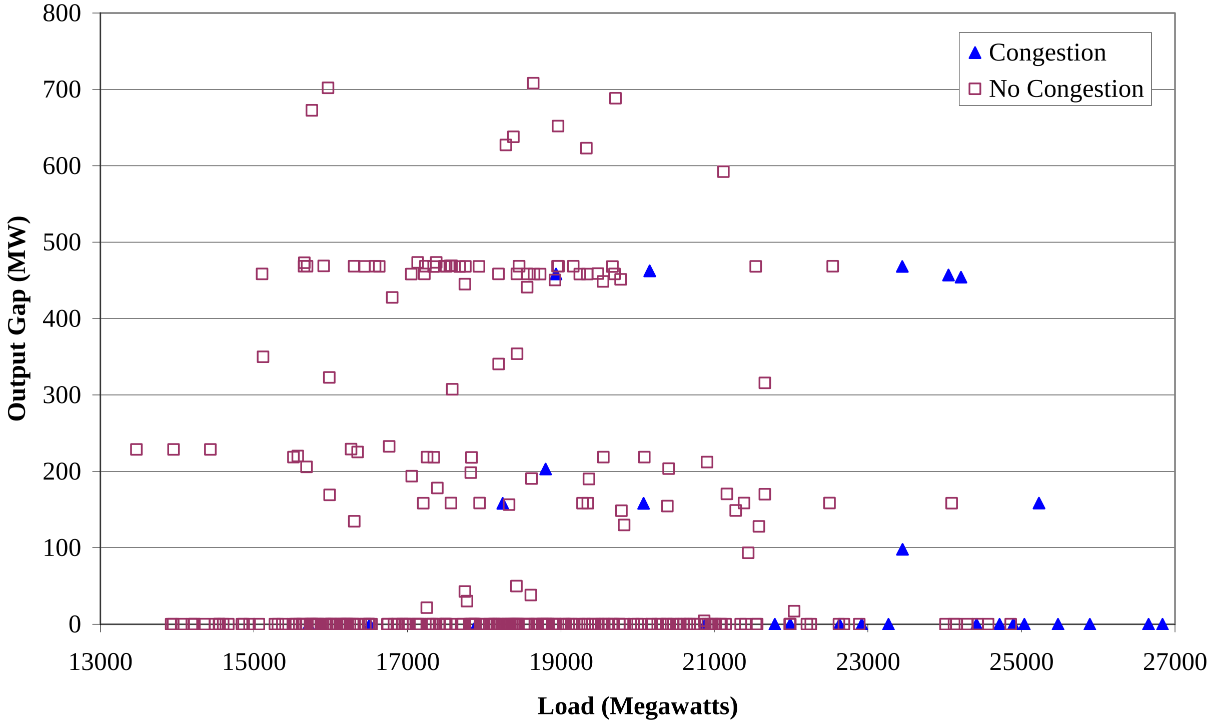
The figure shows that the output gap for the other suppliers in NEMA/Boston is very low, and it exhibits a downward trend as load increases. However, the output gap for the largest supplier is larger and does not exhibit a clear downward trend. The primary assets of the largest supplier in NEMA/Boston in 2005 were offered into the market by a different entity for most of 2004, so the identify of the largest supplier changed when these assets changed hands. In 2004, the comparable output gap statistics for these resources averaged between 1 percent and 3 percent of capacity when load exceeded 17 GW. In 2005, these resources had output gap quantities that averaged nearly 6 percent when load exceeded 17 GW. Additionally, in approximately one-third of the hours when load exceeded 17 GW, the largest supplier's output gap averaged more than 300 MW. This increase in the output gap of the largest supplier from 2004 to 2005 warrants additional review.

The output gap statistics shown in Figure 34 should be considered in the context of several other factors affecting the incentives of the largest supplier. The units on which the output gap occurred were frequently committed for local reliability reasons or self-scheduled. Conduct was identified in Section IV.D. that resulted in increases in the local reliability payments to the supplier. The fact that the supplier increased its offer prices (contributing to the output gap results reported in this section) is consistent with the "pay-as-bid" incentives that a supplier faces when it receives compensation based primarily on its offer price (rather than a market-clearing price). Even in perfectly competitive pay-as-bid markets, firms with no market power will rationally raise their offer above marginal costs because they do not receive a market-clearing price. Although offers by competitive suppliers in pay-as-bid markets will rise above marginal costs, one cannot conclude that all increases in offer prices by suppliers that face pay-as-bid incentives are competitively justified. To the extent that suppliers hold resources needed to meet local reliability requirements and do not face competition to meet those requirements, they may have local market power that can be exercised by inflating the guarantee payments they receive from the ISO to make the resources available.

Because the output gap could indicate an attempt to exercise market power by raising prices or an attempt to increase NCPC payments, we present additional analyses below intended to distinguish between strategies. In particular, it is useful to analyze the conditions under which the conduct occurred. A strategy to increase uplift payments is more likely to be effective under a variety of market conditions, whereas a strategy to profit from increasing prices is likely to only be profitable during periods of congestion in to the NEMA/Boston area or under very high load conditions.

The following analysis examines the correlation between congestion into NEMA/Boston and the output gap of the largest supplier. Figure 35 shows the output gap associated with on-line and quick start units of the largest supplier on an hourly basis for the peak load hour of each day during 2005. Days with real-time congestion in the afternoon into NEMA/Boston are denoted with solid triangles, while the remaining days are shown with outlined squares.

Figure 35
Hourly Output Gap of Largest Supplier in NEMA/Boston versus Congestion
By Load Level, On-Line and Quick Start Units
Daily Peak Load Hour – 2005



The figure shows that there were only 28 days with congestion in the peak hours into NEMA/Boston, which is consistent with the fact that NEMA/Boston was import-limited in just 2 percent of the hours in the real-time market. There were five days with congestion into NEMA/Boston when the largest supplier had an output gap for on-line units of more than 450 MW, and five additional days when the largest supplier had an output gap for on-line units of 100 to 200 MW. While the output gap most likely had a substantial price impact on these 10 days, the pattern of behavior is not focused on these days. In addition, the output gap from on-line units was close to zero on 64 percent of the days with afternoon congestion into NEMA/Boston.

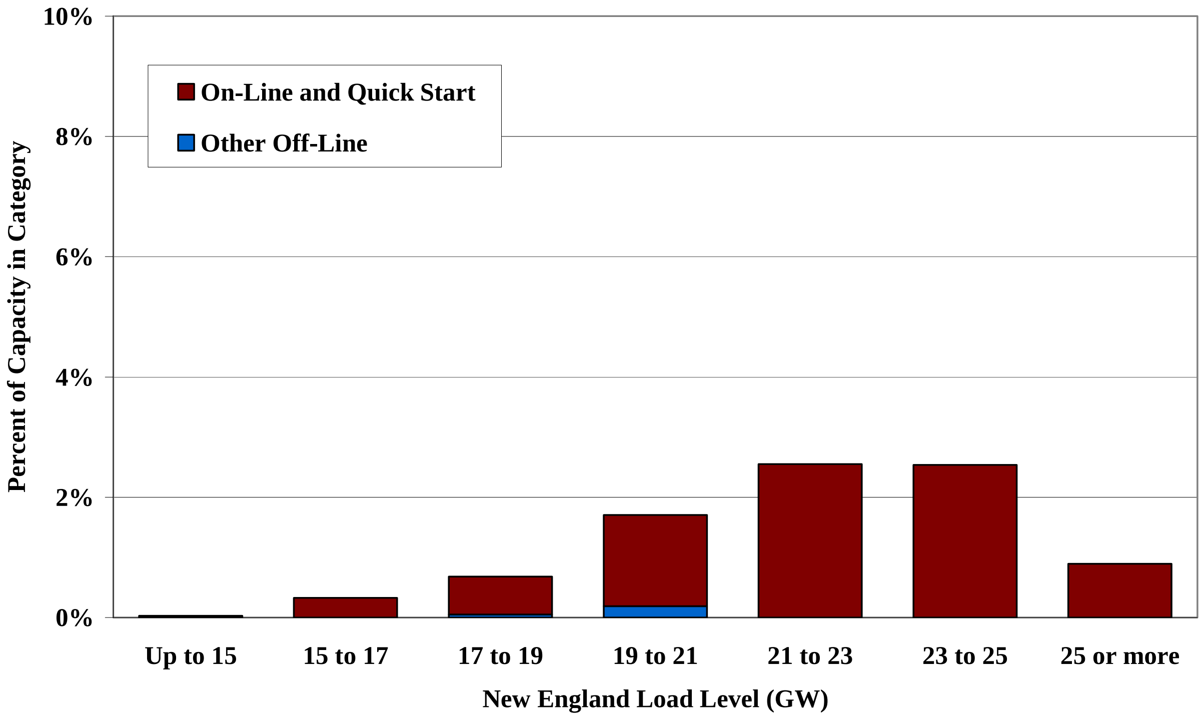
The pivotal supplier analysis from the previous sub-section indicates that the probability of the largest supplier being pivotal was highly correlated with load, and that the largest supplier was usually pivotal when load rose above 19 GW. However, the figure shows that the output gap occurred during a wide range of load conditions. If the output gap indicated an attempt to exercise market power by raising prices in the area, we would expect it to be concentrated at higher load levels.

The fact that the pattern of higher output gap levels occurred over a wide range of load levels is, therefore, more likely to reflect the pay-as-bid incentives associated with the NCPC payments. Further, when the supplier self-committed its resources, it increases the supply in the NEMA/Boston area and generally reduced clearing prices and muted the congestion into Boston. This reduces the potential concern that the output gap was the result of an attempt to exercise market power by raising energy prices. However, we remain concerned that this conduct did result in substantial increases in NCPC payments, as described in Section IV.D.

3. Output Gap in Connecticut

There are two areas within Connecticut that are examined in this assessment. Based on the pivotal supplier analysis in the previous sub-section, there is significant potential for market power in Norwalk-Stamford. However, it is unlikely that any suppliers outside Norwalk-Stamford would profit from withholding. Figure 36 summarizes output gap results for Norwalk-Stamford by load level. In order to verify the conclusion of the earlier analysis that withholding would not be profitable outside Norwalk-Stamford, we show output gap results for the entirety of Connecticut later in this sub-section. Figure 36 shows the average output gap quantities for Norwalk-Stamford during 2005. In this area, there is only one supplier so the figure does not compare results by size of supplier.

Figure 36
Average Output Gap by Load Level
Norwalk-Stamford – 2005

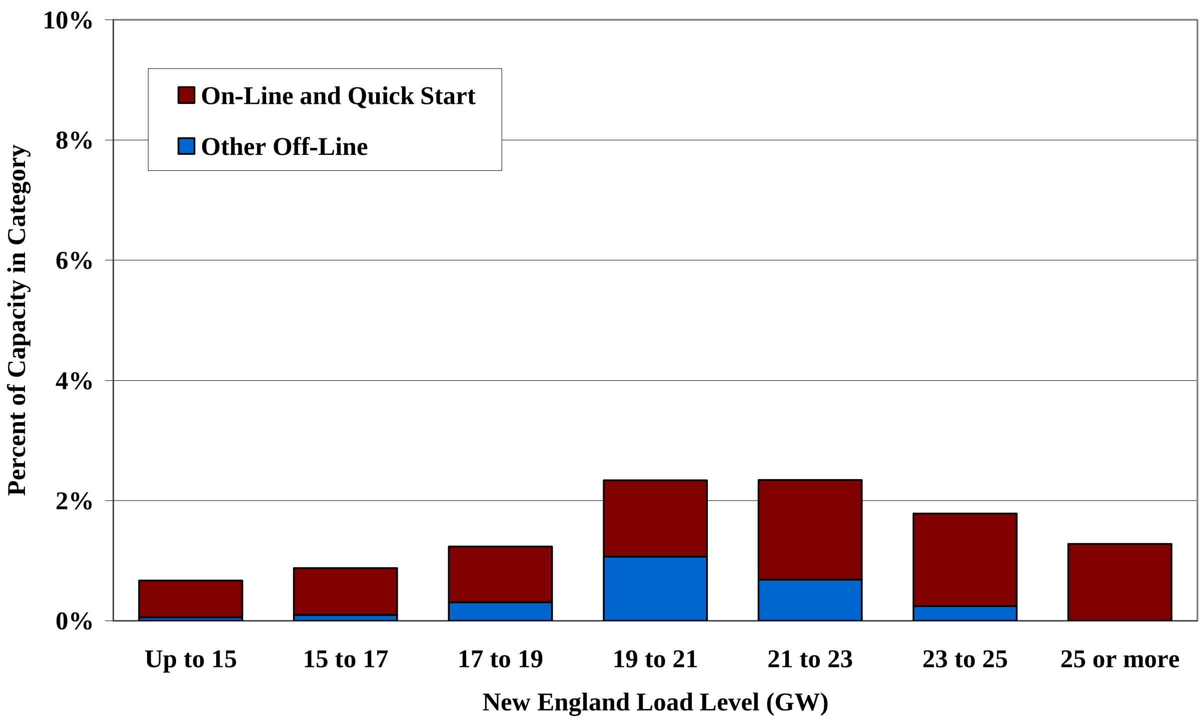


The output gap quantities for the supplier in Norwalk-Stamford generally average less than 1 percent of the supplier's total capacity in these areas. The output gap rises above 2 percent during hours when load is between 21 GW and 25 GW. The upward trend in the output gap as load rises is generally a concern, although the magnitude of the output gap is relatively small at all load levels.

Although the structural analysis in the previous section indicates that there are strong incentives to exercise market power in the Norwalk-Stamford area, our analysis provides little evidence of substantial market power abuse in 2005. We reviewed the incremental offer patterns of the two largest units in the Norwalk-Stamford in comparison to energy reference levels of the units. The median difference between the incremental offer and the reference level was $24.72/MWh for one unit and $24.62/MWh for the other unit. Given that these units are typically subject to the $25/MWh constrained area threshold for the conduct test used to determine conduct that may warrant mitigation, this pattern suggests that they generally raise their offer as much as the conduct test allows. These units are also frequently committed supplementally for local reliability and, therefore, face significant "pay-as-bid" incentives. As with the largest supplier in NEMA/Boston, it is not clear whether they are raising their offer prices in order to generate larger uplift payments, to raise the clearing price, or both.

Our next analysis focuses on all of Connecticut. The results of this analysis, presented in Figure 37, include the output gap results for the Connecticut by load level.

Figure 37
Average Output Gap by Load Level
Connecticut – 2005

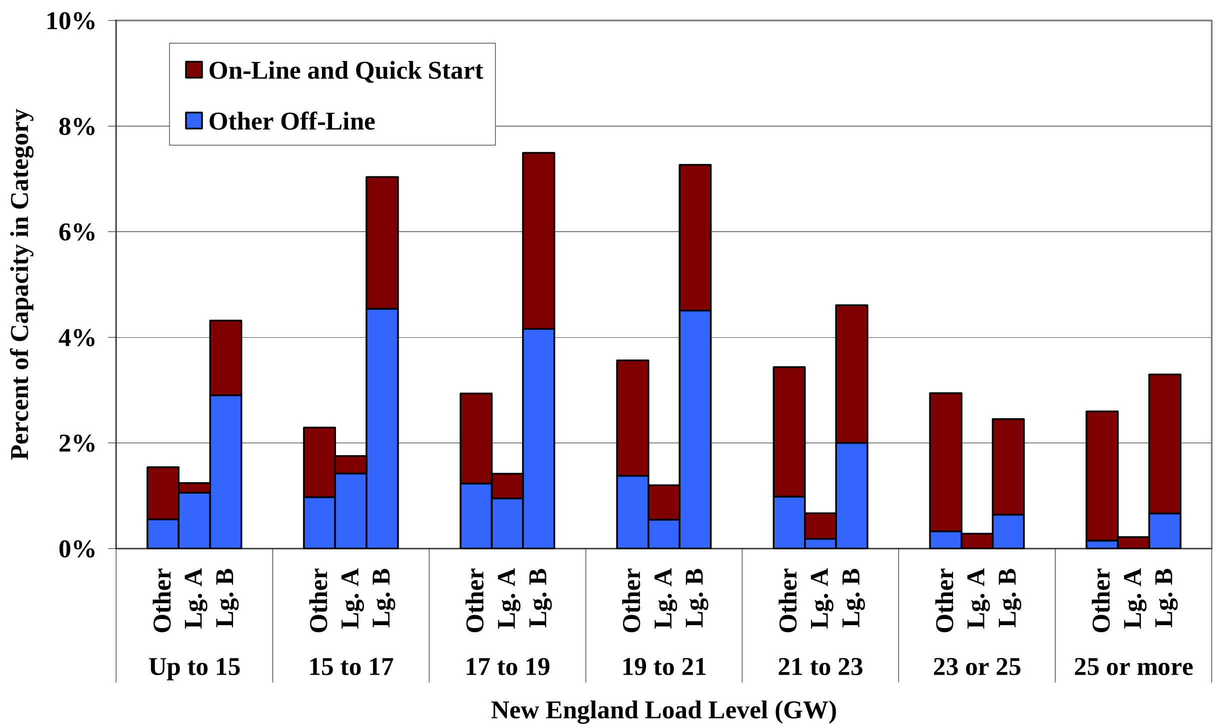


The average output gap for this zone was generally 2 percent or less under all load conditions, which is generally consistent with expectations of a competitive market. Thus, the import-constrained areas within Connecticut do not show evidence of substantial withholding behavior under the current market conditions. This result may be due, in part, to two factors that are likely to change in the future. First, large amounts of capacity in Connecticut are under reliability agreements that effectively reduce the incentives for their owners to exercise market power in the spot market. Second, the frequent supplemental commitments for local reliability reduce the potential for tight conditions when suppliers are more likely to have the ability to raise prices substantially by withholding. As these conditions change and new markets are introduced, monitoring the competitive conditions within Connecticut will be very important.

4. Output Gap in All New England

Figure 38 summarizes output gap results for all of New England by load level for three categories of supply. Supplier A has the largest portfolio in New England and was pivotal in approximately 8 percent of the hours during 2005 (excluding capacity under reliability agreements). Supplier B was also pivotal during a small number of hours, but is shown separately because their portfolio includes the NEMA/Boston resources discussed earlier in this subsection. Other suppliers are also shown for reference.

Figure 38
Average Output Gap by Load Level and Type of Supplier
All of New England – 2005



The figure shows that Supplier A exhibits a small output gap under all load conditions, and thus provides little evidence of strategic withholding. Supplier B exhibits much larger output gap quantities, although it declines from approximately 7 percent for loads between 15 GW and 21 GW to less than 5 percent for loads above 21 GW. This pattern is primarily due to the offer patterns of its NEMA/Boston resources that are discussed earlier in this section and raises little concern regarding the competitive performance of the market outside of NEMA/Boston.

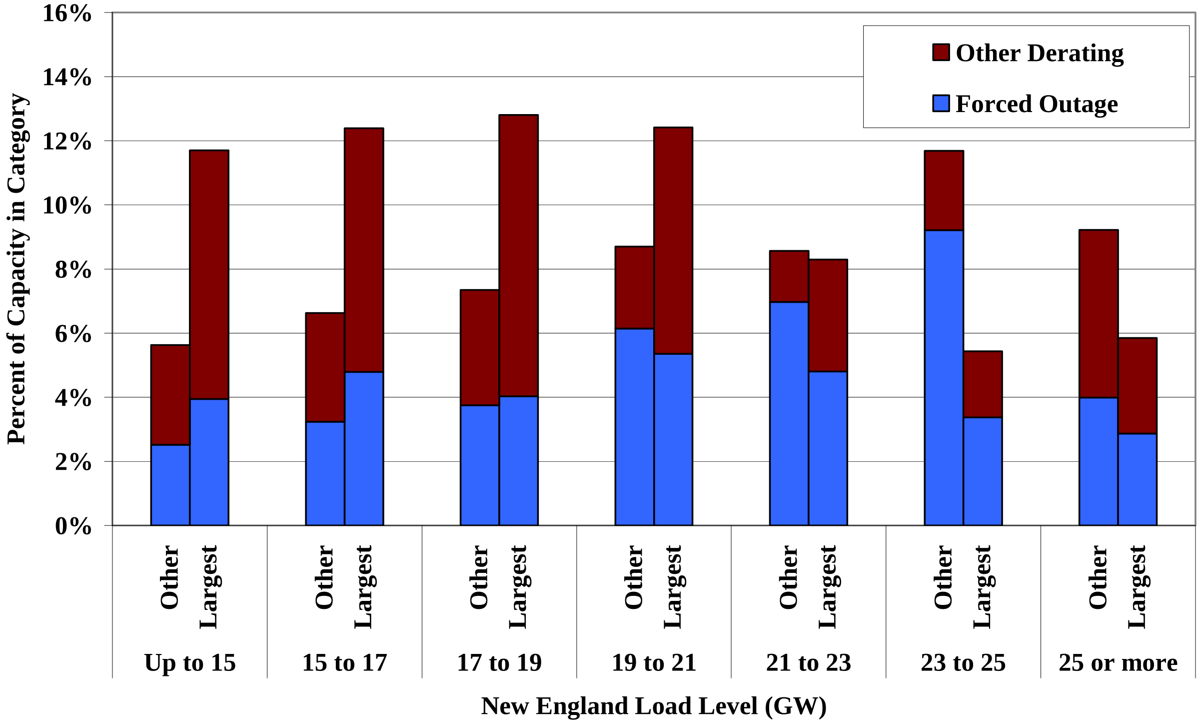
D. Physical Withholding

This sub-section of the report examines forced outages and other non-planned deratings to assess whether they have occurred in a manner that is consistent with the exercise of market power. IN this sub-section, we analyze each of the six areas examined in the pivotal supplier analysis above.

1. Potential Physical Withholding in NEMA/Boston

Figure 39 shows forced outages and other deratings in the NEMA/Boston area for various load levels. Outage and derating statistics are shown for the dominant supplier compared with all other suppliers in the area. Based on the pivotal supplier analysis in the previous sub-section, the dominant supplier can be expected to be pivotal in most hours when load exceeds 19 GW. The "other deratings" shown in the figure include reductions in the hourly capability of a unit from its maximum seasonal capability that is logged as a forced outage or planned outage. These deratings are frequently the result of ambient temperatures or other factors that affect the maximum capability of a unit.

Figure 39
Forced Outages and Other Deratings by Load Level and Type of Supplier
NEMA/Boston - 2005



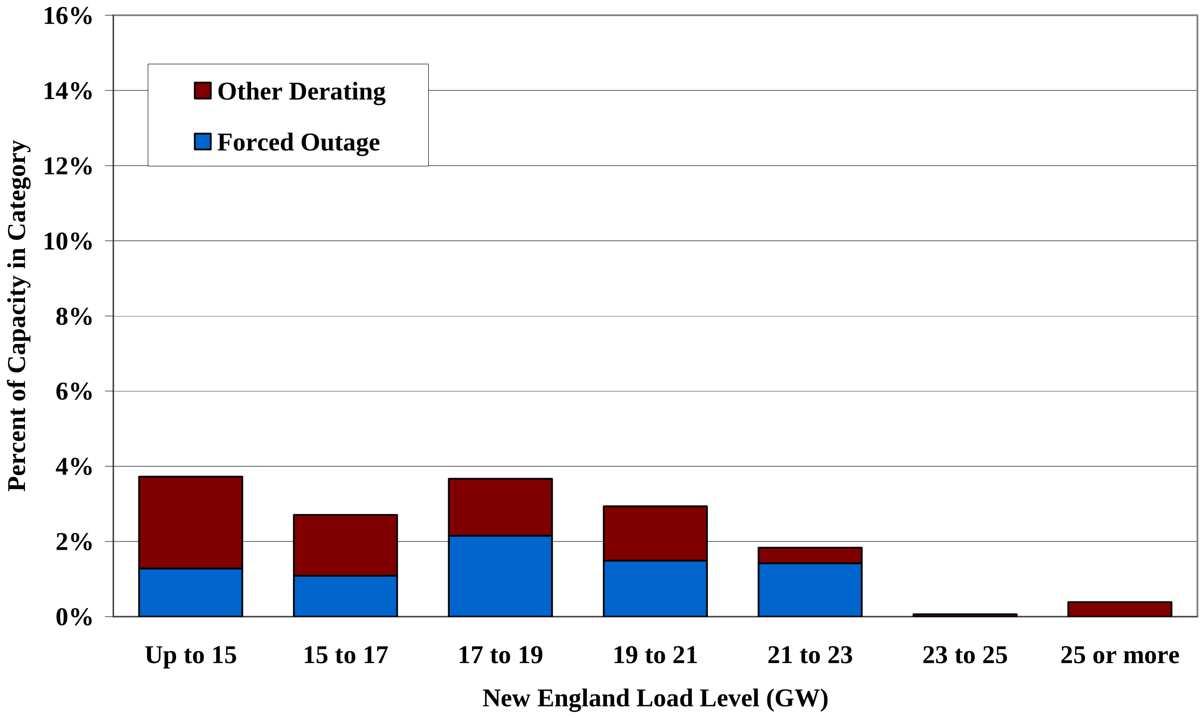
The figure shows the largest supplier's physical deratings as a percentage of its portfolio, which are generally close to 12 percent for most load levels. However, deratings and outages decline to 8 percent when load is between 21 GW and 23 GW, and fall below 6 percent when load rises above 23 GW. The average physical deratings of other suppliers is lower when load is below 19 GW, rising above the largest supplier's share when load is greater than 23 GW.

Overall, Figure 39 suggests that the pattern of deratings and outages is consistent with a competitive market for at least two reasons. First, the results for the largest supplier indicate levels of outages and deratings that are not consistently higher than the comparable quantities for other suppliers. Second, the deratings and outages of the largest supplier generally decline as load increases to the highest load levels. Even though running units more intensely under peak demand conditions increases the probability of an outage, the results in the figure suggest that market participants have kept capacity available during periods of high load when it is most valuable. This indicates that physical withholding has not been a substantial concern because deratings decrease under the high load conditions when the market is generally more susceptible to the exercise of market power.

2. Potential Physical Withholding in Connecticut

There are two import-constrained areas within Connecticut that are reviewed in this report, Norwalk-Stamford and the rest of Connecticut. Based on the pivotal supplier analysis in the previous sub-section, there is significant potential for market power in Norwalk-Stamford. Figure 40 and Figure 41 summarize forced outages and other deratings in these areas by load level.

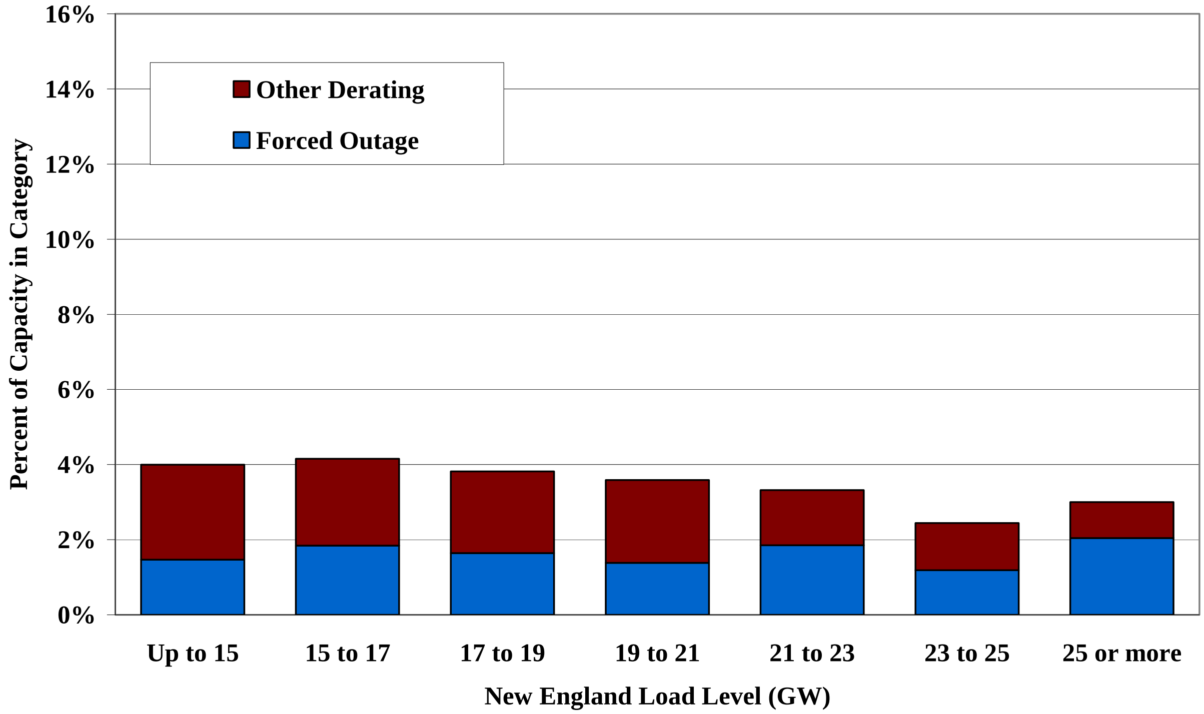
Figure 40
Forced Outages and Other Deratings by Load Level and Type of Supplier
Norwalk-Stamford – 2005



While the presence of only one supplier in the local market raises market power concerns, Figure 40 shows that the physical derating quantities are quite small on average for this supplier. Furthermore, they generally decrease as load rises and do not provide evidence of strategic physical withholding.

Figure 41 summarizes physical deratings results for the Connecticut load zone by load level.

Figure 41
Forced Outages and Other Deratings by Load Level and Type of Supplier
Connecticut – 2005

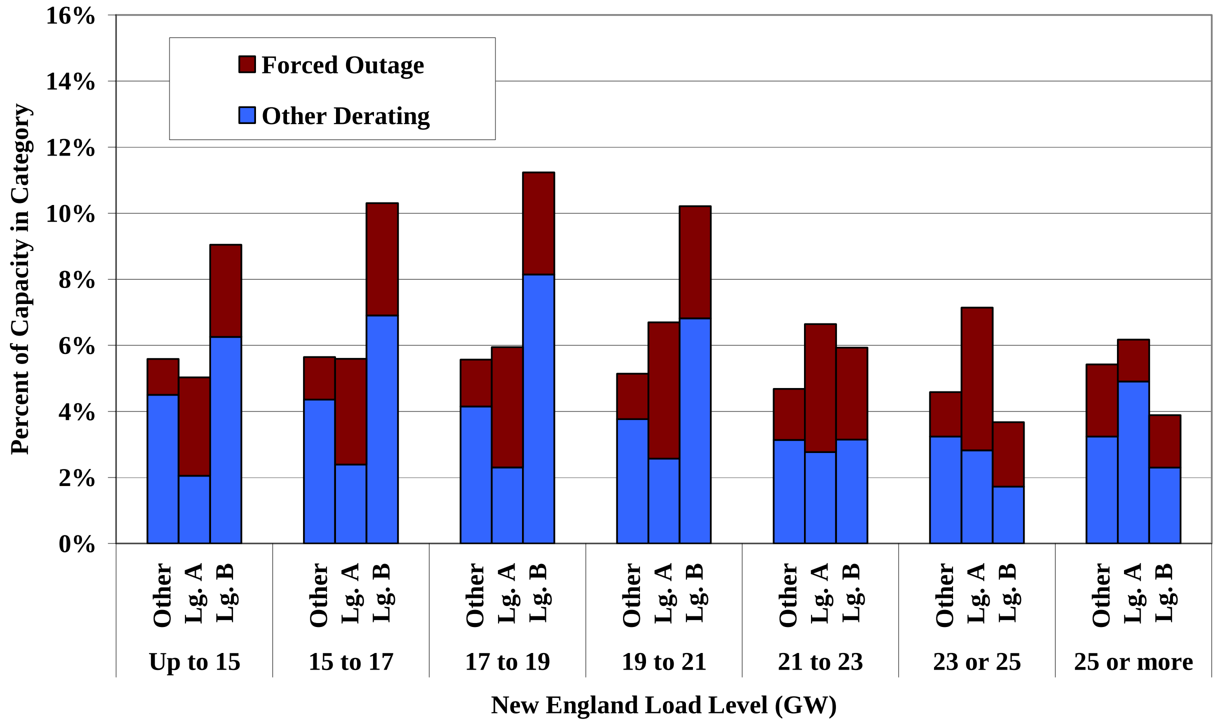


The physical deratings were relatively low in Connecticut during 2005, averaging slightly less than 4 percent when load is below 23 GW. When load is greater than 23 GW, physical deratings ranged between 2 percent and 3 percent. The quantities shown in the figure above are relatively small and do not provide evidence of systematic physical withholding.

3. Potential Physical Withholding in All New England

Figure 42 summarizes physical withholding analysis for all of New England by load level. Supplier A has the largest portfolio in New England and was pivotal in approximately 8 percent of the hours during 2005 (excluding capacity under reliability agreements). Supplier B was also pivotal during a small number of hours. Its portfolio includes the NEMA/Boston resources discussed earlier in this subsection. Other suppliers are also shown for comparison purposes.

Figure 42
Forced Outages and Other Deratings by Load Level and Type of Supplier
All New England – 2005



The figure shows that Supplier A's forced outages and other non-planned deratings grow from around 6 percent of its capacity when load is below 19 GW to as much as 7 percent when load is between 23 GW and 25 GW. On the other hand, the potential physically withheld capacity for other suppliers consistently averages 6 percent when load is below 19 GW and between 4 percent and 5 percent when load is greater than 19 GW. This trend raises concerns about possible physical withholding.

The other deratings at high load levels for the largest supplier were due to reductions in capability from ambient temperature restrictions at two plants. Naturally, ambient temperature restrictions increase with load and are, therefore, difficult to distinguish from physical withholding. It is beyond the scope of this report to determine whether the reductions were warranted. However, the overall quantity of capacity subject to the deratings was generally small relative to the total size of Supplier A's portfolio, so we find little evidence that these deratings constituted an exercise of market power.

E. Conclusions

Based on the analyses of potential economic and physical withholding in this section, we find little evidence of significant withholding that might indicate market power abuses in any of the four regions during 2005. Furthermore, the pivotal supplier analysis suggests that market power is limited by the large amount of capacity under reliability agreements. Nonetheless, the ISO should continue to monitor for potential economic and physical withholding, particularly in constrained areas after the reliability agreements expire.