2007 Assessment of the Electricity Markets in New England

By:

David B. Patton, Ph.D.
Pallas LeeVanSchaick, Ph.D.
POTOMAC ECONOMICS, LTD.

Independent Market Monitoring Unit
ISO New England Inc.

June 2008

Table of Contents

List of Figures

List of Tables

Guide to Acronyms

ASM	Ancillary Services Market
FCM	Forward Capacity Market
FTR	Financial Transmission Rights
GW	Gigawatt (1 GW = 1,000 MW)
HHI	Herfindahl-Hirschman Index, a standard measure of market concentration
IMMU	Internal Market Monitoring Unit
ISO	Independent System Operator
LFRM	Locational Forward Reserve Market
LMP	Locational Marginal Price
LOC	Lost Opportunity Cost, a component of the regulation price
MMbtu	Million British Thermal Units, a measure of energy content in natural gas
MW	Megawatt
MWh	Amount of energy equal to producing 1 Megawatt for a duration of one hour
NCPC	Net Commitment Period Compensation
NEMA	North East Massachusetts
NERC	North American Electric Reliability Corporation
NOPR	Notice of Proposed Rulemaking
NPCC	Northeast Power Coordinating Council, Inc.
PUSH	Peaking Unit Safe Harbor, a pricing rule covering certain units
RAA	Reserve Adequacy Assessment
RCP	Regulation Clearing Price
RCPF	Reserve Constraint Penalty Factors
RMR	Reliability Must-Run
RTO	Regional Transmission Organization
SEMA	South East Massachusetts
SCR	Special Constraint Resources
SMD	Standard Market Design
TMNSR	Ten-minute non-spinning reserves
TMOR	Thirty-minute operating reserves
TMSR	Ten-minute spinning reserves
UDS	Real-time dispatch software

I. Executive Summary

This report assesses the efficiency and competitiveness of New England's wholesale electricity markets during 2007. The current wholesale electricity markets began operation in March 2003. ISO New England has made enhancements to these markets and introduced additional markets for other products, which have improved the overall efficiency of the markets. ISO New England's markets currently include:

- *Day-ahead and real-time energy*, which coordinate commitment and production from the region's generation and demand resources, and facilitate wholesale energy trading;
- *Financial Transmission Rights ("FTRs")*, which allow participants to hedge the congestion costs associated with delivering power to a location that is constrained by the limits of the transmission network;
- *Forward and real-time operating reserves*, which are intended to ensure that sufficient resources are available to satisfy demand when an outage or other contingency occurs;
- *Regulation*, which allows the ISO to instruct specific generators to increase or decrease output moment-by-moment to keep system supply and demand in balance; and
- *Forward Capacity Market ("FCM")*, which is intended to provide efficient long-term market signals to govern decisions to invest in new generation and demand resources and to maintain existing resources.

These markets provide substantial benefits to the region by ensuring that the lowest cost supplies are used to meet demand in the short-term and by establishing transparent, efficient price signals that govern investment and retirement decisions in the long-term. Although it is difficult to quantify the benefits that result from market coordination, good coordination is essential due to the physical characteristics of electricity and the transmission network used to deliver it to customers. This coordination affects not only the prices and production costs of electricity, but also the reliability with which it is delivered.

A. Introduction and Summary of Findings

In addition to providing a summary of market outcomes in 2007, this report includes findings in two primary areas: the competitive performance of the market, and the operational efficiency of the market. The broad findings in each of these areas are discussed below.

Competitive Performance of the Market

Based on our evaluation of the markets in New England (in both constrained areas and the broader market), we find that the markets performed competitively in 2007. We find little evidence that suppliers withheld resources to raise prices in the New England markets. Although energy prices increased in 2007, this was due primarily to increases in fuel prices and demand. Because fuel costs constitute the vast majority of the marginal costs of generation, higher fuel costs translate to higher offer prices and market clearing prices.

However, we find that frequent supplemental commitment has encouraged some generators to raise offers above competitive levels (i.e., above marginal cost). Generators committed for local reliability often do not face meaningful competition and may have local market power.[1] The market power mitigation measures have generally limited the ability of suppliers to exercise market power.[2] However, due to the chronic nature of some local reliability commitments, the mitigation measures have not been fully effective at addressing certain conduct. In particular, conduct by a large supplier in Boston resulted in substantial increases in Net Commitment Period Compensation ("NCPC") payments in 2007. NCPC payments are made to ensure a supplier recovers its full offer costs. To address this issue, we have worked with the internal market monitor to develop changes to the mitigation criteria that should be proposed later this year.

Operational Efficiency of the Markets

In general, the day-ahead and real-time markets operated efficiently in 2007 with prices that reflected underlying market fundamentals. 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 constrained areas, the ISO has taken appropriate actions to supplement the commitments from the day-ahead market with additional resources. However, these supplemental commitments tend to diminish energy and ancillary services price signals in

---

1 When local reliability requirements are satisfied outside the normal market process, the suppliers are generally paid their offer price. This gives them incentives to submit offers above their marginal costs (i.e., "pay-as-bid" incentives), even when they face competition. Hence, it can be difficult to distinguish economic withholding from a competitive outcome when suppliers have pay-as-bid incentives.

2 Market power mitigation measures are contained in ISO New England's Tariff. They address potential abuses of market power by allowing the ISO to modify suppliers' offers when certain criteria are satisfied.

constrained areas and increase NCPC costs, which are difficult for load-serving entities to hedge. This issue is common to all electricity markets and arises when the markets do not fully satisfy the reliability needs of the system. Additionally, the limited number of fast-start units in New England increases the need to commit larger, slower-starting generation to assure reliability in constrained areas. The ISO has made a number of changes in its market rules and worked with participants to address the underlying reasons for the supplemental commitments, including:

- New transmission investment into the Boston area has allowed ISO New England recently to revise its reliability requirements, which has resulted in a dramatic reduction in supplemental commitment in Boston and the associated costs.
- The ISO made several market enhancements in October 2006, including adding local requirements to the forward reserve market and the introduction of real-time reserve markets with local requirements that are co-optimized with the energy market.
- ISO New England implemented a forward capacity market which procures capacity three years forward on a locational basis. The FCM is intended to facilitate the entry of new supply and demand resources. The first auction was conducted successfully in February 2008 to meet the capacity requirements for June 2010 through May 2011.

These changes are important because markets with local requirements reduce the need for manual actions by operators, lower uplift costs, and improve economic signals. The improved economic signals should reduce New England's heavy reliance on reliability agreements (used to ensure that units needed for reliability remain in operation). Reliability agreements are poor substitutes for transparent market prices and do little to facilitate efficient investment.

Recommendations

Overall, we conclude that the markets performed competitively in 2007 and were operated well by the ISO. Based on the results of our assessment, however, we offer some recommendations to further improve the performance of the New England markets. They are listed in a table at the end of this executive summary. The following sections summarize the findings of the report.

B. Energy Prices and Congestion

Although we conclude that the markets performed competitively in 2007, electricity prices in both the day-ahead and real-time energy markets increased by more than 10 percent. This increase in energy prices was primarily due to increases in natural gas and oil prices and an increase in load. The correlation between natural gas prices and energy prices is consistent with a well-performing market, because fuel costs constitute the vast majority of most generators' marginal costs and natural gas-fired units frequently set the market price in New England.

There were no significant price spikes or capacity deficiencies in 2007 as peak demand levels were considerably lower in 2007 than in 2006 the system was operated effectively. The peak demand in 2007 was 26.2 GW, a substantial reduction from the all-time peak demand of 28.0 GW that occurred in 2006.

Congestion and Financial Transmission Rights

Under SMD, New England has experienced relatively little congestion in historically-constrained areas such as Boston 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. In 2007, the Lower Southeast Massachusetts area ("Lower SEMA") had the most congestion of any area in New England. Energy prices averaged $5 per MWh higher in Lower SEMA than at the New England Hub in the day-ahead market. This congestion is due primarily to the small quantity of generation within Lower SEMA. New transmission should reduce congestion and the other costs to maintain reliability in Lower SEMA.

Congestion into Norwalk-Stamford was much less severe in 2007 than in 2006. The average congestion price difference between the New England Hub and Norwalk-Stamford decreased from more than $25 per MWh in 2006 to less than $5 in 2007. This reduction was largely due to new transmission added under Phase I of the Southwest Connecticut 345 kV Transmission Project and the expiration of the Peaking Unit Safe Harbor ("PUSH") offer rules, which had allowed certain suppliers to raise their offers without risk of mitigation. The local requirements in the forward reserve market and FCM eliminated the need for the PUSH rules.

The ISO operates annual and monthly markets for FTRs.[3] FTRs are invaluable in a locational energy market because they allow participants to hedge the congestion and associated basis risk

---

3 FTRs entitle the holder to the congestion price difference between the FTR's source and sink in the day-ahead market (i.e., the congestion price at the sink minus the congestion price at the source).

on the network. Since FTR auctions are forward financial markets, efficient FTR prices should reflect the expectations of market participants regarding congestion in the day-ahead market. Our analysis of FTR prices indicates:

- FTR prices were consistent with the congestion that prevailed in the energy markets in 2007, which suggests that the markets have sufficient liquidity to produce efficient prices.
- The consistency of FTR prices and congestion improved from the annual auction to the monthly auctions. This result is expected because participants gain additional information about market and system conditions after the annual auction.

We also conducted a preliminary analysis of the potential liabilities of participants in the FTR market. This analysis was prompted by two participants in PJM that defaulted on FTR payment obligations of more than $65 million in 2007. These defaults underscore the importance of accurately assessing default risk and applying appropriate credit requirements for FTR holders. The greatest source of default risk is from participants that buy negatively-priced FTRs, which provide an initial payment to the holder and usually obligate the holder to make payments over the life of the FTR. However, positively-priced FTRs can also be a source of default risk when congestion patterns change substantially. Our analysis of this issue indicates that:

- Holders of negatively-priced FTRs were obligated to pay $52 million in 2007, while holders of positively-priced FTRs were obligated to pay $17 million.
- On a portfolio basis, only two participants had a substantial negative net value for their FTRs, based on the FTR purchase prices.

These results show that the default risk facing ISO New England was limited to a small number of participants that hold portfolios of negatively-priced FTRs. However, they also indicate the need to maintain appropriate credit requirements for all FTRs that result in payment obligations, regardless of whether the FTRs were positively or negatively-priced originally. ISO New England's credit requirements are currently under review and proposed changes should better address the potential default risks in the FTR market.

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

We evaluated price convergence at the New England Hub, which is broadly representative of prices outside of transmission-constrained areas. Consistent with results in prior years, average prices in the day-ahead market were slightly higher than average prices in the real-time market ($1.06 per MWh in 2007). The small but persistent difference is partly due to the allocation of uplift for NCPC payments, which is higher for purchases in the real-time market than in the day-ahead market. When the uplift allocations are considered, the price differences are very small, which indicates that day-ahead and real-time prices were generally well-arbitraged in 2007. However, prices were not well-arbitraged at some import-constrained locations in SEMA and Connecticut due to the higher price volatility and supplemental commitment in these areas.

C. External Interface Scheduling

In this report, we evaluated transaction scheduling between New England and the three adjacent regions: Quebec, New Brunswick and New York.

Quebec and New Brunswick Interfaces

Power is usually imported from Quebec and New Brunswick. Average net import levels range from 1,370 MW during peak hours to 660 MW during off-peak hours in 2007, which is consistent with the management of hydroelectric resources in Canada. ISO New England is working with participants and the New Brunswick System Operator to implement intra-hour scheduling between the regions, which should allow more efficient scheduling of the interface.

New York Interface

New England and New York are connected by one large interface between western New England and eastern up-state New York, and by two small interfaces between Connecticut and Long Island. Exports are consistently scheduled from Connecticut to Long Island over the smaller interfaces (averaging 270 MW in 2007), while power flows in both directions on the large interface between the markets. In 2007, an average of 285 MW was exported to New York during peak hours and 200 MW was imported from New York during off-peak hours.

Market participants should arbitrage the prices in the two areas by scheduling power from the low-priced market to the high-priced market. However, uncertainty and long scheduling lead times have prevented participants from fully utilizing the interfaces with New York. Explicit coordination of the physical interchange of power between the markets is likely needed to achieve efficient utilization of the interfaces between New York and New England. Our estimates of the benefits of full utilization of the interfaces indicate that consumers in New England would have saved $61 million in 2006 and $22 million in 2007 from full convergence. However, these estimates will rise sharply in the future if the frequency of operating reserve shortages increases because full utilization of the interface can prevent such reserve shortages.

D. Reserve Markets

In October 2006 under Phase II of ASM, the ISO added local requirements to the forward reserve market, and introduced real-time reserve markets with local requirements that are co-optimized with the real-time energy market. These enhancements better enable the wholesale market to meet the reliability needs of the system and reduce the need for out-of-market actions by the operators. This section summarizes our evaluation of the reserve markets.

Real-Time Reserve Markets

By co-optimizing the scheduling of energy and reserves, the market is able to reflect the re-dispatch costs that are incurred to maintain reserves in the clearing prices of both energy and reserves. These effects were not reflected in the energy-only market. When available reserves are not sufficient to meet the required levels, the real-time model will be short of reserves and set the reserve clearing price at the level of the Reserve Constraint Penalty Factor ("RCPF").

Local reserve requirements can be met with reserves on internal resources or unused import capability into the load pockets ("imported reserves"). Currently, ISO New England is the only RTO that optimizes the level of imported reserves to constrained load pockets in real time. This innovation is important because the New England market meets most of its local area reserve requirements with imported reserves rather than internal reserves (74 percent the Boston area requirement and 48 percent of the Connecticut area requirement during constrained periods are met by imported reserves).

Real-Time Reserve Market Results

Reserve clearing prices were relatively low in the real-time market in 2007. Average clearing prices were less than 50 cents per MWh for all classes of reserves in all locations. Our analysis indicates a strong negative correlation between the local reserve clearing price and the amount of local excess capacity.[4] Therefore, it is important that the Reserve Adequacy Assessment ("RAA") process, which is used to make supplemental commitments for reliability, minimize any unnecessary commitments. We support ISO New England's on-going efforts to improve the efficiency of the RAA process, which are discussed in the System Operations section of this report.

Based on our review of the real-time reserve market results, we also found that actions taken by the ISO to maintain local reserves are often more costly than the RCPF, which indicates that the RCPFs may be set inefficiently low. Setting RCPFs at appropriate levels is important because:

- RCPFs contribute to setting prices in the reserve markets and the energy market when the reserve requirements cannot be met;
- RCPFs cause the market to utilize all available resources and reduce the need for market operators to take actions outside of the market process to maintain reliability.

Although higher RCPFs appear appropriate, one must balance the efficiency benefits against the potential for increased local market power in the constrained areas.

Finally, the report evaluates the designation of the local reserve zones, which initially were defined to include Boston, Southwest Connecticut, and Connecticut. There are five other local areas that require the commitment and dispatch of resources to meet local second contingency protection requirements.[5] Because they are not designated as local reserve zones, the ISO relies entirely on imported reserves to maintain reliability in these areas. Designating new reserve zones for these areas would: a) allow the model to satisfy the requirements with the least-cost mix of internal resources and imported reserves; and b) produce reserve clearing prices for the areas, which provide short-term and long-term price signals to prospective suppliers of reserves.

4 We define excess capacity as the amount of local capacity that is online or capable of starting within 30 minutes in excess of the amount of local capacity that is required to meet load and reserve requirements

5 These areas are Norwalk-Stamford, West Connecticut, Lower Southeast Massachusetts, Western New England, and Maine.

Forward Reserve Market Results

The Locational Forward Reserve Market ("LFRM") is a seasonal auction held twice a year where suppliers sell reserves that they are obligated to provide in real-time. LFRM obligations must be provided from an online resource with unused capacity or an offline resource capable of starting quickly (i.e. fast-start generators). The auction procures 10-minute non-spinning reserves ("TMNSR") for all of New England and 30-minute operating reserves ("TMOR") for All of New England, Boston, Connecticut, Southwest Connecticut, and Rest of System.

This report evaluates the results of the forward reserve auctions that overlapped with 2007 and examines how suppliers satisfied their obligations in the real-time market. In the two Forward Reserve Auctions that were held in 2007, prices cleared at the $14,000/MW-month price cap in the local areas where supply was not sufficient to meet the local requirements. Outside the local areas, TMNSR cleared at $9,050 and $10,800/MW-month, while TMOR cleared at $3,550/MW-month in one auction and was not procured in the subsequent auction.[6] The fact that there is a single cap of $14,000 for all local reserves has raised the following potential incentive concerns.

- Suppliers with 10-minute reserve-capable units have the incentive to sell 30-minute reserves because there is no incremental revenue for selling higher-quality reserves.
- Likewise, suppliers with reserves in narrower constrained areas (e.g., Southwest Connecticut) have the incentive to sell their reserves in broader areas (e.g., Connecticut).

Both of these behaviors have been observed in the forward reserve markets. Modifying the price cap to differentiate the payment for higher quality reserves or reserves in more constrained areas would address these incentive issues.

E. Regulation Market

Regulation expenses increased substantially after a new market design was deployed in October 2005, due to reduced supply of regulation capability in late 2005, higher natural gas prices, and

6 Forward reserve clearing prices are affected by the market rule that suppliers do not receive capacity payments for their forward reserve sales. In 2007, the capacity revenue was from Transition Payments of $3,050/MW-month. Thus, a seller of TMOR outside the local areas in the Summer of 2007 would receive $3,550/MW-month, but also give up $3,050/MW-month.

issues associated with the new market design that were addressed in January 2007. Our 2006 assessment of the New England markets provides a detailed and discussion of these issues, as does the 2006 Annual Markets Report by the Internal Market Monitor. This increase in regulation prices was relatively short-lived. Regulation expenses decreased in 2006 as additional supply entered the market and decreased further in 2007 after the design issues were addressed.

Overall, we find that the performance of the regulation market improved substantially in 2007. Regulation suppliers have responded as expected to relatively high regulation prices, and the market design improvements have been effective. However, given the complex interaction of the regulation market with the energy market, significant benefits likely could be achieved by allowing the real-time market to better allocate resources to provide energy, regulation, and operating reserves.

F. Real-Time Pricing and Market Performance

The goal of the real-time market is the efficient procurement of the resources required to satisfy the reliability needs of the system. To the extent that reliability needs are not fully satisfied by the market, the ISO must procure needed resources outside of the market, consistent with its operating procedures. However, these out-of-market actions tend to undermine the market prices because the prices will not fully reflect the reliability needs of the system. Efficient real-time prices are important because they encourage competitive scheduling by suppliers, participation by demand response, and investment in new resources when and where needed.

It is particularly important for the market to set efficient real-time price signals during shortages of operating reserves, as recently recognized by the Commission in its Notice of Proposed Rule-making ("NOPR") on organized markets. The NOPR identifies ISO New England's approach to shortage pricing as an effective method that may serve as a model for other ISOs.[7] ISO New England uses the operating reserve demand curve approach to set real-time clearing prices during operating reserves shortages. We evaluated five aspects of the real-time market related to pricing and dispatch in 2007.

7 See P. 125. Wholesale Competition in Regions with Organized Electric Markets, 122 FERC 61,167 (2008) ("NOPR").

1. *Price Corrections*: We find that price corrections were very infrequent, which is notable because the implementation of the real-time reserve markets in October 2006 required significant changes to the market software. The low frequency of price corrections indicates the high quality of the work done to implement the real-time reserve markets.

2. *Real-Time Pricing of Fast-Start Resources:* Prices in the real-time market do not always reflect the high costs of fast-start resources when they are used to manage congestion or satisfy load. This causes real-time prices to be understated and affects participants' short-term and long-term incentives. This issue is common to most RTO markets because:
   - Fast-start resources are generally inflexible, and generators can typically only set prices when they are dispatched in their flexible range; and
   - Market clearing prices are set based only on suppliers' incremental energy offers and do not include resources' commitment costs (start-up costs and no-load costs). Hence, the full cost of a decision to start a fast-start unit may not be included in the real-time prices.

3. *Real-Time Pricing During Transmission Scarcity:* Local shortages can arise when local generation and transmission capability into an area are not sufficient to meet demand in the area. Although such shortages are uncommon, it is important for markets to set efficient prices that reflect such conditions. The following issues can compromise efficient pricing under these conditions and are addressed by our recommendations:
   - The use of a "relaxation" algorithm that effectively raises the transmission limit when the constraint cannot be managed; and
   - The use of "penalty factors" that do not reflect the economic value of the constraint. Penalty factors indicate the maximum value the market should incur to redispatch generation to manage a constraint.

4. *Real-Time Pricing During Demand Response Activation:* Price-responsive demand has surged in New England, from 530 MW in January 2006 to 1684 MW in January 2008. While demand response resources provide substantial benefits to the market, they also pose significant challenges for efficient real-time pricing:
   - Real-time demand response resources are not dispatchable and must be activated in advance of real time.[8] These inflexibilities prevent demand response resources from setting prices and can cause the real-time market not to perceive a shortage, which undermines the efficiency of the real-time market signals during shortage conditions.
   - This issue is not unique to New England, because very little of the demand response in any market is dispatchable in real-time markets. Steps are being taken by a number of RTOs to address this issue.

8 This refers to resources that are able to modify their consumption or generation in response to remote dispatch instructions from the ISO generated by the real-time market.

5. *Ex Ante and Ex Post Pricing:* Like PJM and the Midwest ISO, ISO New England re-calculates prices after each interval (ex post pricing) rather than using the "ex ante" prices produced by the real-time dispatch model. Our evaluation of New England's ex post pricing results indicates that it: a) creates a small upward bias in real-time prices in uncongested areas; and b) periodically distorts the value of congestion into constrained areas.

Conclusions and Recommendations

Efficient prices are a critical priority for the real-time energy market because they provide incentives for suppliers to offer competitively, for demand response to participate in the wholesale market, and for investors to build new resources when and where they are most valuable. These incentives cause participants to assist the ISO in maintaining a reliable system.

Although the issues listed above did not undermine the performance of the market in 2007, our evaluation leads to four real-time pricing recommendations that will improve the performance of the market in the future. These changes will be increasingly important if certain trends continue, such as the rapid growth in demand response resources. Therefore, it is prudent to begin the work necessary to evaluate and address these issues before they raise more serious concerns.

G. System Operations

The wholesale market provides efficient incentives for participants to make resources available to meet the RTO's reliability requirements. When the wholesale market does not meet all of these requirements, the ISO will commit additional generation or take other actions. In addition to additional NCPC costs of these actions, these commitments result in added supply that lowers real-time prices and reduces incentive for loads to purchase their full needs in the day-ahead market. Hence, such commitments should only be made when necessary. In this section, we evaluate several aspects of the ISO's process for satisfying reliability requirements in 2007.

Commitment for Local Reliability

Overall, supplemental commitment for reliability increased from a daily average of 1,310 MW in 2006 to 1,600 MW in 2007. Such commitment declined in 2007 in Connecticut and West-Central Massachusetts. However, supplemental commitment continued to be substantial in Lower SEMA and increased in Boston, despite transmission upgrades into Boston in 2007.

- Boston: Behavior by the largest supplier in the area caused its units to be committed less frequently in the day-ahead market and compelled the ISO to make more supplemental commitments. This issue has been resolved in 2008 because the ISO was able to modify its local reliability requirements for Boston due to the new transmission into the area.
- Lower SEMA: Continues to require one large unit to be committed almost continuously for local reliability protection of the Cape Cod area. These units are rarely committed in the day-ahead market for economic reasons and must, therefore, frequently be supplementally committed. Transmission upgrades planned to be in-service in 2009 should substantially reduce the frequency of these commitments and the resulting uplift costs.

Evaluation of Local Second Contingency Commitments

We evaluated supplemental commitments to determine whether those made for local second contingency protection were necessary to meet forecasted minimum capacity requirements in constrained areas. It is important for the ISO to avoid making excess reliability commitments because this depresses economic signals in constrained areas and leads to inflated uplift costs. Our analysis indicates that 85 percent of the supplemental commitments in 2007 were necessary to meet the ISO's local reliability requirements. This level is not closer to 100 percent because:

- Operators may be concerned about the accuracy of the forecasted peak load in the constrained area, may be uncertain about the status or availability of a key resource in the area, or may doubt the reliability of fuel supplies to some units.
- Long lead times can cause the ISO to commit resources prior to the completion of the day-ahead market, increasing the uncertainty regarding the need for additional resources.

We also found that the lower transmission limits the ISO uses to hold reserves on the import capability into certain constrained areas were determined in an unbiased and accurate manner. Work is underway at ISO New England to employ additional analytic tools to determine when commitments are needed for local reliability requirements. We support this work, which should reduce supplemental commitments in the future.

Accuracy of Load Forecasting

The day-ahead load forecast is significant because market participants may use it and other available information to inform their decisions regarding fuel procurement, management of energy limitations, formulation of day-ahead bids and offers, and outage scheduling. In addition, the ISO uses the forecast to estimate the amount of resources that will be needed to satisfy the load and reserve requirements of the system. Based on our analysis of ISO New England's load forecasts, we find that the forecasting was very accurate in 2006 and 2007, and generally superior to comparable results in other RTO markets.

Self Commitment after the Reserve Adequacy Assessment

The last analysis in this section finds that self-commitment after the RAA was the primary cause of excess capacity in Boston in 2007. This is due to the conduct of the largest supplier in the area that began in early 2007:

- Higher day-ahead offers reduced the day-ahead commitment of the supplier's large units;
- This required the ISO to supplementally commit some of the supplier's other capacity;
- The supplier frequently self-committed the large economic units when they were not committed by the ISO, leading to substantial excess capacity in the Boston area and rendering the supplemental commitments by the ISO unnecessary in retrospect.

This conduct is substantially similar to conduct by the supplier in 2005. However, it did not occur in 2006 because the supplier's key capacity was under a reliability agreement that stipulated that the capacity be offered at marginal cost. Hence, the large economic units were usually committed in the day-ahead market in 2006. The recent modifications to the local reliability requirements for the Boston area (which were made possible by the new transmission capability added into the area) should remove the incentive to engage in this conduct in 2008.

Conclusions – System Operations

In general, we conclude that the ISO's operations to maintain reliability in 2007 were reasonably accurate and consistent with the ISO's procedures. However, substantial quantities of supplemental commitment continue to occur in several constrained areas because these areas do not have a large quantity of fast-start resources that can help meet local reserve requirements. These supplemental commitments raise efficiency concerns because they:

- Diminish the efficiency of New England's overall commitment;
- Dampen economic signals to invest in areas that would benefit the most from additional investment in generation, transmission and demand response resources;

- Increase uplift costs that are difficult for participants to hedge, and that can be volatile; and
- Create incentives for units frequently committed for reliability to avoid market-based commitment and seek additional payments through the reliability commitment process.

The ISO has implemented, or is pursuing, several measures to minimize reliance on supplemental commitments in load pockets including:

- An approach to modeling combined cycle units that enables them to provide additional flexibility and non-spinning reserve capability in load pockets (implemented in 2007);
- Operating reserve markets which provide better incentives for resources in the load pockets, particularly new fast-start units (implemented in late 2006).
- Transmission upgrades into Boston (completed in Spring 2007) and associated changes in the area's local reliability requirements (implemented in early 2008).
- Transmission upgrades into Southeast Massachusetts that enable the ISO to maintain reliability in these areas with less internal capacity (planned for 2009).
- Upgrades to the software tools used to calculate transmission capability into local areas. The new PowerWorld based application is expected to improve the accuracy, reliability, and efficiency of the calculations (planned for 2008).

In addition, we recommend three changes listed in the table of recommendations below. These changes, together with the pricing improvements proposed above, should improve the performance of the real-time markets and improve the economic signals that they produce.

H. Competitive Assessment

The final section of the report evaluates the market concentration and competitive performance of the markets operated by ISO New England in 2007. Given the constraints on the transmission network, the most substantial market power exists in constrained areas that can become separate geographic markets with a limited number of suppliers when congestion arises. This assessment evaluates the conduct of market participants in these areas.

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.

This analysis identifies conditions under which the energy and operating reserve requirements cannot be satisfied without the resources of a given supplier (i.e., the "pivotal supplier").

Based on our analyses in the competitive assessment section of the report, we found:

- The largest suppliers in six of the seven areas are pivotal in a large number of hours.
- However, when we account for the large amounts of nuclear capacity and the effects of reliability agreements, we find a pivotal supplier in: (i) SEMA in 88 percent of hours, (ii) Boston in 25 percent of hours, and (iii) All of New England in 14 percent of hours.
- Market power will be a more significant concern in Connecticut once the large quantity of reliability agreements begin to expire. Hence, it will be important to continue to monitor these areas and ensure that the market power mitigation measures are fully effective.

The second part of this assessment examines market participant behavior to identify potential exercises of market power. We analyzed potential economic withholding (i.e., raising offer prices to reduce output and raise prices) and physical withholding (i.e., reducing the claimed capability of a resource or falsely taking a resource out of service). Based on our evaluation in the Competitive Assessment section of this report, as well as the monitoring we performed over the course of the year, we find very little evidence of attempts to exercise market power.

While there is no substantial evidence that suppliers withheld capacity from the market to raise clearing prices, suppliers can also exercise market power by raising their offer prices to inflate the NCPC payments they receive when committed for local reliability. The conduct described above that occurred in the Boston area substantially increased NCPC payments, as did conduct in the SEMA area to a lesser extent. We have been coordinating with the Internal Market Monitoring Unit to evaluate the criteria used to mitigate offers that increase NCPC payments. We agree with the IMMU's preliminary conclusion that the mitigation criteria for conduct affecting NCPC should be tightened, particularly in chronically constrained areas that routinely require supplemental commitments. A proposal to address this issue will likely be presented to participants later this year.

I. Table of Recommendations

Recommendation	Section	High Benefit	Feasible in ST[9]
Energy Pricing and Market Design			
1. Evaluate potential pricing changes that would allow costs of fast-start units to be more fully reflected in real-time prices.	VII.B	✓	
2. Develop rules to allow demand response resources to set prices when they are needed to avoid a shortage.	VII.D	✓	
3. Consider replacing the current ex post pricing process with one that uses ex ante prices for settlement.	VII.E		
4. Consider providing suppliers with flexibility to modify their offers closer to real-time to reflect changes in marginal costs.	VIII.E		
Ancillary Services Markets			
5. Set the local RCPFs at levels that are more consistent with the costs incurred to meet the local-area reserve requirements.	V.B	✓	✓
6. Create additional local reserve zones in the real-time market to satisfy the local reliability requirements more efficiently.	V.C		✓
7. Consider whether the "Rest of System" TMOR requirement is necessary in the forward reserve market.	V.D		✓
8. Consider replacing the forward reserve market's price cap with a tiered cap to recognize higher-value reserves.	V.D		✓
9. Evaluate the benefits of moving to a regulation market that is co-optimized with the energy and ancillary services markets.	VI.D		
System Operations			
10. Consider changes in rules or cost allocation to discourage inefficient self-commitments after the RAA process.	VIII.B		✓
11. Develop provisions to coordinate the physical interchange between New York and New England in real-time.	III.C	✓	
12. Discontinue relaxation of violated transmission constraints -- set penalty factors that reflect the value of constraints and allow them to determine LMPs when a constraint is violated.	VII.C		✓
Market Power Mitigation			
13. Modify the mitigation criteria to address inflated NCPC payments to suppliers whose units are frequently needed for local reliability.	VIII.B		✓

9 *Feasible in Short-Term*: indicated if the recommendation is likely to be feasible within one to two years at a reasonable cost. Others likely require study of costs and benefits, or research to identify a feasible approach. *High Benefit*: Indicated for recommendations that will likely produce considerable efficiency benefits.

II. Prices and Market Outcomes

In this section we review wholesale market outcomes in New England during 2007. Our review includes analyses of overall price trends, patterns of transmission congestion, and convergence of prices in the day-ahead and real-time markets.

A. Price Trends

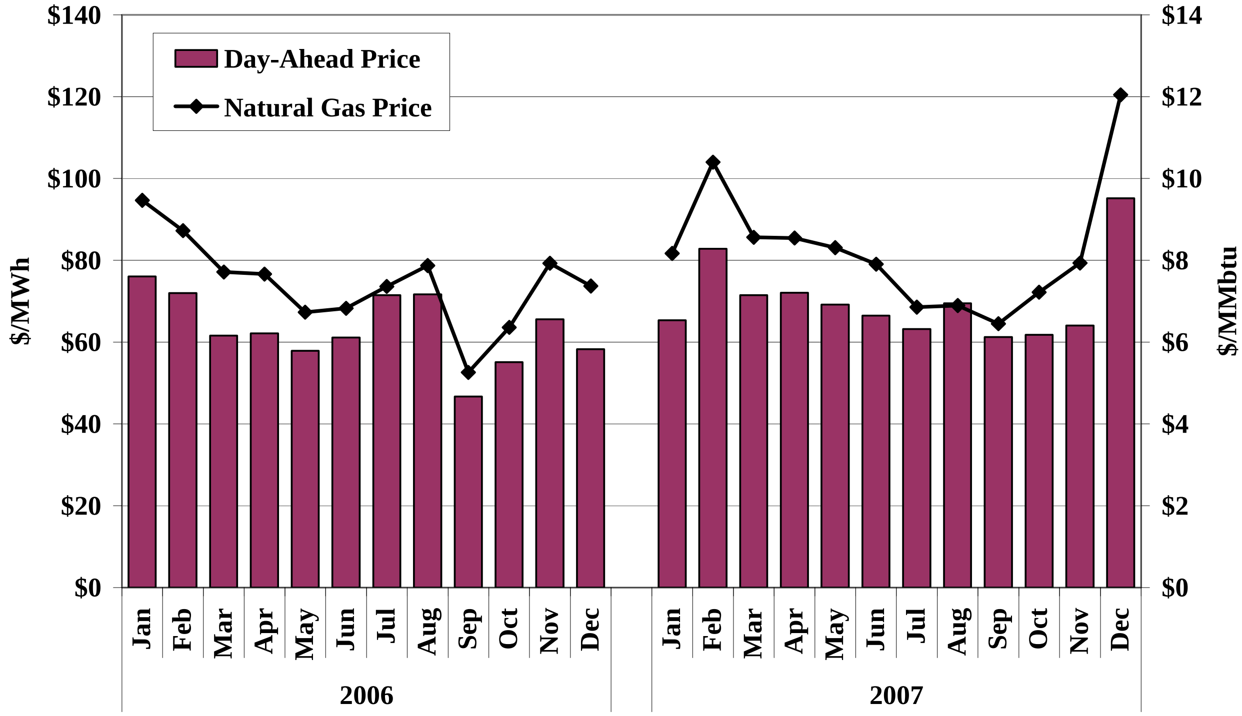
Our first analysis examines day-ahead prices at the New England Hub during 2006 and 2007. The New England Hub is located at the geographic center of New England and is an average of prices at 32 individual pricing nodes. The New England Hub price has been developed and published by the ISO to disseminate price information that facilitates bilateral contracting. The average New England Hub price increased more than 10 percent from 2006 to 2007, primarily due to increased fuel prices. These price movements are evaluated and discussed in more detail below.

Figure 1 shows the average price at the New England Hub in the day-ahead market for each month in 2006 and 2007.[10] The figure also shows the average price for natural gas in the region, which should be a key driver of electricity prices when the market is operating competitively. Currently, almost half of the generating capacity in New England burns natural gas.[11] Low-cost coal and nuclear resources typically produce at full output, while natural gas-fired resources are on the margin and sets the market clearing price in most hours. Therefore, electricity prices should be closely correlated with natural gas prices. This relationship is evident in Figure 1.

10 This average is weighted by the New England load level in each hour.

11 ISO New England, "2008-2017 Forecast Report of Capacity, Energy, Loads, and Transmission (CELT) Report," April 2007.

Figure 1: Monthly Average Day-Ahead Prices and Natural Gas Prices
New England Hub, 2006-2007

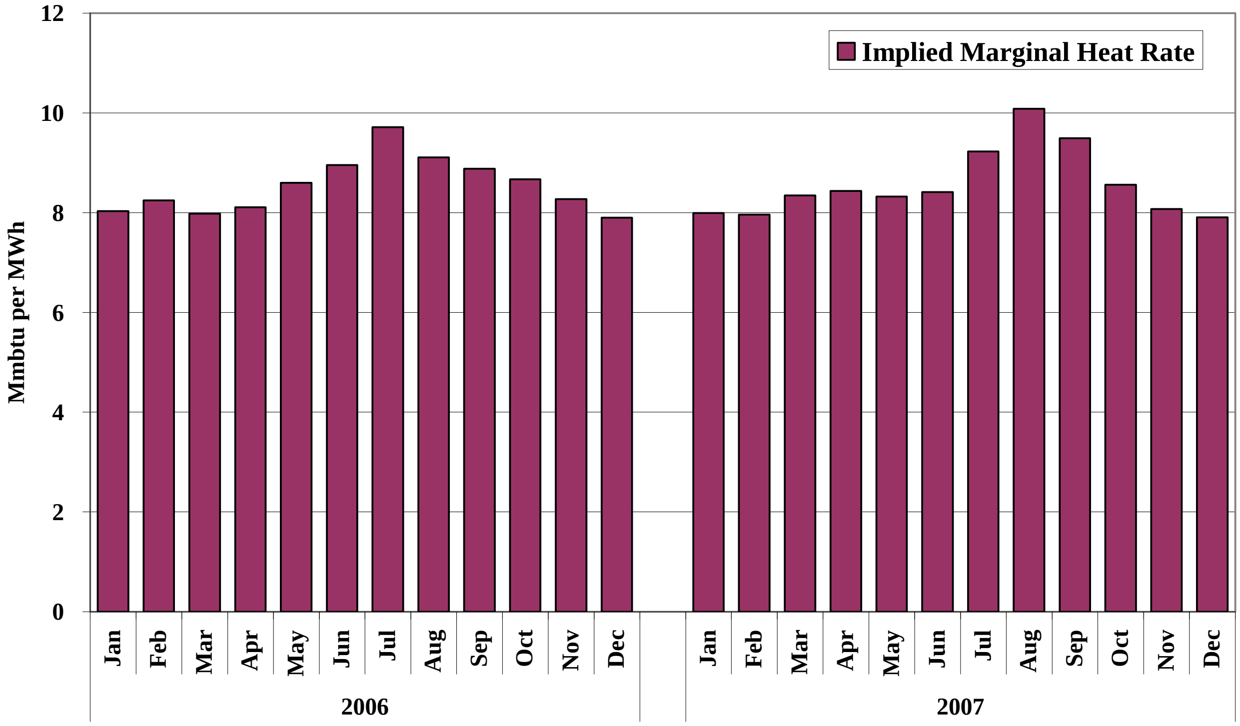


Note: Monthly average prices are load-weighted.

As expected, natural gas price fluctuations were a primary driver of the movement in electricity prices in 2006 and 2007. Gas prices decreased sharply from August to September 2006, leading to a similar decline in power prices. Similarly, gas prices increased sharply in February and December 2007, leading to significant increases in average power prices. High summer and winter loads due to heating and cooling demand also influence prices, but the effects of changing demand in the New England region are smaller than the effects of changing fuel prices.

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 measured in MMbtu. Thus, if the electricity price is $72 per MWh and the natural gas price is $9/MMbtu, this would imply that an 8.0 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 2006 and 2007.

Figure 2: Monthly Average Implied Marginal Heat Rate
Based on Day-ahead Prices at New England Hub, 2006-2007



Note: Monthly average prices are load-weighted.

By adjusting for the variation in natural gas prices, the implied marginal heat rate shows more clearly the seasonal variation in electricity prices. During the summer months (including June through September), the implied marginal heat rate averaged 9.2 MMbtu/MWh in 2006 and 9.3 MMbtu/MWh in 2007. Outside the summer months, the implied marginal heat rate averaged 8.2 MMbtu/MWh in both years. This seasonal increase is due primarily to the higher loads and tighter market conditions that prevail on the hottest days during the summer. Overall, however, these results indicate that both the price levels and seasonal patterns in 2007 were consistent with 2006.

B. Prices in Transmission Constrained Areas

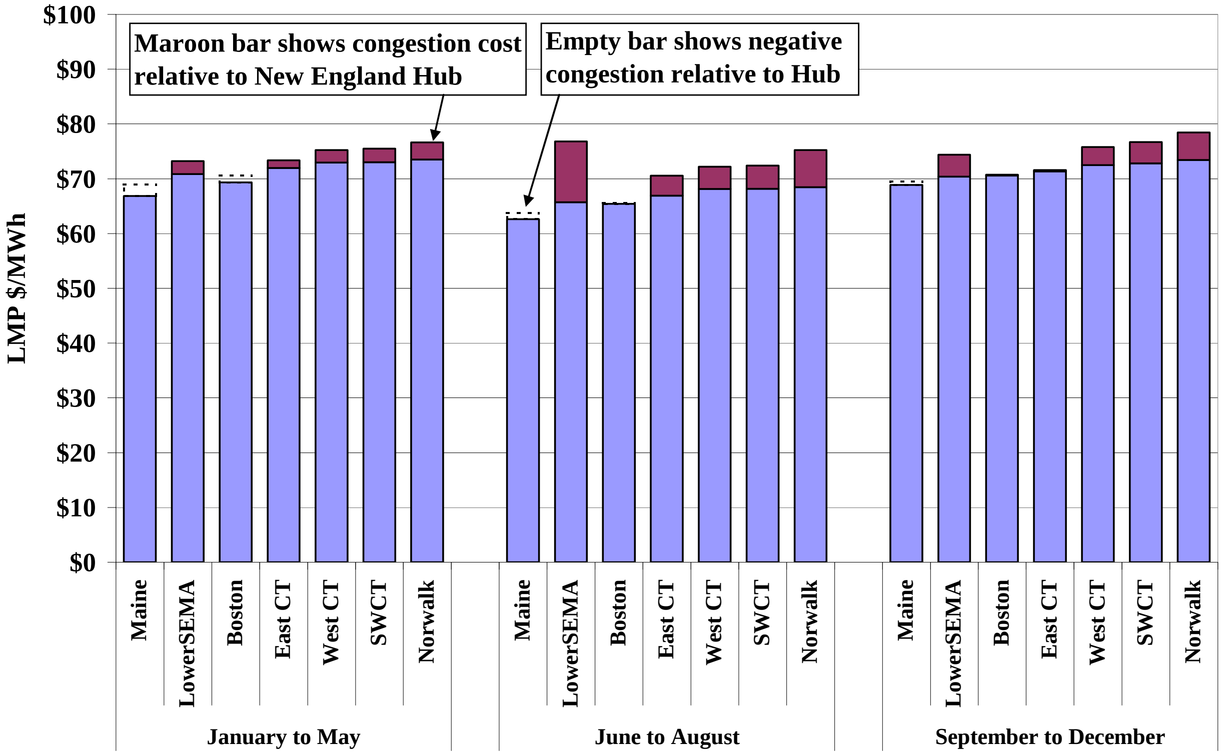
Historically, there have been significant transmission limitations between net-exporting and net-importing regions in New England. In particular, exports from Maine to the rest of New England are frequently limited by transmission constraints, while Connecticut and Boston are sometimes unable to import enough power to satisfy demand without dispatching expensive local generation. Standard Market Design ("SMD") was implemented in 2003 to manage transmission constraints in an efficient manner and producing locational marginal price ("LMP") signals. In LMP markets, the variation in prices across the system reflects the marginal value of transmission losses and congestion and ensures incentives for the efficient dispatch of resources.

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 when the lowest-cost resources cannot be fully dispatched because transmission capability is not sufficient to deliver their output to end-users. When congestion arises, LMP markets establish a spot price for energy at each location on the network that reflects the marginal system cost of meeting load at that location. The marginal system cost can vary substantially over the system, reflecting the fact that higher-cost units must be dispatched in place of lower-cost units to serve incremental load while not overloading any transmission facilities. This results in higher spot prices at "constrained locations" than occur in the absence of congestion.

Just as transmission constraints limit the delivery of energy into an area and require higher cost generation to operate in the constrained area, transmission constraints may also require additional operating reserves in certain locations to maintain reliability. In October 2006, the ISO implemented real-time reserve markets with locational requirements under Phase II of the ASM project, providing improved locational price signals for reserves and energy, particularly during shortages. When generation is redispatched in real-time to provide additional reserves to a local area, the marginal system cost of the redispatch is reflected in the LMPs. The reserve markets are discussed in Section V.

We analyzed the differences in energy prices between several key locations during the study period. Figure 3 shows load-weighted average day-ahead LMPs for the Maine load zone, Lower SEMA, NEMA/Boston load zone, and four areas within Connecticut. Connecticut is divided into: East Connecticut, the portion of West Connecticut that excludes Southwest Connecticut, the portion of Southwest Connecticut that excludes Norwalk-Stamford, and Norwalk-Stamford.

Figure 3: Average Day-ahead Prices by Location
2007



Note: The average prices reported for SWCT exclude Norwalk-Stamford, and the prices for West CT exclude SWCT and Norwalk-Stamford.

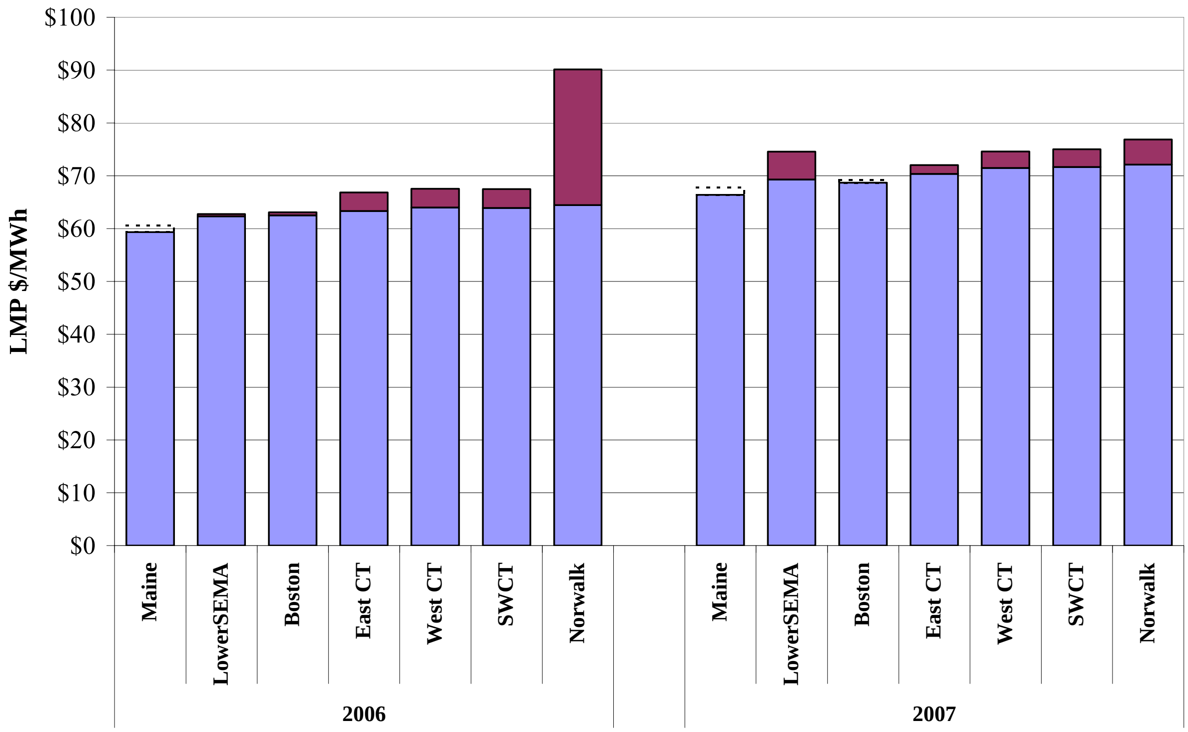
For each location, the load-weighted average LMP (including the effects of marginal transmission losses) is indicated by the height of the solid bars. The maroon portion of the bars indicates positive congestion to the location from the New England Hub, while negative congestion is indicated by the empty bars. Thus, prices in Maine are lower than the New England Hub partly due to congestion, while the other areas are load pockets that typically exhibit positive congestion from the Hub.

Of the areas shown in Figure 3, Lower SEMA was the most affected by congestion in 2007. The ISO began enforcing second contingency reliability requirements in Lower SEMA in 2006. The new requirements reduced the amount of power that could be imported to Lower SEMA from the rest of New England, leading to more frequent congestion. The second contingency requirements for the Lower SEMA area are discussed in greater detail in Sections V.C and

VIII.B. Although Lower SEMA was most affected by congestion, LMPs were higher on average in some areas of Connecticut due to the effects of transmission losses.

The next figure is similar to the prior figure, but it summarizes changes in congestion patterns from 2006 to 2007.

Figure 4: Average Day-Ahead Prices by Location 2006-2007



Congestion into Norwalk-Stamford declined significantly from 2006 to 2007, which is the most notable change shown in the figure. The average congestion price difference between the New England Hub and Norwalk-Stamford decreased from more than $25 per MWh in 2006 to less than $5 per MWh in 2007. The reduction in congestion in the summer months was even more substantial: the average congestion price difference decreased from more than $60 per MWh during the summer of 2006 to $7 per MWh in 2007.

Two factors explain the dramatic reduction in congestion into Norwalk-Stamford. First, Phase I of the Southwest Connecticut 345 kV Transmission Project was completed in October 2006. The additional transmission capability reduced the need to dispatch expensive resources in

Norwalk-Stamford. Second, the Peaking Unit Safe Harbor ("PUSH") offer rules expired in June 2007, leading to lower offer prices for supplies in Norwalk-Stamford.[12] The PUSH offer rules allowed owners of low capacity-factor generators in Designated Congestion Areas to include levelized fixed costs in energy offers without risk of mitigation. Since the expiration of the PUSH program in June 2007, some of the affected units have entered into Reliability Agreements with the ISO that require the units to submit offers equal to marginal cost.

There was virtually no congestion into Boston in 2007 because the NSTAR 345 kV Transmission Project was brought in-service in the spring of 2007, substantially increasing the import capability into Boston. In addition, the behavior of the largest supplier in Boston led to significant amounts of excess committed capacity in the area. This behavior is discussed in greater detail in Section VIII.B.

C. Convergence of Day-ahead and Real-Time Prices

The day-ahead market allows participants to make forward purchases and sales of power for delivery in the real-time. The market provides a valuable financial mechanism that allows participants to hedge their portfolios and manage risk. Loads can hedge price volatility in the real-time market by purchasing in the day-ahead market. Suppliers can avoid the risk of starting-up their generator on an unprofitable day, because the day-ahead market will only accept their offer when they will profit from being committed. However, suppliers that sell in the day-ahead market are exposed to some risk because they are committed to deliver energy in the real-time market. An outage can force them to purchase replacement energy from the spot market during a price spike.

In well-functioning day-ahead and real-time markets, we expect that day-ahead and real-time prices will not systematically diverge. If day-ahead prices were predictably higher than real-time prices, buyers would decrease purchases and sellers would increase sales in the day-ahead market. Alternatively, if day-ahead prices were foreseeably lower than real-time prices, buyers would increase purchases day-ahead and sellers would decrease their day-ahead sales.

12 PUSH rules expired June 18, 2007; the program was in effect from June 1, 2003.

Historically, average day-ahead prices tend to be relatively consistent with the average real-time prices in New England, although it has been common for day-ahead prices to carry a slight premium over real-time prices. Predictable day-ahead price premiums encourage speculative market participants to schedule *incs* or "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 tends to limit the size of the average day-ahead premium. Price convergence is desirable because it promotes the efficient commitment of generating resources and scheduling of external transactions.

In the remainder of this section, we evaluate the convergence of prices between day-ahead and real-time markets. Section D examines convergence of energy prices at the New England Hub, which is broadly representative of the New England market. Section E examines convergence of energy prices in several areas that are sometimes isolated from the rest of New England by transmission constraints.

D. Price Convergence at the New England Hub

Examining price convergence between day-ahead and real-time markets at the New England Hub provides an indication of the overall price convergence in the region. In this section, two measures are used to assess price convergence. The first measure reports the simple difference between the average day-ahead price and the average real-time price. The second measure reports the average absolute difference between day-ahead and real-time prices on an hourly basis. The first measure is an indicator of the systematic differences between day-ahead and real-time prices, while the second measure captures the overall variability between day-ahead and real-time prices over the year.

Table 1 shows load-weighted average day-ahead and real-time energy prices at the New England Hub in 2006 and 2007. The table also shows the average allocation of Net Commitment Period Compensation ("NCPC") charges to participants that purchase energy from the market. NCPC payments are made to generators that are committed and dispatched by the ISO but do not recover their as-bid cost from market revenue.

Table 1: Convergence of Day-Ahead and Real-Time Prices at New England Hub 2006-2007

		2006	2007
Day-Ahead Market:			
Average Price	(1)	**$63.50**	**$70.26**
NCPC Allocation to Load	(2)	**$0.07**	**$0.12**
Price plus NCPC Allocation	= (1) + (2)	**$63.57**	**$70.38**
Real-Time Market:			
Average Price	(3)	**$62.67**	**$69.20**
NCPC Allocation to Load	(4)	**$0.74**	**$0.56**
Price plus NCPC Allocation	= (3) + (4)	**$63.41**	**$69.75**
Average DA minus Average RT:			
Price Only	= (1) - (3)	**$0.83**	**$1.06**
Price plus NCPC Allocation	= (1) + (2) - (3) - (4)	**$0.16**	**$0.63**
Average Absolute Difference	(5)	**$10.64**	**$10.26**
(as a percent of RT Price)	= (5) / (3)	**17%**	**15%**

The table shows that in both years, the day-ahead prices were higher than real-time prices on average. While day-ahead prices tend to be slightly higher than real-time prices, NCPC allocations tend to be higher in real-time than in the day-ahead market.[13] Hence, when NCPC payments are included in the assessment of convergence, the average day-ahead premium becomes smaller. In general, these differences between day-ahead and real-time prices are modest compared to other RTO and ISO markets.

The second measure of price convergence, the average absolute difference between day-ahead and real-time prices, fell slightly from 2006 to 2007. When considered as a percentage of real-time prices in each year, the average absolute difference decreased from 17 percent to 15 percent. The hotter summer weather in 2006 contributed to larger differences between day-ahead and real-time prices in 2006. The eight hours of reserve shortages on August 1 and 2,

13 Both tendencies are common in integrated power markets with day-ahead and real-time markets, but neither is guaranteed. Energy prices tend to be higher day ahead because load is willing to pay a small premium for the relative stability of day-ahead prices compared to real-time prices. NCPC costs tend to be higher in real-time because the system will have less flexibility in responding to changing resource outputs and load patterns in real time than in the day ahead time frame, often requiring the selection of more costly alternatives. Additionally, commitments made solely for reliability are generally made after the day-ahead market.

2006 exhibited real-time clearing prices near $1000 per MWh. In these hours, day-ahead clearing prices ranged from $148 to $218 per MWh at New England Hub, indicating that the market did not fully anticipate the real-time conditions.

The factors that affect real-time prices on a particular day are inherently difficult to predict. Changing weather patterns can lead to large differences between forecasted demand and actual demand. Generation outages and transmission outages can arise, leading to sharp reductions in supply. These factors can lead day-ahead and real-time prices to differ significantly on individual days, even if prices are converging on average.

E. Price Convergence in Transmission Constrained Areas

When the transmission system is unconstrained, all buyers and sellers effectively participate in a single, regional market. Hence, resources throughout the system are utilized to respond to unexpected changes in load or available supply, which diminishes the price effects from these events. When transmission constraints are binding, such events can have a much greater effect in the congested area. This section examines price convergence in locations that are most frequently isolated from the rest of New England by congestion.

The following table summarizes convergence between day-ahead and real-time prices at the New England Hub, one frequently export-constrained location (Maine), and several frequently import-constrained locations. Connecticut is divided into four regions: East Connecticut, the portion of West Connecticut that excludes Southwest Connecticut, the portion of Southwest Connecticut that excludes Norwalk-Stamford, and Norwalk-Stamford. As before, we report two measures of convergence: (i) the difference between the average day-ahead and average real-time prices and (ii) the average absolute difference between hourly prices in the day-ahead and real-time markets as a percentage of the average real-time clearing price. The difference in average prices shows whether prices over the entire period were higher in the day-ahead or real-time market. The average absolute difference shows the size of the hourly price differences.

Table 2: Convergence between Day-Ahead and Real-Time Prices by Region 2006-2007

Region	Real-Time Clearing Price ($/MWh) 2006	Real-Time Clearing Price ($/MWh) 2007	Day-Ahead - Real-Time Price Difference ($/MWh) 2006	Day-Ahead - Real-Time Price Difference ($/MWh) 2007	Hourly Absolute Price Difference (percent of RT Price) 2006	Hourly Absolute Price Difference (percent of RT Price) 2007
New England Hub	$62.67	$69.20	$0.83	$1.06	17%	15%
Maine	$58.62	$65.91	$0.70	$0.45	17%	15%
Lower Southeast Massachusetts	$61.12	$70.80	$1.65	$3.79	18%	18%
Boston	$63.60	$68.07	-$0.50	$0.76	19%	15%
Areas in Connecticut:						
East Connecticut	$64.73	$73.34	$2.12	-$1.34	19%	18%
West CT (excluding SWCT)	$65.46	$75.97	$2.07	-$1.38	19%	18%
SWCT (excluding Norwalk)	$65.26	$75.45	$2.22	-$0.41	19%	18%
Norwalk-Stamford	$86.19	$76.40	$3.95	$0.46	24%	19%

Table 2 shows that price convergence was generally better in the less congested locations, reflecting that market events tend to have larger price effects in isolated areas. The difference between the average day-ahead and real-time prices, was highest for Norwalk-Stamford in 2006 and Lower SEMA in 2007. Likewise, the second measure of convergence, the average absolute difference, also tended to be higher in the import-constrained locations than at the Hub.

Changes in the commitment of key generators after the day-ahead market contribute to poor convergence between the day-ahead and the real-time market in some load pockets. This was evident from the $3.95 per MWh day-ahead premium in Norwalk-Stamford in 2006 and the $3.79 per MWh day-ahead premium in Lower SEMA in 2007. On many days, the majority of the generation in these areas was committed after the day-ahead market. As a result, congestion in the day-ahead market was often based on load bids and virtual transactions with no physical resources scheduled.

Notwithstanding the poor convergence in a Norwalk-Stamford and Lower SEMA, we find that the overall convergence between day-ahead prices and real-time prices in New England was relatively good. The average differences are very similar to those in other RTO markets and the average absolute differences are the lowest of any of the RTOs in the eastern Interconnect. We attribute the latter result to the relatively low real-time price volatility in New England.

III. External Interface Scheduling

This section examines the scheduling of imports and exports between New England and adjacent regions. New England receives imports from Quebec and New Brunswick in most hours, which reduces wholesale power costs for electricity consumers in New England. Between New England and New York, power flows in both directions depending on market conditions. Overall, New England was an exporter of power to New York in 2007. The transfer capability between New England and adjacent control areas is large relative to the typical load in New England, making it particularly important to schedule interfaces efficiently.

Consumers benefit from the efficient use of external transmission interfaces. The external interfaces allow low-cost external resources to compete to serve consumers who would otherwise be limited to available internal resources. The ability to draw on neighboring systems for emergency power, reserves, and capacity also helps lower the costs of meeting reliability standards in the interconnected system. Wholesale markets facilitate the efficient use of both internal resources and transmission interfaces between control areas.

ISO-NE is interconnected with three neighboring control areas: the New York ISO, TransEnergie (Quebec), and the New Brunswick System Operator. New England and New York are interconnected by three interfaces: the Roseton Interface, which consists of several lines linking New England to up-state New York; the 1385 Line, a controllable AC interconnection between Norwalk and Long Island; and the Cross Sound Cable, a DC interconnection between Connecticut and Long Island. New England and Quebec are interconnected by two interfaces: Phase I/II, which is a large DC interconnection; and the Highgate Interface, which is a smaller AC interconnection between Vermont and Quebec. New England and New Brunswick are connected by a single interface.

This section evaluates several aspects of transaction scheduling between New England and adjacent control areas. Section A summarizes scheduling between New England and adjacent areas in 2007. Section B evaluates the efficiency of scheduling by market participants between New York and New England. Section C presents an estimate of the benefits that would result from efficient coordination of interchange between New York and New England by the ISOs. This section also discusses efforts to reduce barriers to efficient scheduling and identifies additional changes that could further improve scheduling across the “seams” between New England and the adjacent markets.

A. Summary of Imports and Exports

The following two figures provide an overview of imports and exports by month for 2007. Figure 5 shows the average net imports across the three interfaces with Quebec and New Brunswick by month, for peak and off-peak periods.[14]

Figure 5: Average Net Imports from Canadian Interfaces 2007

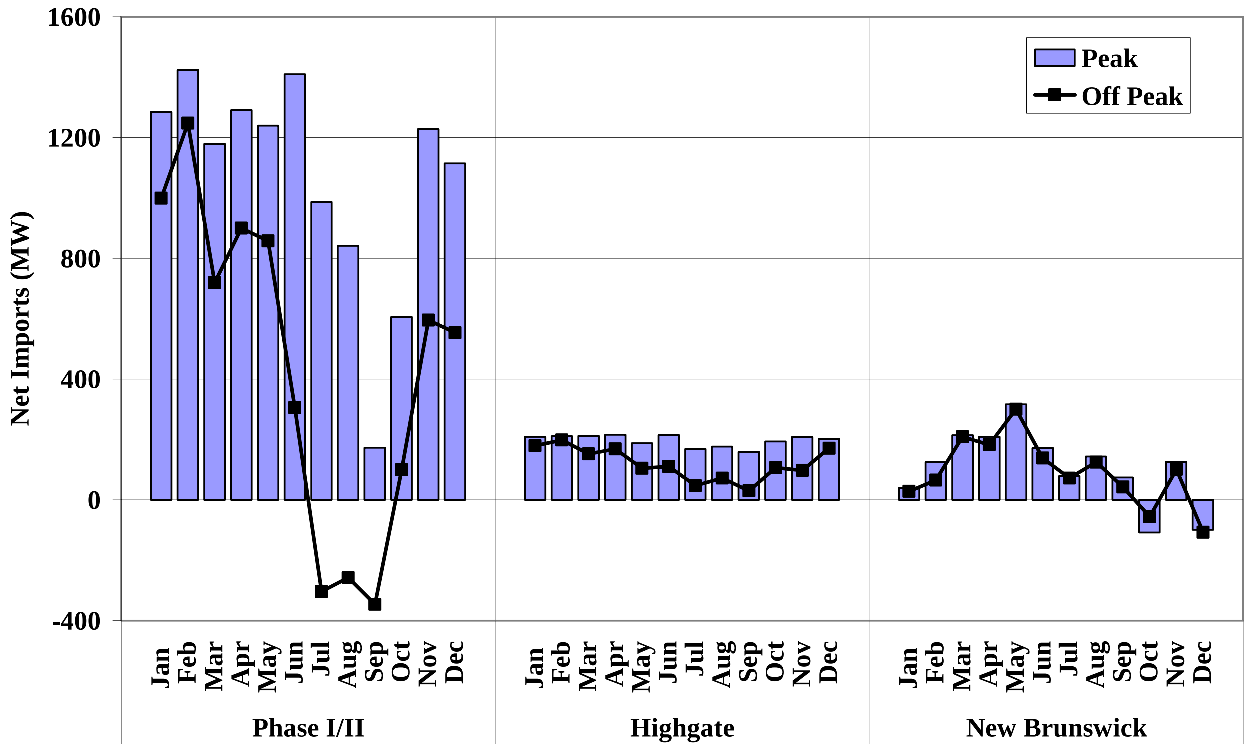


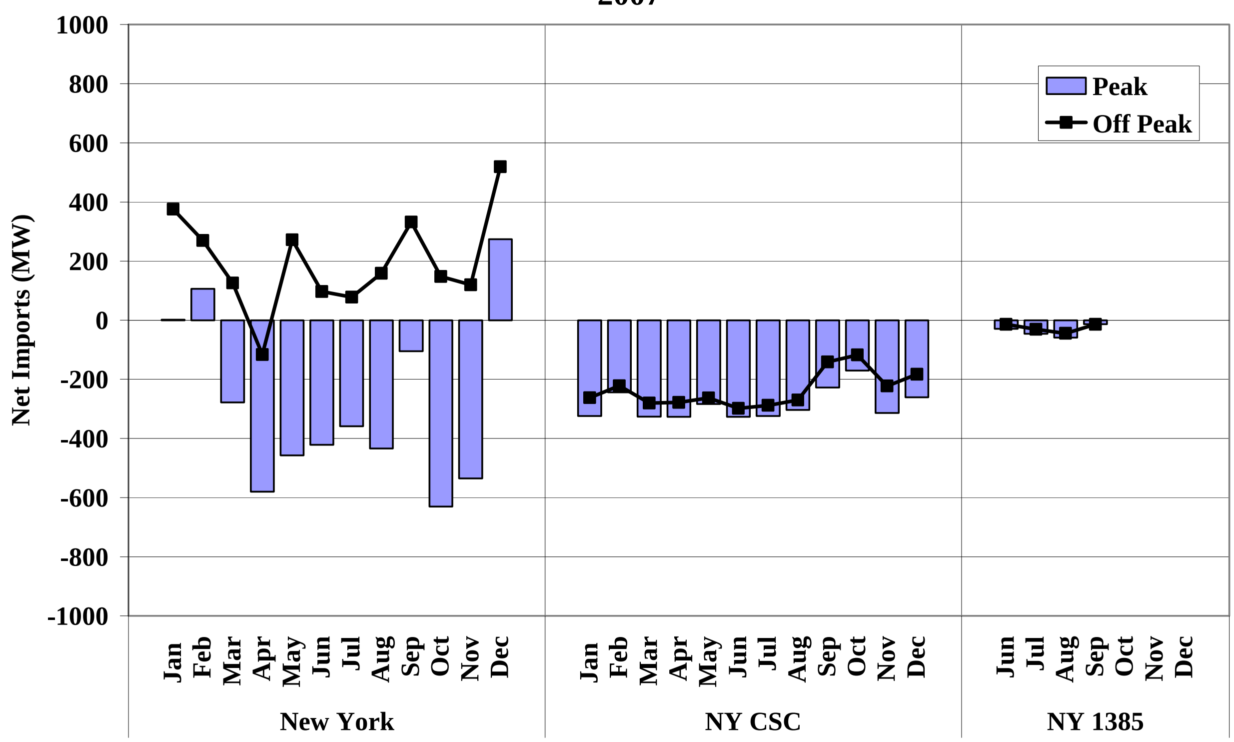
Figure 5 shows that power is generally imported over the interfaces with Quebec and New Brunswick. Across the two interfaces with Quebec, net imports were 700 MW higher on

14 Peak hours include hours-ending 7 to 22, Monday through Friday, and the remaining hours are included in Off-Peak.

average during peak hours than during off-peak hours. In the summer months, an average of about 10 MW was exported to Quebec during off-peak hours, but this shifted to an average import of 1,267 MW during peak hours. These patterns reflect the tendency for hydro resources in Quebec to store water during low demand periods in order to make more power available during high demand periods. Net imports over the New Brunswick interface were much lower than the Quebec interfaces and did not vary significantly from peak to off-peak hours.

Figure 6 shows average net imports over the three interfaces with New York by month in 2007 for peak and off-peak periods. The figure shows relatively stable flows from New England into Long Island over the Cross-Sound Cable. In contrast, flows across the up-state New York AC interface tend to flow into New York during peak periods and into New England during off-peak periods. Hence, power tends to flow in from Canada and out to New York during peak periods. The next section includes an evaluation of the efficiency of flows between New England and New York. In total, New England is a net importer of power from adjacent areas.

Figure 6: Average Net Imports from New York Interfaces 2007



The 1385 Line was treated as a part of the New York AC interface prior to June 27, 2007, so the figure does not report flows across the 1385 Line before this date. The 1385 Line was out of service beginning on September 10, 2007, resulting in 0 MW for the last three months of 2007. Based on the first three months of operation as a separately scheduled interface, the 1385 Line was generally used to export a small amount of power to Long Island.

B. Interchange with New York

The performance of wholesale electricity markets depends not only on the efficient use of internal resources, but also the efficient use of transmission interfaces with adjacent areas. This section evaluates the efficiency of scheduling between New England and New York. Since both regions have real-time spot markets, market participants can schedule market-to-market transactions based on transparent price signals in each region. Based on the prevailing prices in each market, we can evaluate whether the interface is scheduled efficiently.

Trading between neighboring markets should bring prices together as participants arbitrage the price differences. When an interface is used efficiently, prices in adjacent areas should be consistent unless the interface is constrained. For example, when prices are higher in New England than in New York, imports from New York should continue until prices have converged or until the interface is fully scheduled. A lack of price convergence indicates that resources are being used inefficiently. In other words, higher-cost resources are operating in the high-priced region that could have been supplanted by increased output from lower-cost resources in the low-priced region.

During peak demand conditions, it is especially important to schedule flows efficiently between control areas. Frequently during such conditions, a small amount of additional imports can substantially reduce prices.

Several factors prevent real-time price differences between New England and New York from being fully arbitraged. First, market participants do not operate with perfect foresight of market conditions when transaction bids and offers must be submitted. Second, differences in the procedures and timing of scheduling in each market serve as barriers to full arbitrage. Third, there are transaction costs associated with scheduling imports and exports that diminish the returns from arbitrage. Participants are not expected to schedule additional power between regions unless they expect a price difference greater than these costs. Last, risks associated with curtailment and congestion reduce participants' incentives to schedule external transactions when the expected price difference is small. Given these considerations, one cannot reasonably expect that trading by market participants will optimize the use of the interface.

Figure 7 shows the distribution of real-time price differences for the primary AC interface and the 1385 Line between New England and New York in hours when the interfaces were unconstrained. The following figures focus on the interface with Upstate New York, which is responsible for most of the flows between the regions. The Cross Sound Cable is not evaluated in the following figures because it is scheduled under separate rules.[15] While the factors listed above prevent complete arbitrage of price differences between regions, trading should help keep prices in the neighboring regions from diverging excessively. Nonetheless, Figure 7 shows that more than 50 percent of the unconstrained hours have real-time price differences of greater than $10 per MWh. In more than 5 percent of the hours, the price difference is greater than $50/MWh.

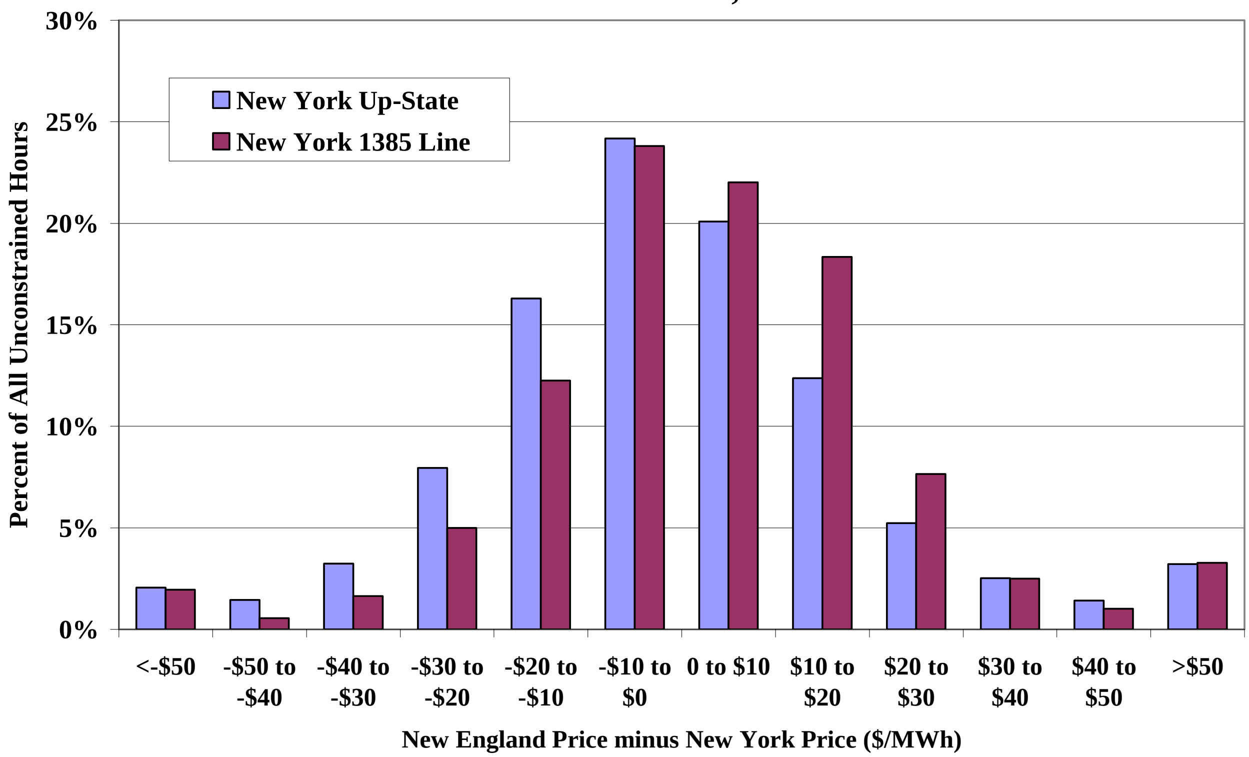
The results shown in the figure indicate that the current process does not maximize the utilization of the interface. Given the size of price differences shown, there are a substantial number of hours when adjustments to increase flows from the lower priced region into the higher priced region would have had significant effects on prices and production costs.

In real-time, it has proven difficult for the adjacent markets to achieve price convergence by relying on transactions scheduled by market participants. Uncertainty, imperfect information, and offer submittal lead times limit the ability of participants to capitalize on real-time arbitrage

15 Service over the Cross Sound Cable is provided under the Merchant Transmission Facilities provisions in Schedule 18 of ISO New England's Tariff, with is separate from the transmission service provisions governing use of the Pool Transmission Facilities. Access to the MTF requires Advance Reservations on the CSC, recommended to be acquired in advance of submitting transactions to the Day Ahead Market, and energy transactions accepted in the ISO New England and NYISO market systems. Scheduling limits restrict the ability to use the CSC interface for short-run arbitrage transactions between Connecticut and Long Island.

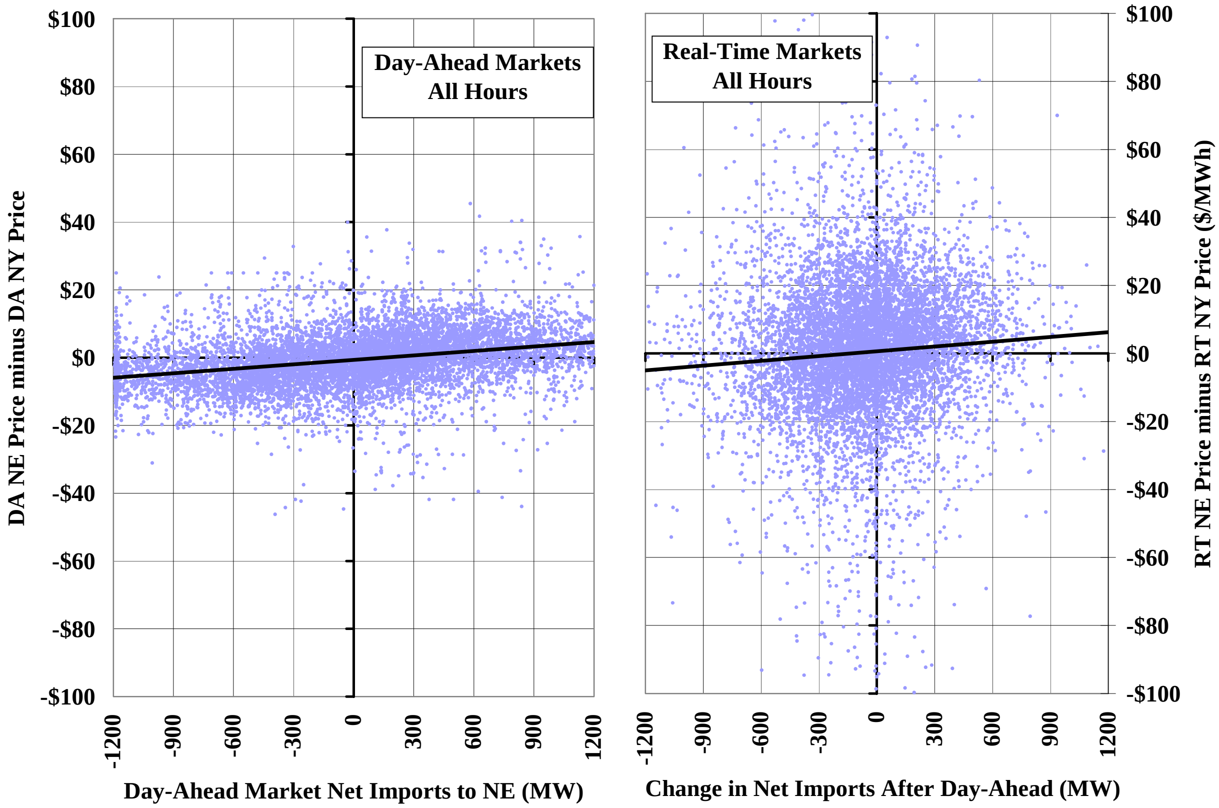
opportunities. This failure to fully arbitrage the interfaces leads to market inefficiencies that could be remedied if the ISOs were to coordinate interchange.

Figure 7: Real-Time Price Difference Between New England and New York Unconstrained Hours, 2007



Although scheduling by market participants has not fully arbitraged the interfaces between New York and New England, the following analysis demonstrates that scheduling by market participants has incrementally improved price convergence. Figure 8 shows net scheduled flows versus price differences between New England and up-state NY. The left side of the figure shows price differences in the day-ahead market on the vertical axis versus net imports scheduled in the day-ahead market on the horizontal axis. The right side of the figure shows hourly price differences in the real-time market on the vertical axis versus the *change* in the net scheduled imports after the day-ahead market on the horizontal axis. For example, if day-ahead net scheduled imports for an hour are 300 MW and real-time net scheduled imports are 500 MW, the change in net scheduled imports after the day-ahead market would be 200 MW.

Figure 8: Efficiency of Scheduling in the Day-Ahead and Real-Time Interface Between Up-state NY and New England, 2007

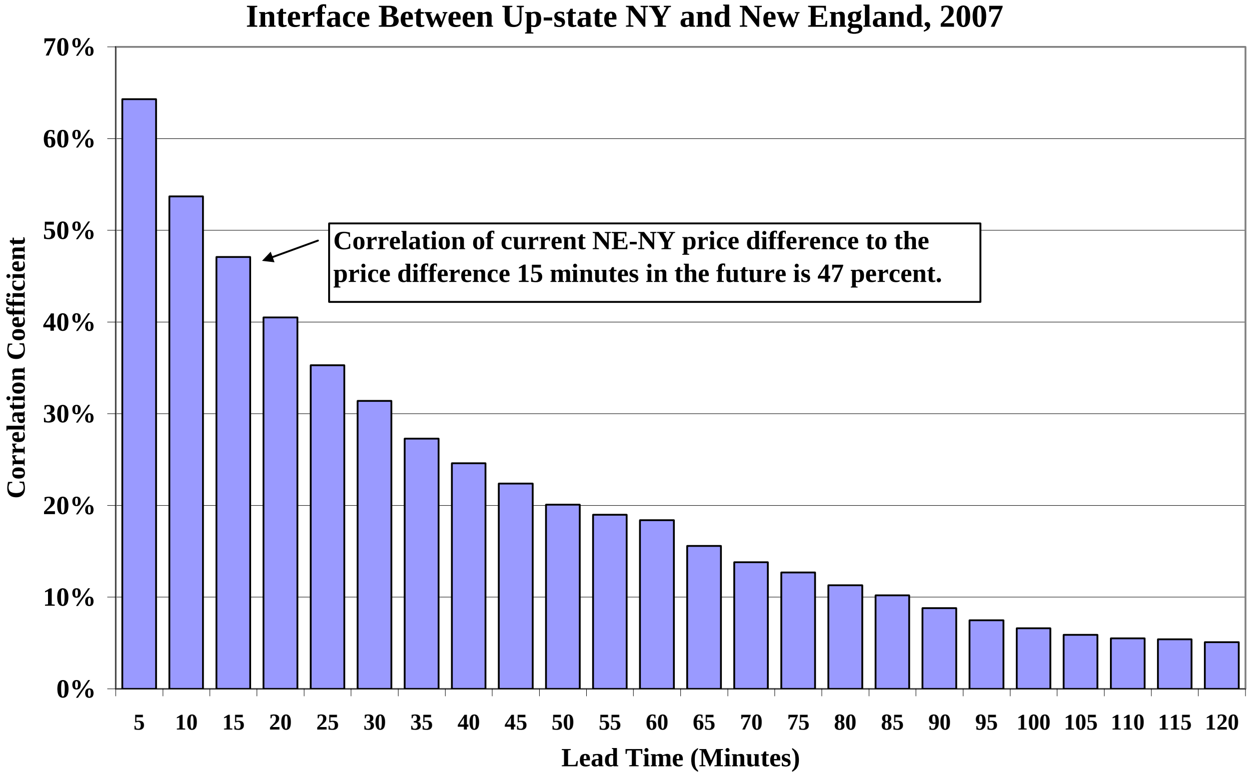


The trend lines presented in each panel of the figure show statistically significant positive correlations between the price difference and the direction of scheduled flows in the day-ahead and real-time markets. A positive correlation indicates that the scheduling of market participants tends to respond to price differences, by increasing net flows scheduled into the higher priced region in the day ahead and in the real time. Total net profits from cross-border scheduling in 2007 was $14.1 million in the day-ahead market and $4.5 million in the real-time market (not including transaction costs). The fact that significant profits were earned from the external transactions provides additional support for the conclusion that market participants generally help improve the convergence of prices between regions, although the arbitrage of prices is far from complete.

The greater dispersion of points on the right reflects that real-time price differences between regions are harder to predict than day-ahead price differences. Forty-five percent of the points in the real-time market panel are in unprofitable quadrants – upper left and lower right – indicating hours when the net real-time adjustment by market participants shifted scheduled flows in the unprofitable direction (increasing output in the high-priced market and reducing output in the low-priced market). Although market participant scheduling has helped converge prices between adjacent markets, Figure 8 shows that there remains considerable room for improvement.

The following analysis examines the correlation between the lead times for scheduling transactions and the predictability of price differences between adjacent markets. Figure 9 shows the correlation coefficient of the real-time price difference between New England and New York between the current period and each subsequent five-minute period over two hours. For example, the correlation of the price difference at the current time and the price difference 15 minutes in the future was 47 percent in 2007.

Figure 9: Correlation of Price Difference to Lead Time
Interface Between Up-state NY and New England, 2007



Not surprisingly, Figure 9 shows that actual price differences are more strongly correlated to price differences in periods near in time than to price differences in periods more distant in time.

Currently, to schedule transactions between New York and New England, market participants must submit their offers 75 minutes before the start of an hour, which is 75 to 135 minutes before the power actually flows since transactions are scheduled in one-hour blocks at the top of the hour. This analysis suggests that reducing the lead times for scheduling would enable market participants to schedule more efficiently.

C. Coordination of Interchange by the ISOs

Incomplete price convergence between New England and New York suggests that more efficient scheduling of flows between markets would lead to production cost savings and substantial benefits to consumers. Although past efforts to reduce barriers to market participant scheduling between regions have improved the efficiency of flows, and additional such efforts would lead to further improvements, uncertainty and risk are inherent in the market participant scheduling process. Hence, even with improvements, one cannot reasonably expect the current process to fully utilize the interface. As is the case for efficient scheduling of the transmission capability within ISO regions, optimal use of transmission capability between ISO regions requires explicit coordination of interchange by the ISOs.

We employed simulations to estimate the benefits of optimal hourly scheduling of the primary interface between New England and New York in 2006 and 2007. The benefits of efficient scheduling include reduced production costs and lower prices for consumers. The production cost net savings represent the increased efficiency of generator operations over the two regions as additional production from lower-cost generators displaces production from higher-cost generators. The net consumer savings arise because improved coordination between the ISOs tends to lower prices on average in both regions. Table 3 summarizes the results of this analysis.

The simulations indicate that better coordination would lead to lower average prices and net savings for consumers in both regions. Adjacent regions are brought into better convergence by increasing production in the low-price region and by decreasing production in the high-price region. In each hour, better convergence would lead to higher prices for one group of consumers and lower prices for the other group of consumers. However, our simulations indicate that both groups of consumers would benefit because prices fall more in the high-price region than they rise in the low-price region due to the convex shape of the supply curve in electricity markets.

Table 3: Estimated Benefits of Coordinated External Interface Scheduling Interface Between Up-state NY and New England, 2006-2007

	2006	2007
Estimated Production Cost Net Savings (in Millions)	**$17**	**$21**
Estimated Consumer Net Savings (in Millions):		
New England Customers	**$61**	**$22**
New York Customers	**$59**	**$177**
Total for New England and New York Customers	**$120**	**$199**
During Reserve Shortage Hours	**$16**	**$75**

Estimated consumer net savings that would have been obtained by consumers in New England were $61 million in 2006 and $22 million in 2007. In New York, estimated consumer net savings increased from $59 million in 2006 to $177 million in 2007. The simulations estimate that a lower portion of the savings would have been realized by New England consumers in 2007. The primary reasons for this result are that the New England system experienced fewer reserve shortages and slightly lower average energy prices than New York in 2007.

Shortage pricing provisions in both the New York and New England markets have contributed to more efficient energy pricing when reserve shortages occur. Coordination of physical interchange between the ISOs can be especially important in avoiding or resolving shortage conditions. Hence, full utilization of external interfaces becomes increasingly important as the ISOs improve pricing of shortages. The estimates in Table 3 suggest that ISO coordination of external flows during reserve shortages would have accounted for almost 40 percent of the total savings in 2007. Hence, as capacity margins decrease and the frequency of shortages increase, the total savings for New England customers could be multiples of the savings estimated for 2007.

The production cost net savings, while not insignificant, naturally tend to be smaller than consumer net savings. Better coordination of flows between regions would not affect the bulk of the generators operating in both systems. In most cases, a few higher-cost generators in the higher-price region would be displaced by a few lower-cost generators in the lower-priced region. Hence, the producer cost effects are smaller than the price effects.

D. Conclusions and Recommendations

Efficient use of transmission interfaces between regions allows customers to be served by external resources that may be lower-cost than available native resources. New England imports large amounts of power from Quebec and New Brunswick, which reduces wholesale power costs for electricity consumers in New England. Power flows in both directions between New England and New York, depending on market conditions in each region.

Our evaluation of external transactions between New York and New England indicates that scheduling by market participants does not fully utilize the external interfaces or achieve all of the potential benefits available from inter-regional trading. Improving the efficiency of flows between regions is particularly important during shortages or very high-priced periods because modest changes in the physical interchange can substantially affect the market outcomes in both New England and New York. Over the past several years, efforts have been made to reduce barriers to scheduling external transactions. While the external transaction scheduling process is functioning properly and scheduling by market participants tends to improve convergence, the data examined suggest that significant opportunities remain to improve scheduled interchange between regions.

Proposals have been made to allow the physical interchange to be adjusted within an hour when prices diverge at the interface between the two markets. By reducing scheduling lead times, such a change would facilitate more efficient interchange and reduce inefficiencies caused by poor convergence. Moreover, better arbitrage would cause prices in both regions to be less volatile and lower overall.

Elimination of remaining barriers to market participant scheduling between regions, while desirable, would not achieve full utilization of the external interfaces. Uncertainty, imperfect information, and a lack of coordination limit the ability of market participants to arbitrage fully the prices between regions. Hence, we continue to recommend that the ISOs develop provisions to coordinate the physical interchange between New York and New England in real-time. Some have argued that this would constitute involving the ISOs in the market, but this is not the case. The ISOs would rely upon bids and offers submitted by participants in each market to establish the optimal interchange between the markets in the same way that they establish optimal power flows across each transmission interface inside both markets.

While our review has focused on the efficiency of flows between New England and New York, we note that ISO New England is working with stakeholders and the New Brunswick System Operator to implement the capability for intra-hour scheduling across the interface. An initial review by the ISO has indicated that existing rules governing external transactions must be changed to accommodate the proposal. The ISO plans to implement an intra-hour scheduling pilot program with limited scope in Fall 2008 that would enable the ISO to reevaluate import and export offers at thirty minutes past each hour. If the pilot is successful, it will provide a framework for reevaluating offers from New Brunswick every 15 minutes. The increased flexibility should allow more efficient scheduling of the interface with New Brunswick.

IV. Financial Transmission Rights

A key function of LMP markets is to set efficient energy prices that reflect the economic consequences of binding transmission constraints. These prices guide the short-term dispatch of generation and establish long-term economic signals, which govern investment in new generation and transmission assets. Hence, a primary focus of this report is to evaluate locational marginal prices and associated congestion costs.

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 revealed in the congestion component of the LMP at each location.[16]

Financial Transmission Rights ("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. 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 a bilateral contract if it owns an FTR between the same receipt and delivery points as the bilateral contract.

Through the auctions it administers, the ISO sells FTRs with one-year terms ("annual FTRs") and one-month terms ("monthly FTRs"). The annual FTRs allow market participants greater certainty by locking-in congestion hedges further in advance. The ISO auctions 50 percent of the

16 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, not including transmission losses.

forecasted capacity of the transmission system in the annual auction, and nearly all of the remaining capacity in the monthly auctions.[17] FTRs are auctioned separately for on-peak and off-peak hours.[18]

In this section, we assess three aspects of the performance of the FTR markets. First, we evaluate the net payments to FTR holders. The net payments to FTRs holders declined in 2007, which is consistent with the overall decline in congestion in the day-ahead and real-time markets. Payments to FTR holders are funded by the congestion revenue collected by the ISO. In 2007, the congestion revenue collected by the ISO was not sufficient to satisfy the obligations to FTR holders (referred to as the "target payment amount"). FTR holders were paid 94 percent of the target payment amount on average in 2007.

Second, we compare FTR prices with congestion prices in the day-ahead and real-time markets. Since FTR auctions are forward financial markets, FTR prices should reflect the expectations of market participants regarding congestion in the day-ahead market. In 2007, FTR prices were relatively consistent with congestion prices in the day-ahead and real-time markets. The consistency of FTR prices with congestion prices improved substantially from the annual auction to the monthly auctions as market participants gained additional information about market conditions.

Third, we review FTR holdings and discuss the importance of credit requirements for market participants that hold FTRs. We find that the greatest source of default risk is from market participants that buy negatively-priced FTRs, which give the holder an upfront payment and usually obligate the holder to make payments over the life of the FTR. Holders of negatively-priced FTRs made $52 million in such payments in 2007. To a lesser degree, positively-priced FTRs can also be a source of default risk. Positively-priced FTRs usually entitle the holder to a

17 In the annual auction the ISO awards FTRs equivalent to 50 percent of the predicted power transfer capability of the system, and in the monthly auctions the ISO awards FTRs equivalent to 95 percent of the remaining predicted power transfer capability after accounting for planned transmission outages. See generally, the *ISO New England Manual for Financial Transmission Rights*, Manual M-06.

18 On-peak hours include hours-ending 7 to 22, Monday through Friday. Off-peak includes all other hours.

stream of payments over the life of the FTR, but when congestion patterns differ significantly from expectations, positively-priced FTRs can require the holder to make payments unexpectedly. Holders of such positively-priced FTRs were obligated to pay $17 million in 2007. These results confirm the need to maintain credit requirements for both positively-priced FTRs and negatively-priced FTRs, although the credit requirements should reflect that greater risk resides with the holders of negatively-priced FTRs.

A. Congestion Revenue and Payments to FTR Holders

As discussed above, the holder of an FTR from point A to point B is generally entitled to a payment equal to the value of the congestion between the two points. The payments to FTR holders are funded from the congestion revenue fund, which is primarily generated from congestion revenue collected in the day-ahead market. The congestion revenues are collected in the following manner:

- Day-ahead congestion revenue is equal to the megawatts scheduled to flow across a constrained interface times the shadow price (i.e., the marginal economic value) of the interface.
- Real-time congestion revenue is equal to the change in scheduled flows (relative to the day-ahead market) across a constrained interface times the real-time shadow price of the interface.
  - ✓ Consequently, when real-time scheduled flows are lower than day-ahead scheduled flows across an interface that is constrained in the real-time market, it results in *negative* congestion revenue.[19]
  - ✓ When congestion revenue collected by the ISO is not sufficient to satisfy the targeted payments to FTR holders, it implies that the quantities sold in the FTR auctions exceeded the capability of the transmission system.

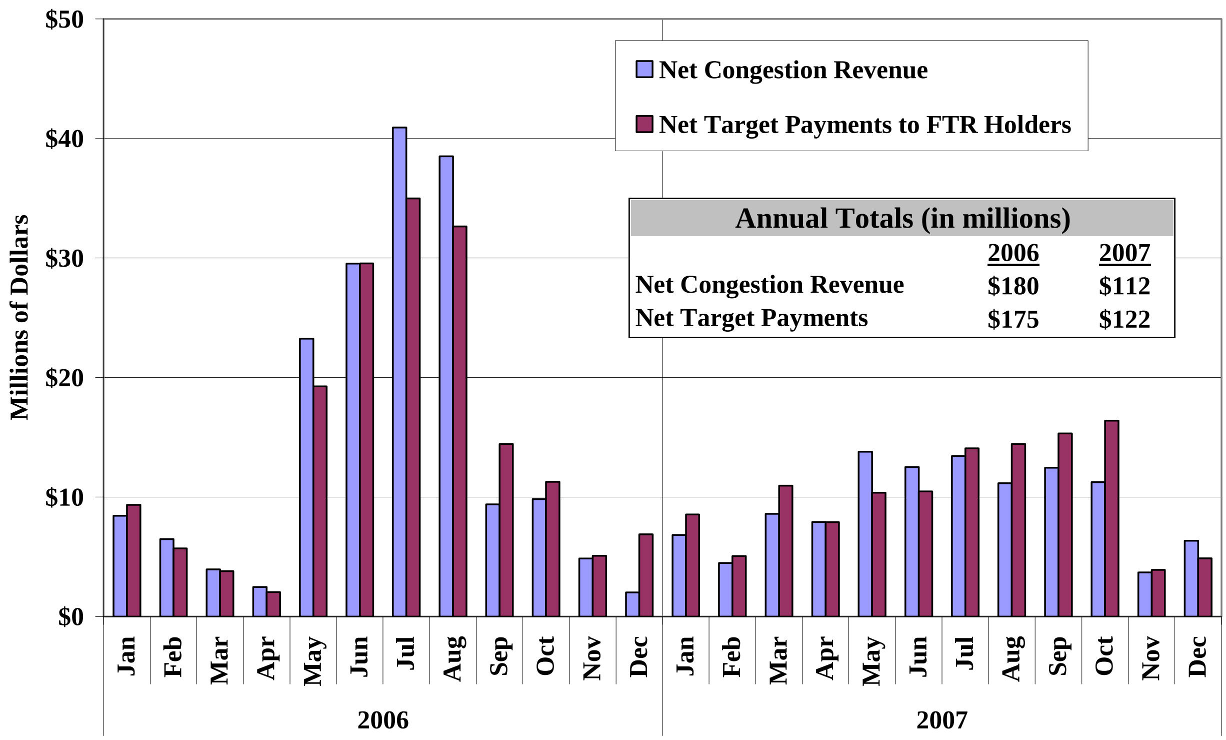
If the ISO does not collect enough congestion revenue to pay the targeted amounts to FTR holders during a month, the unpaid amounts are accrued until the end of the year. At the end of

19 For example, suppose 100 MW is scheduled to flow across a particular interface in the day-ahead market, and the interface is constrained when 90 MW is scheduled to flow across it in the real-time market (due to a reduction in capacity after the day-ahead market). If the real-time shadow price of the constraint is $50 per MWh, the 10 MW flow reduction from the day-ahead to the real-time market will result in negative $500 of congestion revenue.

the year, any excess congestion revenues remaining from months with a surplus are used to pay amounts accrued, plus interest, from months with a shortage. If the end-of-year surplus is less than the total accrued shortfall amounts, the end-of-year payments on shortfall amounts are discounted *pro rata*.

Figure 10 compares the net congestion revenue collected by the ISO with the net target payments to FTR holders in each month of 2006 and 2007. Net congestion revenue includes the sum of all positive and negative congestion revenue collected from the day-ahead and real-time markets. Net target payments to FTR holders include the sum of all positive target payments to FTR holders and all negative target payments (i.e., minus payments from FTR holders). The table in the figure reports these quantities by year.

Figure 10: Congestion Revenue and Target Payments to FTR Holders 2006-2007



The figure shows that net congestion revenue and net targeted payments to FTR holders were substantially lower in 2007 than in 2006, primarily due to reduced congestion during the summer months. Net congestion revenue dropped from $180 million in 2006 to $112 million in 2007, while net target payments to FTR holders fell from $175 million in 2006 to $122 million in 2007. Congestion decreased primarily due to the transmission additions in Southwest Connecticut placed in service in October 2006 and the expiration of PUSH bidding rules in June 2007, which both reduced congestion into Norwalk-Stamford. The patterns of congestion are evaluated in greater detail in the Section B.

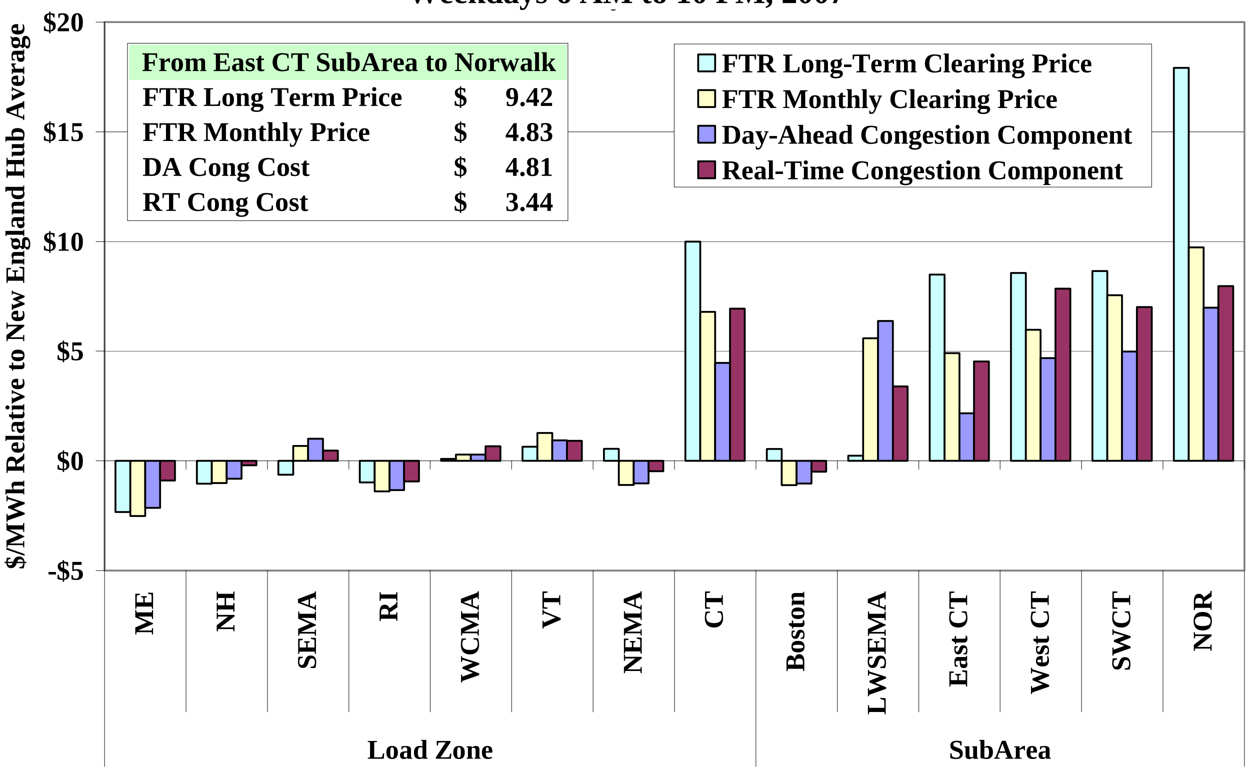
The figure shows that there were eight months in 2007 when net congestion revenues were less than the net target payments to FTR holders. When this happens, positive payments to FTR holders are reduced to the sum of net congestion revenues plus the payments from FTR holders (i.e., negative target payments). Shortfall amounts are accrued and paid at the end of the year from surplus congestion revenues collected in other months. However, insufficient surplus congestion revenue was collected to cover all of the shortfalls at the end of 2007. Overall, the ISO collected $112 million in net congestion revenue and $69 million from FTR holders that were obligated to make payments. This was $10 million less than the $192 million needed to cover positive targeted payments to FTR holders, so FTR holders received 94 percent of the positive target payments in 2007, on average. The practice of discounting payments to FTR holders when net congestion revenues are insufficient may lead to lower FTR auction revenues in the future.

B. Congestion Patterns and FTR Prices

In this section, we compare the FTR prices to the congestion prices in the day-ahead and real-time markets. FTR auctions take place in the prior month (for monthly auctions) or at the end of the preceding year (for annual auctions). Prices in the FTR auctions reflect the expectations of market participants regarding congestion in the day-ahead and real-time markets. As expected, FTR prices from the annual auction were less accurate predictions of day-ahead and real-time congestion than the FTR prices from the monthly auction. Furthermore, the FTR prices from the annual auction were more consistent with congestion patterns in the previous year than FTR prices from the monthly auction.

Figure 11 shows day-ahead and real-time congestion prices and FTR prices for each of the eight New England load zones and six sub-areas of interest in 2007. The congestion prices shown are calculated for on-peak hours relative to the New England hub. Hence, if the congestion price in the figure indicates $4 per MWh, this is interpreted to mean the cost of congestion to transfer a megawatt-hour of power from the New England Hub to the location averaged $4 per MWh during on-peak hours. The congestion price difference between any two points shown in the figure is the congestion price at the sink location less the congestion price at the source location. For example, a -$2.50 per MWh FTR price for Maine and $10 per MWh FTR price for Connecticut would indicate a total price for an FTR from Maine to Connecticut of $12.50 per MWh. Aside from the eight load zones, the figure shows prices for Boston, Lower SEMA, and four areas within Connecticut. Connecticut is divided into: East Connecticut, the portion of West Connecticut that excludes Southwest Connecticut, the portion of Southwest Connecticut that excludes Norwalk-Stamford, and Norwalk-Stamford.

Figure 11: FTR Auction Prices vs. Day-Ahead and Real-Time Congestion Locational Averages Shown Relative to New England Hub Price Weekdays 6 AM to 10 PM, 2007



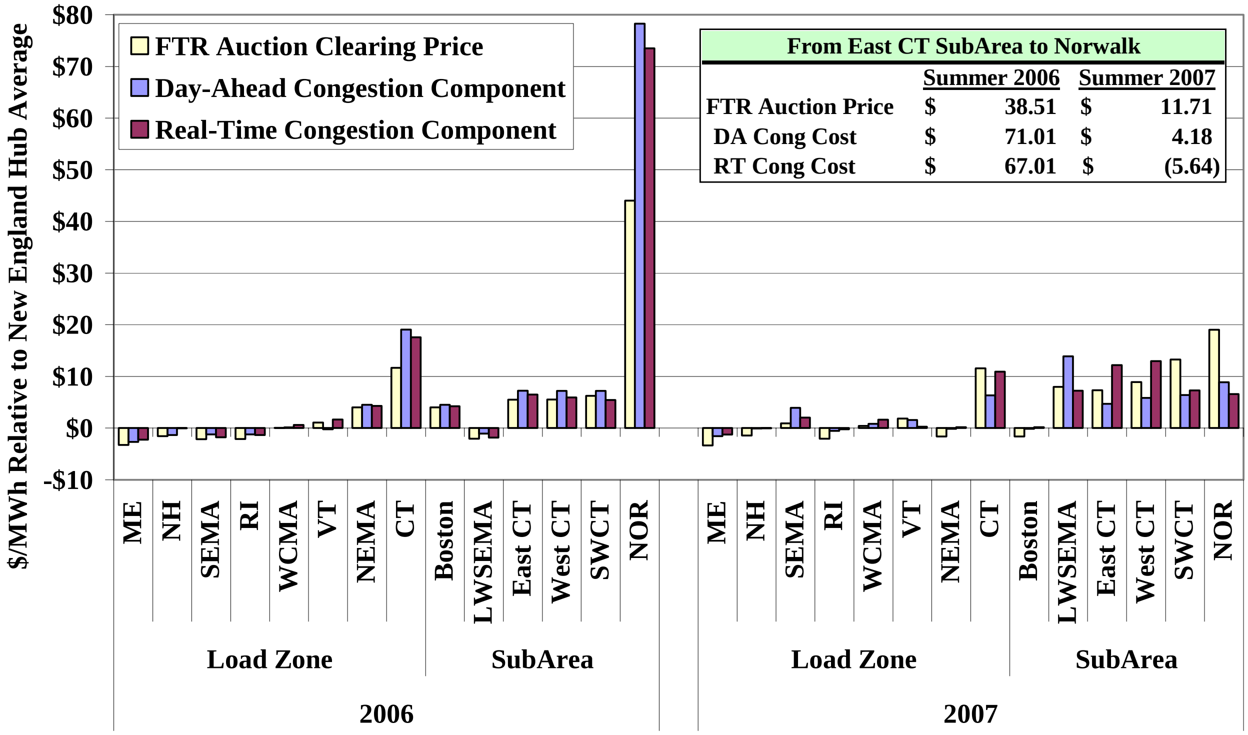
For each location, the figure shows the forward auction prices in chronological order, leading up to real-time from left-to-right. The annual FTR auction occurs first, then the monthly FTR auction, and then the day-ahead market auction. In 2007, monthly FTR prices were relatively consistent with congestion prices in the day-ahead and real-time markets. Annual FTR prices were less closely correlated with day-ahead congestion prices. For example, the table shows that, from East Connecticut to Norwalk-Stamford, the annual FTR price was substantially higher than day-ahead and real-time congestion. However, the monthly FTR price was only slightly higher than the day-ahead and real-time congestion. This pattern is expected because market participants face greater uncertainty and have less information in the annual auction regarding likely congestion levels than at the time of the monthly auctions. For Norwalk-Stamford, these results suggest that market participants underestimated the decrease in congestion that resulted from the addition of transmission capability in late 2006 and the expiration of PUSH pricing rules.[20]

Into Lower SEMA, annual FTR prices were substantially lower than the average monthly FTR prices and the average day-ahead congestion prices in 2007. The figure suggests that very little congestion was anticipated into Lower SEMA in the annual FTR auction. As market participants observed increased congestion in 2007 relative to 2006, they updated their expectations and the monthly FTR prices converged more closely to the day-ahead congestion levels.

The next analysis presents the same results for the summer months in 2006 and 2007. The analysis focuses on the summer because system peaks generally occur in the summer due to cooling demand and the transmission system is under the greatest stress. In addition, higher summer loads generally result in higher congestion prices and greater financial risks for market participants, making FTRs most valuable during the summer. Figure 12 shows the average monthly FTR clearing prices, day-ahead congestion price, and real-time congestion price for the peak hours during the summer season for the same locations as the previous figure.

20 The reduced congestion into Norwalk-Stamford is discussed further in Section II.

Figure 12: FTR Auction Prices vs. Day-Ahead and Real-Time Congestion
Locations Shown Relative to New England Hub Average Price
Weekdays 6 AM to 10 PM, June to August, 2006-2007



FTR prices and day-ahead and real-time congestion prices declined in Boston and Connecticut from 2006 to 2007, particularly in the Norwalk-Stamford. As noted previously, the addition of transmission capability in Southwest Connecticut and the expiration of the PUSH bidding rules reduced congestion into the area. Conversely, FTR prices and day-ahead and real-time congestion prices increased into Lower SEMA after the ISO began to model the transfer limits into the area in late 2006.

The table in the figure highlights the significant changes in congestion from 2006 to 2007 into Norwalk-Stamford. In the summer of 2006, the FTR market under-estimated day-ahead congestion between these areas by more than 40 percent. In the summer of 2007, the FTR market substantially over-estimated congestion in Norwalk-Stamford. These outcomes reflect the difficulty of predicting congestion prices in the day-ahead and real-time markets.

The table also indicates that day-ahead congestion prices were not very consistent with real-time congestion prices between East Connecticut and Norwalk-Stamford in the summer of 2007. In the day-ahead market, congestion prices in Norwalk-Stamford were $4.18 per MWh higher than in East Connecticut. In contrast, real-time congestion prices in Norwalk-Stamford were $5.64 per MWh *lower* than in East Connecticut. Day-ahead congestion patterns were consistent with historic patterns of congestion, while real-time congestion patterns were heavily affected by acute congestion across the transformers at the Manchester station in Connecticut from the 345 kV system to the 138 kV system. In general, congestion at the Manchester station results in very high prices in portions of East Connecticut and the portion of West Connecticut outside Southwest Connecticut. Although the transformers at the Manchester station were frequently congested in the day-ahead market, the severity of congestion was much less than in the real-time market and resulted in the poor price convergence.

Given the volatile nature of congestion patterns, we found that FTRs were valued reasonably well in the FTR auctions. As expected, the monthly auctions generally 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.

C. Credit Requirements for FTR Holders

During 2007, two participants in the PJM FTR market defaulted on FTR-related payment obligations resulting from holding counter-flow FTRs. PJM has estimated that the total costs of the defaults will be more than $65 million.[21] As a result of the default, ISO New England is reviewing its credit policies for FTR holders. On December 26, 2007 PJM filed proposed changes to its credit requirements for relatively diversified portfolios.[22] On January 31, 2008 PJM filed additional changes to its credit requirements to address market participants holding more speculative positions.[23] These events underscore the need for ISOs to employ credit requirements that protect other market participants from the financial consequences of a default.

21 PJM Interconnection, "Member Payments Default, Updated Projections," April 7, 2008. Estimated total reflects the two firms defaulting in 2007 and two additional firms declared to be in default in January, 2008. PJM has indicated that the losses were due in part to congestion conditions not reflective of historical norms.

22 PJM Interconnection, Filing in FERC Docket No. ER08-376-000.

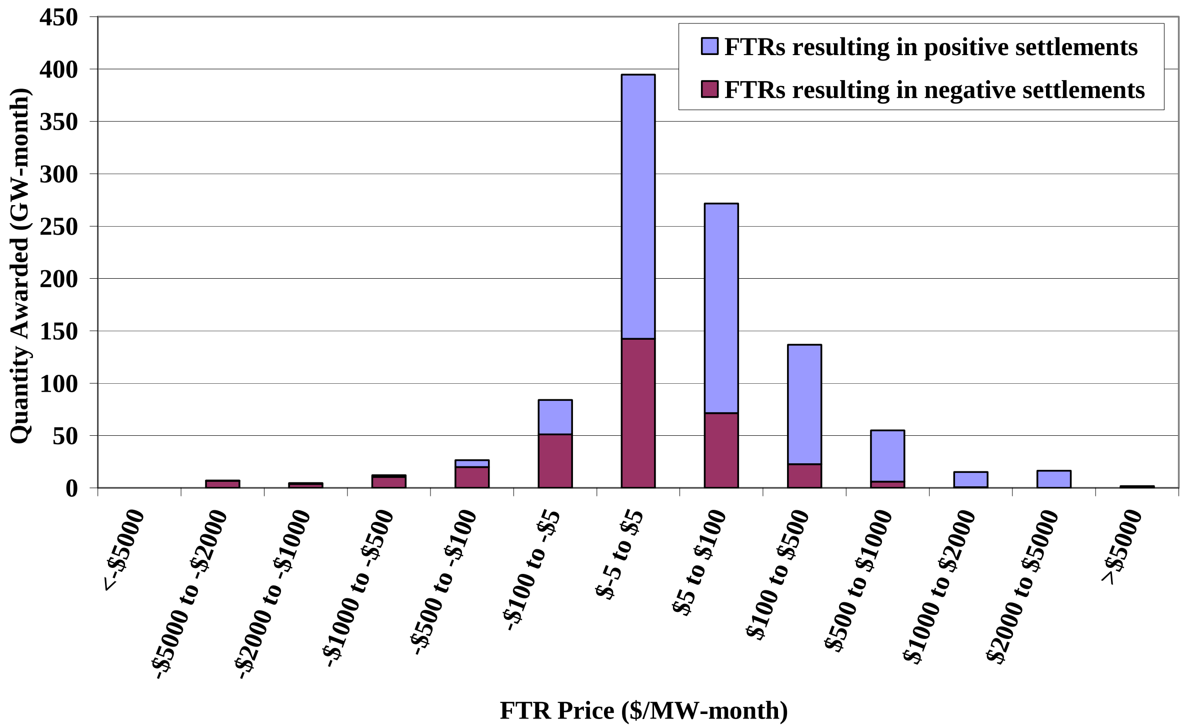
23 PJM Interconnection, Filing in FERC Docket No. ER08-520-000.

In this section, we summarize FTR holdings in New England in 2007. Specifically, we show the aggregate quantities of FTRs and target allocations to FTR holders for FTRs with varying clearing prices. This evaluation provides a sense of the potential risks to the market from potential default by individual market participants. In general, we find that most FTR market participants hold relatively balanced FTR portfolios, which present limited risk exposure when congestion patterns stay within expected ranges. Some market participants hold FTR portfolios with greater potential for risk, although these holdings are modest relative to the overall size of the market. Furthermore, the current credit requirements reduce the likelihood of substantial loss for the market.

When a market participant buys a positively-priced FTR, the market participant expects to receive a positive stream of payments based on day-ahead congestion. Similarly, when a market participant "buys" a negatively-priced FTR, the market participant receives an up-front payment at the time of the FTR auction and the market participant typically makes payments over the life of the FTR. Any FTR can result in a net payment either to the FTR holder or to the ISO, depending upon the location and direction of the congestion on the ISO system. Typically, FTRs are sold at a positive price because they are expected to result in payments to the FTR holder. Negatively-priced FTRs, because they produce an up-front payment to the FTR holder with the expectation that the FTR holder will make payments over time, raise greater risk issues for the ISO. The analyses in this section of the report attempt to provide some perspective on that risk.

The sums of the bars in Figure 13 show the total quantity of FTRs in gigawatt-months that are sold in various price ranges. Annual FTRs are broken into 12 monthly FTRs of equal price. For example, a 10 megawatt-year FTR purchased for $600/MW-year would be shown in the figure as 120 megawatt-months of FTRs priced at $50/MW-month. The bottom bars show the quantity of FTRs that have negative settlements (i.e., that result in a net payment to the market participant). On-peak and off-peak FTRs are summed together in the figure.

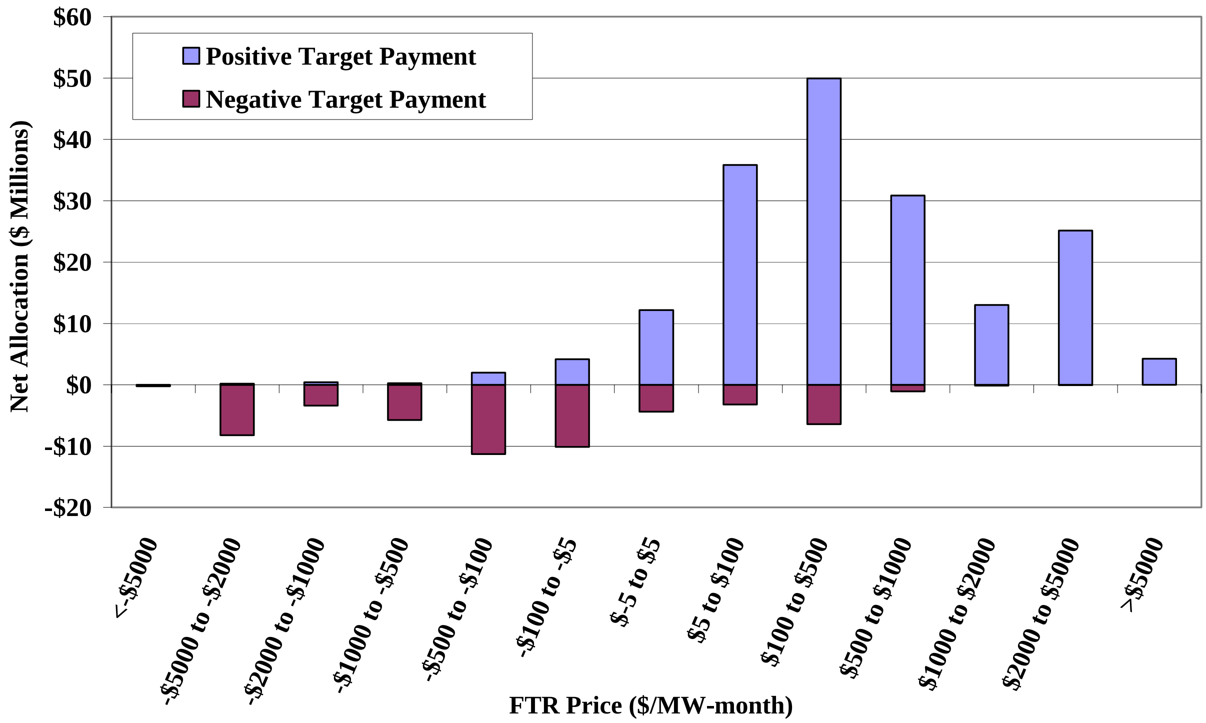
Figure 13: Distribution of FTRs Awarded by Auction Prices 2007



The figure shows that most FTRs are bought at positive prices. Approximately 13 percent of the FTRs were purchased at prices significantly lower than zero (i.e., less than -$5/MW-month). As expected, FTRs bought at positive prices usually result in net payments to the holder, while FTRs bought at negative prices usually result in an obligation to pay the ISO over the term of the FTR. However, the figure does reveal that a modest proportion of FTRs with positive prices up to $100/MW-month and even some FTRs with prices as high as $1000/MW-month result in net payment obligations by the market participant. Likewise, some FTRs sold at negative prices result in additional payments to the market participant over the term of the FTR.

Figure 14 summarizes the target payments to and from FTR holders in 2007. Target payments are shown according to the FTR prices, similar to the previous figure. Positive target payments (received by FTR holders) are shown separately from negative target payments (obligations that must be paid by FTR holders). The actual payments received by FTR holders were slightly lower than the positive target payments shown in the figure below due to the congestion revenue shortfall discussed earlier.

Figure 14: Comparison of FTR Prices and FTR Net Payments 2007



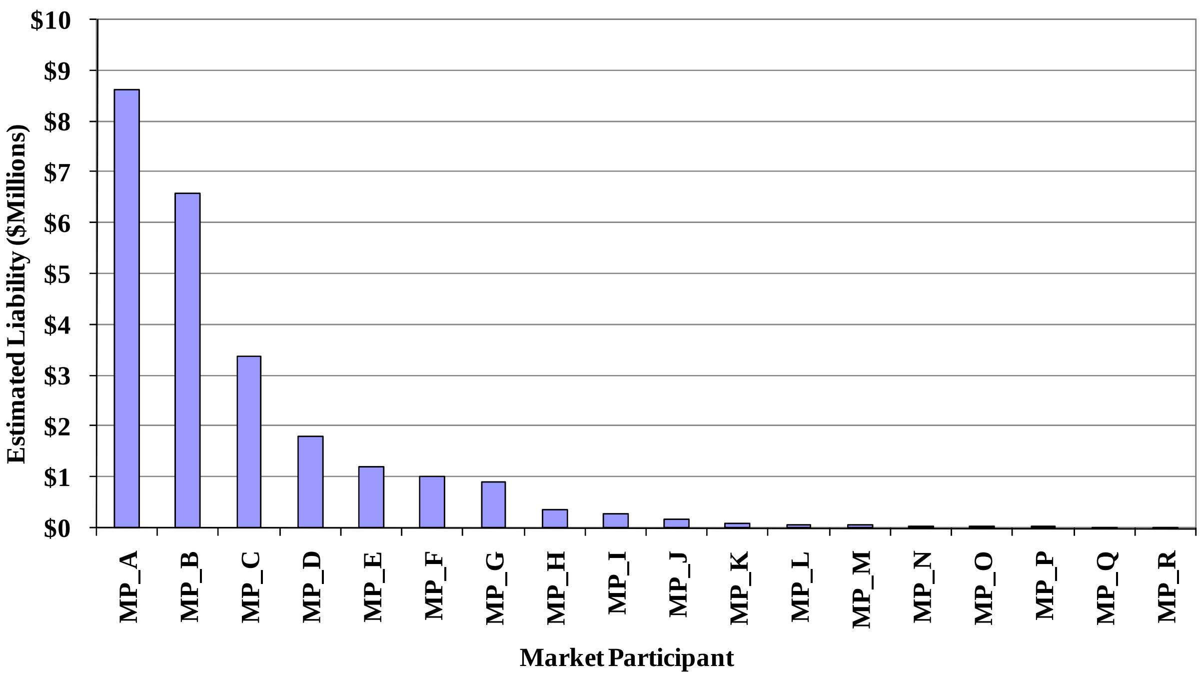
The previous figure showed a large quantity of FTRs priced between -$5/MW-month and $5/MW-month, but this figure shows that these account for a relatively small portion of the total value of FTRs. Correspondingly, high-priced FTRs make up a substantial share of the total FTR settlements because they tend to result in larger payments per megawatt-month.

The figure shows a total of $192 million in positive target payments to holders of FTRs and a total of $69 million in negative target payments from FTR holders. Due to the strong correlation between FTR prices and the resulting payments to FTR holders, the amount of FTR payments from holders of FTRs priced greater than -$5/MW-month was relatively small. From these FTR holders, the figure shows just $17 million in negative target payments in 2007. These results confirm the need for credit requirements for both positively-priced FTRs and negatively-priced FTRs. However, the predominance of the default risk resides with the holders of negatively-priced FTRs.

The risk to the market from default by individual market participants depends on how widely negatively-priced FTRs are held. In addition, the risk to the market is reduced to the extent that the market participants holding negatively-priced FTRs also hold positively-priced FTRs because the likely stream of payments from the positively-priced FTRs will offset the obligations from the negatively-priced FTRs.

An analysis of FTR positions in 2007 shows that 18 of 58 market participants had net positions that were negatively-priced (i.e., the payments they received for negatively-priced FTRs in the FTR auctions exceeded what they paid for positively-priced FTRs in the FTR auctions). The net negative values of the FTRs held by these 18 market participants are shown in **Error! Reference source not found.**.

Figure 15: Estimated Liability of Market Participants from FTR Market 2007



Error! Reference source not found. shows that the estimated liability was relatively low for many of these participants, in part because many had diversified portfolios with substantial holdings of positively-priced FTRs. The net negative purchase-value of FTRs was less than $2 million for all but three of these market participants.

Adequate characterization of default risk associated with FTR holdings is complicated by the need to rely on historical data to estimate future congestion conditions. Over the life of the FTR, such conditions may diverge substantially from historical experience. In addition, total risk exposure is unlikely to vary in any simple way in proportion to net settlement price. Due to the complex network of relationships among FTRs, the net value/liability of any portfolio of FTR holdings can vary substantially over time.

The ISO and market participants are in the process of reevaluating the FTR market credit policies in 2008. The analysis here confirms certain expected relationships between FTR prices and net payment obligations (and therefore default risk). However, exceptions to the expected relationships cannot be ignored, such as positively-priced FTRs that result in payment obligations by the holder due to changes in congestion patterns over the term of the FTR. Our examination suggests that relatively few market participants maintained FTR portfolios constituting a significant net liability during 2007. Good FTR credit policies limit the exposure of the market to such liabilities.

V. Reserve Markets

This section evaluates the operation of the Operating Reserve Markets during 2007. The current design of the Reserve Markets was implemented in October 2006 under Phase II of the ISO-NE's Ancillary Services Markets project ("ASM II"). ASM II included two primary market enhancements. First, a real-time reserve market with locational requirements was integrated with the existing real-time energy market. Second, locational requirements were added to the existing forward reserve market in which suppliers sell reserves that must be provided in the real-time market. These enhancements have better enabled the wholesale market to meet the reliability needs of the system, thereby reducing the need for manual action by the ISO operators.

Under ASM II, the real-time market software co-optimizes the scheduling of reserves and energy. This enables the real-time market to reflect the re-dispatch costs that are incurred to maintain reserves in the clearing prices of energy and reserves. Previously, the energy-only market did not recognize the economic trade-offs between scheduling a resource for energy or reserves. It is particularly important to consider such trade-offs during tight operating conditions because efficient scheduling reduces the likelihood of a reserve shortage. When available reserves are not sufficient to meet the required levels, the real-time model will be short of reserves and set the reserve clearing price at the level of the Reserve Constraint Penalty Factor ("RCPF").

Suppliers sell reserves into the Locational Forward Reserve Market ("LFRM") auction on a seasonal basis. Suppliers satisfy their LFRM obligations by providing reserves in real-time from online resources with unused capacity or offline resources capable of starting quickly (i.e. fast-start generators). The LFRM is intended to attract investment in capacity that is able to provide reserves at relatively low cost, particularly fast-start generation.

This section evaluates the following aspects of the reserve markets:

- Real-Time Reserve Market
- Reserve Constraint Penalty Factors

- Local Reserve Zones
- Forward Reserve Market

The final part of this section provides a summary of our conclusions and recommendations regarding the reserve markets:

A. Real-Time Reserve Market

1. Real-Time Reserve Requirements

The real-time market is designed to satisfy the system's reserve requirements, including locational requirements to maintain minimum reserve levels in certain areas. There are four geographic areas with real-time reserve requirements: Boston, Southwest Connecticut, Connecticut, and the entire system (i.e. all of New England).

In addition to the different locations, the reserve markets recognize three categories of reserve capacity:

- 10-Minute Spinning Reserves ("TMSR"),
- 10-Minute Non-Spinning Reserves ("TMNSR"), and
- 30-Minute Operating Reserves ("TMOR").

Sufficient reserves must be held in the New England reserve zone to protect the system in case contingencies (e.g. generator outages) occur. The ISO must hold an amount of 10-minute reserves (i.e. TMSR plus TMNSR) equal to the largest generation contingency on the system, which averaged 1,323 MW in 2007. Based on system conditions, the operator determines how much of the 10-minute reserve requirement to hold as TMSR. ISO-NE held an average of 42 percent of the 10-minute reserve requirement in the form of TMSR during intervals with binding 10-minute spinning reserve constraints in 2007. [24]

The ISO must hold an amount of 30-minute reserves (i.e. TMSR plus TMNSR plus TMOR) equal to the largest generation contingency on the system plus half of the second-largest

24 The 10-minute spinning reserve requirement was binding in 0.5 percent of the intervals in 2007.

contingency on the system. The 30-minute reserve requirement averaged 1,921 MW in 2007. Since higher quality reserves may always be used to satisfy requirements for lower quality products, the entire 30-minute reserve requirement can be satisfied with TMSR or TMNSR.

In each of the three local reserve zones, the ISO is required to schedule sufficient resources to maintain service in case the two largest local contingencies occur within a 30-minute period, resulting in two basic operating requirements. First, the ISO must dispatch sufficient energy in the local area to prevent cascading outages if the largest transmission line contingency occurs. Second, the ISO must schedule sufficient 30-minute reserves in the local area to maintain service if a second contingency occurs after the largest transmission line contingency. Alternatively, the local 30-minute reserve requirement can be met with 10-minute reserves or by *importing* reserves, which is accomplished by producing additional energy within the local area in order to unload transmission into the area. Although ISO-NE is not the first RTO to co-optimize energy and reserves in the real-time market, it is the first to optimize the level of imported reserves to constrained load pockets.

2. Real-Time Reserve Market Design

The real-time market software jointly optimizes reserves and energy schedules. By co-optimizing the scheduling of energy and reserves, the market is able to reflect the re-dispatch costs incurred to maintain reserves in the clearing prices of both energy and reserves. For example, if a $40 per MWh combined cycle unit is backed down to provide reserves when the LMP is $50 per MWh, the marginal re-dispatch cost is $10 per MWh and the reserve clearing price will be no lower than $10 per MWh. The marginal system cost used to schedule the reserves and set reserve clearing prices includes both the redispatch cost (if any) and the offer price for the resource. When excess reserves are available without incurring any costs, reserve clearing prices will be $0 per MWh.

Higher quality reserve products may always be used to satisfy lower quality reserve requirements, ensuring that the clearing prices of higher quality products are never lower than the clearing prices of lower quality products. For instance, if TMOR is available to be scheduled at a marginal system cost of $5 per MWh and an excess of TMNSR is available at no cost, the real-time market will fully schedule the TMNSR to meet the 30-minute reserve requirement. If the zero-cost TMNSR is exhausted before the requirement is met, the real-time market will then schedule TMOR and set the clearing prices of TMNSR and TMOR at $5 per MWh.

When multiple reserve constraints are binding, the clearing price of the highest quality product will be the sum of the underlying marginal system costs for each product. For example, suppose the marginal system costs were $3 per MWh to meet the 10-minute spinning reserve constraint, $5 per MWh to meet the 10-minute reserve constraint, and $7 per MWh to meet the 30-minute reserve constraint. In this case, the TMSR clearing price would be $15 per MWh because a megawatt of TMSR would help satisfy all three constraints. Likewise, the TMNSR clearing price would be $12 per MWh because a megawatt of TMNSR would help satisfy two of the constraints.

ISO-NE is the first RTO to include the level of imported reserves to constrained load pockets in the co-optimization of energy and reserves. Since local reserve requirements can be met with reserves on internal resources or import capability that is not used to import energy, allowing the real-time model to import the efficient quantity of reserves is a substantial improvement over other market designs. This enhancement is particularly important in New England where the market meets a large share of its local area reserve requirements with imported reserves. For example, imported reserves satisfied 74 percent of the Boston requirement and 48 percent of the Connecticut requirement during constrained intervals.

The marginal system costs that the market incurs to satisfy reserve requirements are limited by RCPFs. There is an RCPF for each real-time reserve constraint. The current RCPFs are:

- $100 per MWh for the system-level 30-minute reserve constraint,
- $850 per MWh for the system-level 10-minute reserve constraint,
- $50 per MWh for the system-level 10-minute spinning reserve constraint, and
- $50 per MWh for the local 30-minute reserve constraints.

These values are differentiated to reflect values of the reserves and the reliability implications of shortages in the various classes of reserves. It is important to remember that these values are additive when shortages in more than one class of reserves, which assures efficient energy and operating reserve prices during shortages. Since energy and operating reserves are co-optimized, the shortage of operating reserves is reflected in energy clearing prices.[25] Less severe conditions generally result in shortages of only 30-minute reserves, which would produce reserve clearing prices of $100 per MWh or more and a contribution to the energy prices of $100 per MWh. Alternatively, more severe conditions that result in shortages of both 30-minute and 10-minute reserves would produce 10-minute reserve clearing prices of $950 per MWh or more ($100 plus $850 per MWh) and energy prices exceeding $1000 ($950 plus the marginal price of energy).

Hence, the system-level 10-minute reserve RCPF of $850 per MWh, together with the other RCPFs, would likely result in energy and operating reserve prices close to the New England market's energy offer cap of $1,000 per MWh during sustained periods of significant operating reserve shortages. The use of RCPFs to set efficient prices during operating reserve shortages was recently affirmed by FERC in its Notice of Proposed Rulemaking ("NOPR"), which identifies ISO New England's approach to shortage pricing as a model for other ISOs.[26]

When available reserves are not sufficient to meet a requirement or when the marginal system cost of maintaining a particular reserve requirement exceeds the applicable RCPF, the real-time model will be short of reserves and set clearing prices based on the RCPF. For example, if the marginal system cost of meeting a local area reserve requirement were $75 per MWh, the real-time market would not schedule sufficient reserves to meet the local requirement and the reserve clearing price would be set to $50 per MWh. This would require the operator to intervene in order to maintain the full level of reserves in the local area. The RCPFs are analyzed in greater detail later in Section B.

---

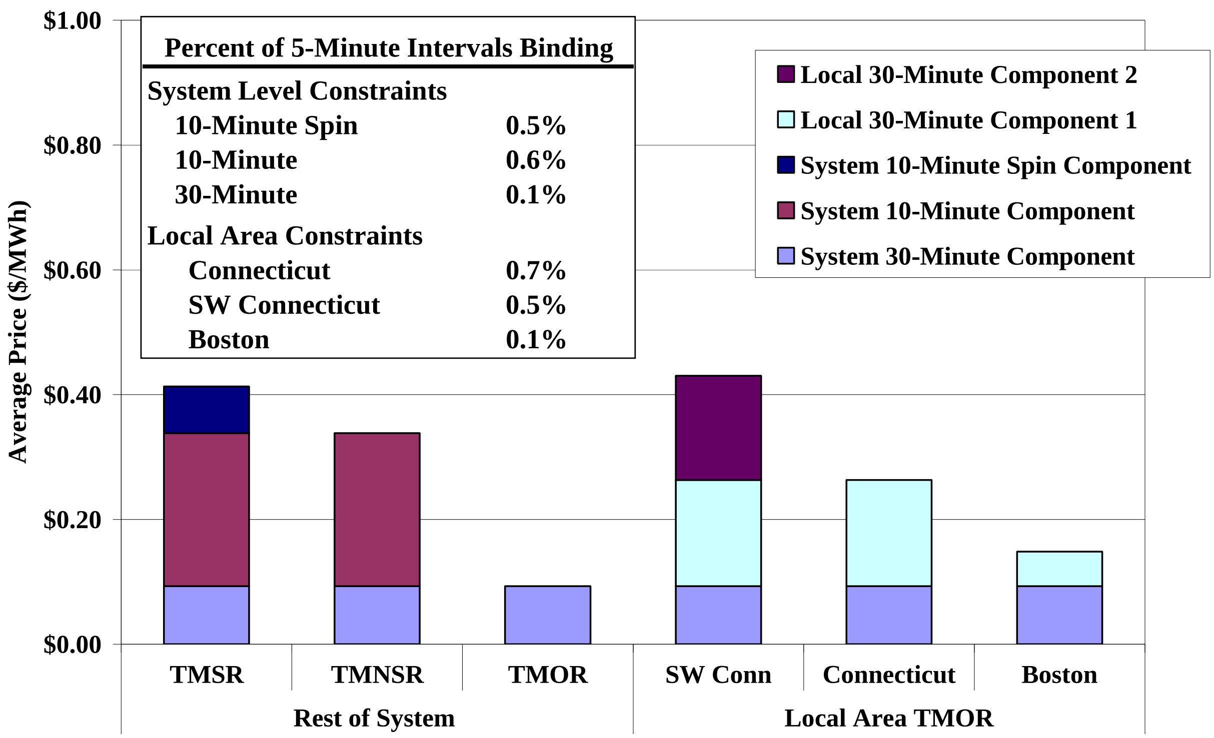
25 This assumes the operating reserve shortage results from a general deficiency of generating capacity.

26 See P. 125. *Wholesale Competition in Regions with Organized Electric Markets*, 122 FERC ¶ 61,167 (2008) ("NOPR").

3. Real-Time Reserve Market Results

Figure 16 summarizes average reserve clearing prices during 2007. The left side of the figure shows prices outside the local reserve zones for all three service types. The right side of the figure shows prices in the three local reserve zones for TMOR only. Each price is broken into components associated with the underlying requirements. For example, the Southwest Connecticut price is based on the costs of meeting three requirements: the Southwest Connecticut 30-minute reserve requirement, the Connecticut 30-minute reserve requirement, and the system-level 30-minute reserve requirement. Likewise, the system-level TMSR price is based on the costs of meeting three requirements: the 10-minute spinning reserve requirement, the 10-minute reserve requirement, and 30-minute reserve requirement.

Figure 16: Average Reserve Clearing Prices by Product and Location
2007



Reserve clearing prices were relatively low in the real-time market in 2007. Outside the local constrained areas, the average TMSR clearing price was 41 cents per MWh. The 41 cents per MWh for TMSR results from an average of 7 cents per MWh for the 10-minute spinning reserve component, 25 cents per MWh for the 10-minute reserve component, and 9 cents per MWh for the 30-minute reserve component.

In the local areas, the highest average TMOR price occurred in Southwest Connecticut. This resulted from an average of 17 cents per MWh for the Connecticut 30-minute reserve component, 17 cents per MWh for the Southwest Connecticut 30-minute reserve component, and 9 cents per MWh for the system 30-minute reserve component. TMNSR and TMSR clearing prices are not shown in the local areas because they can also be derived from the underlying requirements. For instance, the average clearing price of TMSR in Southwest Connecticut was 75 per MWh. This is composed of 41 cents per MWh for TMSR outside the local areas plus the Southwest Connecticut and Connecticut 30-minute reserve components, which were both 17 cents per MWh.

Figure 16 indicates that reserve prices were relatively low in 2007. As described in the next part of the section, reserve clearing prices were $0 in most periods because substantial excess capacity was usually online in each of the relevant areas.

4. Unit Commitment and the Real-Time Reserve Market

The adequacy of reserves in real-time is primarily determined by processes that occur in the 24 to 48 hours leading up to real-time. The majority of supply resources are committed in the day-ahead market based on economic criteria or self schedules. In the Reserve Adequacy Assessment (“RAA”) process, additional resources may be committed for reliability reasons based on projections of real-time conditions, which may differ from actual real-time conditions for several reasons. Between the start of the RAA process and real-time operation, forecasted demand and local import capability may change significantly, generators may self commit, and capacity may be lost due to an outage. Thus, the RAA process may commit more or less capacity than is necessary to satisfy reliability criteria in real-time. This section evaluates the relationship between the adequacy of committed generation and reserve clearing prices in real-time.

In real-time, we can assess the adequacy of supply to meet demand for energy and reserves in the reserve zone by analyzing the quantity of Excess Capacity. We define Excess Capacity as the amount of capacity in the reserve zone that is online or capable of starting within 30 minutes relative to the amount of capacity that is required to meet load and reserve requirements in the reserve zone:

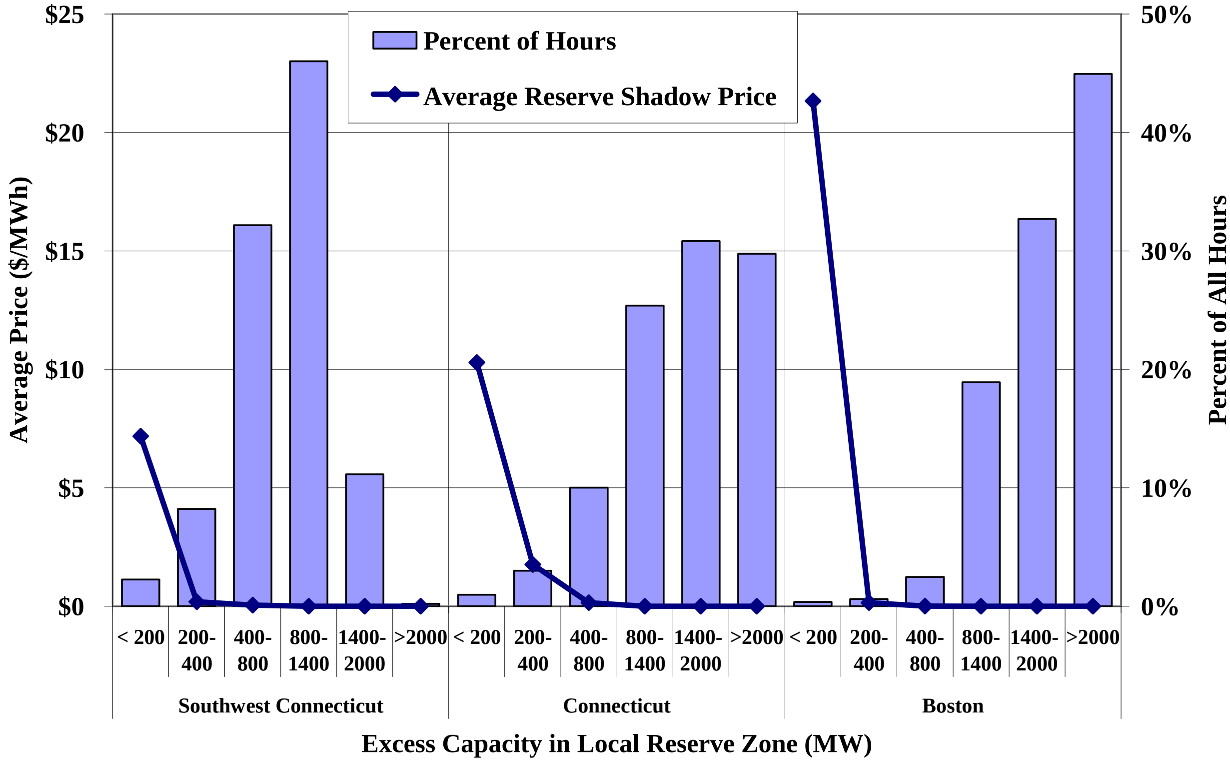
Excess Capacity = Online Reserves +
Offline Reserves Deployable within 30 minutes +
Imported Reserves –
Reserve Requirement

Thus, Excess Capacity includes online capacity, offline reserves deployable within 30 minutes, and imported reserves not necessary to meet the energy demand and reserve demand in the reserve zone.

Figure 17 summarizes the relationship of Excess Capacity to reserve clearing prices in each of the three local reserve zones. For each local reserve zone, a histogram shows the frequency of hours when Excess Capacity was in each range of values during the period. For example, there was between 400 MW and 800 MW of Excess Capacity in Southwest Connecticut in approximately 32 percent of the hours during 2007. For each local reserve zone, a line shows the average TMOR shadow price in the hours that correspond to each range of Excess Capacity. For example, in hours when there was less than 200 MW of Excess Capacity in Southwest Connecticut, the average TMOR shadow price was approximately $7 per MWh.

Figure 17 shows there is a strong correlation between the local reserve clearing price and the amount of local Excess Capacity. When Excess Capacity is less than 0 MW (i.e. there is a shortage) in a particular reserve zone, the local TMOR shadow price rises to the RCPF ($50 per MWh). As the amount of Excess Capacity increases above 0 MW, the local TMOR shadow price declines relatively quickly. This relationship is expected because the marginal cost of supplying reserves is very low for most units.

Figure 17: Excess Capacity and TMOR Shadow Prices in Local Reserve Zones 2007



There are many days when Excess Capacity occurs in one or more local areas as a result of normal market activity. For example, Excess Capacity arises when a relatively large quantity of generation in the local area is economic at the prevailing day-ahead prices, which induces a high level of commitment by the market. However, Excess Capacity may raise concerns when it results from the following two factors. First, significant amounts of Excess Capacity resulting from supplemental commitment for reliability may indicate that more supplemental commitments were made than necessary. Second, Excess Capacity may also raise concerns when it results from self commitment in local areas where local reliability requirements have already been satisfied. Although self commitment by units with relatively short start times can be an efficient response to emergent real-time market conditions, frequent self commitment by units in local areas can result in inefficient levels of Excess Capacity.

When the ISO makes supplemental commitments for reliability, three factors tend to increase the amount of Excess Capacity in local reserve zones:

- The size of the shortage forecasted in the RAA process may be significantly smaller than the sizes of the generators that are available to be committed for reliability. For example, if the ISO forecasts a 50 MW shortfall and the smallest generator available to address the shortage is 250 MW, committing the generator will lead to 200 MW of Excess Capacity.
- The ISO may forecast a transitory shortage that requires the commitment of a generator with a minimum run time much longer than the shortage (e.g., 12 or 24 hours). Even though this commitment is required to prevent a shortage in the peak hour(s), it creates Excess Capacity in the remaining hours of the generator's minimum run time.
- Some of the ISO's second contingency commitment requirements are not reflected in the locational reserve requirements, such as the requirement for Norwalk-Stamford. The commitments made to satisfy these requirements can result in Excess Capacity relative to the requirements of defined local reserve zones.

This evaluation shows how supplemental commitment for reliability and self commitment after the start of the RAA process contributes to Excess Capacity and dampens real-time reserve clearing prices in local areas. Since outcomes in the day-ahead market are driven primarily by expectations of real-time prices, low real-time reserve prices reinforce the tendency of the day-ahead market to under-commit in local areas. For this reason, the ISO attempts to minimize supplemental commitments while continuing to meet reliability requirements and provide incentives for units to schedule in the day-ahead market.

B. Reserve Constraint Penalty Factors

In the real-time market, the RCPFs limit the cost that the model may incur to meet the reserve requirements. Consequently, if the cost of maintaining the required level of a particular reserve exceeds the applicable RCPF, the real-time market model will incur a reserve shortage and set the reserve clearing price based on the level of the RCPF.[27] For example, suppose an online generator with a $60 per MWh incremental offer could be backed down to provide reserves when the LMP is $160 per MWh. In this case, the marginal cost to the system of providing

27 If only one reserve constraint is binding, the reserve clearing price will be set equal to the RCPF of the reserve that is in shortage. However, if multiple reserve constraints are binding, the reserve clearing price will be set equal to the sum of binding constraint shadow prices. For example, if the market is short of Connecticut reserves and the marginal cost of meeting 30-minute reserves at the system-level is $10 per MWh, the Connecticut reserve clearing price is equal to the sum of the two shadow prices, which is $60 per MWh ($50 per MWh for the Connecticut area and $10 per MWh for the system requirement).

reserves from this unit is the opportunity cost of the unit not providing energy at the LMP. This opportunity cost is equal to the difference between the LMP and the incremental offer of the unit or $100 per MWh in this example ($160 per MWh LMP minus $60 per MWh incremental cost). If the RCPF is $50 per MWh, the market will not back the unit down to provide reserves and the system would be short of reserves since the marginal system cost of doing so ($100 per MWh) exceeds the RCPF ($50 per MWh).

The RCPF levels are important because they determine how the real-time market responds under tight operating conditions. When it is not possible to meet the reserve requirements, the RCPFs prevent the model from incurring extraordinary costs for little or no benefit. However, if RCPFs are not sufficiently high, the market may not schedule all available resources to meet reliability requirements. In such cases, like the example above, the operator will likely intervene to maintain reserves and significantly affect market prices in the process. It is important to evaluate the RCPF levels currently used by ISO-NE to determine whether modifications are warranted.

We performed two analyses to evaluate the RCPFs. Both analyses seek to determine whether the RCPFs are set at levels consistent with the costs that the ISO regularly incurs to maintain local reserves. The first analysis compares the RCPF used in local reserve zones to the re-dispatch costs incurred to maintain local-area reserves in the real-time market. The second analysis compares the RCPF used in the local reserve zones to the NCPC costs that are incurred from local second contingency commitments made to meet local-area reserve requirements.

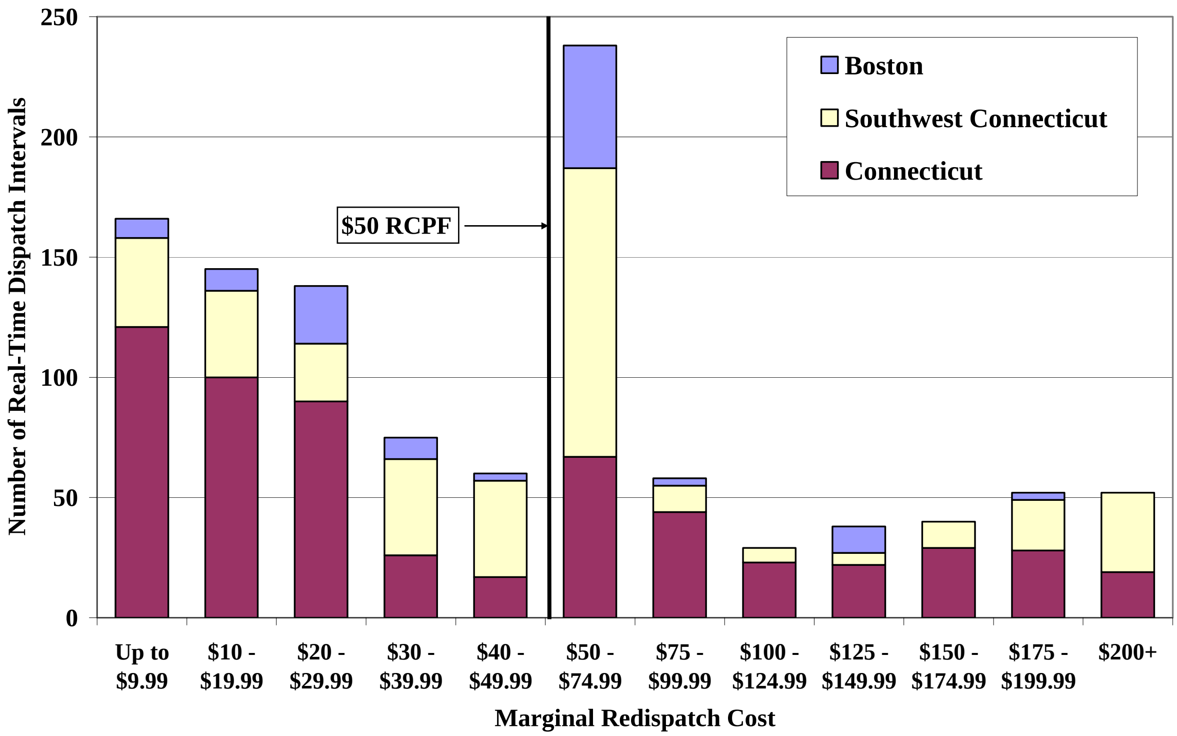
1. RCPFs and Real-Time Dispatch

As discussed above, the real-time market may experience a shortage of reserves if the model does not schedule the required level of reserves because reserves are available at a cost that exceeds the RCPF. In this case, the ISO is required to take additional actions to maintain the required level of reserves if the reserves are available.

There are at least two ways for the ISO to maintain the required level of reserves when the real-time model does not schedule all available reserves. First, the operator can manually adjust the dispatch of certain units in order to provide more reserves in a local area. In the example above, the operator could manually adjust downward the dispatch level of the unit that is capable of providing reserves at an opportunity cost of $100 per MWh. Second, the operator can impose a transmission constraint in the real-time market that forces the model to import a certain amount of reserves (i.e., hold the reserves as import capability on the transmission interface). [28] When possible, the operators use real-time transmission constraints to maintain reserves rather than manual dispatch instructions.

The following analysis compares the local-area RCPF ($50 per MWh) to the marginal re-dispatch costs incurred to meet the local-area reserve requirement during 2007. The marginal re-dispatch costs in this analysis include: (i) the shadow price of the local reserve constraint, which is limited by the RCPF, and (ii) the shadow price of any transmission constraint that is intended to provide imported reserves (i.e. a proxy second contingency constraint). Each bar shows the how frequently the marginal re-dispatch costs were in each range shown on the x-axis.

Figure 18: Marginal Re-dispatch Costs to Meet Local Reserve Requirements 2007



---

28 This is called a proxy second contingency limit. This type of constraint reduces the limit of the interface below the first contingency limit (the normal limit). The difference between the proxy second contingency limit and the first contingency limit is the amount of reserves that are imported (i.e. held on the interface).

Figure 18 shows that the marginal cost of meeting the local reserve requirements exceeded the RCPF in approximately half of the intervals where redispatch was necessary. The marginal redispatch cost was $50 per MWh or more in 56 percent of the intervals shown for Boston, 40 percent of the intervals shown for Connecticut, and 54 percent of the intervals shown for Southwest Connecticut.

This analysis indicates that the RCPF was not sufficiently high to maintain reserves in the local areas under normal operating conditions during 2007. As a result, the ISO was compelled to take additional actions to maintain reserves in a substantial number of intervals.

2. Cost of Maintaining Reserves in the Unit Commitment Process

In the day-ahead market, units are committed economically based on bids from physical and non-physical demand, offers from physical and non-physical supply, and transmission constraints. Hence, greater demand in the day-ahead market results in more unit commitment. If load does not fully purchase in the day-ahead market, or if incs (virtual supply) are scheduled in larger quantities than decs (virtual demand), the amount of capacity that is committed in the day-ahead market or available offline may not be sufficient to meet local-area reserve requirements.

Most supplemental commitment takes place in the RAA process after the day-ahead market on the day prior to the real-time market. If insufficient resources are anticipated to be online and available to meet forecasted reliability requirements, the ISO must supplementally commit additional resources.

The following analysis compares the local-area RCPF to the uplift costs incurred to satisfy the Boston, Connecticut, and Southwest Connecticut reserve requirements in the RAA process. Units committed to meet local reserve requirements are flagged as Local Second Contingency Protection resources. We divide the resulting uplift from NCPC payments by the number of megawatt-hours of local reserve requirements satisfied on each day and summarized in Figure 19. For example, if a $100k uplift payment results when the ISO commits a unit to meet a 200 MW reserve shortfall lasting 4 hours, the figure would report this as $125 per MWh (= $100k ÷ 200 MW ÷ 4 hours). Each bar shows the number of days when the uplift from NCPC payments per megawatt-hour of reserve requirement satisfied was in each range shown on the x-axis.

Figure 19: Uplift Cost per MWh of Local Reserves Needed
Boston, Connecticut, and Southwest Connecticut, 2007

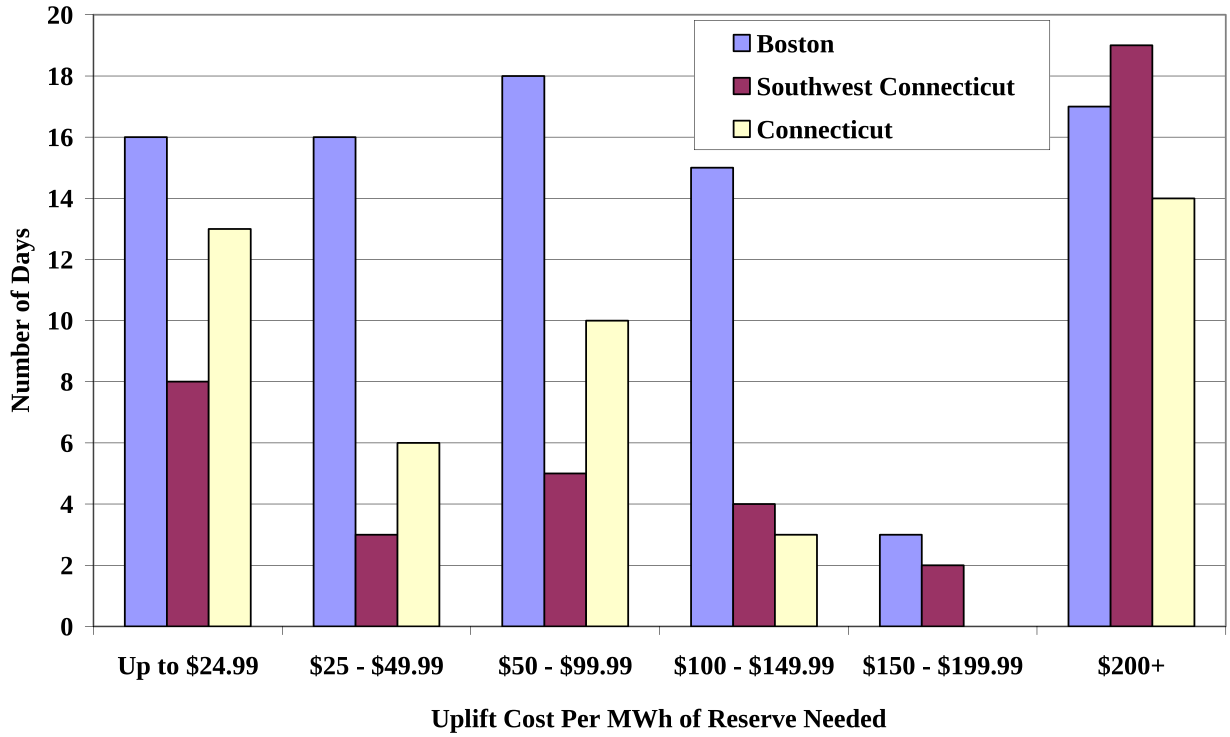


Figure 19 shows that the uplift costs per megawatt-hour of local reserve requirements satisfied exceeded the RCPF on a substantial share of the days in each local reserve area. The average uplift costs were greater than or equal to the $50 per MWh RCPF on 62 percent of the days shown for Boston, 59 percent of the days shown for Connecticut, and 72 percent of the days shown for Southwest Connecticut. Furthermore, there were a substantial number of days when the uplift costs incurred to meet the local reserve requirements exceeded $200 per MWh. This analysis indicates that the RCPF is set at a level that is lower than the costs routinely incurred to ensure a sufficient level of reserves in the local areas.

In general, the potential risk of price spikes arising from real-time shortages is a factor that encourages LSEs and other participants to buy more in the day-ahead market, which will bid-up day-ahead clearing prices. Higher day-ahead prices should, in turn, lead to additional market-based commitment in the day-ahead market and reduce the need for supplemental commitments through the RAA process. The current level of the local RCPFs limits the size of real-time price spikes to a level that appears to be lower than the costs that the ISO routinely incurs to maintain reserves. It also limits the extent to which the day-ahead reflects the need for capacity in local areas.

3. Reserve Constraint Penalty Factors – Conclusions

The previous two analyses indicate that the cost of maintaining local reserves frequently exceeds the local RCPF. This is reflected in real-time operations when the operator must take additional actions to maintain local reserves. There were a substantial number of intervals when the operator attempted to maintain reserves by imposing a proxy second contingency limit, which causes the real-time market model to import reserves. The cost of maintaining local reserves is also reflected in the RAA process when it is necessary to commit generators for local reliability. While generators are committed in order from least expensive to most expensive, there is no limit on the costs that can be incurred to satisfy local reserve requirements. Our analysis indicated that on many days, the NCPC costs incurred by the ISO were substantially higher than the RCPF.

A higher RCPF would more accurately reflect the cost of maintaining local reserves in the real-time market and increase incentives for more market-based day-ahead commitment in the local areas. This would, in turn, reduce the need for supplemental commitment in the RAA process and shift more of the local reliability costs from NCPC payments to higher market clearing prices. To the extent that a higher RCPF would better reflect the cost of maintaining reserves, increasing the RCPF would improve market-based signals for investment in areas where local reserves are most valuable. Hence, we recommend that the ISO re-evaluate the local RCPFs and set them to levels that are consistent with the costs necessary to meet the local-area reserve requirements. Based on our analysis, this would require RCPFs of more than $200 per MWh in the local areas. Because RCPFs are used to set clearing prices during reserve shortages, the ISO's evaluation should also consider the potential effects of increased RCPFs on the incentives of suppliers to exercise market power.

C. Local Reserve Zones

The ISO is required to schedule sufficient resources in local reserve areas to satisfy local second contingency protection requirements (i.e., maintain service in case the largest two local contingencies occur within a 30 minute period). This requires the ISO to schedule local 10-minute and 30-minute reserves and/or import reserves from outside the local reserve area. Three areas are designated as local reserve zones in the real-time reserve market: Boston, Southwest Connecticut, and Connecticut. The ISO schedules reserves in the three local reserve zones primarily by modeling local reserve requirements in the real-time market software.

There are other local areas that require the commitment and dispatch of resources to meet local second contingency protection requirements. The ISO's operating procedure for security monitoring discusses the process for maintaining operating reserves in six local areas: the three local reserve zones, as well as West Connecticut, Norwalk-Stamford, and Southeast Massachusetts.[29] Additionally, the ISO maintains sufficient operating reserves in Western New England and Maine. In areas requiring local operating reserves that are not designated as Local Reserve Zones, the ISO maintains reserves by modeling proxy second contingency limits in the real-time market software.

The following table summarizes the actions taken to meet local area reserve requirements in the real-time market during 2007. For eight local areas, the table reports the frequency and average shadow price of binding constraints in the real-time market. Local reserve constraints and proxy second contingency constraints are reported separately.[30]

---

29 See SOP-RTMKTS.0060.0020, *Monitor System Security*, Section 5.6.

30 The use of proxy second contingency constraints to satisfy local reserve requirements is also discussed in Section B.

Table 4: Summary of Real-Time Market Constraints to Maintain Local Reserves 2007

Location	Reserve Constraints: Frequency of Constraints	Reserve Constraints: Average Shadow Price	Proxy 2nd Contingency Constraints: Frequency of Constraints	Proxy 2nd Contingency Constraints: Average Shadow Price
Local Reserve Zones:				
Boston	**0.1%**	**$45**	**0.1%**	**$53**
Connecticut	**0.7%**	**$27**	**0.5%**	**$91**
Southwest Connecticut	**0.5%**	**$37**	**0.3%**	**$108**
Other Areas:				
Norwalk-Stamford			**1.6%**	**$62**
West Connecticut			**1.9%**	**$35**
West of East-to-West Interface			**1.2%**	**$29**
Lower Southeast Massachusetts			**9.1%**	**$31**
Maine			**0.2%**	**$45**

The table shows that the ISO redispatched the system to meet local reserve requirements in a very small portion of real-time market intervals in 2007. It is notable that maintaining reserves in Norwalk-Stamford, West Connecticut, and Lower SEMA, which are not designated as local reserve zones, is more costly than maintaining reserves in any of the three designated local reserve zones.

The most efficient way to satisfy local reserve requirements in the real-time market is to explicitly model reserve requirements, rather than to satisfy them by imposing proxy second contingency limits. When local reserve requirements are explicitly modeled in the real-time market software, the software selects the least-cost mix of internal and imported reserves to meet the requirement. Furthermore, the real-time market produces a reserve clearing price, which is a transparent signal of the value of reserves provided by offline and online units. When proxy second contingency limits are modeled in the real-time market software, the software tends to rely too heavily on imported reserves to meet the requirement. Furthermore, the lack of a reserve clearing price in this case causes the market to provide no incentive for suppliers to provide reserves in the local area, particularly off-line fast-start resources.

Hence, we recommend that the ISO consider creating additional Local Reserve Zones in order to satisfy local reliability requirements more efficiently in areas that are currently managed using proxy second contingency limits in the real-time market software. Expanding the number of real-time reserve zones would not require the ISO to expand the set of local reserve zones that are modeled in the Forward Reserve Market Auction. Differences already exist between the products that are procured in the Forward Reserve Market and the products that are procured in the Real-Time Reserve Market, and the current settlement rules adequately account for such differences.

For example, although there is no TMSR product in the Forward Reserve Market, TMSR is always procured in the Real-Time Market. When suppliers use TMSR capacity to satisfy their TMOR obligations in real-time, they receive a Forward Reserve Payment for TMOR plus the difference between the real-time clearing prices of TMSR and TMOR at their location. Such settlement rules provide suppliers with incentives to satisfy their Forward Reserve Obligations with higher quality reserve capacity when it is efficient to do so. Applying similar rules to local reserve zones in the Real-Time Market that are not defined in the Forward Reserve Market would maintain incentives for suppliers to meet their Forward Reserve Obligations in an efficient manner.

D. Locational Forward Reserve Market

Each year, the ISO holds two auctions for Forward Reserves, one for the summer procurement period (the four months from June through September) and one for the winter procurement period (the eight months from October through May). Suppliers that sell in the Forward Reserve auction satisfy their obligations by providing reserves in real-time from online resources or offline resources capable of starting quickly (i.e. fast-start generators). In October 2006, locational requirements were added to the previously existing Forward Reserve Market. Because the cost of maintaining local reserves at reliable levels varies greatly across New England, local requirements improve the economic signals provided by the Forward Reserves Market. For 2007, this section evaluates the results of the forward reserve auctions and examines how suppliers satisfied their obligations in the real-time market.

1. Background on Forward Reserve Market

The ISO purchases several reserve products on behalf of load serving entities in the Forward Reserve Market auction. There are two categories of forward reserve capacity: 10-Minute Non-Spinning Reserves ("TMNSR") and 30-Minute Operating Reserves ("TMOR"). The forward reserve market has five geographic zones: Boston, Southwest Connecticut, Connecticut, Rest of System (i.e. areas outside Connecticut and Boston), and the entire system (i.e. all of New England). With two exceptions, the reserve products sold in the forward reserve market are consistent with the ones sold in the real-time market. First, the forward reserve market has no requirement for 10-Minute Spinning Reserves ("TMSR"). Second, the forward reserve market has a minimum requirement for reserves in Rest of System, while there is no corresponding requirement in the real-time market. The additional reserve zone is intended to ensure that some forward reserves are provided outside local areas.

Forward reserves are cleared through a cost-minimizing uniform-price auction, which sets clearing prices for each category of reserves in each reserve zone. Suppliers sell forward reserves at the portfolio level, which allows them the flexibility to shift where they hold the reserves on an hourly basis. Suppliers also have the flexibility to trade their obligations prior to the real-time market. The flexibility provided by portfolio-level obligations rather than unit-level and bilateral trading enables suppliers to satisfy their obligations more efficiently.

Forward reserve obligations may be satisfied in real-time with reserves of equivalent or higher quality. When obligations are met with reserves of equivalent quality, the reserve provider receives the forward reserve payment instead of real-time market revenue based on the reserve clearing price. When obligations are met with reserves of higher quality, the reserve provider receives the forward reserve payment in addition to real-time market revenue based on the difference in clearing prices between the higher and lower quality products. For example, if Boston TMOR obligations are satisfied in the real-time market with Boston TMSR, the reserve provider will receive the forward reserve payment for Boston TMOR plus the revenue from the price difference between Boston TMSR and Boston TMOR.

2. Forward Reserve Auction Results

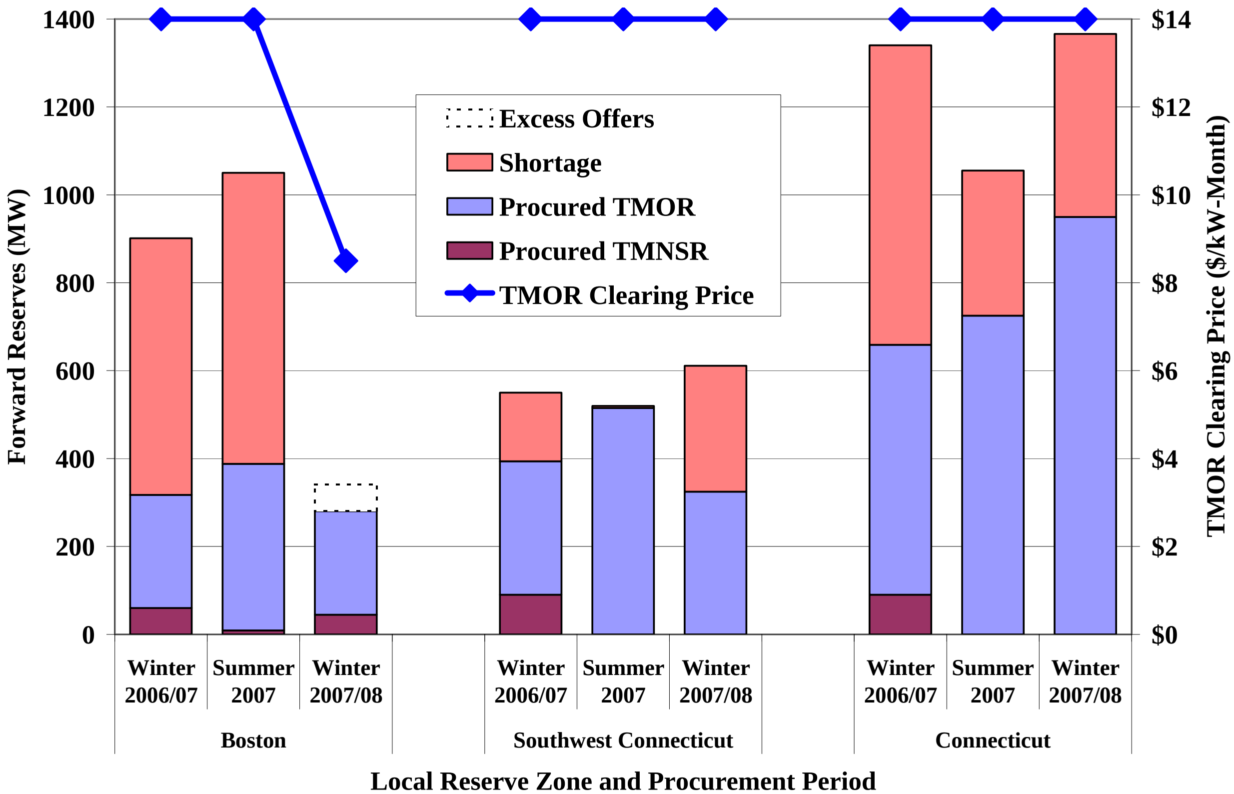
Forward Reserve Market ("LFRM") auctions are held approximately one-and-a-half months prior to the first month of the corresponding procurement period. For example, the auction for the Winter 2007/08 procurement period (October 2007 to May 2008) was held in August 2007. Prior to each auction, the ISO sets minimum purchase requirements as follows. For the system-level, the TMNSR requirement is based on 50 percent of the forecasted largest contingency, and the TMOR requirement is based on 50 percent of the forecasted second largest contingency. For Rest of System (i.e. areas outside Connecticut and Boston), the effective TMOR requirement is 798 MW.[31] For each local reserve zone, the TMOR requirement is based on the 95th percentile of the local area reserve requirement in the daily peak hour during the preceding two years, adjusted for major changes in the topology of the system or the status of supply resources.

In the Forward Reserve Market auction, an offer of a high quality reserve product is capable of satisfying multiple requirements in the auction. In such cases, the higher quality product is priced according to the sum of the values of the underlying products, although this is limited by the $14/kW-month price cap. For instance, one megawatt of TMNSR sold in Boston contributes to meeting three distinct requirements: the system-level TMNSR requirement, the system-level TMOR requirement, and the Boston TMOR requirement. The Boston TMNSR clearing price equals the system-level TMNSR clearing price (which incorporates the clearing price of the system-level TMOR) plus the difference between the Boston TMOR clearing price and the system-level TMOR clearing price.

The following two figures summarize the quantities purchased in the last three forward reserve auctions towards each requirement. Figure 20 shows auction outcomes for the three local reserve zones, and Figure 21 shows auction outcomes for the system-level and Rest of System requirements. For each local reserve zone in each procurement period, Figure 20 shows the TMOR clearing price, the quantity of TMOR and TMNSR procured, the shortage quantity if the requirement was not met, and the quantity of excess offers if the requirement was met.

31 The requirement is 600 MW, although this is multiplied by 1.33 to account for the expected performance of off-line reserve providers.

Figure 20: Summary of Forward Reserve Auction for Local Areas Procurement for October 2006 to May 2008



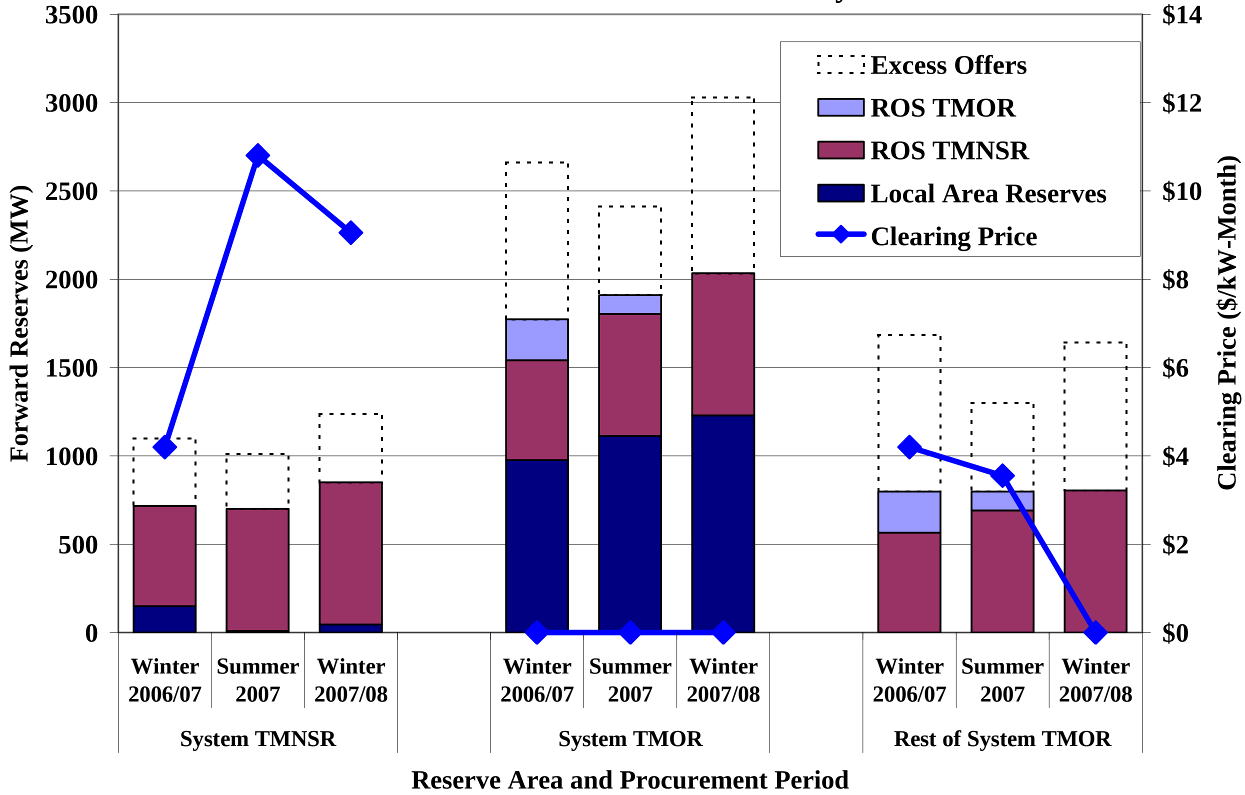
The local reserve zone requirement was satisfied for only one of the nine local reserve procurements shown in Figure 20. A substantial amount of transmission capability was added into the Boston area prior to the Winter 2007/08 auction, which led to a 770 MW reduction in the required amount of local reserves. As a result, the full Boston requirement was met and the TMOR price cleared at $8.50/kW-month. The Boston TMNSR price cleared at $14/kW-month because the combined value of Boston TMOR and system-level TMNSR exceeded the price cap. For the other eight local reserve procurements shown above, the local reserve zone requirement was not satisfied. The shortage quantities ranged from 5 MW for Southwest Connecticut in the Summer 2007 to 681 MW for Connecticut in the Winter 2006/07. The forward reserves procured for Southwest Connecticut are shown both separately and as a subset of the total procurement for Connecticut.

Figure 20 shows that a small amount of TMNSR has been sold in the local reserve zones, even though there are approximately 600 to 700 MW of TMNSR-capable resources in Connecticut and 200 to 300 MW of TMNSR-capable resources in Boston. The low level of TMNSR sales is likely a response to the incentives that arise from the $14/kW-month price cap. When the local reserve clearing price rises to the price cap, suppliers receive the same compensation for TMNSR and TMOR, even though TMNSR may be more costly to deliver or less easily traded in the bilateral market. Furthermore, the supplier who sells TMOR in the Forward Reserve Auction will receive a higher real-time settlement than the supplier who sells TMNSR. This is because real-time reserve providers are paid the difference in prices between the product they sold in the Forward Reserve Market and the product they actually provided in real-time. Hence, suppliers with TMNSR-capable resources have a strong incentive to sell TMOR rather than TMNSR in the Forward Reserve Auction when they will receive the price cap of $14/kW-month in either case.

For similar reasons, the price cap has also discouraged suppliers from selling forward reserves in Southwest Connecticut. Figure 20 shows that the quantity of reserves procured in Connecticut increased 225 MW from the Summer 2007 auction to the Winter 2007/08 auction, consistent with the seasonal increase in capability. However, the quantity of reserves procured in Southwest Connecticut declined 190 MW over the same period. This occurred because suppliers with fast-start capacity in Southwest Connecticut began selling Forward Reserves at the Connecticut location. Suppliers with resources in Southwest Connecticut have an incentive to sell at the Connecticut location in the Forward Reserve Auction when they expect to receive the price cap of $14/kW-month because they cannot receive any additional revenue for selling in Southwest Connecticut.

Figure 21 shows the same analysis for the system-level and Rest of System requirements. For each procurement period, Figure 21 shows the TMOR clearing price, the quantity of TMOR and TMNSR procured, the shortage quantity if the requirement was not met, and the quantity of excess offers if the requirement was met.

Figure 21: Summary of Forward Reserve Auction for Outside Local Areas Procurement for October 2006 to May 2008



Outside of the local reserve areas, the forward reserve requirements were satisfied. In the three auctions, the cost of meeting the system-level TMOR requirement was $0 because the requirement was met by the purchases for other requirements. In other words, no additional costs had to be incurred or purchases made to satisfy the system-wide TMOR requirement. Likewise, the Rest of System TMOR price cleared at $0 in the Winter 2007/08 auction because the requirement was met by procurement for the TMNSR requirement. In the Winter 2006/07 auction, TMNSR and TMOR sold at the same price because the TMNSR requirement was met by the combination of procurement for local areas and the Rest of System TMOR requirement.

Figure 21 shows that a large share of the TMNSR requirement was procured outside of the local areas. On average, just 67 MW of TMNSR was procured in the local areas, even though approximately 275 MW of TMNSR-capable fast-start capacity exists in the local areas. The low level of TMNSR sales in the local areas is likely a response to the incentives that arise from the $14/kW-month price cap. When the local reserve clearing price rises to the price cap, suppliers receive the same compensation for TMNSR and TMOR, providing no incentive to sell TMNSR rather than TMOR. The lack of TMNSR sales in the local areas has resulted in higher clearing prices for TMNSR system-wide. The same incentives also discourage suppliers from selling forward reserves at the Southwest Connecticut location. To address the adverse incentive effects that arise from the price cap, we recommend the ISO evaluate the potential benefits of implementing a tiered price cap. A tiered price cap that allows different price caps for different products could provide suppliers in local areas with better incentives to sell higher-quality forward reserve products than the current market.

3. LFRM Obligations in the Real-Time Market

Forward reserve providers satisfy their obligations in the real-time market by assigning individual resources to provide specific quantities of forward reserves in each hour from 7:00 AM to 11:00 PM, Monday through Friday. Resources assigned to provide forward reserves must be fast-start units or units that are online. These resources must be capable of ramping quickly enough to provide the specified quantity of reserves in 10 minutes for TMNSR and 30 minutes for TMOR. The assigned resources must offer the assigned quantity of incremental energy at a minimum price level.[32] Resources assigned to provide forward reserves forfeit any NCPC payments that they would otherwise receive. Forward reserve providers can arrange bilaterally for other suppliers to meet their obligations, although bilateral trading of obligations (distinct from transactions involving other products) was limited in 2007. Suppliers that do not meet their forward reserve obligations incur a Failure to Reserve Penalty.[33]

There are several types of costs that suppliers consider when assigning units to provide forward reserves. First, suppliers with forward reserve obligations face the risk of financial penalties if

---

32 This level, known as the "Threshold Price," is equal to the monthly fuel index price posted prior to each month multiplied by a constant of approximately 14.4 MMbtu per MWh. Hence, if the monthly natural gas index price is $8 per MMbtu, it would result in a Threshold Price of approximately $115 per MWh. The month fuel index price is based on the lower of the natural gas or diesel fuel index prices in dollars per MMbtu.

33 The Failure to Reserve penalty is equal to the number of megawatts not reserved times 1.5 times the Forward Reserve Payment Rate, which is the forward reserve clearing price (adjusted for capacity payments) divided by the number of obligation hours in the month.

their resources fail to deploy during a reserve pick-up.[34] Suppliers can reduce this risk by meeting their obligations with resources that are more reliable. Second, suppliers with forward reserve obligations forego the value of those reserves in the real-time market. For instance, suppose that real-time clearing prices are $10 per MWh for TMOR and $15 per MWh for TMNSR. A supplier that has TMOR obligations would be paid $0 if scheduled for TMOR or $5 per MWh if scheduled for TMNSR. Hence, this cost is the same regardless of whether the supplier is ultimately scheduled for TMOR, TMNSR, TMSR, or energy in the real-time market.

Third, suppliers may forego profitable energy sales as a result of offering incremental energy at the Threshold Price. For instance, suppose the Threshold Price is $130 per MWh and a supplier assigns a generator that has incremental costs of $80 per MWh to provide forward reserves. Because the supplier is required to offer at $130 per MWh, the supplier will not be scheduled to sell energy when the LMP is between $80 per MWh and $130 per MWh. The magnitude of this opportunity cost decreases for units that have high incremental costs (this opportunity cost is zero for units that have incremental costs greater than the Threshold Price).

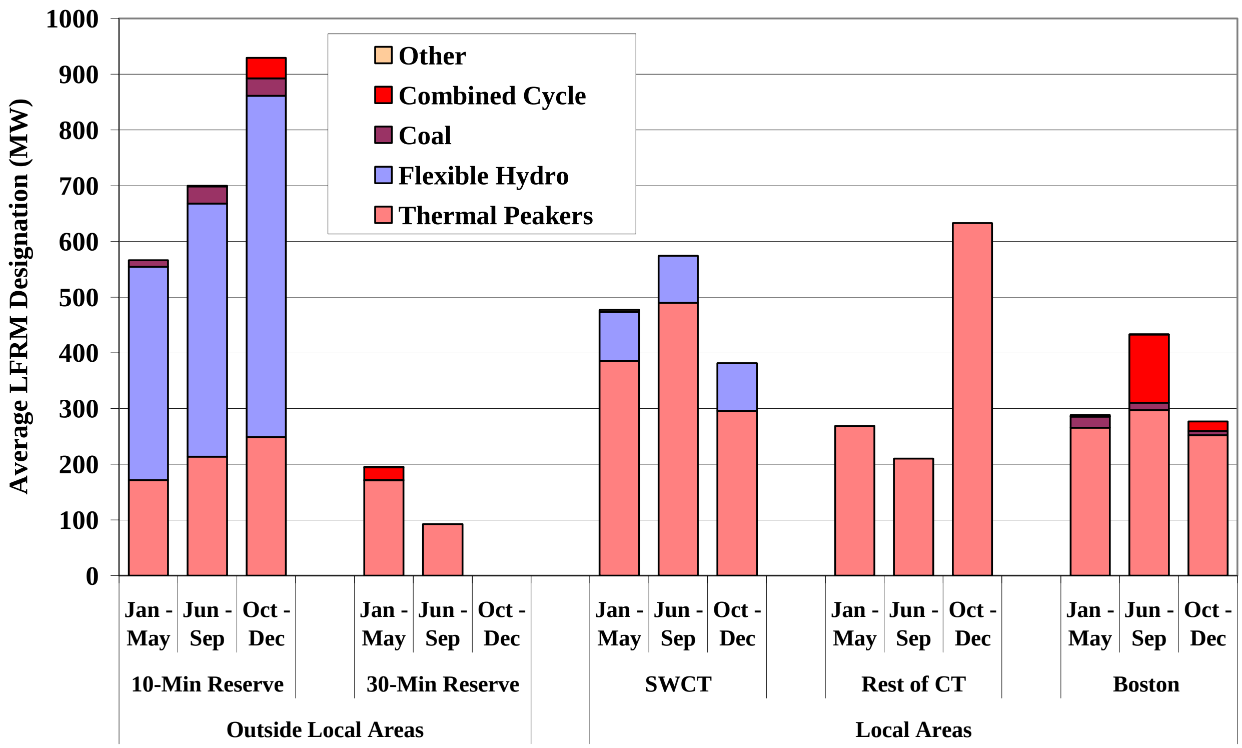
The previous three cost categories may be incurred by all units that provide forward reserves, but there are additional costs that are only faced by units that must be online to provide reserves. In order to provide reserves from a non-fast start unit, a supplier may have to commit a unit that would otherwise be unprofitable to commit. This type of cost is zero when energy prices are high and the unit is profitable to operate based on the energy revenues. However, when energy prices are low, the commitment costs incurred by some units may far exceed the net revenue that they earn from the energy market. Because fast-start resources do not face this cost, it is generally most economic to meet forward reserve obligations with fast-start units.

The following analysis evaluates how market participants satisfied their forward reserve obligations in 2007 by procurement period. The figure shows the average amount of reserves assigned in each region by type of resource.

---

34 The Failure to Activate penalty is equal to the number of megawatts that does not respond times the sum of the Forward Reserve Payment Rate and the Failure to Activate Penalty Rate, which is 2.25 times the higher of the LMP at the generator's location or the Forward Reserve Payment Rate.

Figure 22: LFRM Assignments by Resource Type 2007



The figure indicates that approximately 94 percent of forward reserve obligations were satisfied by hydro and thermal peaking resources capable of providing offline reserves. In some cases, these units were online and providing energy (which is acceptable as long as they offer in accordance with the forward reserve rules). The frequent assignment of fast-start resources to provide forward reserves confirms that it is generally more costly to provide forward reserves from non-fast-start resources.

Other than fast-start and hydro resources, combined cycle units satisfied the most forward reserve obligations during the summer months. A substantial amount of forward reserves were procured for the Summer 2007 procurement period for Boston. Combined cycle units tend to be online during a larger share of hours during the summer months, making them more economic to provide forward reserves.

Other than fast-start and hydro resources, coal-fired steam units were used most often to satisfy forward reserve obligations outside the summer months. Coal units have two characteristics that can make them relatively efficient providers of forward reserves. First, it is nearly always economic to commit coal-fired units, so suppliers do not face significant costs from committing them uneconomically. Second, most coal-fired units have a small emergency range that they can use to provide spinning reserves. Production of energy in the emergency range is relatively costly so they do not incur a substantial opportunity cost by offering a small amount of incremental energy at the Threshold Price.

In summary, the preponderance of forward reserves is provided by fast-start units, even in areas where the clearing price rises to the cap of $14/kW-month. This suggests that many non-fast-start resources do not sell forward reserves because the expected costs of providing forward reserves exceed the price cap. However, non-fast-start units that could provide forward reserves at a cost below the price cap may be discouraged from participating because:

- Units under reliability agreements do not have a financial incentive to participate in the forward reserve market. As these agreements expire, participation in the forward reserve market by non-fast start capacity may increase.
- Units that are frequently committed for local reliability and receive substantial NCPC payments have disincentives to provide forward reserves because they would be required to forgo the NCPC payments.

There was a hope that the Forward Reserve Market would lower NCPC costs because high-cost units committed for local reliability would sell Forward Reserves. However, this objective has not been realized.

E. Reserve Market – Conclusions and Recommendations

The ASM II project brought several major changes to the Real-Time Market and the Forward Reserve Market in New England. In the Real-Time Market, the scheduling of operating reserves and energy is now co-optimized, which improves market efficiency by allowing the real-time model to consider how the costs of energy is affected by the need to maintain operating reserves, and vice versa. ISO-NE is the first electricity market operator to determine in the real-time market the amount of reserves that are held on resources inside a local area versus the amount of reserves that are imported to the area. This innovation helps reduce the overall cost of meeting the local reserve requirements. In the Forward Reserve Market, clearing prices now vary by location, providing stronger signals for investment in capacity that is able to provide reserves at relatively low cost, particularly fast-start generation.

The co-optimized scheduling of energy and operating reserves enables real-time clearing prices to reflect the costs that are incurred to maintain reserves in the clearing prices of energy and reserves. Furthermore, during reserve shortages, the real-time market sets the reserve clearing prices according to the RCPFs. The use of RCPFs to set clearing prices during reserve shortages provides a robust mechanism for shortage pricing. The enhanced mechanism for determining real-time price signals under ASM II provides better incentives for efficient dispatch, commitment, and investment.

Based on our evaluation of the Real-Time Reserve Market in 2007, we find that:

- Supplemental commitment for reliability and self commitment after the start of the RAA process contributes to Excess Capacity that dampens real-time reserve clearing prices. Expectations of low real-time reserve prices reinforce the tendency of the day-ahead market to under-commit in local areas. For this reason, the ISO should minimize supplemental commitments while continuing to meet reliability requirements.
  - ✓ Section VIII discusses local reliability commitment and self commitment in greater detail and suggests several changes for reducing these quantities. The ISO is currently conducting an evaluation of how to limit self commitment that leads to inefficient levels of Excess Capacity, higher NCPC costs, and depressed prices.[35]
- The cost of maintaining operating reserves in local areas frequently exceeds the local RCPF. A higher RCPF would more accurately reflect this cost in real-time prices and improve incentives for market-based day-ahead commitment in the local areas. Increased market-based commitment would help shift some of the local reliability costs from NCPC payments to higher market clearing prices.
  - ✓ We recommend that the ISO re-evaluate the local RCPFs and set them to levels that are consistent with the costs necessary to meet the local-area reserve requirements. Based on our analysis, this would require RCPFs of more than $200 per MWh in the local areas. The ISO is currently reassessing the level of the local RCPFs to address such concerns.

35 See presentation: *Review of NCPC*, which is posted with the materials for the NEPOOL Markets Committee meeting on April 23-24, 2008 at www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/index.html.

- There are five areas that are not defined as local reserve zones where the ISO re-dispatches to maintain local operating reserves. In these areas, local reserve requirements are managed using proxy second contingency transmission limits. It would be more efficient to explicitly model reserve requirements in these areas. We recommend that the ISO consider creating additional local reserve zones in areas that are currently managed using proxy second contingency transmission limits in the real-time market.

Based on our evaluation of the Forward Reserve Market in 2007, we find that:

- In the first three Forward Reserve Auctions with local requirements, prices have generally cleared at the $14/kW-month price cap. These prices will encourage investment in resources that can provide operating reserves at relatively low cost, such as fast-start generators and qualifying demand response resources.
- Substantial amounts of TMNSR-capable fast-start capacity exist in the local areas, although relatively little has been sold in the Forward Reserve Auctions. This is likely a response to the incentives that arise from the $14/kW-month price cap. The lack of TMNSR sales in the local areas has resulted in higher clearing prices for TMNSR outside the local areas.
  - ✓ We recommend that the ISO evaluate the potential benefits of implementing a tiered price cap. A tiered price cap (different price caps for different products) would provide suppliers in local areas with better incentives to sell higher-quality forward reserve products in higher value locations.
- The Forward Reserve Market has requirements for TMOR in "Rest of System" and at the system-level. Resources in Boston and Connecticut can satisfy the system-level requirement but not the "Rest of System" requirement.
  - ✓ We recommend that ISO New England consider whether the "Rest of System" requirement is necessary given that there is already a system-wide requirement. Such a change would increase the competitiveness of the forward reserve market outside of the local areas and be more consistent with the real-time reserve requirements.

VI. Regulation Market

Regulation is the capability of specially equipped generators to increase or decrease their output on a moment-to-moment basis in response to signals from the ISO. The system operator uses regulation capability to maintain the balance between actual generation and load in the New England Control Area. The Regulation market provides a market-based system for meeting the system's Regulation requirements.

The ISO determines the quantity of Regulation capability required to manage the system based on historical performance and ISO New England, NERC and NPCC control standards. Requirements may be adjusted by the ISO as needed to assure continued compliance with these standards. The average quantity of regulation capacity scheduled has been reduced in each of the last three years: from 153 MW in 2004, to 143 MW in 2005, to 134 MW in 2006, to 129 MW in 2007. The ISO indicates that improved generator responsiveness to operator signals has permitted reductions in the quantity of regulation required. Generally speaking, the ISO maintains a schedule for acquiring Regulation that ranges from 70 MW to 220 MW depending upon season and time of day. The ISO has historically acquired about 15 to 20 MW more Regulation in summer and winter months than it has acquired in spring and fall. During Emergency Conditions, the ISO may deviate from the Regulation Requirement to maintain system reliability.

In this section of the report, we evaluate several aspects of the market for regulation, including (a) the market design changes implemented since 2005, (b) the overall costs of procuring regulation and related market outcomes, and (c) the pattern of supply offers from regulation providers.

A. Regulation Market Design

In October 2005, the ISO implemented significant changes to the regulation market, revising its methods for selecting and paying resources to provide regulation. Currently, resources are paid:

- *A Capacity Payment* – This equals the Regulation Clearing Price ("RCP") times the amount of regulation capability provided by the resource. The RCP is based on the highest accepted offer price.
- *A Mileage Payment* – This 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 was expected to generate mileage payments and capacity payments of similar magnitude in the long term.
- *A Lost Opportunity Cost ("LOC") Payment* – This is the opportunity cost of not providing the optimal amount of energy when the resource provides regulation service.

A summary of these payments is shown in Figure 23 by month from 2005 to 2007.

The Regulation market selects suppliers for the upcoming hour with an objective of minimizing consumer payments. Consumer payments are estimated for each resource by calculating a rank price, and the model selects the resources with the lowest rank price to provide regulation. The rank price is the sum of the following four quantities:

- *Estimated Capacity Payment* – In the first iteration of the model, this is the offer price of each resource. But since the RCP is set by the highest accepted offer, the subsequent iterations set this equal to the higher of the offer price and the previous iteration's highest priced accepted offer.
- *Estimated Mileage Payment* – This is equal to the estimated capacity payment.
- *Estimated Lost Opportunity Cost Payment* – This is the estimated opportunity cost from being dispatched at a level that allows a resource to provide regulation rather than at the most economic dispatch level given the resource's offer prices and the prevailing LMP.
- *The Look Ahead Penalty* – This is equal to 17 percent of the maximum possible change in the energy offer price within the regulating range. This is included in order to avoid selecting resources that would earn large opportunity cost payments if they were to regulate into a range of their energy offer priced at extreme levels.

The ranking process iterates until the set of resources selected to provide regulation does not change for two consecutive iterations. However, if the RCP rises from one iteration to the next, the model will use the previous iteration to rank resources.

In January 2007, the method of calculating the rank price was modified to address issues regarding the performance of the market that arose shortly after it was implemented in October 2005. Regulation market expenses increased dramatically in late 2005 and early 2006. We concluded that the high regulation expenses could be attributed to several factors, including two market design issues that led the model to not select the lowest-cost set of resources and to reduce the competitiveness of the market.

In conjunction with the Internal Market Monitor, who conducted a review of the market, we recommended changes to the selection formula. In 2006, the ISO filed proposed changes with FERC. First, reduce the ratio used to calculate the Look Ahead Penalty from 100 percent to 17 percent. Second, eliminate a fifth quantity that was previously used to calculate the rank price called the Estimated Production Cost Change, which was largely duplicative of the estimated opportunity cost. The Commission accepted the proposed changes to become effective on January 12, 2007.[36] These changes strengthened the incentives to submit competitive regulation offers and improved the efficiency of the selection of resources to provide regulation.

B. Regulation Market Expenses

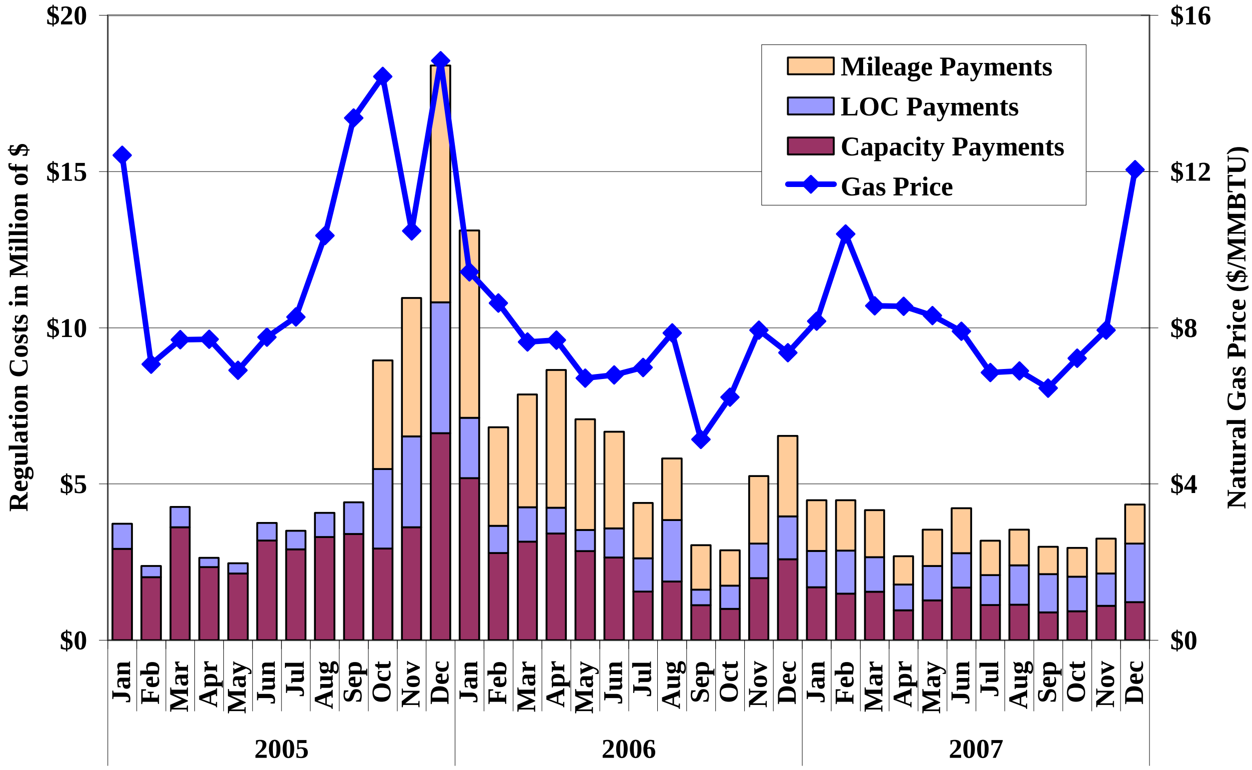
Figure 23 summarizes regulation market costs from 2005 through 2007 for each category of expenses. The figure also shows the monthly average natural gas prices. This figure shows that regulation market expenses rose sharply in the last three months of 2005 after the new regulation market was implemented in October 2005. Regulation expenses generally decreased over 2006 as supply increased, decreasing from an average of $8.4 million per month in the first half of 2006 to an average of $4.7 million per month in the second half of the year. Regulation market expenses decreased further to $3.7 million per month in 2007 after the design improvements were implemented.

The addition of the Mileage Payment contributed to higher expenses after the new market design was introduced in October 2005. The Mileage Payments increased revenues to regulation providers, which was expected to give regulation providers the incentive to reduce their offer prices. Since most suppliers did not immediately reduce their offer prices, total regulation expenses increased substantially. After gaining experience with the current market design, many suppliers have lowered their offer prices as expected.

---

36 See FERC docket no. ER07-201-000.

Figure 23: Regulation Market Expenses 2005-2007



Many of the other changes in regulation market expenses from 2005 to 2007 are explained by changes in offer patterns. The periods of very high expenses during late 2005 and the first half of 2006 coincided with periods of low offer quantities from online resources and higher offer prices than during other periods. Offer patterns are examined in Section C.

The refinements in the market design implemented in January 2007 likely contributed to the decline in regulation market expenses during the year. As explained above, the initial formula used in the market to select regulation resources over-weighted the estimated lost opportunity costs payments and under-weighted the Capacity Payments and Mileage Payments, which are driven by offer prices. Not surprisingly, Figure 23 shows that LOC Payments increased in 2007 as a percentage of total regulation market expenses. In 2006, Capacity Payments and Mileage Payments together represented 83 percent of total regulation expenses of about $78 million. In 2007, Capacity Payments and Mileage Payments together represented about 68 percent of total regulation expenses of about $44 million.

Figure 23 shows the monthly average natural gas price because input fuel prices can affect regulation market expenses. First, generators may consume more fuel to produce a given amount of electricity when they provide regulation, leading the costs of providing regulation to be correlated with the price of fuel. Market participants reflect these costs in their regulation offer prices, which directly affect Capacity Payments and Mileage Payments. Second, natural gas-fired generators are committed less frequently during periods of high gas prices. As a result, such generators are less likely to be available to provide regulation when gas prices are high. Despite somewhat higher natural gas prices in 2007 compared to 2006, regulation market expenses were substantially lower in 2007. This indicates that the regulation market performance improved in 2007 following the resolution of the market design issues.

C. Regulation Offer Patterns

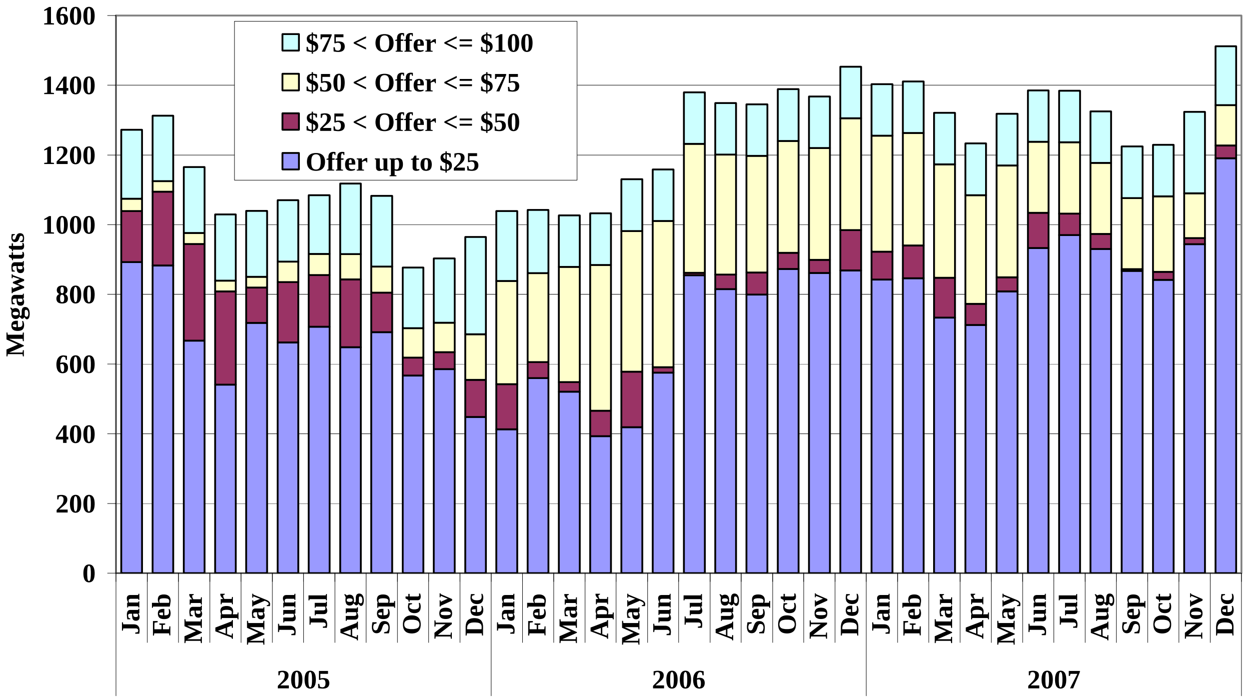
Competition should be robust in New England's regulation market in most hours because the amount of capability available in New England generally far exceeds the amount required by the ISO. This section evaluates the offer patterns of regulation suppliers.

Selection of units to provide regulation is limited to units that are online at the time the service is needed, since offline units cannot provide regulation service. For this reason, we separately examine regulation offers from all units, and then from committed units only. There have been significant variations in the prices and quantities of regulation offers over the past three years. From February to April 2005, there was a drop in regulation capability offered into the market due to the exit of several units from the market. In October 2005, there was a significant decrease in the quantity of low-price offers that coincided with the change in market design. Once the new market design was in place, total offer quantities showed several months of steady increase. The offer prices also increased substantially over this period, particularly from the largest suppliers.

Figure 24 shows monthly averages of the quantity of regulation offered into the market by all resources. The differing colors on the bars in the chart show the average quantities offered by offer price range.

There have been significant variations in the prices and quantities of regulation offers over the past three years. From February to April 2005, there was a drop in regulation capability offered into the market due to the exit of several units from the market. In October 2005, there was a significant decrease in the quantity of low-price offers that coincided with the change in market design. Once the new market design was in place, total offer quantities showed several months of steady increase. The offer prices also increased substantially over this period, particularly from the largest suppliers.

Figure 24: Monthly Average Supply of Regulation from All Resources 2005-2007

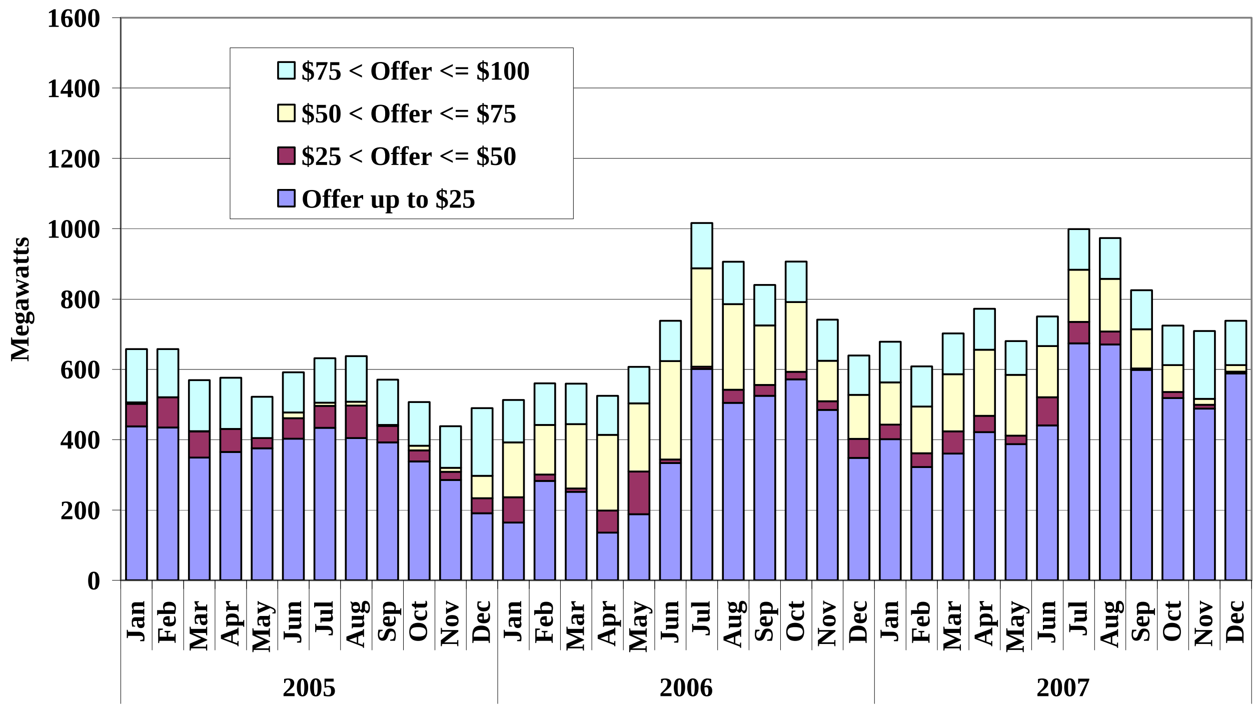


The quantity of regulation offered at prices under $25/MW increased substantially in summer 2006, and the quantity of low cost offers remained high through 2007. In June and July 2006, several units that had not previously participated in the regulation market entered the market and a number of existing units lowered their offer prices. The quantity of offers has remained relatively consistent since July 2006, although the portion offered below $25/MW has increased gradually.

On average, approximately half of the regulation offered day-ahead is available to the hourly real-time selection process. Regulation-capable capacity can be unavailable in a given hour because the capacity is on a resource that was not committed for the hour, or because the capacity is held on a portion of a resource that was self-scheduled for energy. More regulation capacity tends to be available during the high-load portion of the day because more units and are on-line. Similarly, more regulation capacity tends to be available during the summer when loads are higher and more generation is committed.

Figure 25 shows the quantity of regulation offers from resources that are online. Like the prior figure, the differing colors on the bars in the chart show the average quantities offered by offer price range.

Figure 25: Monthly Average Supply of Regulation from Committed Resources 2005 - 2007



Because the figure is limited to resources that are actually available to provide regulation, the changes in offer quantities and prices should more closely correspond to market outcomes. The introduction of the new market design in October 2005 was followed by a reduction in total quantity available to the market and an increase in regulation offer prices. The pattern resulted from:

- Increasing fuel costs, which lead to higher costs to provide regulation and less frequent commitment of combined cycle units;
- Unfamiliarity of market participants with the market design; and
- The lack of contestability of the market.

During 2007, significantly more regulation capability was offered into the market than was actually procured by the ISO. This excess supply generally limits competitive concerns 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, regulation supplies may be tight in low-demand periods when many regulation-capable resources are off-line. These conditions can lead to transitory periods of high regulation prices.

D. 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. We attributed the increase in costs to the supply reductions and market design issues described in this section.[37]

Changes to regulation market design implemented in January 2007 were intended to correct the identified market design issues. Even with higher natural gas prices on average in 2007, the quantity of regulation resources offered at lower prices has increased and overall regulation expenses have been reduced to levels similar to those existing prior to the implementation of the

37 See *2006 Assessment of the Electricity Markets in New England* and *2005 Assessment of the Electricity Markets in New England*.

new regulation market in 2005. Hence, the performance of the regulation market improved substantially in 2007 and the market design improvements have been effective.

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. Given the complex interaction of the regulation market with the energy market, particularly with respect to commitment decisions made in the day-ahead market, we recommend that the ISO consider day-ahead and real-time regulation markets that are co-optimized with the energy market.

VII. Real-Time Pricing and Market Performance

The goal of the real time market is the efficient procurement of the resources required to meet the reliability needs of the system. To the extent that reliability needs are not fully satisfied by the market, the ISO must procure needed resources outside of the market process. Whenever possible, operations should be performed in a manner that results in efficient real-time price signals. In particular, it is important for market operations to produce real-time price signals that encourage competitive conduct by suppliers, efficient participation by demand response, and investment in new resources or transmission where it is needed most. Hence, it is beneficial to regularly evaluate whether the market produces efficient real-time price signals.

In this section, we evaluate several aspects of the market operations related to pricing and dispatch in the real-time market in 2007. This section examines the following areas:

- Frequency of price corrections,
- Prices during the deployment of fast start units,
- Prices during periods of scarce transmission capability,
- Prices during the activation of real-time demand response, and
- The efficiency of the ex post pricing methodology.

It is also important for the market to set efficient real-time price signals during shortages of operating reserves. This point was recently affirmed by FERC in its NOPR, which identifies ISO New England's approach to shortage pricing as an effective method that serves as a model for other ISOs.[38] ISO New England uses RCPFs to set real-time clearing prices during operating reserves shortages. This pricing method is discussed in greater detail in Section V of this report, which evaluates the reserve markets.

---

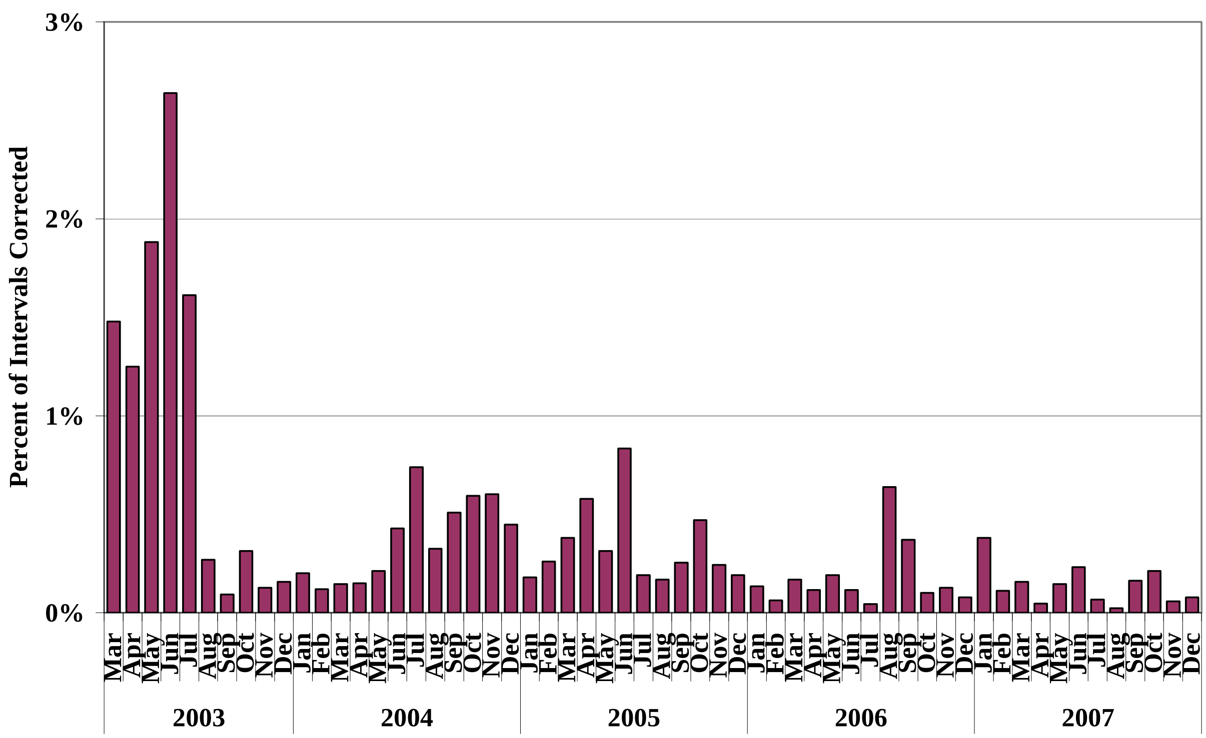
38 See P. 125. *Wholesale Competition in Regions with Organized Electric Markets*, 122 FERC ¶ 61,167 (2008) ("NOPR").

A. Price Corrections

This subsection evaluates the rate of real-time price corrections during 2007. 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 price corrections. Substantial and frequent corrections raise ISO and market participant costs and 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 26 below shows the rate of real-time price corrections in New England from March 2003 through December 2007.

Figure 26: Rate of Real-Time Price Corrections
March, 2003 to December, 2007



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 0.3 percent in most months. It is particularly notable that the frequency of price corrections was very low after the initial implementation of real-time reserve markets in October 2006. Real-time co-optimization of energy and reserves required significant changes to the market software. Major software deployments often lead to more frequent price corrections. These results support the conclusion that the real-time reserve market development and deployment were well-managed.

B. Real-Time Commitment and Pricing of Fast-Start Resources

Fast-start units are generally capable of starting from an offline status and ramping to their maximum output within 30 minutes of receiving an instruction. This enables them to provide reserves while offline. Areas without significant quantities of fast-start generation must maintain more reserves on online units, which can be very expensive. Another benefit of fast-start units is that they ramp to their maximum output level more quickly than most baseload units, and better enable the system operator to respond rapidly to unexpected changes in load.

The ISO's real-time dispatch software, called "UDS," is responsible for scheduling generation to balance load and satisfy operating reserve requirements, while not exceeding the capability of the transmission system. UDS provides advance notice of dispatch instructions to each generator for the next dispatch interval based on a short-term forecast of load and other operating conditions.[39] Most commitment decisions are made prior to the operation of UDS in the day-ahead timeframe, so the primary function of UDS is to adjust the output levels of online resources.[40] The only resources that UDS can commit (i.e., start from an off-line state) are fast-start units. Allowing UDS to start fast-start resources is more efficient than relying exclusively on operators to manually commit such units.[41]

---

39 Generators are usually given instructions 15 minutes in advance, but this can be set higher or lower by the operator.

40 Fast-start units are units that are capable of providing 10-minute or 30-minute non-synchronous reserves and have a minimum run time and a minimum down time of one hour or less.

41 Based on its real-time optimization, UDS recommends that individual fast-start units be started. However, the final decision to start a unit remains with the real-time operator.

When determining dispatch instructions for most generators, UDS considers only incremental offer prices, since the generator will be online in any case. However, for offline fast-start generators, UDS takes commitment costs into account. Commitment costs include a start-up cost for a unit that is offline and a "no-load" cost reflecting the fixed hourly cost of keeping a unit online.

For instance, suppose UDS needs to schedule an additional 20 MW and has the choice of increasing the output of an online unit with an incremental offer price of $120 per MWh or starting up a 20 MW fast-start unit with an incremental offer price of $75 per MWh, a no-load offer price of $300/hour, and a start-up offer price of $500 (which UDS amortizes over one hour). The average total offer of the offline unit is $115 per MWh = ($75 per MWh + $300/hour ÷ 20 MW + $500/hour ÷ 20 MW). Hence, the offline unit is more economic than the available capacity of the online unit.

Although the fast-start unit in this example is committed and dispatched in merit order, the full cost of the decision is not reflected in real-time prices under the current market design. Marginal cost pricing considers only the incremental offer price of the last accepted megawatt. If the last accepted megawatt came from the fast-start unit, the clearing price would be set at the incremental offer price of $75 per MWh, even though it cost substantially more to bring the unit online. As a result, the owner of the fast-start unit would receive an NCPC payment to make up the difference between the average total offer of $115 per MWh and real-time market revenue.

Additionally, fast-start units may not always set energy prices when they are needed to satisfy energy, operating reserves, or local reliability requirements. When a fast-start unit does not set prices, the price will be set by a lower-cost resource even if committing the fast-start resource was economic. In the example above, therefore, the clearing price determined in the real-time market could even be less than $75 per MWh.

The following table summarizes commitment of fast-start units by UDS in 2007. Information is shown separately for fast-start units that are deployed within congested areas because these deployments generally occur under higher price conditions and frequently involve more expensive offers. The table provides additional details for intervals when the average total offer of a deployed fast-start unit exceeds the LMP at its location.[42] The average total offers are used by UDS to establish the economic merit order of offline fast-start units. Hence, when the LMP is less than the average total offer, the LMP does not fully reflect the cost to the system of meeting demand.

Table 5: UDS Deployment of Fast-Start Units
2007

	No Congestion	Fast-Start Unit in Congested Area
Total Frequency of Deployments (% of all intervals)	**4.4%**	**1.7%**
Deployments where LMP < Marginal Fast-Start Offer:		
Frequency of Deployments (% of all intervals)	**1.2%**	**0.7%**
Avg. Offer of Marginal Fast-Start Unit ($/MWh)	**$154**	**$208**
Avg. LMP at Marginal Fast-Start Unit ($/MWh)	**$90**	**$169**
Avg. Difference Between Offer and LMP ($/MWh)	**$63**	**$39**

UDS deployed fast-start units in unconstrained areas in 4.4 percent of the intervals in 2007. In many of these intervals, the average total offers of committed fast-start units were lower than the LMP. However, in 27 percent of these intervals, at least one fast-start unit had a higher average total offer. In these intervals, the average total offer of the marginal fast-start unit (i.e. the last fast-start unit deployed in merit order) was $154 per MWh on average, while the LMP at the location of the marginal fast-start unit was $90 per MWh on average. The average difference between the LMP and the cost of the marginal deployment was $63 per MWh in these intervals. Similar figures are shown in the table above for units in import-constrained areas.

This analysis shows that fast-start units are routinely committed and dispatched in merit order, but real-time prices do not always reflect the underlying costs of the units. This result can lead to inefficient market signals. First, understated real-time prices will reduce the incentives to fully schedule load through the day-ahead market because the day-ahead prices will tend to be

42 The average total offer is the sum of incremental, no-load, and start-up offer components averaged over the economic maximum of the unit for the one hour amortization period.

higher than the real-time prices if load is fully scheduled day ahead. One consequence of under-scheduling day ahead is that fewer slow-starting units will be committed and the market will rely more heavily on fast-starting resources in real time to meet the incremental load. This pattern reduces the overall market efficiency and increases uplift costs.

Second, it does not provide a correct signal to participants that may import or export power to or from New England. The understated price in this case will lead to fewer net imports and increase New England's deployment of the fast-start resources. Finally, it diminishes the price signals that govern new investment in the long term. Hence, we recommend that the ISO evaluate potential changes in the pricing methodology that would allow the deployment costs of fast-start units to be more fully reflected in the real-time market prices. The Midwest ISO has been engaged in research on this issue and should be testing the feasibility of an alternative pricing methodology in a small scale software application later this year. Hence, it may be beneficial for ISO New England to coordinate with the Midwest ISO on this project.

C. Real-Time Pricing During Transmission Scarcity

Local shortages arise when local generation plus the transmission capability into the local area are not sufficient to satisfy demand for energy and reserves in the area. Although such shortages are relatively uncommon, it is important for wholesale markets to set efficient prices that reflect the tight operating conditions during such periods. Efficient prices provide generation and demand response resources incentives to respond to maintain reliability. Efficient prices also provide signals that attract new investment when and where needed.

Under the ISO's current operating procedures, UDS re-dispatches generation when a transmission limit is binding so that flows do not exceed the limit. UDS can use nearly all available resources to manage transmission flows.[43] On occasion, the marginal re-dispatch cost (i.e. shadow price) necessary to manage the flow over a transmission facility reaches

43 UDS will not use re-dispatch options that exceed the level of the Transmission Constraint Penalty Factor, although the penalty factor is ordinarily set to a very high level. Also, UDS will not re-dispatch resources that have a sensitivity factor with a magnitude of less than 2 percent relative to the flow over the transmission facility.

extraordinary levels (e.g. greater than $10,000 per MWh). When UDS does not have sufficient resources to reduce the flow under the limit, a violation occurs and the shadow price of the constraint is set by the marginal available resource(s).

The current procedures have functioned effectively, allowing the ISO to re-dispatch the lowest-cost offers available to maintain reliability under tight operating conditions. Yet, it is important to assess the efficiency of price signals under such conditions because prices give generators and demand response resources incentives to respond and attract investment. This section provides an assessment of market outcomes during periods of acute transmission constraints, focusing on:

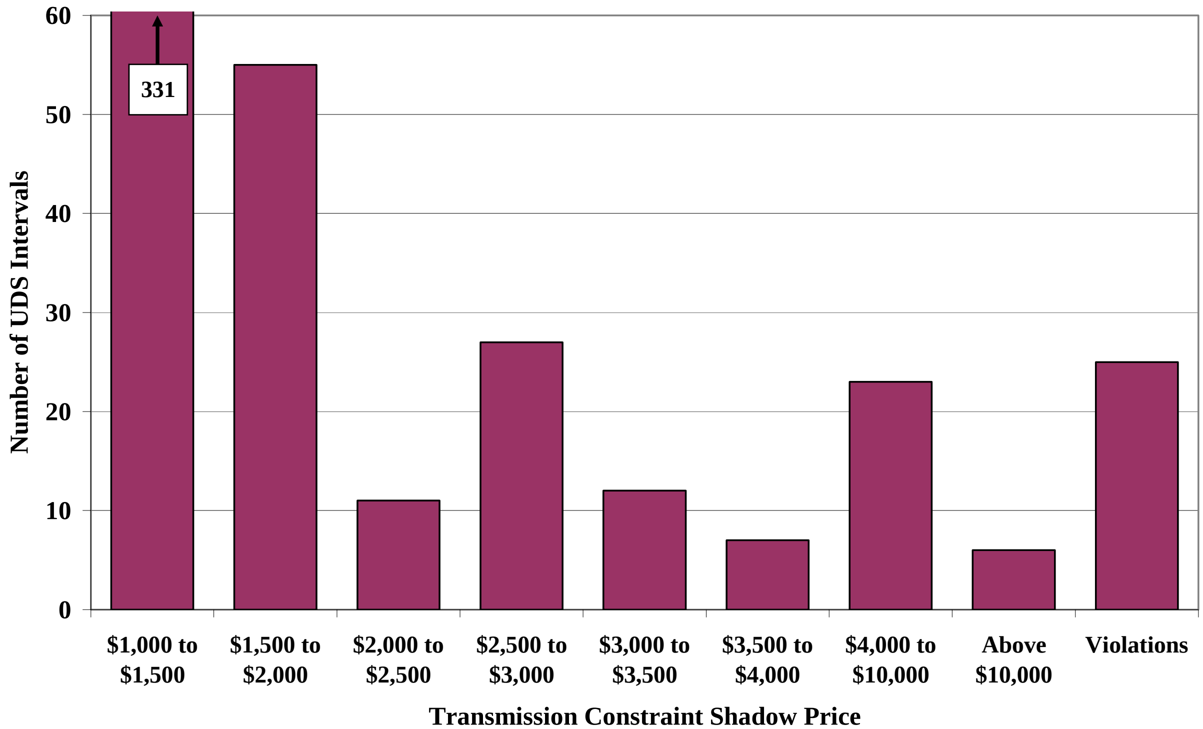
- The efficiency of the prices when resources are insufficient to manage the constrained transmission line; and
- Whether excessive redispatch costs are incurred to manage the constraints, i.e., redispatch costs that exceed the value of reducing the flow on the constrained transmission line.

Regarding the second issue, whether such costly re-dispatch is warranted depends on the reason why the transmission limit was initially imposed. Some transmission limits may be safely violated for an extended period with no substantial effect on reliability while other violations may necessitate immediate curtailment of firm load to maintain reliability.[44] Hence, it would be beneficial to develop procedures that distinguish between these two situations and only incur extraordinary re-dispatch costs under more acute conditions.

The following figure illustrates the significance of periods when transmission congestion is particularly acute. The figure shows 497 UDS intervals in 2007 when either a transmission constraint shadow price exceeded $1,000 per MWh or a transmission limit was violated.

44 ISO-New England Operating Procedure No. 19 – *Transmission Operations* describes how Normal, Long-Term Emergency, Short-Term Emergency, and Drastic Action Limits are used to develop the limits that are used by UDS to determine dispatch instructions.

Figure 27: Frequency of UDS Intervals with High Re-Dispatch Costs 2007



There were 57 intervals when the constraint was resolved with a shadow price between $2,000 and $4,000 per MWh, 29 intervals when the constraint was resolved with a shadow price exceeding $4,000 per MWh, and 25 intervals when the limit was violated. Although the figure indicates that acute conditions were relatively infrequent, such periods provide important market signals that can influence commitment, dispatch, and investment.

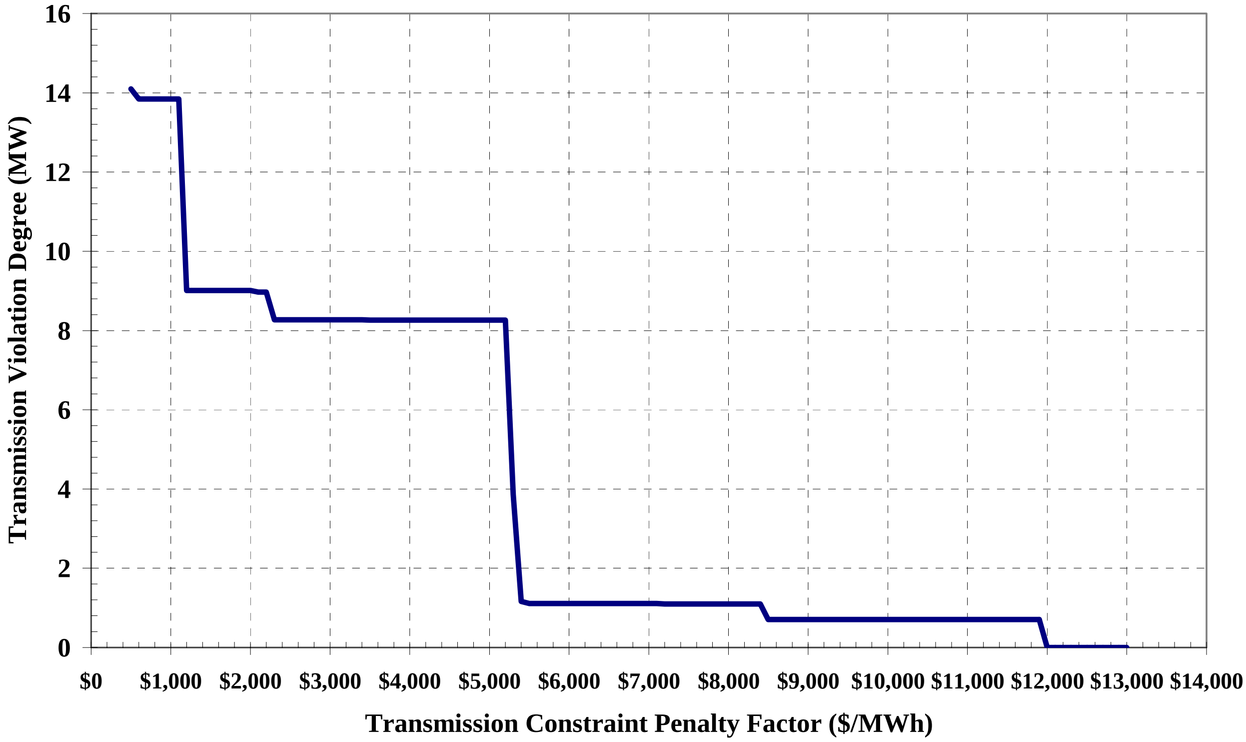
In the 25 intervals when the limit was violated, the shadow price was set by the marginal available offers. In these intervals, the shadow price was below $100 per MWh in 18 intervals, between $100 and $1,000 per MWh in 3 intervals, and between $1,000 and $11,000 per MWh in 4 intervals. These pricing outcomes suggest that the current procedures do not always result in price signals that reflect the shortage of transmission capability. When a constraint is unmanageable, an algorithm is used to “relax” the limit of the constraint for purposes of calculating a shadow price for the constraint and the associated LMPs. Based on our analysis of the same software in the Midwest ISO, we have found that this algorithm is flawed and prone to produce inefficiently low shadow prices when a constraint is in violation (zero in many cases).

Hence, we have recommended in recent State of the Market reports that the Midwest ISO discontinue use of the relaxation algorithm and set LMPs based on a shadow price for any violated constraint equal to a penalty factor set to reasonably reflect the value of the constraint (e.g., $2000 per MWh). Later in this section, we recommend that the ISO consider a similar approach for New England, although this issue is far less urgent in New England because the frequency with which constraints are violated is much lower than in the Midwest ISO region.

Most of the intervals where the transmission limit was resolved but the shadow price exceeded $10,000 per MWh occurred on September 26. In these intervals, LMPs at several nodes exceeded $5,000 per MWh. Such costly re-dispatch should be limited to situations where it is absolutely necessary for reliability. Depending on the reason for the transmission limit, it may be possible to exceed the limit for a period of time without a significant degradation of reliability. For example, NERC allows some limits to be in violation for up to 30 minutes before it deems a reliability standard to have been violated. In such cases, it would be beneficial to impose a ceiling on the re-dispatch costs that can be incurred to manage the transmission constraint. A lower penalty factor could be used to impose a reasonable ceiling on re-dispatch costs.

The following case study provides some indication of how outcomes could be affected if a ceiling, or penalty factor, were imposed on re-dispatch costs. In the 1:15 PM UDS interval on September 26, the Scobie B172 facility was binding and the resulting marginal re-dispatch cost was $11,848 per MWh. In this interval, approximately 150 MW was flowing across the Scobie B172 facility. The following figure shows how the flow would have changed if a penalty factor was used to place a ceiling on the costs that could be incurred to manage the constraint. The y-axis shows the violation (i.e. number of megawatts in excess of the flow limit) that would have occurred for a given penalty factor, which is shown on the x-axis.

Figure 28: Effect of Reducing Transmission Constraint Penalty Factors
Scobie B172 Facility, 1:15 PM UDS Interval on September 26, 2007



As expected, if the penalty factor (shown on the x-axis) exceeded $11,848 per MWh, the transmission constraint would be fully resolved. However, if the penalty factor were reduced, some re-dispatch options would be too costly and UDS would violate the constraint rather than exceed the penalty factor. The figure shows that if the penalty factor were reduced below $11,848 per MWh, UDS would violate the constraint by 0.7 MW. The amount of the violation would increase if the penalty factor were reduced. For example, if the penalty factor were reduced to $1,000 per MWh, it would result in a violation of approximately 14 MW. Although the figure illustrates just one example of how adjusting a penalty factor would affect operations, it suggests that, in some cases, reducing the penalty factor would lead to only a modest violation that would not significantly undermine reliability.

Hence, by adjusting the penalty factors for transmission constraints, it may be possible to limit extraordinarily costly re-dispatch to circumstances when failing to do so would seriously affect reliability. The penalty factors could also be used to improve the efficiency of price signals during periods of scarce transmission capability. Just as RCPFs are used to set prices when the market is short of operating reserves, Transmission Constraint Penalty Factors could be used to set prices during periods of transmission scarcity. [45] For example, if a Transmission Constraint Penalty Factor of $4,000 per MWh was used to manage the constraint shown in Figure 28, it would result in an 8.2 MW violation of the limit, a $4,000 per MWh shadow price, and correspondingly lower LMPs. This approach would also safeguard the market by not allowing the relaxation algorithm to establish inefficiently low shadow prices when a constraint is violated. Hence, we recommend that the ISO evaluate potential enhancements to the current operating procedures that would establish reasonable Transmission Constraint Penalty Factors and allow them to set LMPs when a constraint is in violation.

D. Real-Time Pricing During the Activation of Demand Response

Price-responsive demand has great potential to enhance wholesale market efficiency. Modest reductions in consumption by end-users in high-price periods can significantly reduce the costs of committing and dispatching generation. Furthermore, price-responsive demand reduces the need for new investment in generating capacity. As interest increases in demand response programs and time-of-day pricing for end-users, demand will play a progressively larger role in wholesale market outcomes.

Demand response participation has surged in New England in recent years. The quantity of resources enrolled in real-time demand response programs has increased from 530 MW in January 2006 to 880 MW in January 2007 and 1,684 MW in January 2008. The ISO has four real-time demand response programs, which are listed below. The first three programs provide emergency demand response resources that can be called during a capacity deficiency, while the fourth program provides a mechanism for loads to respond to high prices in the wholesale market.[46]

---

45 The use of RCPFs in the real-time market is described in Section V.B.

46 Real-Time 30-Minute Demand Response Program resources are activated under OP-4 Actions 9 and 12. Real-Time 2-Hour Demand Response Program resources and Real-Time Profiled Response Program resources are activated under OP-4 Action 3. Real-Time Price Response Program resources are given the

- Real-Time 30-Minute Demand Response Program – 86 percent of real-time demand response capability is enrolled in this program. These resources may be interrupted for anticipated capacity deficiencies with 30 minutes notice and receive the higher of the LMP or $500 per MWh for a minimum duration of 2 hours.
- Real-Time 2-Hour Demand Response Program – 7 percent of real-time demand response capability is enrolled in this program. These resources may be interrupted for anticipated capacity deficiencies with 2 hours notice and receive the higher of the LMP or $350 per MWh for a minimum duration of 2 hours.
- Real-Time Profiled Response Program – 1 percent of real-time demand response capability is enrolled in this program. These resources may be interrupted for anticipated capacity deficiencies with 2 hours notice and receive the higher of the LMP or $100 per MWh for a minimum duration of 2 hours.
- Real-Time Price Response Program – 6 percent of real-time demand response capability is enrolled in this program. These resources may be interrupted with notice on the previous day and receive the higher of the LMP or $100 per MWh for a duration of 4 or 6 hours.

The majority of demand response resources are enrolled in the Real-Time 30-Minute Demand Response Program, slightly more than half of which are located in the Connecticut zone. Since the resources participating under the Real-Time 30-Minute Demand Response Program can be activated with just 30 minutes notice, they provide a higher degree of reliability benefit than resources participating under the other three programs.

Although increased demand response should generate substantial market efficiencies, they also present significant challenges for efficient real-time pricing. Real-time demand response resources are not dispatchable[47] and must be activated in advance based on forecasted conditions for a duration of at least two hours. These inflexibilities lead to two problems for the efficiency of real-time prices. First, the amount of demand response activated may exceed the amount necessary to avoid the conditions that triggered the activation. Second, the minimum curtailment duration of the demand response resources may be longer than the duration of the conditions that triggered the activation. Both problems can lead to situations when the activation of demand

instruction to curtail on the previous day when forecasted zonal prices are greater than or equal to $100 per MWh.

47 This refers to resources that are able to modify their consumption or generation in response to remote dispatch instructions from the ISO generated by the real-time market.

response depresses real-time prices substantially below the marginal cost of the foregone consumption by the demand response resources.

When a capacity deficiency is anticipated, resources enrolled in the Real-Time 30-Minute Demand Response Program, the Real-Time 2-Hour Demand Response Program, and/or the Real-Time Profiled Response Program are activated according to the OP-4 protocol. In 2007, resources from all three programs were activated in Maine on December 1st and 2nd for a total of 15 hours. During these hours, an average of 150 MW actually curtailed, and the hourly average real-time clearing price for the Maine load zone ranged from $89 to $230 per MWh, averaging $131 per MWh over the period. Although the activation of these demand response resources helped keep the system reliable, real-time clearing prices in Maine did not reflect the cost of activating the demand response resources, most of which were paid $500 per MWh to curtail. Because these resources are not dispatchable in the real-time market, they do not set clearing prices even when they are needed to avoid a capacity deficiency. As a result, there is a tendency for real-time prices to be substantially lower than the marginal cost of deploying demand response. This undermines the efficiency of the real-time market, which should provide clear price signals during capacity shortages. Hence, it is important develop pricing mechanisms that allow demand response resources to set clearing prices when they are needed to avoid a shortage.[48] This would better reflect market conditions in these cases and would result in more efficient economic signals.

Real-time clearing prices did not reflect the cost of activating resources under the Real-Time Price Response Program during 2007. The ISO activates these resources when it forecasts that real-time prices will reach $100 per MWh for one or more hours on the following day (not including weekends). Resources are activated for four or six hours, depending on the season, and are paid the higher of $100 per MWh or the real-time zonal clearing price. When resources were activated under this program in 2007, the average real-time clearing price was substantially lower than the average cost of activating these resources. Of the 968 hours when these resources were activated, the clearing price at the New England Hub was less than $100 per MWh in 79

48 The Commission's NOPR generally endorses such measures. See P. 98.

percent of the hours and less than $70 per MWh in 37 percent of the hours.[49] One reason for the low prices is that the duration of the load curtailment is usually longer than the forecasted duration of $100 per MWh prices. Another reason is that the demand resources are not dispatchable in the real-time market, and therefore, do not set clearing prices.

For example, suppose that the ISO activates demand response resources at a cost of $100 per MWh, allowing the ISO to back down a $105 per MWh generator. In this case, the clearing price would be set by the next most expensive generator, which might be at a cost of less than $100 per MWh. In such cases, allowing the demand response resources to set the clearing price could lead to real-time prices that better reflect the cost of deploying resources to meet the demand for energy and operating reserves. Currently, the Real-Time Price Response Program has a relatively small effect on real-time prices because enrollment in the program is limited. However, if participation in price-responsive programs grows, developing mechanisms that enable these resources to set clearing prices will be critical.

The ISO has recognized the difficulties that arise from participation by non-dispatchable resources and has sought ways to better integrate demand response in the real-time market. The ISO launched the Demand Response Reserves Pilot Program to allow demand response resources to participate in the reserve markets. Under this program, demand response resources with the capability of responding to a reserve deployment within 30 minutes can qualify to sell TMOR in the real-time market and/or the forward reserve market. During the summer 2008, 50 MW of demand response resources will be able to participate in the pilot program. If the pilot is successful and substantial quantities of demand response resources participate in the reserve market, it is expected to significantly reduce the cost of meeting the reliability needs of the system.

The growth of demand response is a positive development that should reduce the cost of operating the system reliably, particularly during peak periods. Demand response provides an alternative to costly new generation investment. However, since demand response resources are

---

49 See *2007 Annual Markets Report* by the Internal Market Monitoring Unit of ISO New England.

not dispatchable in the real-time market, it can be challenging to set prices that reflect scarcity during periods when demand response resources are activated. Hence, we recommend that the ISO develop rules for allowing non-dispatchable demand response resources to set clearing prices when there is a capacity deficiency or when there would have been a deficiency without the activation of demand response resources.

E. Ex Ante and Ex Post Pricing

The ISO adopted the ex post pricing method when it originally implemented the SMD market design in 2003. The ex post pricing method is also used by PJM and the Midwest ISO, while other ISOs use the ex ante pricing method. In this section, we evaluate the efficiency of the real-time prices produced by the ex post pricing method.

Ex ante prices are produced by the real-time dispatch model (UDS) and are consistent with the cost-minimizing set of dispatch instructions. The prices are set to levels that give generators an incentive to follow their dispatch instructions.[50]

Ex post prices are produced by the LMP Calculator. At the end of each interval, the LMP Calculator re-calculates dispatch quantities and prices using inputs that are different in several respects from the inputs used by UDS. For each flexible[51] resource, a "real-time offer price" is used in place of its offer curve. For a resource following dispatch instructions, its "real-time offer price" equals the ex ante price at its location or, if it is operating at its maximum output level, the offer price corresponding to its actual production level. For a resource that is under-producing, the "real-time offer price" equals the offer price corresponding to the resource's actual production level. Each flexible resource is treated as having a small dispatchable range around its actual production level, where the upward range is much smaller than the downward

50 This assumes the generators are offered at marginal cost.

51 For most resources, they are treated as flexible if they are producing more than 0 MW and they meet one of the following conditions: (i) being committed for transmission, (ii) being dispatchable and producing less than 110 percent of their dispatch instruction, and (iii) being dispatchable and having a real-time offer price at their actual production level that is less than or equal to the ex ante price.

range (e.g. approximately 0.1 MW up and 2 MW down). The purpose of the ex post pricing method is to generate a set of prices that is consistent with the actual production levels of generators in the market, rather than their dispatch instructions.

The evaluation in this section addresses three areas:

- The current implementation of ex post pricing results in a small but persistent upward bias in real-time prices.
- Ex post pricing does not improve the incentives to follow dispatch instructions.
- Occasional distortions caused by the ex post pricing method lead to inefficient pricing in congested areas.

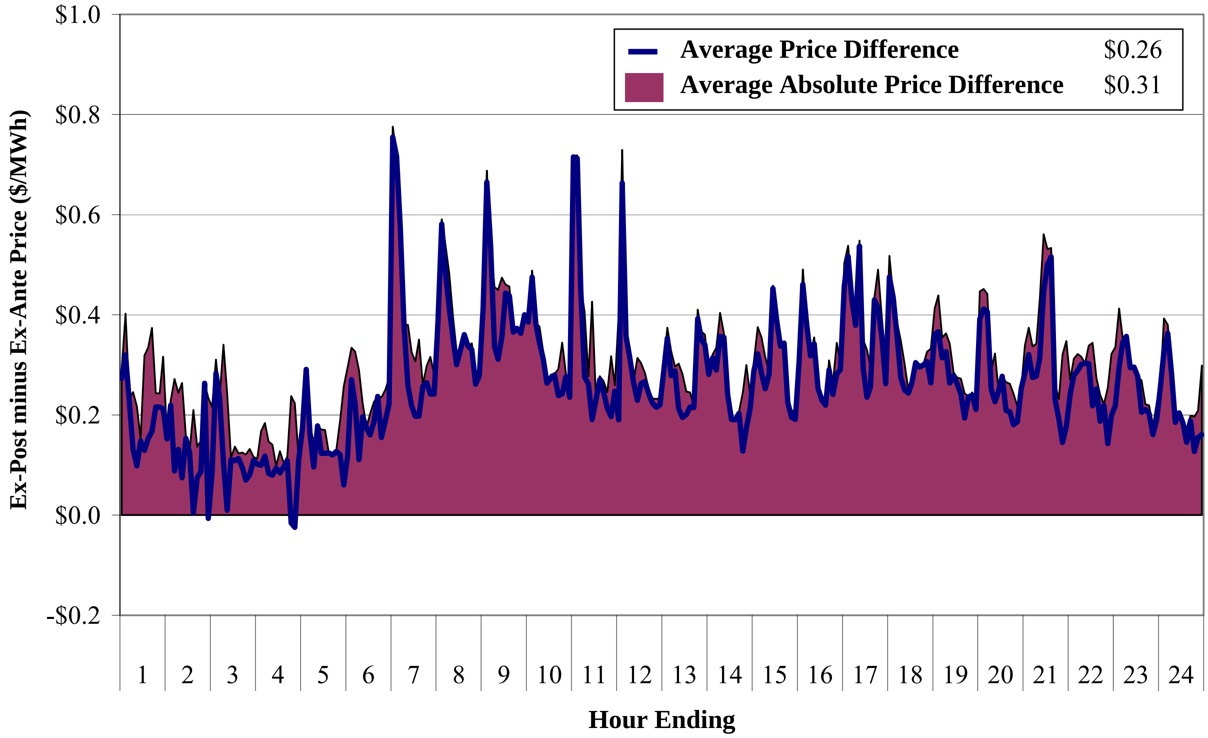
Persistent Differences Between Ex Ante and Ex Post Prices

The first analysis highlights an issue with the current implementation of ex post pricing that leads to a small but persistent upward bias in real-time prices. The following figure summarizes differences between ex ante and ex post prices in 2007 at a location close to the New England Hub.[52] This location is relatively uncongested, making it broadly representative of prices throughout New England. The red line shows average ex post price minus average ex ante price by the time of day. The blue area shows the average absolute price difference by the time day.

The average differences between the ex post and ex ante prices were relatively small in 2007. However, the line shows a persistent bias that causes the ex post prices to be slightly higher than ex ante prices in the vast majority of intervals. As a result, average ex post prices were $0.26 per MWh higher than ex ante prices at this location. The persistent bias results from a combination of two factors. First, loss factors change slightly between the ex ante price calculation and the ex post price calculation as the pattern of generation and load changes. Even though many units' "real-time offer prices" are equal to the ex ante price (which should make them economically equivalent), these changes in loss factors affect the relative offer costs of the resources. The second factor is that the dispatchable range of each resource is generally 20 to 40 times larger in the downward direction than the upward direction.

52 The MillBury station was selected because it is near the New England Hub. The New England Hub was not chosen because UDS does not calculate ex ante prices for load zones or the New England Hub.

Figure 29: Average Difference Between Five-Minute Ex Post and Ex Ante Prices 2007



In a typical interval, there may be 100 or more flexible resources. At locations where the loss factors increase the most from the ex ante to the ex post model, resources will appear most costly and be moved downward in the ex post. Since the downward dispatchable range is much larger than the upward dispatchable range, many resources will be ramped up to their maximum to replace the unit that is ramped down. In a random interval we examined without congestion, three units were moved down and more than 70 units were moved up. As the units moving up reach their assumed maximum, increasingly more expensive units will set the ex post prices. Hence, the resource that is marginal in the ex post calculation usually has a loss factor that is higher than in the ex ante calculation, thereby leading to an upward bias in prices.

Theoretical Problems with Ex Post Pricing

Ex post pricing has been justified, in part, as a means to provide resources with incentives to follow dispatch instructions. However, ex post pricing does not efficiently provide such an incentive for several reasons. First, suppliers that are primarily scheduled day-ahead will not be substantially harmed by small adjustments in the real-time price. Second, with the exception of the periodic price effects in congested areas, the pricing methodology will not usually result in significant changes in prices when a unit does not follow dispatch instructions. In general, this is the case because many other units will have real-time offer prices in the ex post model equal to the ex ante price that can replace the unit following dispatch. Hence, it is very unlikely that the ex post pricing enhances incentives to follow dispatch instructions.

In fact, because ex post pricing can, on occasion, substantially affect prices in congested areas, it can diminish suppliers' incentives to follow ex ante dispatch instructions when prices in the congested area are volatile. A much more efficient means to send targeted incentives to respond to dispatch instructions is the use of uninstructed deviation penalties.

A final theoretical concern is that ex post prices are theoretically less efficient than ex ante prices. The ex ante dispatch and prices represent the least cost dispatch of the system, given bids, offers, and binding constraints. If a unit is unable to respond to the dispatch instruction, then it implies that less supply is available to the market, and thus, the price should have been set by a more expensive offer. In other words, a higher-cost offer would have been taken if the market had known the unit could not respond. In such a case, however, the ex post pricing method would reduce the energy prices from the ex ante level.

Pricing Outcomes in Congested Areas

On occasion, the ex post pricing model substantially alters prices in congested areas. Such occasions arise when the marginal unit for the binding constraint becomes inflexible or flexible but with a reduced offer price[53] in the ex post pricing.

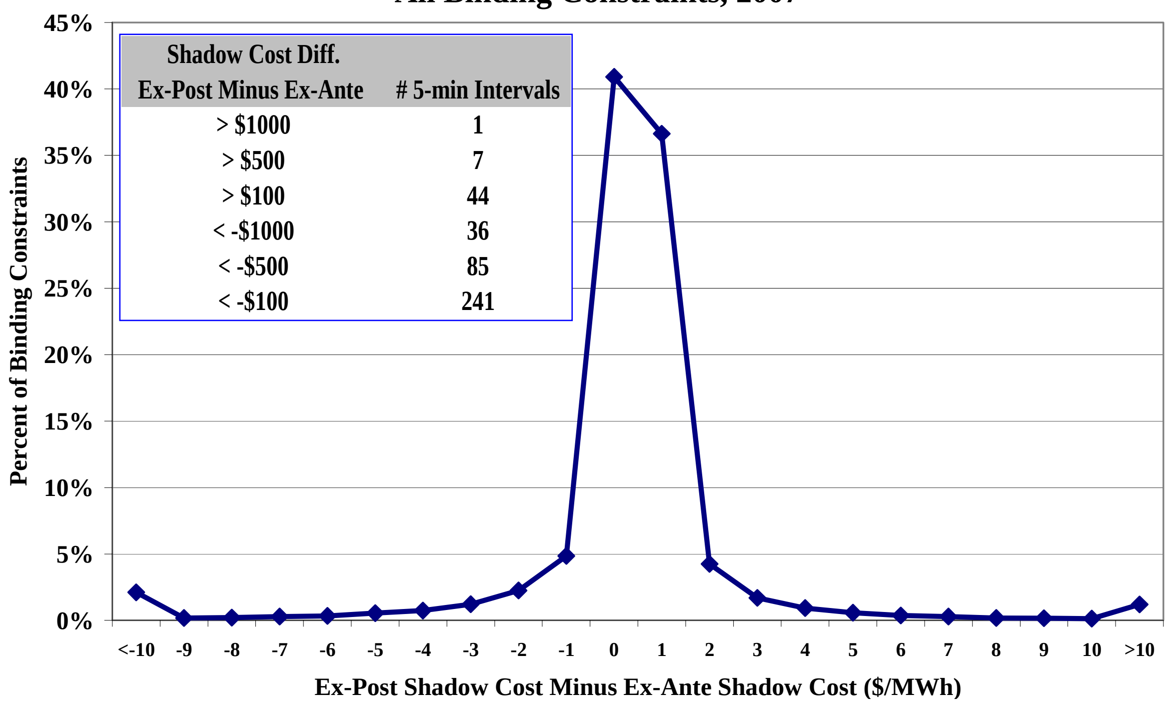
For example, suppose a combustion turbine with an incremental offer of $150 per MWh and an amortized start-up and no load cost of $100 per MWh is started in order to resolve a load pocket constraint. Suppose that there is also a $50 per MWh unit in the load pocket that is dispatched at

53 When a quick start unit is committed by UDS, its combined offer that adds its start-up and no-load cost on top of its incremental energy cost is used. In the ex post pricing, however, only its incremental energy offer is honored.

its maximum level. The ex ante LMPs in the load pocket will be $250 per MWh. Two pricing inefficiencies can occur in the ex post calculation. First, if the combustion turbine has not started because its start-up time has not elapsed or because it comes on late, the turbine will be deemed inflexible in the ex post calculation. This causes the $50 per MWh unit to set prices because it is the only flexible resource in the load pocket. Second, if the combustion turbine does start-up and is deemed flexible, the amortized start-up and no-load offers are not reflected in the current ex post pricing. As a result, the turbine would set a $150 per MWh ex post price in the load pocket. In either case, the ex post congestion value is substantially reduced, causing significant discrepancy between ex ante and ex post prices in the load pocket. In both cases, the marginal source of supply costs $250 per MWh and the ex ante price is therefore the efficient price.

The significance of this issue depends on the frequency of such instances. Figure 2 summarizes differences in constraint shadow prices between ex post and ex ante calculations in 2007. A positive value indicates a higher shadow cost in the ex post calculation. For example, the number “2” in X-axis means the ex post shadow cost is higher than the ex ante cost by $1 to $2.

Figure 30: Difference in Constraint Shadow Costs Between Ex Post and Ex Ante All Binding Constraints, 2007



The average difference was not significant in 2007. Nearly 97 percent of all differences were within ten dollars and more than 90 percent were within three dollars. However, there were a small number of intervals with substantial differences in congestion costs between the ex ante and ex post calculations. There are only 44 intervals during which ex post shadow prices were at least $100 per MWh higher than ex ante prices, and 241 intervals during which ex post shadow prices were at least $100 per MWh lower than ex ante prices.

Conclusion

Our evaluation of the ex post pricing results indicates that it:

- Creates a small upward bias in real-time prices in uncongested areas;
- Introduces small potential inefficiencies by setting prices that are not consistent with dispatch instructions; and
- Periodically distorts the value of congestion into constrained areas.

The most significant, and perhaps only, benefit of ex post pricing is that it allows the ISO to correct the real-time prices when the ex ante prices are affected by corrupt data or communication failures. Given the theoretical and practical problems with ex post pricing, we recommend that the ISO consider an ex post process that would utilize corrected ex ante prices for settlement, rather than the current ex post prices.

F. Real-Time Pricing and Performance – Conclusions and Recommendations

Efficient price formation is an important function of real-time market operations. Efficient real-time price signals provide incentives for suppliers to offer competitively, for demand response to participate in the wholesale market, and for investors to build capacity in areas where it is most valuable. Hence, efficient prices provide market participants with incentives that are compatible with the ISO's mandate to maintain the reliability of the system.

This section evaluates several aspects of real-time pricing in the New England market during 2007. Our evaluation leads to the following conclusions and recommendations:

- Price corrections were very infrequent, which is particularly notable since the implementation of the real-time reserve markets in October 2006 required significant changes to the market software. Major software deployments often lead to more frequent price corrections, supporting the conclusion that the real-time reserve market deployment and the overall operation of the real-time market system have been well-managed.

- Fast-start units are routinely committed and dispatched in merit order, but the resulting costs are not fully reflected in real-time prices. This leads to inefficiently low prices, particularly in areas that rely on fast-start units to manage local congestion.
  - ✓ We recommend that the ISO evaluate potential changes in the pricing methodology that would allow the deployment costs of fast-start units to be more fully reflected in the real-time market prices.
- The current operating procedures use the lowest-cost resources to maintain reliability when acute transmission constraints are binding. However, this process does not always result in efficient prices that accurately reflect operating conditions, and sometimes incurs excessive redispatch costs to manage a constraint.
  - ✓ We recommend that the ISO evaluate potential enhancements to current operating procedures that would establish reasonable Transmission Constraint Penalty Factors and allow them to set LMPs when a constraint is in violation.
- The recent surge in participation in demand response programs is a positive development that will reduce the cost of operating the system reliably, particularly during peak periods. However, the inflexibility of demand response resources creates challenges for setting efficient prices that reflect scarcity during periods when emergency demand response resources are activated.
  - ✓ We recommend that the ISO develop rules for allowing non-dispatchable demand response resources to set clearing prices when there is a capacity deficiency or when there would have been a deficiency without the activation of demand response resources.
- Finally, given the theoretical and practical problems with ex post pricing, we recommend that the ISO consider an ex post process that would utilize corrected ex ante prices for settlement, rather than the current ex post prices.

VIII. System Operations

The ISO ensures that sufficient resources will be available in the operating day to satisfy forecasted load and reserve requirements without exceeding the capability of the transmission system. The wholesale market is designed to help the ISO meet these requirements efficiently. In particular, the Day-Ahead Market and the Forward Reserve Market are intended to provide incentives for market participants to make resources available to meet these requirements. The day-ahead market clears physical and virtual load bids and supply offers, and produces a coordinated commitment of resources. The Forward Reserve Market provides suppliers with incentives to make reserve capacity available, particularly from off-line fast-start resources.

When the wholesale market does not meet all forecasted reliability requirements for the operating day, the ISO performs the RAA to ensure sufficient resources will be available. The primary way in which the ISO makes sufficient resources available is by committing additional generation. Such commitments generate expenses that are uplifted to the market and increase the amount of supply available in real-time, which depresses real-time market prices and leads to additional uplift. Hence, out-of-market commitment tends to undermine market incentives for meeting reliability requirements.

In this section, we evaluate several aspects of market operations that are related to the ISO's process to ensure that sufficient resources are available to meet the forecasted reliability requirements. In particular, we evaluate the following:

- Accuracy of Load Forecasting – The ISO's load forecasts are used by market participants to inform scheduling in the day-ahead market and by the ISO to determine the forecasted reliability requirements.
- Reliability Commitment – This section summarizes and evaluates reliability commitments, as well as the self commitment patterns that affect decisions made in the RAA.
- Out-of-Merit Generation and Uplift Expenses – These sections examine the by-products of out-of-market commitment.

A. Accuracy of ISO Load Forecasts

The ISO produces a load forecast seven days into the future and publishes the forecast on its website. This forecast is significant because market participants may use it and other available information to inform their decisions regarding:

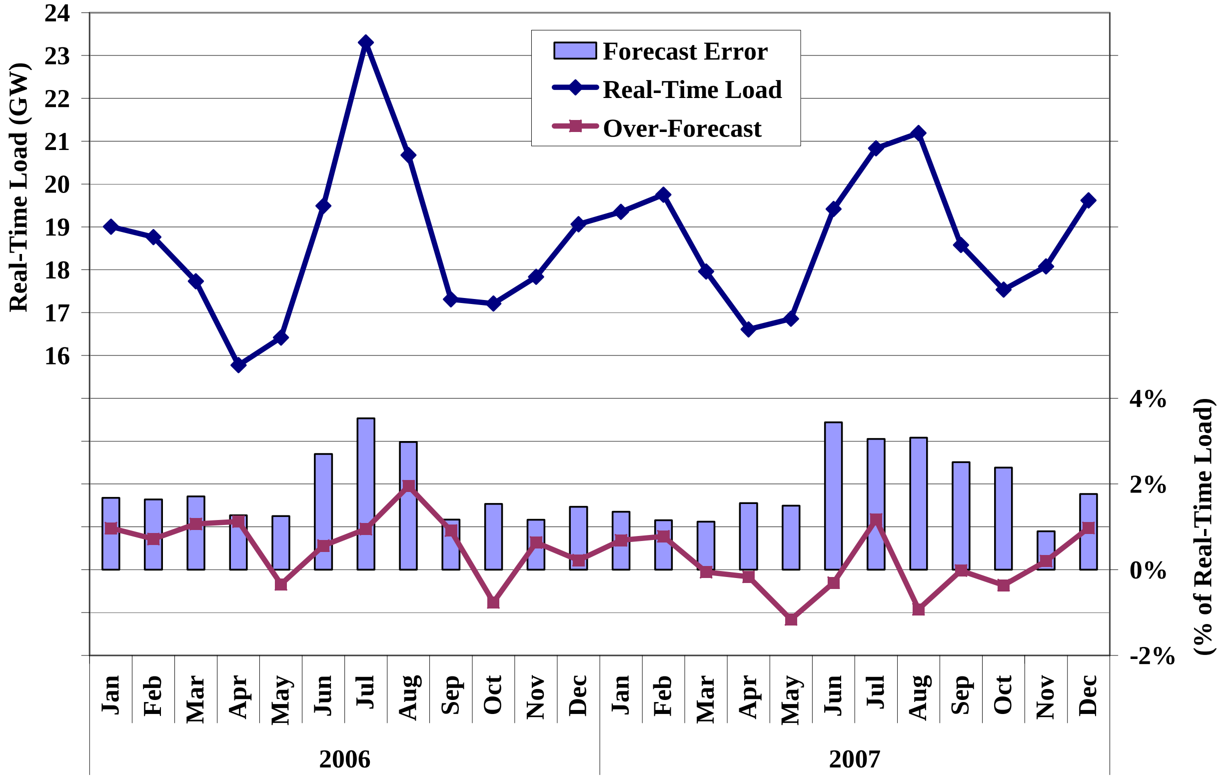
- Fuel procurement
- Management of energy limitations
- Formulation of day-ahead bids and offers; and
- Short-term outage scheduling.

In addition, the ISO uses the forecast to estimate the amount of resources that will be needed to satisfy load and reserve requirements without exceeding the capability of the transmission system. The day-ahead forecast is the most important because most scheduling and unit commitment takes place on the day prior to the operating day (either in the day-ahead market or in the RAA).

Accurate load forecasts promote efficient scheduling and unit commitment. Inaccurate load forecasts can cause the day-ahead market and/or the ISO to commit too much or too little capacity, which can affect prices and uplift. Therefore, it is desirable for the day-ahead forecast to accurately predict actual load.

Figure 31 summarizes daily peak loads and two measures of forecast error on a monthly basis during 2006 and 2007. The *Over-Forecast* is the percentage by which the average day-ahead forecasted daily peak load exceeded the average real-time daily peak load in each month. Positive values indicate over-forecasting on average and negative values indicate under-forecasting on average. The *Forecast Error* is the average of the absolute difference between the day-ahead forecasted daily peak load and the actual daily peak load, expressed as a percentage of the average actual daily peak load.

Figure 31: Average Daily Peak Forecast Load and Actual Load
Weekdays, 2006-2007



The figure shows a characteristic pattern of high loads during the winter and summer and mild loads during the spring and fall. The summer of 2006, which still holds the New England peak load record of 28.0 GW, experienced considerably higher load levels than the summer of 2007. The 2007 annual peak load of 26.2 GW occurred on June 27.

Forecasted load closely tracked actual load in most months of 2007. The monthly average over-forecast was generally close to zero, but ranged as low as -1.2 percent in May and as high as 1.2 percent in July. The annual average over-forecast was just 0.1 percent in 2007, down from 0.7 percent in 2006. Overall, the ISO's day-ahead load forecasts were highly consistent with actual load in 2007.

The figure also shows the average forecast error, which is the average of the absolute value of the difference between the daily forecasted peak demand and the daily 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 average forecast load would be the same as the average actual load. Our analysis shows that the forecast error as a percent of the actual peak demand averaged 1.8 percent in 2006 and 2.0 percent in 2007. On the basis of these results, we find that the load forecasting performance of the ISO remains good.

B. Commitment for Local Congestion and Reliability

In New England, several load pockets import a significant portion of their total electricity consumption. To ensure these areas can be served reliably, a minimum amount of capacity must be committed in the load pocket. Specifically, sufficient online capacity is required 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 the two largest contingencies;
- Support voltage in specific locations of the transmission system; and
- Manage constraints on the distribution system that are not modeled in the market software (known as Special Constraint Resources ("SCRs")).

In the day-ahead market, generators are scheduled based on the bids and offers submitted by buyers and sellers. A generator is committed when demand bids from load serving entities and virtual traders are high enough for the unit to be economic given its start-up, no-load, and incremental offer components. The willingness of load serving entities and virtual traders to buy (or sell) power in the day-ahead market is partly based on their expectations of LMPs in the real-time market on the following day. Thus, the day-ahead market commitment is strongly affected by expectations of real-time prices.

After the day-ahead market, the ISO may need to commit generation with high commitment costs to meet local reliability requirements. Once the commitment costs have been incurred, these generators may be inexpensive providers of energy and reserves in the local area. Because these commitment costs are not reflected in the market prices, the real-time LMPs frequently do not reflect the full value of on-line and fast-start capacity in local areas. Like any forward financial market, the day-ahead market LMPs tend to converge with the real-time LMPs. Hence, day-ahead LMPs also do not reflect the full value of on-line and fast-start capacity in local areas, which reinforces the tendency of the day-ahead market-based commitment to not satisfy local reliability requirements.

Given the effects of supplemental commitment on market signals, it is important to minimize these commitments while still maintaining reliability. Periodically, the ISO evaluates refinements to the procedures and tools used in the RAA to make the process more efficient. The ISO has also made market enhancements that better reflect local reliability requirements in the real-time market, reducing the need for supplemental commitment. Nonetheless, supplemental commitments are still frequently needed to meet local requirements, so it is important to continue evaluating potential market improvements. This section discusses several initiatives by the ISO to reduce the frequency and effects of supplemental commitment.

In this section, we examine several issues that are related to supplemental commitment for local reliability. This section:

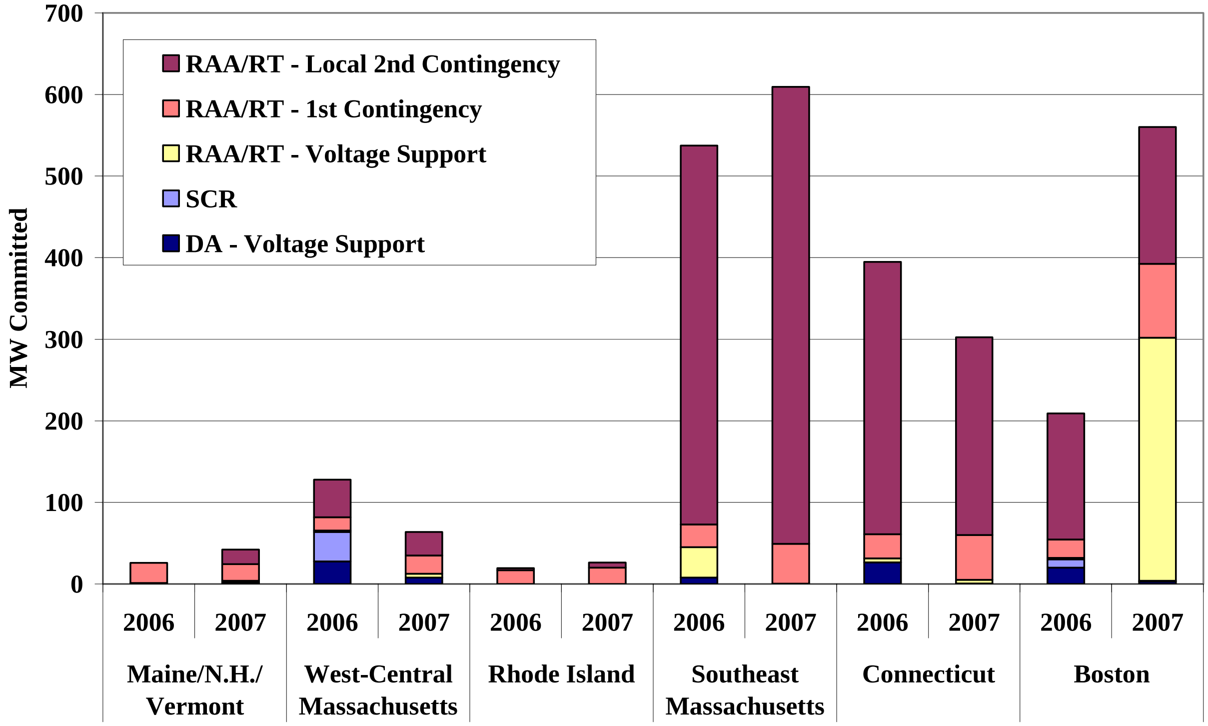
- Summarizes supplemental commitment for local reliability in the past two years;
- Evaluates the consistency of the ISO's operating procedures with decisions to commit resources for local second contingency protection in the RAA;
- Evaluates the accuracy of local second contingency transfer limits forecasted in the RAA which help determine the requirements in local areas; and
- Examines self scheduling behavior that affects decisions in the RAA.

1. Summary of Commitment for Local Needs

Figure 32 shows the average amount of capacity committed to satisfy local requirements in the daily peak load hour in each zone during 2006 and 2007.[54] The figure shows the entire capacity of these units, although their impact on prices depends on the amounts of energy and reserves they provide to the real-time market.

54 In accordance with its Tariff, the ISO-NE classifies certain day-ahead commitments as Local Second Contingency 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 32: Commitment for Local Reliability by Zone
Daily Peak Hour, 2006–2007



Note: Capacity committed day-ahead for voltage support that would have been economically committed in the day-ahead market is excluded from the figure.

In 2007, supplemental commitment declined significantly in Connecticut and West-Central Massachusetts, increased modestly in Southeast Massachusetts, and increased markedly in Boston. The increased supplemental commitment in Boston is particularly notable given that substantial import capability was added into the area in the spring of 2007. Due to the substantial increase of supplemental commitments in Boston, total supplemental commitments increased 22 percent overall, from an average of 1,310 MW in 2006 to 1,600 MW in 2007.

In SEMA, supplemental commitment is frequent because the units needed to ensure local reliability in the Cape Cod area are usually not economic at day-ahead price levels. The ISO maintains sufficient reserves to respond to the two largest local contingencies without relying upon load shedding, which usually requires at least one of the units at the Canal plant to be online. Before 2006, these units were often committed economically in the day-ahead market, but changes in fuel prices and offers led these units to be economically committed less frequently in the day-ahead market. Hence, the units have been supplementally committed more frequently and have received higher NCPC payments since 2006.

Upgrades to the transmission system in lower SEMA are planned to come in-service during 2009. These upgrades will substantially reduce the frequency with which the ISO will need to commit generation for local reliability in this area and the associated uplift costs.

Despite substantial transmission upgrades into Boston in the spring of 2007, supplemental commitment for voltage support increased in that area in 2007. This increase is largely attributable to a change in behavior by the largest supplier. Starting in early 2007, the supplier began to raise its day-ahead offer prices to avoid commitment in the day-ahead market. This frequently required the ISO to commit some of the supplier's capacity for local reliability, primarily voltage support. In 2006, most of this supplier's capacity was covered by a reliability agreement. Since the reliability agreement stipulated that the capacity be offered at marginal cost, the units were usually committed in the day-ahead market and there was little need to supplementally commit units in Boston. This behavior is discussed in greater detail later in Part 4 of this section.

Commitments in the Boston area for local reliability are expected to be much less frequent in 2008. Following transmission upgrades that were made in the spring 2007, the ISO worked with NSTAR to revise the reliability requirements for Boston-area voltage. As a result of these revisions, fewer commitments have been necessary to support voltage in Boston since April 2008. Later in this section, we address how the changes in the reliability requirements are likely to affect the behavior of the largest supplier in Boston.

The ISO has implemented two recent market design changes to reduce the need for supplemental commitment. First, the ISO implemented Flexible Combined Cycle Modeling in December 2007, which allows market participants to offer their combined cycle units under different configurations. This enables owners of combined cycle resources to offer their units more efficiently in the day-ahead market. This change also allows the owners to offer non-spinning reserves from offline combined cycle units in some cases.

Second, the ISO began to operate a Real-Time Reserve Market and a Forward Reserve Market with locational requirements in October 2006. Reserves are needed in the local areas to meet local second contingency protection requirements. Due to the limited quantity of fast-start resources in these areas, a large portion of these reserves must be held by online resources. The introduction of the real-time reserve markets increases the likelihood that market-based commitments will satisfy local requirements and reduces reliance on supplemental commitment. These markets also provide economic signals supporting investment in new fast-start resources in these areas, which would reduce the frequency and quantity of supplemental commitment.

In addition to these recent changes, the ISO is currently evaluating two additional changes that should reduce the amount of supplemental commitment for local reliability and associated uplift costs. First, we are working with the Internal Market Monitoring Unit to assess whether the mitigation measures should be modified to more effectively address cases where suppliers raise their offers above marginal costs to extract larger NCPC payments. The second change is to market rules relating to self-scheduling after the start of the RAA. In some cases, self-scheduling after the RAA can cause the RAA to make unnecessary supplemental commitments, leading to excess capacity and depressed price signals. We support both of these efforts and discuss them in greater detail in Part 4 of this section.

The ISO has already implemented or plans to implement several initiatives that should help reduce the need for supplemental commitment in the future. However, if substantial amounts of supplemental commitment remain necessary, we it may be beneficial to integrate local capacity requirements in the day-ahead commitment software. To the extent that local capacity requirements can be forecasted accurately, it is most efficient to commit units for local reliability in the day-ahead market. This allows the day-ahead market software to determine the optimal solution, taking into account the commitments that are needed to meet local requirements. When an additional resource is committed supplementally after the day-ahead market, one or more units that were committed in the day-ahead market may no longer be efficient to commit. Such units contribute to over-commitment, which depresses market signals and reinforces the need for supplemental commitment.

The supplemental commitments in Boston, Connecticut, and Lower SEMA have contributed to low levels of congestion in these areas. In Section C, we examine how much energy is dispatched out-of-merit as a result of these supplemental commitments.

2. Evaluation of Second Contingency Commitments

Supplemental commitment for local reliability can significantly affect market outcomes in constrained areas, so it is important that such commitments be made only when actually needed for reliability. This part of the section summarizes our evaluation of the consistency of the ISO's operating procedures with its decisions to commit generation for local second contingency protection.

The ISO's operating procedures explain the RAA process and the criteria for committing generation for local reliability.[55] Normally, the ISO waits until the close of the Re-Offer Period at 6 pm on the day-ahead of the operating day before determining whether additional resources are needed for reliability. However, the assessment of local requirements may occur earlier "when it is recognized that required resources have long notification and start-up times."[56] When the amount of capacity that is required to meet the local second contingency requirements exceeds the amount of capacity that is expected to be online, the ISO commits additional generation. The amount of capacity required to meet the local second contingency requirements is calculated using the RMR Calculation Worksheet. The amount of capacity that is expected to be online is the sum of the generation that was committed in the day-ahead market, self-scheduled during the Re-Offer Period, or committed already for another reliability reason.

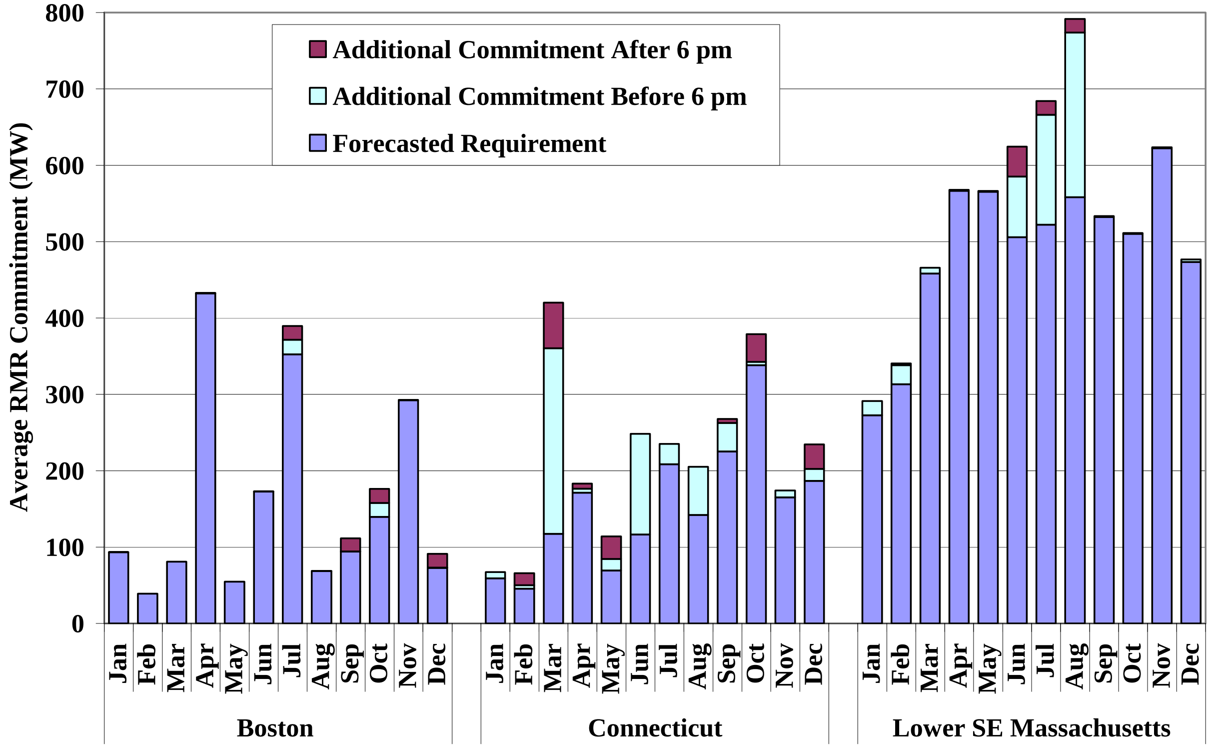
We evaluated local second contingency commitments that occurred on the day or evening prior to the operating day in Connecticut, Boston, and SEMA in 2007. The evaluation separated the second contingency commitments into (i) commitments that were needed to meet the forecasted second contingency requirements for one or more local areas as calculated in the RMR

55 See SOP-RTMKTS.0050.0010 – *Perform Reserve Adequacy Assessment* and SOP-RTMKTS.0050.0005 – *Determine Reliability Commitment for Real-Time*.

56 See Section 5.1.2 in SOP-RTMKTS.0050.0005.

Calculation Worksheet[57] and (ii) additional commitments that were made in excess of those requirements.[58] The additional commitments were further separated according to whether they occurred before or after 6 pm. Figure 33 shows the results of the evaluation. The results for areas in Connecticut are shown together, although Connecticut contains four nested local second contingency protection areas: Norwalk-Stamford, Southwest Connecticut, West Connecticut, and Connecticut.

Figure 33: Evaluation of Local Second Contingency Commitments 2007



Local second contingency commitments averaged 171 MW per day in Boston, 238 MW per day in Connecticut, and 543 MW per day in SEMA. The majority of capacity committed for local second contingency protection was necessary given the forecasted requirements for the following

57 This evaluation used the requirements calculated in the final RMR Calculation Worksheet.

58 If only a portion of a second contingency protection resource is needed to meet the forecasted second contingency requirements calculated in the RMR Calculation Worksheet, the entire unit is categorized as satisfying the second contingency requirement.

day. Additional commitments that did not appear necessary to satisfy the local requirements in the RMR Calculation Worksheet represented 8 percent of the commitments in Boston, 35 percent of the commitments in Connecticut, and 9 percent of the commitments in SEMA.

Additional commitments are made for a variety of reasons, including concern by the operators regarding the forecasted peak load in the constrained area, uncertainty about the status or availability of a key resource in the area, and doubt regarding fuel supplies to some generation. In some cases, additional commitments are made to provide second contingency coverage to local areas that are not covered by the RMR Calculation Worksheet.[59] Additionally, when some candidates for reliability commitment have long notification times or start-up times, the ISO may need to commit resources prior to the close of the Re-Offer Period or the day-ahead market. At this point, there is less certainty about the need for additional resources. Figure 33 shows that more than three-quarters of the additional commitments were made before the close of the Re-Offer Period, indicating that long notification times and start-up times likely affected the amount of additional commitments.

To the extent that some commitments are not necessary to maintain reliability, the ISO should seek ways to minimize them in the future because they can inefficiently mute congestion into the constrained areas. In Section V, we evaluate the effects of excess capacity on reserve clearing prices in local areas in 2007 and find that modest amounts of excess capacity can have substantial effects on clearing prices.

Even when local second contingency commitments are necessary based on forecasted operating conditions, there are several other factors that contribute to excess capacity in 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 local second contingency requirement in a particular hour. Increased reliance on small-scale, fast-start resources in the future should reduce this

---

59 See Section 5.5.6 in SOP-RTMKTS.0050.0005, which describes the use of special studies for such local areas. The procedure for conducting special studies is outlined in SOP-OUTSCH.0050.0020 – *Perform Complex Studies*.

source of over-commitment. Second, sometimes suppliers self-commit after the ISO commits resources to meet local second contingency requirements, making some of the commitments by the ISO no longer necessary to satisfy the local second contingency requirement. Self-commitments are examined further in Part 4 of this section.

3. Forecasted Local Second Contingency Requirements

In the RAA, the ISO ensures that sufficient resources will be available to meet the forecasted load and reserve requirements during the current and next operating day. The ISO determines the generation and reserve needs in each local area based on forecasted load in the area, the Current Operating Plan, and forecasted transmission capability into the area.[60] Therefore, supplemental commitment decisions partly depend on the forecasted transmission capability. Over-forecasting the transfer capability of an interface can cause under-commitment inside the load pocket. Conversely, under-forecasting the transfer capability leads to over-commitment within the load pocket. Thus, it is important to forecast accurately factors that affect the capability of the transmission system.

In these areas, the required amount of internal generation and reserves depends on the local second contingency operating criteria as follows:

$$\text{Internal Load minus Internal Supply} \leq \text{Second Contingency Limit}$$

Internal supply includes generation, online reserves, and offline reserves capable of producing within 30 minutes. The Second Contingency Limit is the lower of (i) the Second Line Contingency Limit, which is the maximum amount of power that could be imported if the two largest line contingencies were to occur, and (ii) the Second Generator Contingency Limit, which is the maximum amount of power that could be imported if the largest line and generator contingencies both occur, minus the largest generator contingency.

The same methods are used for calculating Second Contingency Limits in the RAA and real-time market. However, real-time capability is estimated based on actual operating conditions, while

60 The Current Operating Plan includes the list of generators that are expected to be online or available to provide reserves while offline.

the capability in the RAA is estimated from forecasts of the next day's operating conditions. Differences between the RAA and the real-time market regarding the following factors can lead to differences in estimated transfer capability:

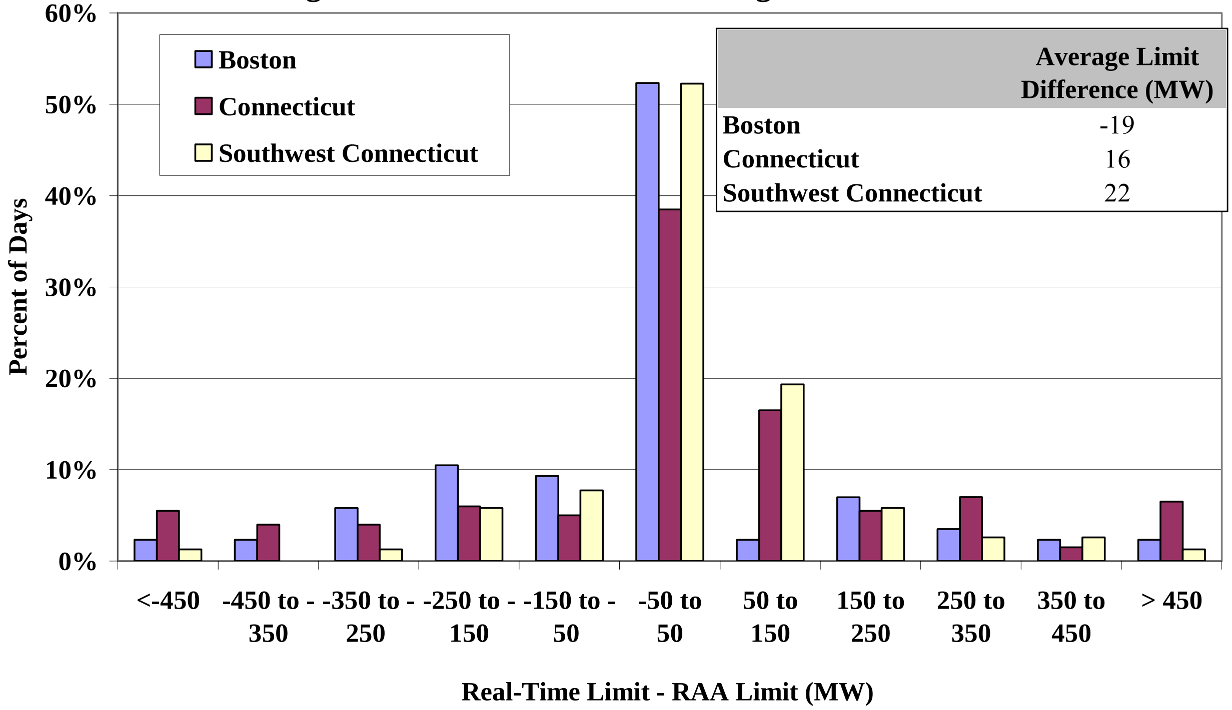
- The thermal limits of individual elements that make up the interface;
- Outages of key transmission lines;
- The commitment status of generators that influence the distribution of real power and/or reactive power flows across the interface;
- The size of the largest generator contingency; and
- The amount of load that can be shed in the event of a contingency.

There will always be differences between forecasted and actual conditions that will give rise to differences in the transfer capability between the RAA and real-time market. In general, these differences should be random and result in relatively small differences in the RAA and real-time transfer capabilities. In some cases, reliability concerns related to unknown factors in the RAA process may justify use of conservative assumptions that would cause RAA transfer capability to be lower than real-time transfer capability.

Figure 34 summarizes the differences between RAA and real-time transfer capability for three key interfaces. For each interface, we evaluated differences in the daily peak load hour on days in 2007 when local second contingency commitments occurred in the local area, excluding commitments that were reflected in the day-ahead market. This included 86 days for Boston, 200 days for Connecticut, and 155 days for Southwest Connecticut. A positive value in the chart indicates that more transfer capability was available in real-time than was estimated to be available in the RAA.

The limit differences were within 50 MW in more than 50 percent of the examined hours in Boston and Southwest Connecticut and in nearly 40 percent of the examined hours in Connecticut.

Figure 34: Differences between Real-Time and RAA Limits
Average Real-Time Limit minus Average RAA Limit, 2007



The inset table shows that the average RAA limit has been comparable to the average real-time limit for all three interfaces, providing no indication that systematic differences were significant during 2007. Hence, we find no significant bias in the direction of changes between the RAA and real-time that would lead to systematic over or under-commitment.

There were a limited number of instances when the differences between the RAA limit and the real-time limit were significant. Connecticut, which had differences exceeding 250 MW on 29 percent of the days shown, exhibited the widest distribution of differences among the three interfaces. Overall, the differences were small given the uncertainties faced in the RAA. Nevertheless, such differences can lead to over-commitment or under-commitment, so it is important to identify ways to improve the accuracy of the forecasted limits.

Currently, the ISO is in the process of upgrading the software tools used to calculate these transmission limits. The new PowerWorld based application replaces older software which required more manual steps, reducing the total calculation time from hours to minutes. The new software is expected to provide:

- Greater accuracy by using a full AC model for all stages of analysis;
- Less dependence on subjective factors since more of the critical inputs to the calculation are pre-defined;
- Increased reliability by allowing the user to run many more scenarios to cover possible uncertainties in the system model;
- Reduced need for ISO employees to perform manual calculations; and
- More capability to re-run studies in case of last minute changes in the system conditions.

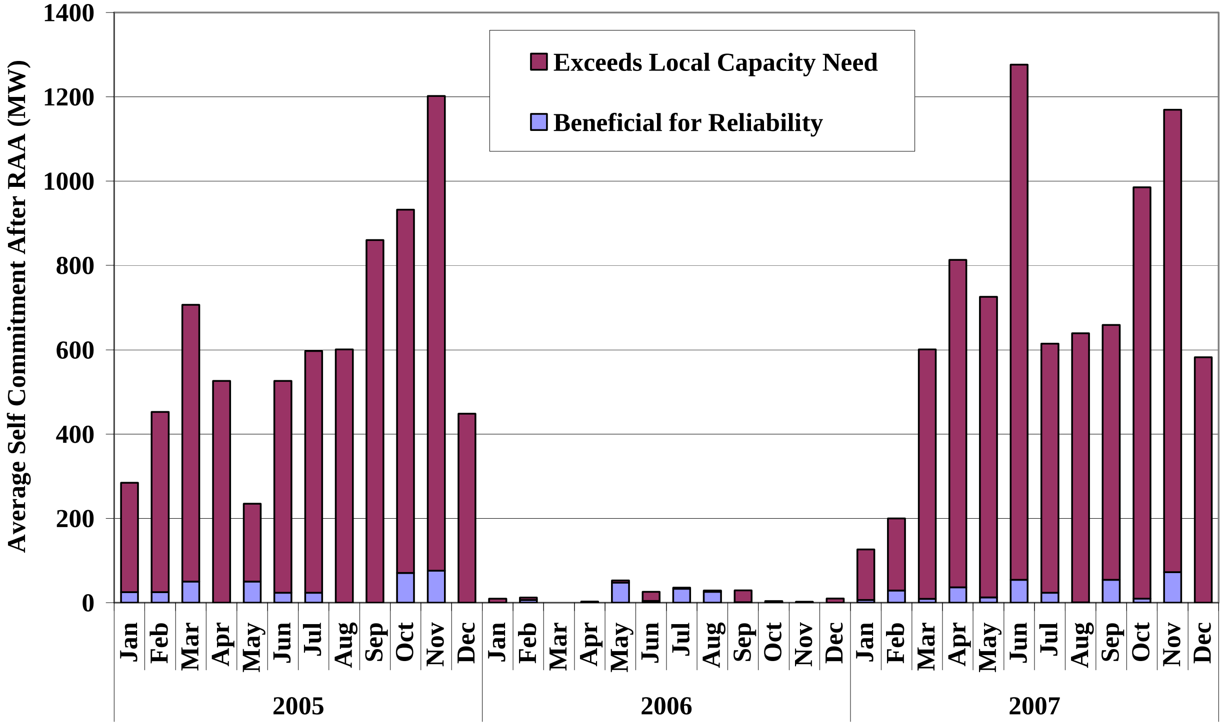
We support the ongoing efforts of the ISO to improve the tools it uses to establish the transfer limits.

4. Self-Commitment after the RAA

Before committing resources to provide local second contingency protection, the ISO calculates the amount capacity that is expected to be online based on the Current Operating Plan. Depending on the timing of the calculation, this may include capacity committed: (i) through the day-ahead market, (ii) day-ahead for voltage support or other reliability reasons, (iii) in the Re-Offer Period by a self-schedule, and (iv) in the RAA for reliability reasons. If the ISO is short of the local capacity requirement, it will commit additional resources. However, if a supplier self-commits a generator after local second contingency protection resources are committed in the RAA, it can lead to excess capacity in the load pocket. This excess creates uplift because it leads to local second contingency protection commitments that would not have been necessary if the ISO had been aware of all self-commitments when it conducted the RAA. This section evaluates self-commitments occurring after the RAA.

In recent years, Boston has been the only area where substantial amounts of capacity have been committed by self-schedules after the RAA. Figure 35 summarizes the extent to which self-commitment after the RAA has helped meet remaining local second contingency requirements in Boston versus how often it has led to excess capacity.

Figure 35: Self Commitment after the Resource Adequacy Assessment
Boston – January 2005 to December 2007



In Boston, the average amount of capacity self-committed after the RAA process has varied dramatically since January 2005. The quantity of self-commitments was considerable in 2005. It decreased almost to zero in 2006, but resumed in 2007. This pattern is primarily attributable to a change in behavior by a single supplier. In 2005, the supplier usually raised its day-ahead offer prices above marginal cost to avoid market-based commitment in the day-ahead market. This frequently required the ISO to commit some of the supplier's capacity for local reliability. In 2006, the ISO signed a reliability agreement with the supplier that covered most of the supplier's capacity. The reliability agreement stipulated that the supplier's capacity be offered in the day-ahead market at marginal cost. As a result, these units were committed in the day-ahead market on most days because they were usually economic. In 2007, the reliability agreement expired, and the supplier resumed the conduct it exhibited in 2005.

Our analysis indicates that only a small quantity of the self commitments were needed to meet the local capacity requirement. It can be efficient to have more than the minimum capacity required in each local area, but a large share of these self-commitments occurred after the ISO had already committed units for local second contingency protection. If the ISO had known for certain that these units would be self scheduled, it would not have needed to commit as many units for local second contingency protection. 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, this process has not been fully effective because self-commitments frequently occur after it is too late to de-commit other resources.

Self-commitment after the RAA can lead to excess capacity and inefficient market outcomes in constrained areas. The excess capacity mutes congestion into the load pocket, depressing real-time prices and increasing uplift costs. Additionally, this type of self-commitment undermines convergence between day-ahead and real-time prices, because load serving entities do not always accurately predict the amount of capacity that will be self-scheduled.

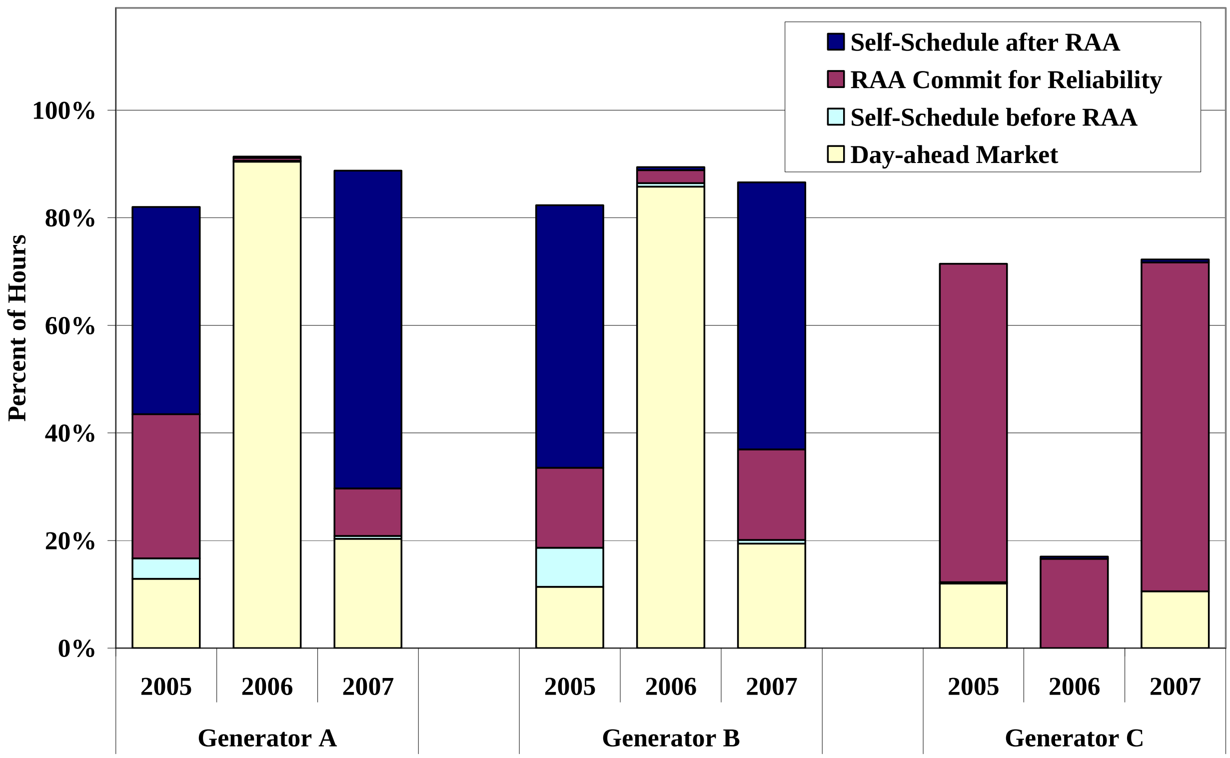
While there are some legitimate reasons for self commitment after the RAA (e.g., suffering a forced outage on a unit that had been scheduled in the day-ahead market), the rise in this activity is also consistent with incentive problems that result from frequent supplemental commitment in an area with high market concentration.[61] In Boston, local reliability requirements are frequently satisfied outside the normal 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 in competitive markets, units with pay-as-bid incentives rationally offer above marginal cost. Suppliers with generation that is frequently committed for local reliability often have some degree of local market power and a greater incentive to offer above marginal cost. Generally, if such suppliers submit high-priced offers in the RAA and their generators are not committed, they risk foregoing the profitable opportunity to sell energy in the real-time market. However, this risk does not exist for suppliers that have generators flexible enough to self-commit after the RAA.

If the rise in self commitment after the RAA in 2007 was caused by inefficient incentives, the supplier with generators that were frequently self-committed after the RAA would also have generators that were frequently committed for local reliability. Figure 36 shows the pattern of

61 Boston-area market concentration is summarized in Section IX.B.

commitment of three generating units owned by one supplier from 2005 to 2007. Generators A and B accounted for virtually all of the capacity self committed after the RAA in Boston in 2005 and 2007. Generator C was rarely committed in the day-ahead market for economics, but was frequently committed for local reliability.

Figure 36: Commitment Patterns of Three Generators in Boston Frequency and Reason for Commitment, 2005–2007



The figure shows that Generators A and B were committed in approximately 87 percent of the hours over the 36 month period, although the way in which they were committed varied significantly. In 2006, the two generators were covered by a reliability agreement, which required that the generators be offered at levels consistent with marginal cost. This led the units to be committed through the day-ahead market, thereby reducing the need to commit units in the Boston area for local first contingency protection, second contingency protection, and voltage support. As a result, Generator C, which is less economic than the other two generators, was committed for local reliability infrequently during 2006.

When Generators A and B were not covered under the reliability agreement, they were committed in the day-ahead market or self-scheduled prior to the RAA only 18 percent of the time in 2005 and 20 percent of the time in 2007. In the remaining hours, these generators were sometimes committed for reliability in the RAA process. When these units were not committed day-ahead or in the RAA, they were usually self-scheduled after the RAA. This indicates that the owner deemed them to be economic at the expected real-time prices. Since the ISO could not be certain whether Generators A and B would be online on the following day, the ISO committed Generator C for local reliability on more than 70 percent of the days in 2005 and 2007.

As described above, some of the commitments made in the RAA become unnecessary after additional units are self committed. This excess capacity depresses real-time prices and results in additional uplift costs. These effects would be avoided if the units were committed in the day ahead market or self-committed prior to the RAA. However, suppliers frequently committed for local reliability have an incentive to wait until after the RAA to self-commit their units because it allows them to sometimes be committed by the ISO in the RAA and receive NCPC payments.

This pattern of self-commitment is not expected to continue in 2008 due to changes in operations. Following the transmission upgrades that were made in the spring 2007, the ISO worked with NSTAR to revise the operating guide for Boston-area reliability. As a result, fewer commitments have been necessary to support voltage in Boston since April 2008. The reduced commitment for reliability has led the owner of Generators A, B, and C to offer more of its generation closer to marginal cost in the day-ahead market. This is expected to substantially reduce commitments for local reliability and the excess capacity in the Boston area.

The ISO is currently working on two initiatives that would better address the incentives that led to the inefficient pattern of self-commitment in Boston. First, we are working with the Internal Market Monitoring Unit to evaluate whether the mitigation measures should be modified to more effectively mitigate suppliers to raise their offers above marginal costs to extract larger NCPC payments. In general, this change involves reducing the conduct and impact thresholds applied to determine when mitigation should be applied to units receiving NCPC payments. Tightening these thresholds would reduce the expected profits from engaging in behavior to increase NCPC payments. Hence, we support the efforts of the ISO to reduce the mitigation thresholds in areas with frequent commitment for local reliability.

Second, the ISO is evaluating whether market rule changes are necessary to address the problems that arise from self-scheduling after the start of the RAA. In Boston, self-scheduling created uncertainties that led the ISO to commit generation for local reliability when it was not necessary in light of subsequent self-commitments. These unnecessary commitments led to excess capacity and depressed price signals. However, self-commitment can be an efficient response to changing market conditions by generators with short to medium start-up times in some cases. We support the ISO's effort to improve the market rules and incentives governing self-commitment.

5. Local Reliability Commitment – Conclusions

The analysis in this section highlights changes in the supplemental commitment patterns and supports several conclusions. Commitment for local reliability declined in 2007 in some areas, but became much more common in Boston despite substantial transmission upgrades in the spring of 2007. In Boston, supplemental commitment increased due to a change in behavior by the largest supplier after the expiration of its reliability agreement. In 2008, commitment for Boston-area reliability is expected to be much less frequent due to changes in the operating procedures and requirements for Boston.

Lower SEMA continues to require one of two large units to be committed almost continuously for local second contingency protection to ensure reliability for the Cape Cod area. Transmission upgrades planned for 2009 are expected to substantially reduce the frequency of these commitments and the resulting uplift charges.

In this section, we found that the majority of the commitments by the ISO for local second contingency protection were necessary to meet forecasted minimum capacity requirements in constrained areas. This is important because unnecessary commitment depresses economic signals in constrained areas. We also found that the forecasted transfer limits used in the RAA were generally consistent with the real-time limits. To the extent that there were inconsistencies, the forecasted limits were not systematically higher or lower than the real-time limits.

The last analysis in this section finds that self commitment after the RAA process was the primary contributor to excess capacity in Boston in 2007. This is not expected to continue in 2008 because the ISO has modified its local reliability requirements so that the incentive for the supplier to self-commit after the RAA should be eliminated.

At the end of this section, we describe recent changes made by the ISO and recommend a limited number of additional changes that should improve the local reliability commitment results in the future.

C. Out-of-Merit Dispatch

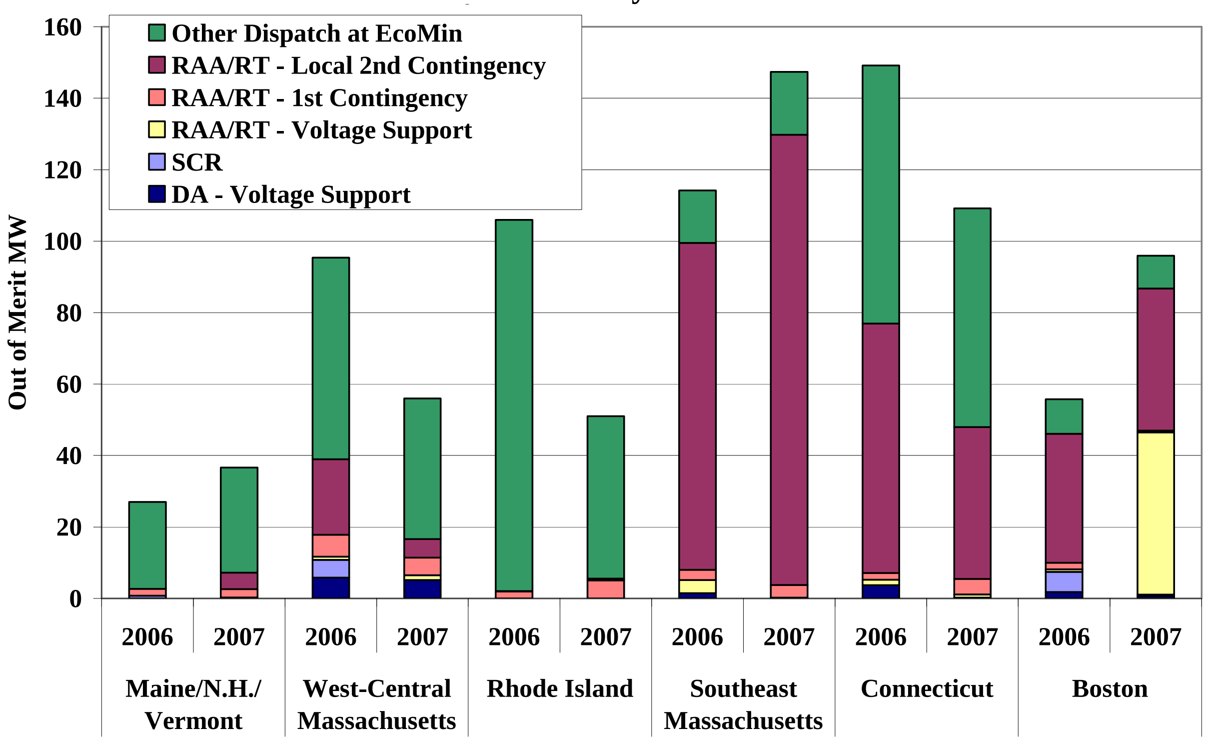
Out-of-merit dispatch occurs in real time when energy is produced from an output range on a unit whose incremental energy offer is greater than the LMP at its location. Out-of-merit generation tends to reduce energy prices by causing lower-cost resources to set the energy price. In a very simple example, assume the two resources closest to the margin are a $60 per MWh resource and a $65 per MWh resource, with the market clearing price set at $65 per MWh in the absence of congestion and losses. When a $100 per MWh resource is dispatched out-of-merit, it will be treated by the software as a must-take resource with a $0 per MWh offer. Assuming the energy produced by the $100 per MWh resource displaces all of the energy from the $65 per MWh resource, the energy price will decrease to $60 per MWh.

A unit may be dispatched out-of-merit for three reasons. First, a unit may run at its EcoMin to satisfy its minimum run time after having run in-merit in previous hours or in anticipation of running in an upcoming hour. 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 are committed for reliability without regard for their incremental offers above EcoMin and are, therefore, more likely than units committed in the day-ahead market to have incremental offers higher than the LMP.

Third, a unit may be dispatched 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 37 summarizes the average out-of-merit dispatch by location for peak weekday hours (6 AM to 10 PM) during 2006 and 2007.

Figure 37 shows that virtually all of the out-of-merit dispatch outside of the constrained areas is attributable to non-local reliability units being dispatched at EcoMin. However, in Boston, SEMA, and Connecticut, most of the out-of-merit dispatch is from units committed in the RAA for local reliability.

Figure 37: Average Hourly Out-of-Merit Dispatch
2005 & 2006 – 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.

The average quantity of out-of-merit dispatch from units committed for local reliability (including first contingency, second contingency, voltage support, and SCR) increased modestly from an average of 266 MW in 2006 to 294 MW in 2007. The amount of out-of-merit energy from non-local reliability units (i.e. Other Dispatch at EcoMin) declined significantly from an average of 281 MW in 2006 to 202 MW in 2007. The "Other Dispatch at EcoMin" category arises partly as a result of the excess capacity that is discussed in the prior sub-section. Excess capacity tends to increase the supply on the system and causes higher-cost resources to reduce their output to EcoMin.

The changes in out-of-market dispatch that occurred in 2007 track the changes in supplemental commitments and were caused by the same underlying factors. The reduced commitment for local second contingency requirements in West-Central Massachusetts and Connecticut led to proportionate reductions in out-of-merit energy in those zones. The increased commitment for voltage support in Boston led to increased out-of-merit dispatch on generators committed for that reason. The second contingency requirements in SEMA continue to result in a substantial amount of out-of-market dispatch in that area.

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 and reserves prices. Furthermore, owners of units that are frequently called out-of-merit order face incentives to offer in excess of marginal costs, which can result in less efficient commitment and dispatch decisions. In addition, when units are offered above marginal costs, it reduces the likelihood that they will be committed economically through the day-ahead market, and increase the need for supplemental commitments. Hence, the pattern can be self-reinforcing.

D. Uplift Costs

To the extent that the wholesale market does not satisfy New England's reliability requirements, the ISO takes additional steps to ensure sufficient supplies are available. The ISO has used reliability agreements and supplemental commitment to ensure reliability, primarily in local import-constrained areas. Reliability agreements give the owners of uneconomic generating facilities supplemental payments in order to keep them in service. Supplemental commitments bring uneconomic capacity online at times when market clearing prices are insufficient. Such generators receive additional payments called NCPC payments, which make up the difference between their accepted offer costs and the market revenue. The costs associated with these payments are recovered from market participants through uplift charges. This section describes the main sources of uplift charges and how they are allocated among market participants.

The following table summarizes several categories of uplift during 2006 and 2007. The main categories of uplift are:

- Reliability Agreements – The uplift from these are allocated to Network Load in the zone where the generator is located.[62] In 2007, 39 percent of the capacity in Connecticut was covered under reliability agreements. The amount of capacity in Boston covered under reliability agreements declined from 62 percent in 2006 to 0 percent by the end of 2007 due to transmission upgrades into Boston and the start of capacity transition payments.
- Local Second Contingency Protection Resources – In 2007, 98 percent of the uplift from these units was allocated to Real-Time Load Obligations and Emergency Sales in the zone where the generator is located.[63] The remaining uplift associated with day-ahead rather than real-time commitments was allocated to day-ahead load schedules in the local zone.
- Special Constraint Resources – The uplift paid to these resources is allocated to the Transmission Owner that requests the commitment.
- Voltage Support Resources – The uplift paid to these resources are allocated to Network Load throughout New England and Through-and-Out transactions.
- Other supplemental commitment (including local first contingency resources) – In 2007, 90 percent of this uplift was allocated to Real-Time Deviations throughout New England.[64] The remaining uplift associated with units committed the in day-ahead market is allocated to day-ahead scheduled load throughout New England.

The vast majority of uplift in each of these categories is incurred to address local supply inadequacies. For this reason, it is generally appropriate to allocate these charges to the local customers who derive benefit from their service. The first three of these categories are allocated

62 Network Load includes transmission customers that are served by the Transmission Owner.

63 Real-Time Load Obligations includes load customers that are served by the Load Serving Entity.

64 Real-Time Deviations include Real-Time Load Obligation Deviations, which are positive or negative differences between day-ahead scheduled load and actual real-time load; generation deviations from day-ahead schedules, which include virtual supply schedules; and generation deviations from the larger of the unit's Economic Minimum and desired dispatch point in each hour.

on a local basis, while the uplift charges for Voltage Support Resources and other supplemental commitment are allocated to customers throughout New England.

The following table summarizes the total costs of uplift associated with reliability agreements and supplemental commitment.

Table 6: Allocation of Uplift for Out-of-Market Energy and Reserves Costs 2006 & 2007

	Millions of Dollars	
Category of Uplift	**2006**	**2007**
Reliability Agreement		
Connecticut	**$223**	**$115**
Boston	**$194**	**$3**
Other Areas	**$65**	**$25**
Local Second Contingencies		
Connecticut	**$60**	**$35**
Boston	**$33**	**$22**
Southeast Massachusetts	**$85**	**$108**
Other Areas	**$3**	**$4**
Special Case Resources	**$9**	**$2**
Voltage Support	**$19**	**$46**
Other (Mostly Local First Contingencies)	**$25**	**$29**
Total	**$715**	**$390**

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 Boston, Connecticut, and other areas.

In 2007, uplift costs totaled $390 million, a decrease from 2006 of 45 percent. This reduction was driven by a $339 million decline in reliability agreement costs. Some of the changes in supplemental commitment patterns from 2006 to 2007 led to corresponding changes in uplift. In Connecticut, the decreased commitment for local second contingency protection drove a $25 million reduction in uplift. The more frequent commitment of generation for voltage support in Boston associated with the conduct described earlier in the report led to a $27 million increase in uplift for voltage support.

The reliability agreement costs decreased due primarily to:

- Transmission upgrades placed in-service during 2007 have enabled the ISO to reduce the portion of Boston capacity under reliability agreements from 62 percent in 2006 to zero by the end of 2007.
- The capacity Transition Payments that began in December 2006 have contributed to the revenue requirements of generation under reliability agreements. The additional capacity revenue reduces the amount of revenue paid under the reliability agreements.

The transition to a forward capacity market with locational price signals will help New England shift away from relying on reliability agreements to meet resource adequacy criteria in the future. Reliability agreements provide additional payments to the least economic resources in the market and do not provide incentives for efficient investment. By compensating all resources in a particular area consistently, capacity markets provide more efficient signals for investment.

Section B discusses several initiatives, either recently implemented or under development, that should help reduce the uplift that arises from supplemental commitment in the next few years. Transmission upgrades have allowed better operating procedures for Boston, reducing the need to commit generation for voltage support in 2008. Transmission upgrades planned for 2009 should greatly reduce the frequency of commitment for local second contingency protection in SEMA. The ISO is evaluating potential rule changes pertaining to mitigation of suppliers that are frequently committed for local reliability, and to self-commitment by suppliers after the RAA. These changes should reduce the ISO's uplift costs.

E. System Operations – Conclusions and Recommendations

In general, we conclude that the ISO's operations to maintain adequate reserve levels in 2007 were reasonably accurate and consistent with the ISO's procedures, although substantial quantities of supplemental commitment continue to occur in several constrained areas of New England. These commitments are necessary because the areas do not have a large quantity of fast-start resources that can help meet the capacity requirements of the local area while offline and the energy and reserves prices in these areas are usually not high enough to support the running costs of the non-fast-start units that are committed for local reliability.

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

- Inefficiencies created 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.
- Dampening of economic signals to invest in areas that would benefit the most from additional investment in generation, transmission and demand response resources.
- Larger and more volatile uplift costs that are difficult for participants to hedge.
- Incentives for generators frequently committed for reliability to avoid market-based commitment to seek additional payments through the reliability commitment process.

The ISO has implemented or is pursuing several additional measures to minimize reliance on supplemental commitments in load pockets including:

- An approach to modeling combined cycle units that enables them to provide additional flexibility and non-spinning reserve capability in load pockets (implemented in 2007);
- Operating reserve markets which provide better incentives for resources in the load pockets, particularly new fast-start units (implemented in late 2006).
- Transmission upgrades into Boston (completed in Spring 2007) and associated changes in the area's local reliability requirements (implemented in early 2008).
- Transmission upgrades into Southeast Massachusetts that enable the ISO to maintain reliability in these areas with less internal capacity (planned for 2009).
- Upgrades to the software tools used to calculate transmission capability into local areas. The new PowerWorld based application is expected to improve the accuracy, reliability, and efficiency of the calculations (planned for 2008).

In addition, we recommend the ISO:

- Modify the mitigation measures to better address the incentives of suppliers that persistently raise their offers above marginal costs to extract larger NCPC payments in areas where generation is frequently committed for local reliability.
  - ✓ The ISO is currently working on a proposal to address this behavior.
- Consider rule changes to discourage self-commitment when it leads to inefficient commitment for local reliability and increased uplift charges.
  - ✓ The ISO is currently working on a proposal to address this problem, although it is a lower priority now that reliability requirements and conduct in Boston have changed.

- Consider providing generators with additional flexibility to modify their offers closer to real-time to reflect changes in marginal costs.
  - ✓ The ISO is currently working on a proposal to allow suppliers with dual-fueled generators to submit one offer for each type of fuel.

Furthermore, we recommend several changes in Sections V and VII that would help the real-time prices of energy and reserves better reflect the costs of maintaining reliability in the local areas. Since expectations of real-time prices are the primary driver of day-ahead prices, these changes should increase the day-ahead market commitment of generators that satisfy the local reliability criteria.

The ISO has recently implemented or plans to implement several initiatives that should help reduce the need for supplemental commitment in the future. However, if substantial amounts of supplemental commitment remain necessary, the ISO should evaluate the feasibility and potential benefits of integrating RAA local capacity requirements in the day-ahead commitment software. To the extent that local capacity requirements can be forecasted accurately, it is most efficient to commit units for local reliability in the day-ahead market. Integrating the RAA requirements into the day-ahead market allows the day-ahead market software to determine the optimal solution, taking into account the commitments that are needed to meet local requirements. This change would help limit over-commitment, improve the convergence of prices in the constrained areas between the day-ahead and real-time market, and provide better incentives for loads to be fully scheduled in the day-ahead market.

IX. Competitive Assessment

This section evaluates the competitive performance of the New England wholesale markets in 2007. This type of assessment is particularly important for LMP markets. While LMP markets increase overall system efficiency, they can provide incentives for the localized exercise of market power in areas with inadequate generation resources or insufficient transmission capability. 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.[65] 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 all or part of the output of a resource is not offered to the market when it is available and economic to operate. Physical withholding can be accomplished by "derating" a generating unit (i.e., reducing the unit's high operating limit).

While many suppliers can cause prices to increase by withholding, not every supplier can profit from doing so. The benefit from withholding is that the supplier will be able to sell into the market at a clearing price above the competitive level. However, the cost of this strategy is that

---

65 See, *e.g.*, *2006 Assessment of the Electricity Markets in New England.*

the supplier will lose profits from the withheld output. Thus, a withholding strategy is only profitable when the price impact overwhelms the opportunity cost of lost sales for the supplier. The larger a supplier is relative to the market, the more likely it is that the supplier will have the incentive to withhold resources to raise prices.

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 reduce their incentive to raise price in the spot market.[66] Second, the incentive to withhold partly depends on the impact the withholding is expected to have on clearing prices. The nature of electricity markets is that when demand levels are high, 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 the market definition is established, it is possible to assess conditions where one or more large suppliers could profitably raise price. This sub-section of the report examines structural

66 When a supplier's forward power sales exceed the supplier's real-time production level, the supplier is a net buyer in the real-time spot market, thus, benefits from low rather than high prices.

aspects of supply and demand affecting market power. We examine the behavior of market participants in later sections.

1. Defining the Relevant Market

Electricity is physically homogeneous, so each megawatt of electricity is interchangeable even though the characteristics of the generating units that produce the 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 meet demand in real time. The lack of economic storage options 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 market is most vulnerable to the exercise of market power in the real-time spot market, when only on-line and fast-start capacity is available for deployment. 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. Hence, we define the relevant product as energy produced in real time for our analysis.

The second dimension of the market to be defined is the geographic area in which suppliers compete to sell the relevant product. In electricity markets, the relevant geographic market is generally defined by the transmission network constraints. Binding transmission constraints limit the extent to which power can flow between areas. When constraints are binding, a supplier within the constrained 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 must be analyzed separately. The following geographic markets are evaluated in this section:

- All of New England;
- All of Connecticut;
- West Connecticut;
- Southwest Connecticut;
- Norwalk-Stamford which is in Southwest Connecticut;
- Boston; and
- Lower SEMA.

This sub-section analyzes the seven geographic areas listed above using the following structural market power indicators:

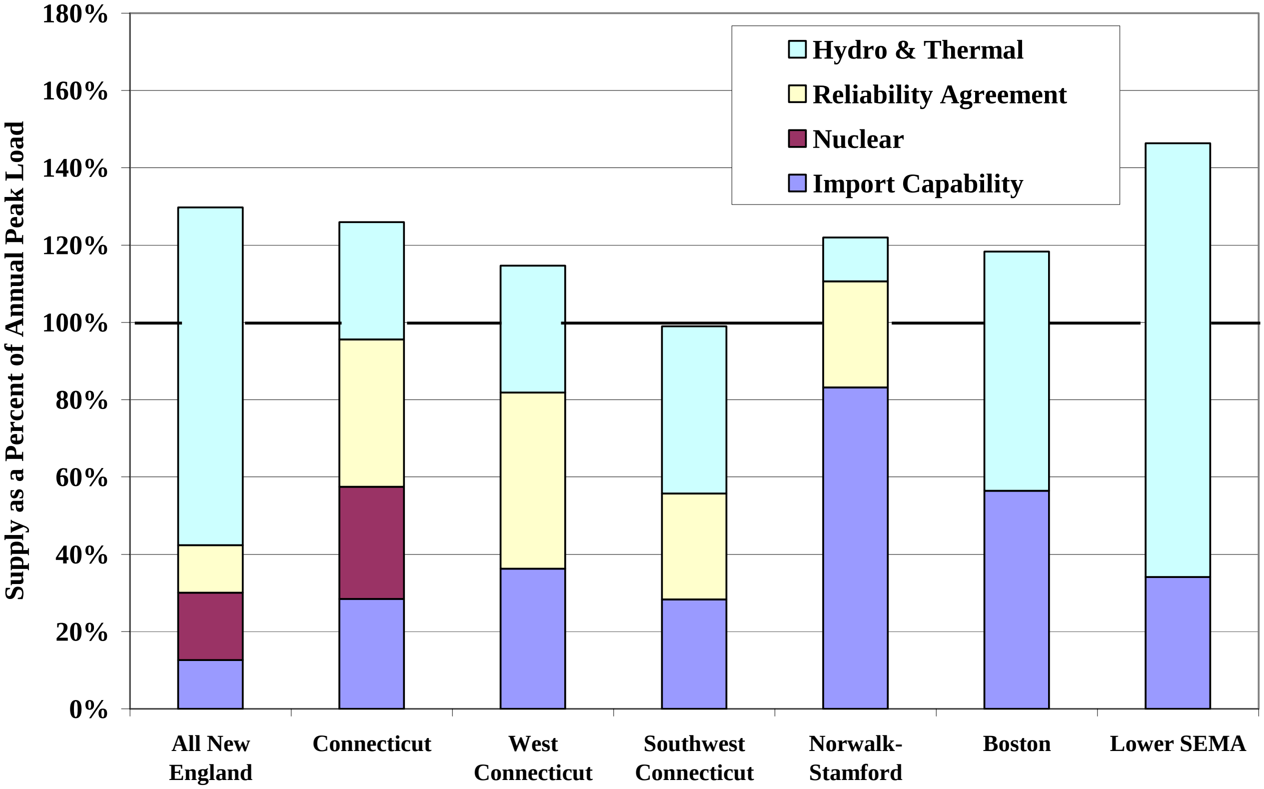
- Supplier market shares;
- Herfindahl-Hirschman indices; and
- Pivotal supplier indices.

The findings from the structural market power analysis in this section are used to focus the analyses of potential economic and physical withholding in Sections C and D.

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 capability of the transmission grid. Figure 38 shows several categories of supply relative to the load in each of the seven regions of interest.

Figure 38: Supply Resources versus Summer Peak Load in Each Region 2007



For each region, Figure 38 shows import capability and three categories of installed summer capability: (i) nuclear units, (ii) units under reliability agreements, and (iii) all other generators. These resources are shown as a percentage of 2007 peak load, although a substantial quantity of additional capacity (typically more than 1900 MW) is also necessary to maintain operating reserves in New England. The figure shows that while imports can be used to satisfy 13 percent of the load in the New England area under peak conditions, the six load pockets can serve larger shares of their peak load with imports. Norwalk-Stamford, which has the largest import capability relative to its size, was able to rely on imports to serve more than 80 percent of its load under peak conditions. The import capability shown above for each load pocket is reduced to account for local reserve requirements.

The relative shares for some categories of supply shown in Figure 38 changed from 2006 to 2007. First, the summer peak load level was lower in 2007 than in 2006, leading to a modest increase in most categories of supply as a share of load. Second, Boston import capability increased from 44 percent of peak load in 2006 to 56 percent in 2007, primarily due to transmission upgrades completed in spring of 2007. Third, import capability to Norwalk-Stamford increased from 73 percent in 2006 to 83 percent of peak load in 2007 due to the completion of Phase I of the Southwest Connecticut 345 kV Transmission Project.

Figure 38 also shows the margin between peak load and the total available supply from imports and native resources. Areas with lower margins may be more susceptible to withholding than other areas. For example, the figure shows that there was no excess available supply in Southwest Connecticut during the annual peak hour, making it more likely that a small amount of withholding would have a significant effect. On the other hand, Boston and Norwalk-Stamford had substantially more supply than was needed to serve the peak load in 2007, due primarily to transmission upgrades into each area. Supply serving Boston exceeded the annual peak load by 18 percent in 2007, up from 4 percent in 2006. The supply serving Norwalk-Stamford exceeded the annual peak load by 22 percent in 2007, versus 4 percent in 2006.

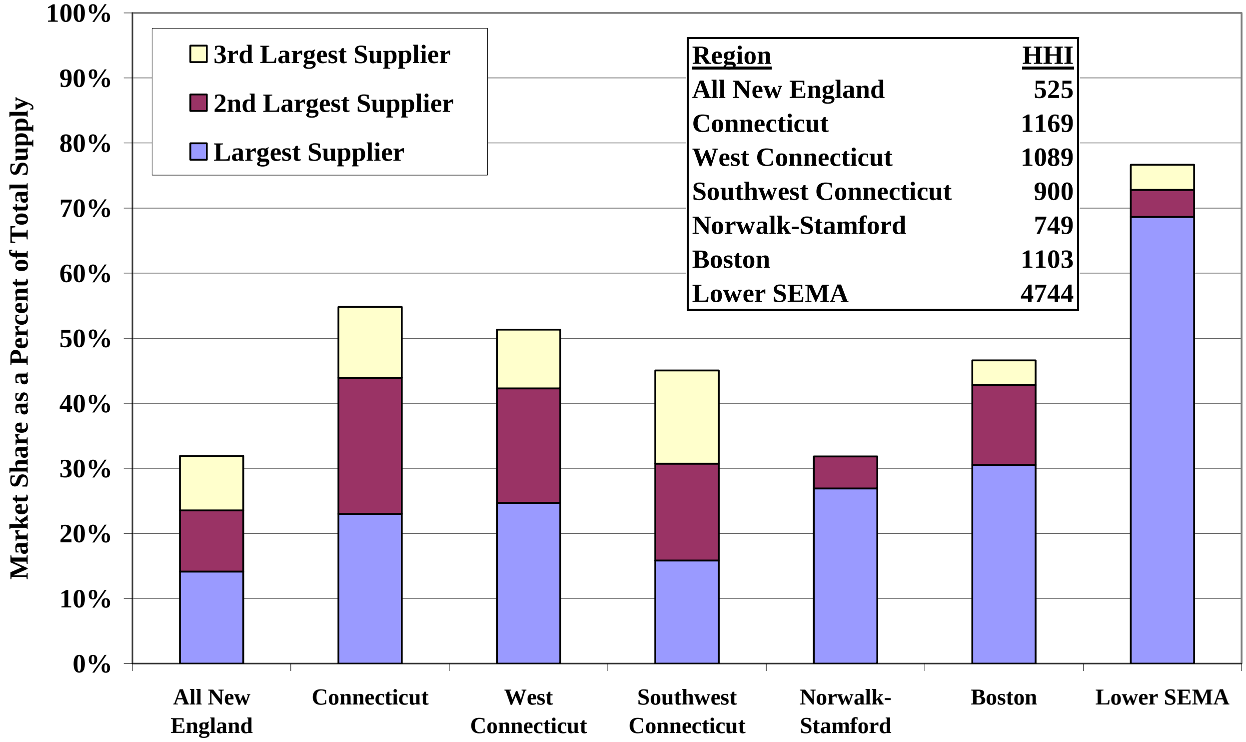
We show nuclear capacity and capacity under reliability agreements separately from other internal generation because these resources are likely to pose fewer market power concerns. In order to exercise market power successfully in an electricity market, it is important to be able to withhold capacity only at times when it will be profitable because the lost revenue on withheld units can be very costly. Nuclear generators typically cannot be dispatched up and down in a way that would 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 agreement contracts 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 monitored on an on-going basis daily by that department using agreed-to fuel indices.

While it is possible for a market participant to physically withhold a unit that is under a reliability agreement, the fixed cost payments will decrease if the unit fails to meet their target available hours as specified in the reliability agreement. Suppliers may have an incentive to report availability greater than actually exists. Although units may report themselves as available when they are not to avoid a reduction to their target available hours, the supplier incurs a significant non-performance penalty if the units are called upon during such a period. The target availability hours provision 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, or to withhold the unit.

Connecticut continued to rely heavily on nuclear capacity and units under reliability agreements in 2007. Reliability agreements reduce the quantity of capacity that may be withheld to exercise market power. In the Norwalk-Stamford load pocket, most internal generation came under a reliability agreement after the expiration of the PUSH provisions in June 2007. As a result, the potential to exercise market power in Norwalk-Stamford was greatly reduced in 2007. A substantial portion of Boston generation came out of a reliability agreement prior to 2007, which removed a factor that reduced the potential for market power in 2006.

The previous figure shows that the capacity margins can go to zero 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 39 shows the market shares of the largest three suppliers coinciding with the annual peak load hour on August 3, 2007. 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 by treating the market share of imports as zero in the HHI calculation. 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 will not be perfectly competitive. In addition, suppliers inside the area may be affiliated with resources in the market outside of the area.

Figure 39: Installed Capacity Market Shares for Three Largest Suppliers August 3, 2007



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 16 percent in Southwest Connecticut, to 69 percent in Lower SEMA. Likewise, there is variation in the number of suppliers that have significant market shares. For instance, Norwalk-Stamford had only two native suppliers with unequal market shares in 2007, while Southwest Connecticut had three native suppliers with comparable market shares.

The HHI figures suggest that only Lower SEMA is highly concentrated.[67] The 749 HHI for Norwalk-Stamford is low. This is counter-intuitive since there are only two suppliers in the area. However, because 83 percent of the load can be served by imports, the local suppliers serve only 17 percent of the market. Of the remaining areas, Connecticut and Boston have the highest HHI statistics with 1169 and 1103, respectively.

67 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.

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 evaluate the potential for market power using a pivotal supplier analysis, which addresses the shortcomings of concentration analyses.

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.[68, 69] The HHI's usefulness is limited by the fact that it reflects only the supply-side, ignoring demand-side factors that affect the competitiveness of the market. The most important demand-side factor is the level of load relative to available supply-side resources. Since electricity cannot be stored economically, production must match demand on a real-time basis. When demand rises, an increasing quantity of generation is utilized to satisfy the demand, leaving less supply 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.

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

---

68 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.

69 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.

and have the incentive to take advantage of their position 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.[70] This section of the report identifies the frequency with which one or more suppliers were pivotal in areas within New England 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 have market power. For a supplier to have the ability to substantially raise real-time 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 identify the areas where market power is a potential concern most frequently, Including all capacity, the pivotal supplier analysis raises potential concerns regarding six of the seven areas shown in Figure 40. The only area that does not raise potential concerns is West Connecticut, where the ownership of capacity is much less concentrated than the other load pockets. Potential local market power concerns are most acute in Lower SEMA, where one supplier owns nearly 90 percent of the internal capacity.

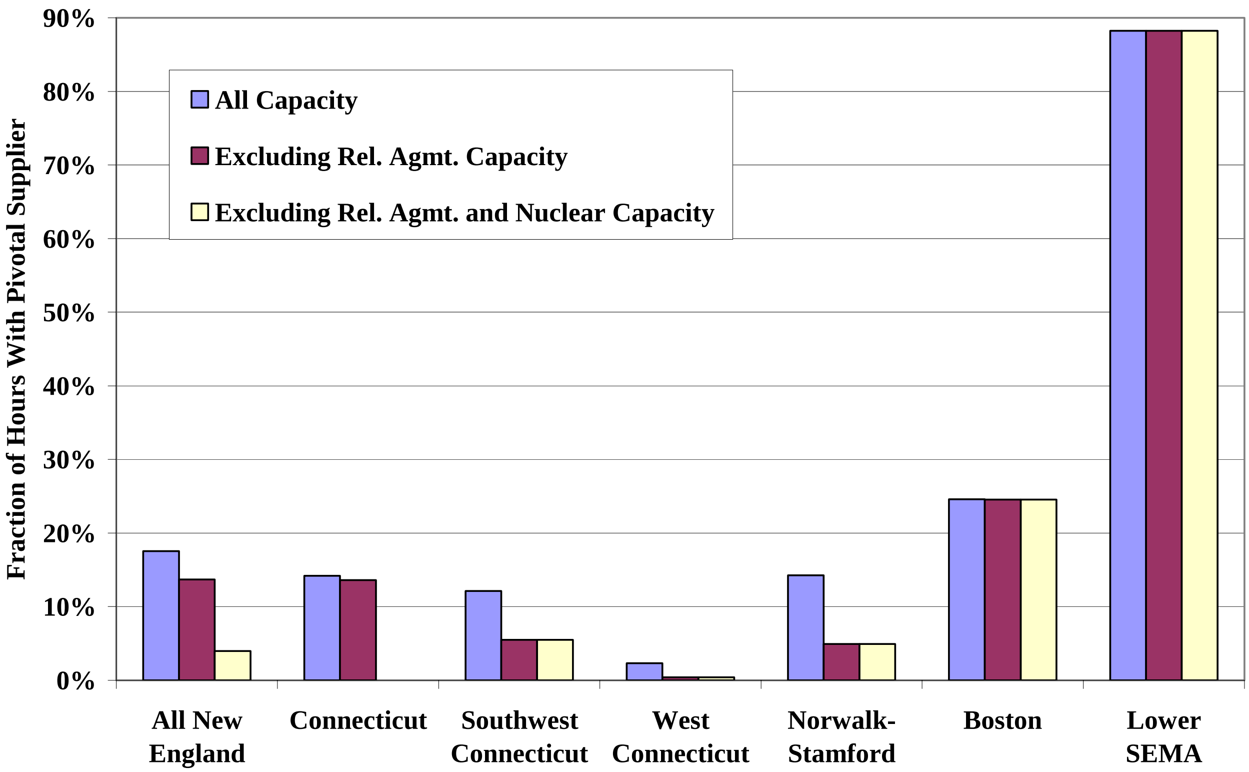
Figure 40 shows the portion of hours where at least one supplier was pivotal in each region during 2007. The figure also shows the impact of excluding nuclear units and units under reliability agreements from the analysis. As discussed above, such units are unlikely to be engaged in economic or physical withholding.

Including all capacity, the pivotal supplier analysis raises potential concerns regarding six of the seven areas shown in Figure 40. The only area that does not raise potential concerns is West Connecticut, where the ownership of capacity is much less concentrated than the other load

70 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.

pockets. Potential local market power concerns are most acute in Lower SEMA, where one supplier owns nearly 90 percent of the internal capacity.

Figure 40: Frequency of One or More Pivotal Suppliers by Type of Withheld Capacity 2007



Boston exhibited the second-highest pivotal supplier frequency. The pivotal supplier frequency for Boston increased from 2 percent in 2006 to 25 percent in 2007. This change was due to the fact that most of the largest supplier's capacity in Boston was under a reliability agreement during 2006, but the agreement lapsed prior to 2007.

In Norwalk-Stamford, the largest supplier's capacity came under a reliability agreement in June 2007. As a result, the fraction of hours in which a supplier was pivotal decreased from 23 percent in 2006 to 5 percent in 2007, excluding reliability agreement capacity.

Although Connecticut had a pivotal supplier in 14 percent of the hours in 2007, 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.[71] Therefore, it is appropriate to exclude the nuclear capacity from the pivotal supplier frequency for Connecticut. This leaves no hours with pivotal suppliers in Connecticut.

For the entirety of New England, the extent of market power depends on how reliability agreements and nuclear capacity affect the incentives of large suppliers. Excluding reliability agreement capacity from the pivotal supplier analysis for all of New England reduces the pivotal frequency from 18 percent to 14 percent of the hours in 2007. Further, excluding nuclear capacity reduces the pivotal frequency to just one percent of hours. However, the rationale for excluding nuclear capacity from the analysis does 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 likely to physically withhold their nuclear capacity from the market, their nuclear capacity would earn more revenue if they withheld their non-nuclear capacity. Accordingly, New England as a whole warrants further review.

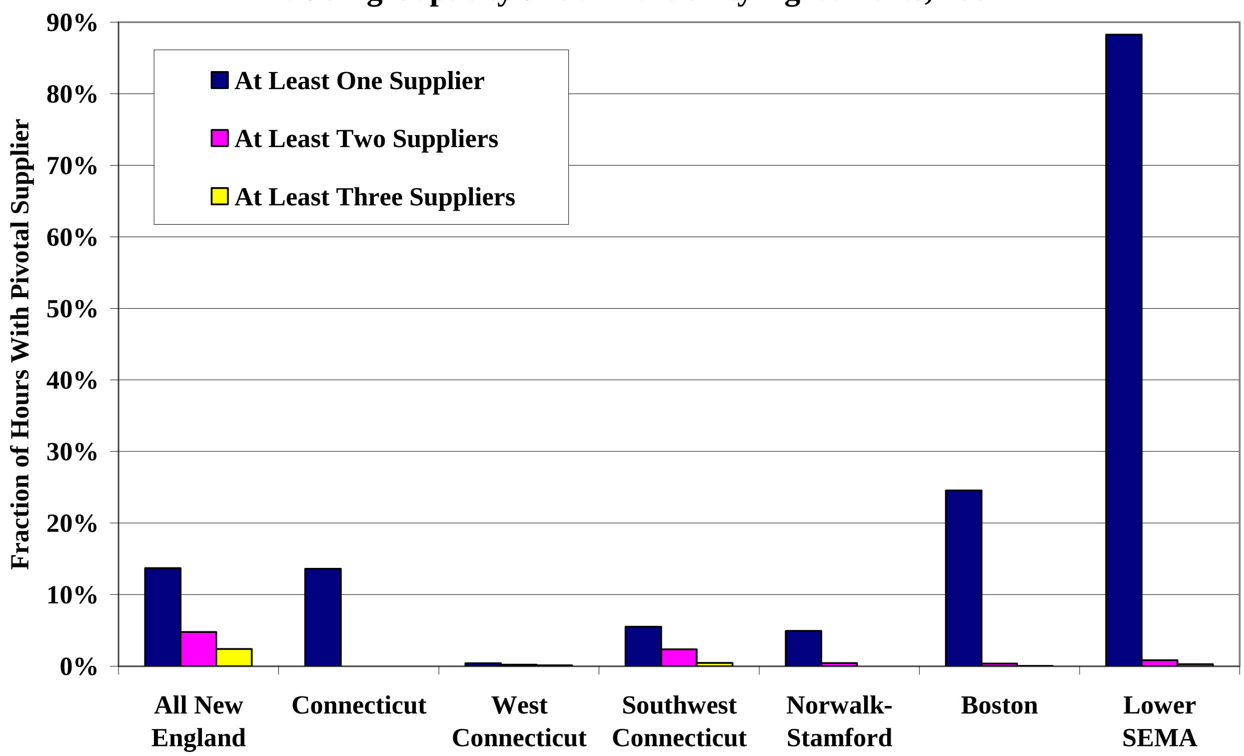
The pivotal supplier summary indicates the greatest potential for market power in Lower SEMA and Boston. A close examination is also warranted for all of New England, while Connecticut raises lesser concerns. The market shares in Figure 39 indicate that there are areas with several dominant suppliers, suggesting that during certain periods, several suppliers might be pivotal simultaneously. Figure 41 shows the number of pivotal suppliers during hours when one or more supplier is pivotal in each region.

The frequencies shown in Figure 41 are the same as those in the previous Including all capacity, the pivotal supplier analysis raises potential concerns regarding six of the seven areas shown in Figure 40. The only area that does not raise potential concerns is West Connecticut, where the ownership of capacity is much less concentrated than the other load pockets. Potential local market power concerns are most acute in Lower SEMA, where one supplier owns nearly 90 percent of the internal capacity.

71 This assumes that the supplier cannot reduce its nuclear output substantially without taking a unit out of service.

Figure 40 that exclude capacity under reliability agreements. But this figure also shows the frequency with which two or three suppliers were pivotal in a single hour. In the six 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 expected to provide that supplier with an incentive to withhold. In All New England, the second-largest supplier was pivotal much less often than the largest.

Figure 41: Frequency of One or More Pivotal Suppliers Excluding Capacity under Reliability Agreements, 2007



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. Thus, there will be some variation in the market shares on a daily basis due to differences in the unit commitments. However, there was little variation in the identity of the largest supplier in each area under most conditions in 2007. Therefore, each area had a single supplier that was most likely to have market power. Accordingly, Sections C and D will closely examine the behavior of the largest single supplier in each load pocket and the three largest suppliers for all of New England.

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 42 shows the fraction of hours when a supplier is pivotal at various load levels. The bars in each load range show the fraction of hours when a supplier was pivotal in Norwalk-Stamford, Southwest Connecticut, All New England, Lower SEMA, and Boston. The bars are arranged according to the frequency with which a supplier is pivotal, from lowest to highest. For example, Lower SEMA on the right had the highest frequency of a supplier being pivotal and is, therefore, shown on the far right. West Connecticut and Connecticut are not shown because there were very few instances of a supplier being pivotal during 2007.

Figure 42: Frequency of One or More Pivotal Suppliers by Load Level Excluding Capacity under Reliability Agreements, 2007

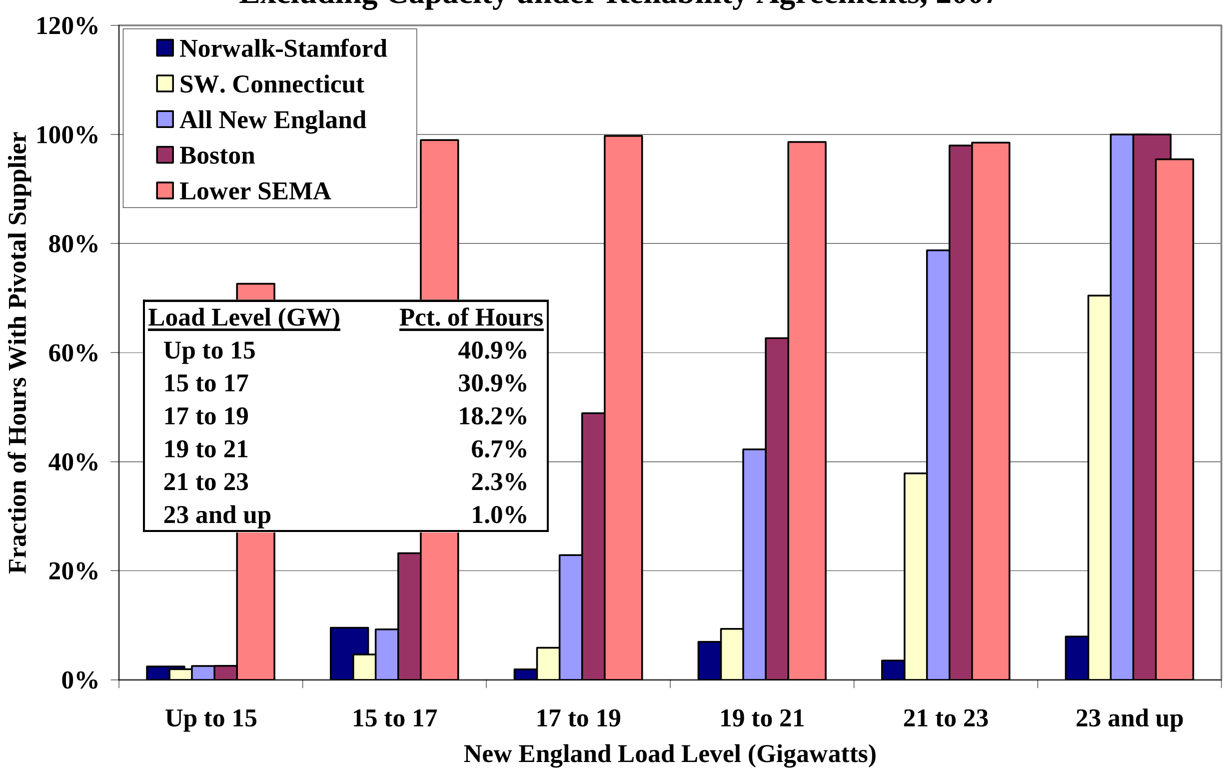


Figure 42 indicates that the largest supplier in Lower SEMA was pivotal in almost every hour in which the load exceeded 15 GW in New England, and in almost 73 percent of all hours in which load was *less* than 15 GW in New England. The analysis indicates less potential for market power in the other areas. The supplier in Boston was pivotal in at least 49 percent of hours when the load exceeded 17 GW in New England. In all of New England, the largest supplier was pivotal in each of the hours when load exceeded 23 GW, and approximately half of the hours when load ranged between 19 and 23 GW. In Norwalk-Stamford, the largest supplier was usually not pivotal under any load conditions.

Based on the pivotal supplier analysis in this sub-section, market power is most likely to be a concern in Lower SEMA at all load levels, in Boston when load exceeds 17 GW, and in All of New England when load exceeds 19 GW. The pivotal supplier results are conservative for "All of New England" because the analysis assumed that imports would not change if the largest supplier were to withhold. In actuality, there would be some increase in imports. 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 this 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. These reference levels are used as part of the market power mitigation measures and are intended to reflect the competitive offer price for a resource. The Internal Market Monitoring Unit has provided us with cost reference levels, which we can use as a competitive benchmark in our analysis of economic withholding.

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, 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 step, we examine whether the unit would have been economic *for commitment* on that day if it had offered at its 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 steps, the marginal costs assumed for the generator are the reference levels for the unit used in the ISO's mitigation measures plus a threshold.

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 based on real-time market outcomes for quick start units.

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

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

$$Q_i^{offer} = \text{ offer output level of i.}$$

By using the greater of actual production or the output level offered at the clearing price, portions of units that are constrained by 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.

It is important to recognize that the output gap tends to overstate the amount of potential economic withholding because some of the offers that are included in the output gap reflect legitimate responses by the unit's owner to operating conditions, risks, or uncertainties. For example, some hydro units are able to produce energy for a limited number of hours before running out of water. Under competitive conditions, the owners of such units have incentives to produce energy during the highest priced periods of the day, and they attempt to do this by raising their offer prices so that their unit will be dispatched only during the highest priced periods of the day. However, the owners of such units submit offers prior to 6 pm on the previous day based on their expectations of market conditions, so if real-time prices are lower than expected, it may lead the unit to have an output gap. Hence, output gap is not necessarily evidence of withholding, but it is a useful indicator of potential withholding. We generally seek to identify trends in the output gap results that would indicate significant attempts to exercise market power.

In previous years, we have observed that some units that expect to be committed for local reliability and receive NCPC payments also produce above average output gap. The explanation was that these units raised their bids in expectation of getting higher NCPC payments, but in fact they were not dispatched. Hence, such instances were flagged as output gap even though the suppliers were not withholding in an effort to raise LMPs. The frequency of such instances was lower in 2007 than in 2006.

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 by load level in the following areas:

- Boston;
- Lower SEMA;
- Southwest Connecticut; and
- All of New England.

2. Output Gap in Boston

Boston is a large net-importing region, making it particularly important to evaluate the conduct of its suppliers. Furthermore, the pivotal supplier analysis raises concerns regarding the potential exercise of market power in Boston in 2007, and a large share of the Boston capacity is no longer under a reliability agreement.

Figure 43 shows output gap results for Boston by load level. Output gap statistics are shown for the largest supplier compared with all other suppliers in the area. Based on the pivotal supplier analysis in the previous sub-section, the largest supplier can expect that its capacity will be pivotal in most hours when load exceeds 17 GW.

Figure 43: Average Output Gap by Load Level and Type of Supplier
Boston, 2007

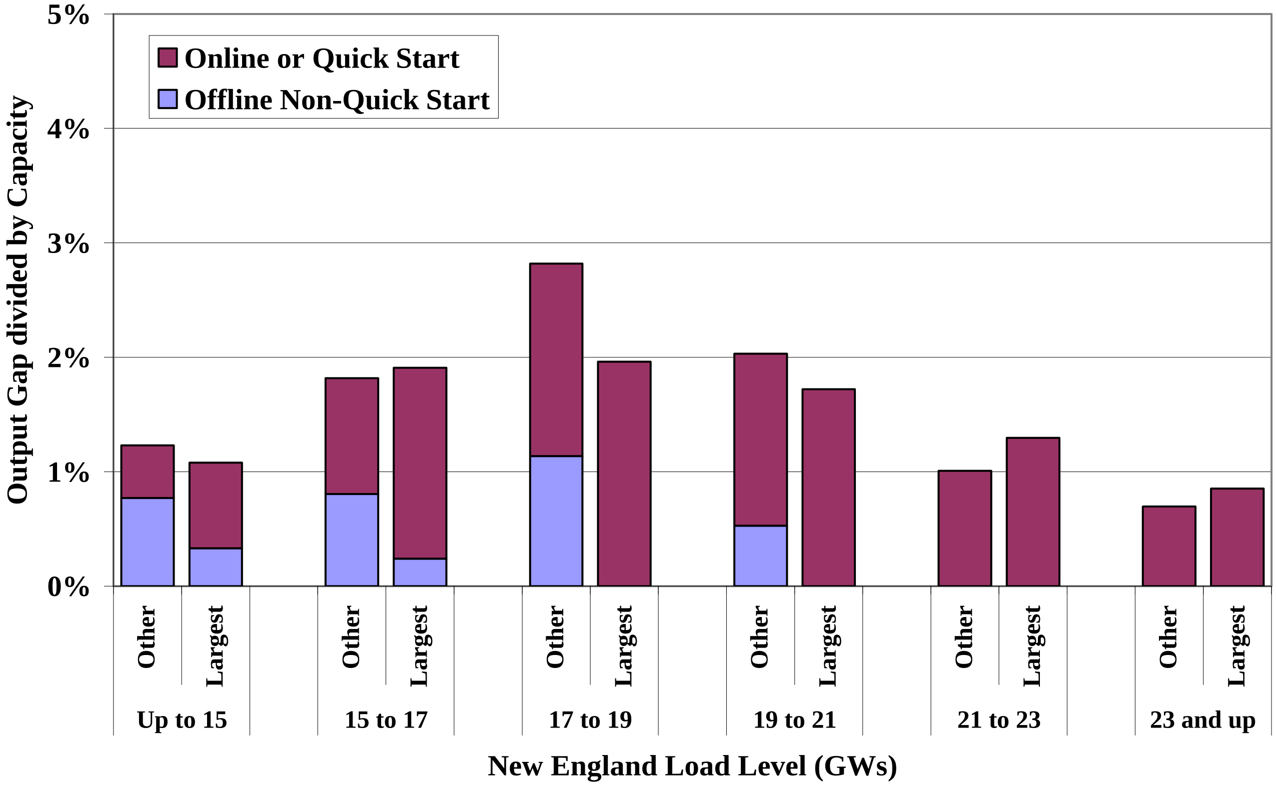


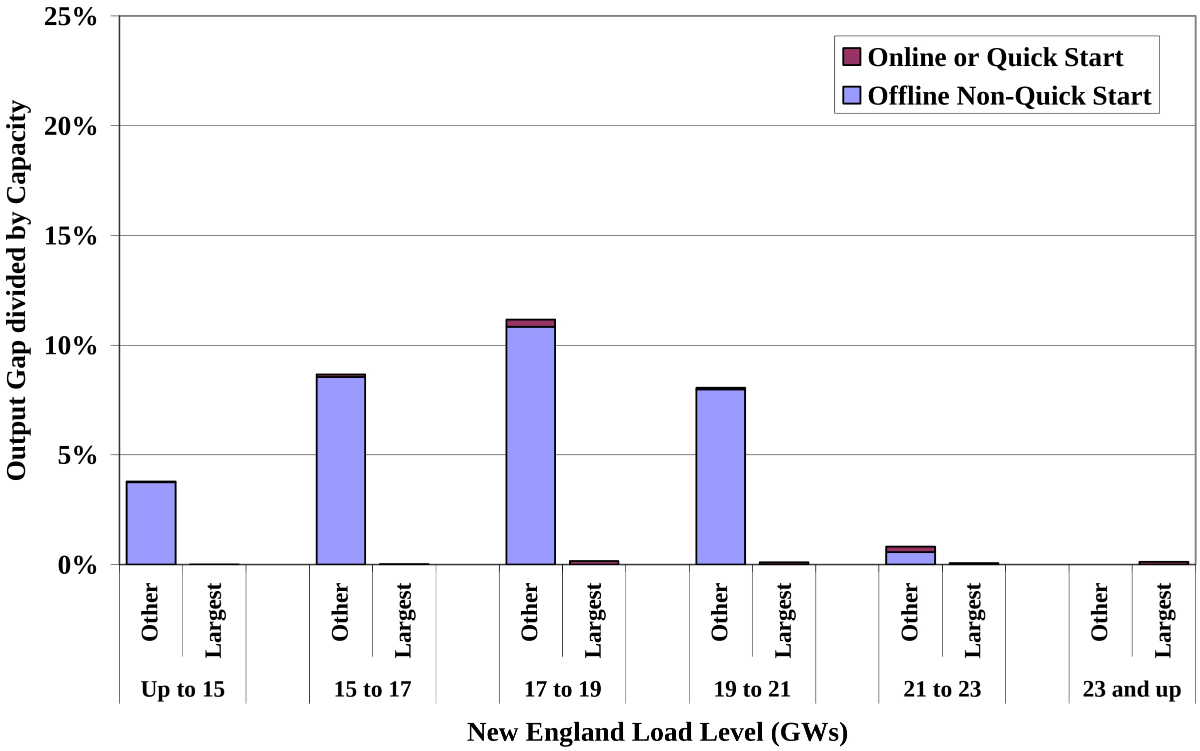
Figure 43 shows that the overall amount of output gap in Boston is modest, ranging from 1 to 3 percent of total capacity depending on load level. This is consistent with the output gap levels for all of New England. The output gap for the largest supplier is comparable to the levels for other suppliers, and the output gap actually falls as load increases above 17 GW. These observations do not raise potential competitive concerns regarding potential economic withholding to raise prices in Boston.

3. Output Gap in Lower SEMA

The pivotal supplier analysis in the previous section indicated that the largest supplier in Lower SEMA was pivotal in the majority of hours in 2007. Also the largest supplier owns 88 percent of the capacity in Lower SEMA. Hence, we closely evaluate the conduct of suppliers in Lower SEMA due to the structural indicators of market power.

The following analysis examines output gap patterns in Lower SEMA to determine whether there is evidence of economic withholding. Figure 44 shows the output gap identified in Lower SEMA in 2007 by load level. The output gap is shown separately for the largest supplier and other suppliers.

Figure 44: Average Output Gap by Load Level and Type of Supplier Lower SEMA, 2007



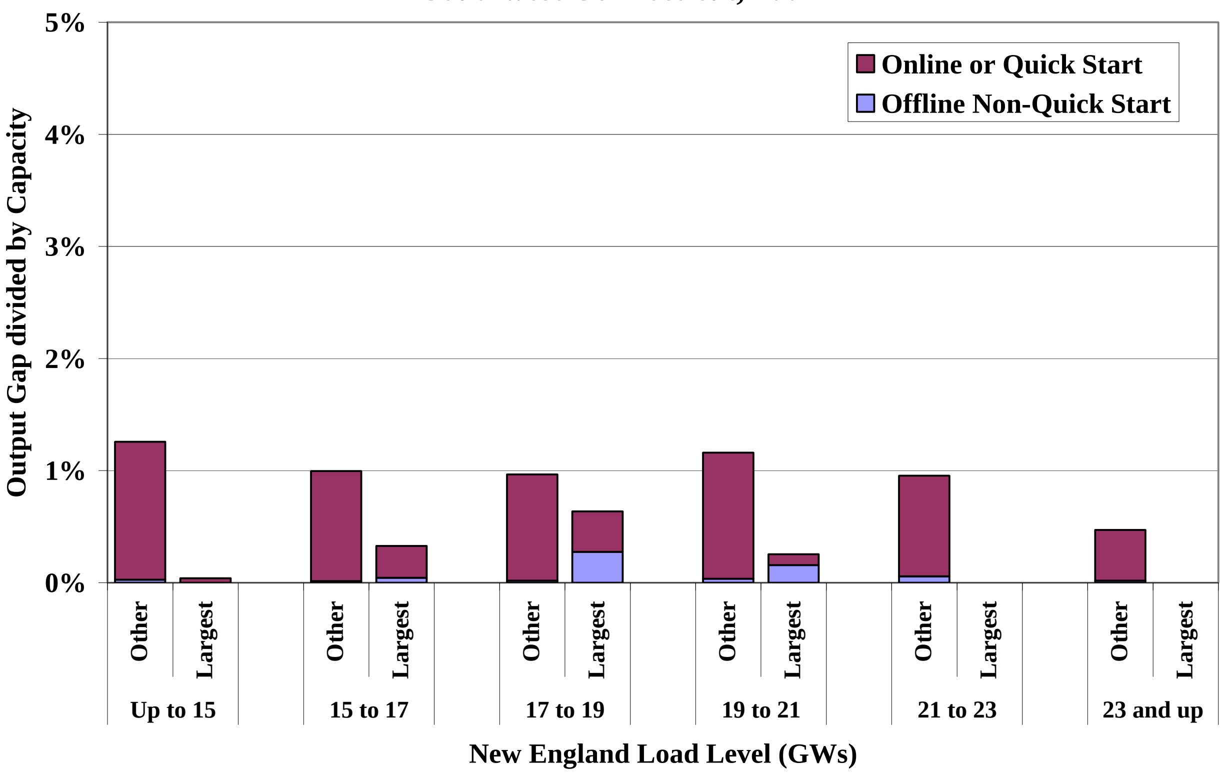
As the figure shows, the output gap of the largest supplier's online and quick-start units was not significant in 2007. This might not be expected given that Lower SEMA was identified as the region with the highest potential for market power in the pivotal supplier section. The largest supplier there is pivotal in the majority of hours. These results clearly indicate that the largest supplier's offers have consistently been priced below the Conduct Threshold for Economic Withholding, which is identified in Appendix A of Market Rule 1.

4. Output Gap in Southwest Connecticut

In this sub-section, we examine potential economic withholding in Southwest Connecticut, which has historically been import-constrained. The pivotal supplier analysis summarized in

Figure 42 raises concerns about the potential for market power in Southwest Connecticut and Norwalk-Stamford. Figure 45 shows output gap results for Southwest Connecticut by load level. Output gap statistics are shown for the largest supplier compared with all other suppliers in the area.

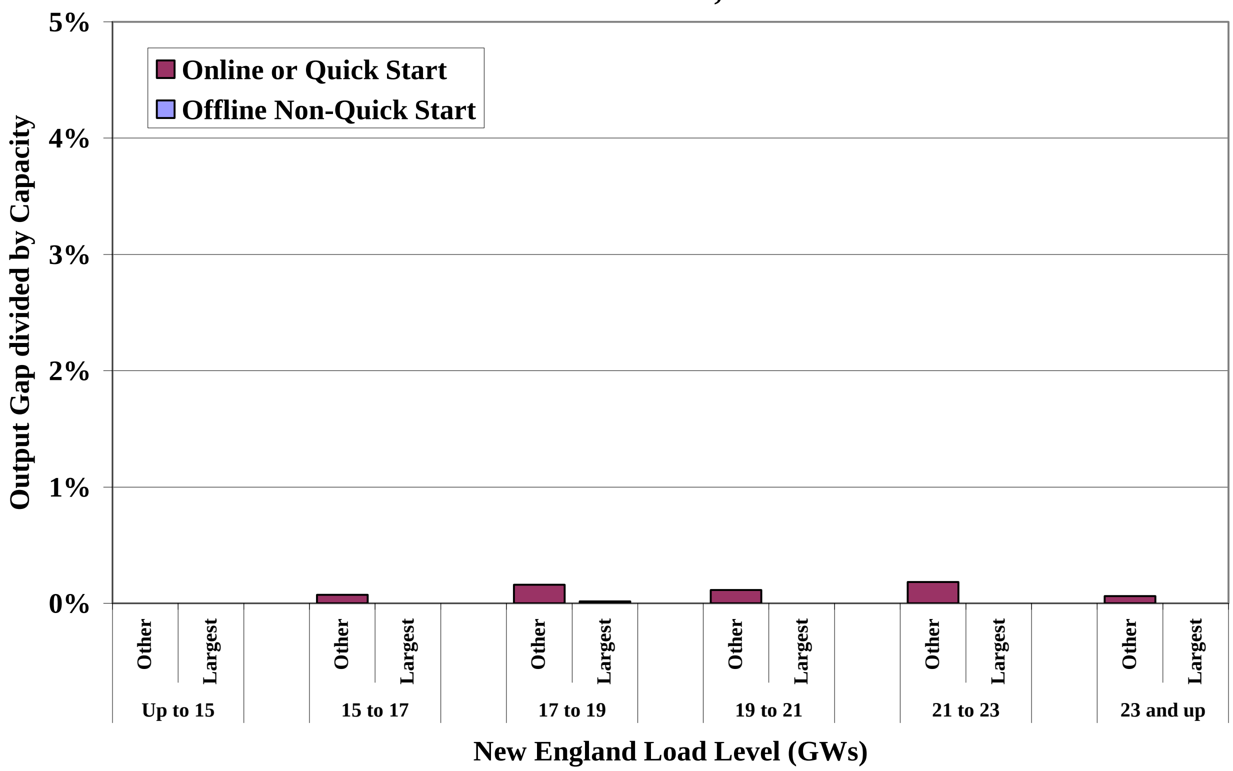
Figure 45: Average Output Gap by Load Level and Type of Supplier Southwest Connecticut, 2007



The pivotal supplier analysis indicated that, excluding capacity under reliability agreements, the largest supplier in Southwest Connecticut was likely to be pivotal in most of the hours when load exceeds 21 GW. Figure 45 shows that the amount of output gap was low relative to the amount of capacity in Southwest Connecticut. The largest supplier had especially low levels of output gap. The other suppliers also produced very little output gap. These results do not raise concerns regarding economic withholding.

Figure 46 shows output gap results for Norwalk-Stamford by load level and by supplier. The pivotal supplier analysis indicated that, excluding capacity under reliability agreements, the largest supplier in Norwalk-Stamford was likely to be pivotal in a relatively small share of hours, and that the share was not correlated with load. Consistent with these results, Figure 46 shows very little output gap in Norwalk-Stamford in 2007.

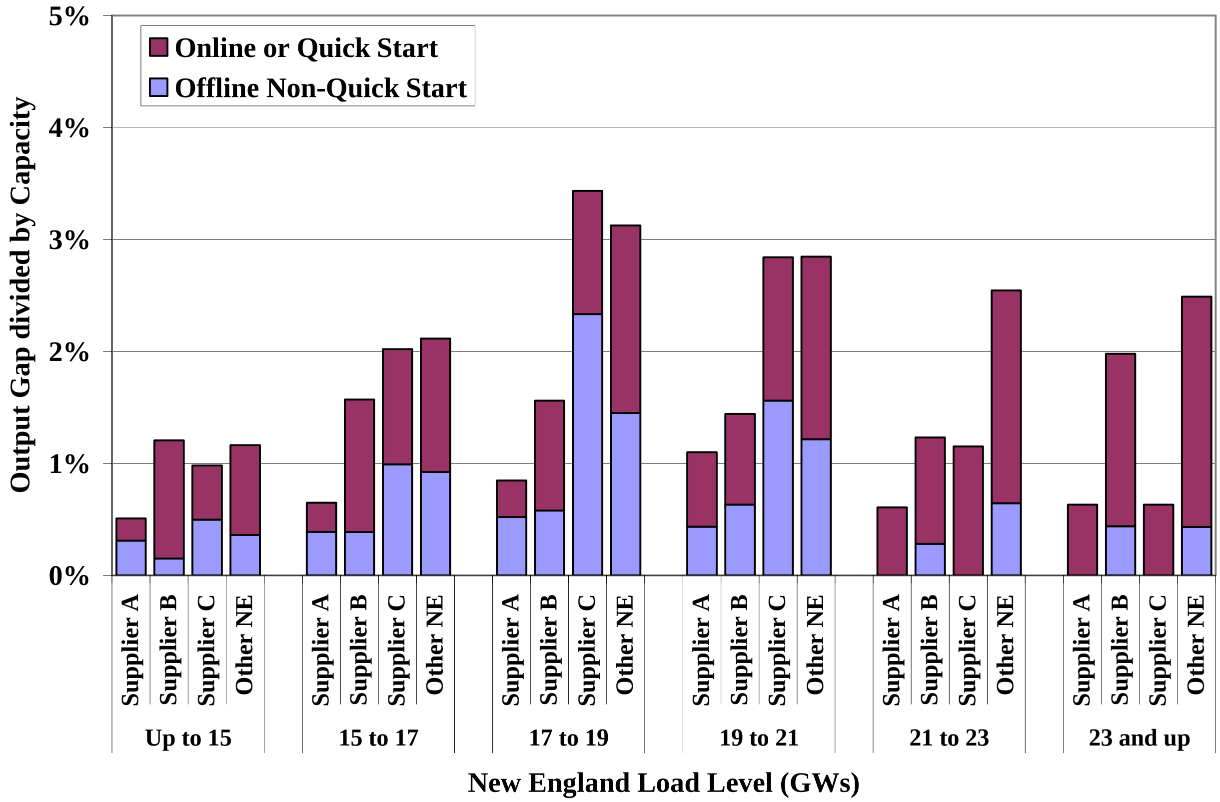
Figure 46: Average Output Gap by Load Level and Type of Supplier Norwalk-Stamford, 2007



5. Output Gap in All New England

Figure 47 summarizes output gap results for all of New England by load level for four categories of supply. Supplier A has the largest portfolio in New England and was pivotal in approximately 13 percent of the hours during 2007 (excluding capacity under reliability agreements). Suppliers B and C were also pivotal during approximately 5 percent and 4 percent of the hours, respectively. All other suppliers are shown as a group for reference.

**Figure 47: Average Output Gap by Load Level and Type of Supplier
All New England, 2007**



The figure shows that the region-wide output gap was generally low for each of the four categories of supply, although some categories exhibited higher output gap quantities at higher load levels. Supplier A exhibited a small output gap under all load conditions. Supplier B exhibited a small output gap under all load conditions, although it was somewhat higher when load exceeded 23 GW. Supplier C exhibited a higher output gap than Suppliers A and B, although it was still generally lower than the Other Suppliers category. A close review of the underlying data indicates that hydro units tend to exhibit larger output gap quantities on average. This explains much of the increase in output gap at moderate to high levels. Overall, these results indicate that economic withholding was not a significant concern in New England in 2007.

D. Physical Withholding

This section of the report examines declarations of 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 analysis, we evaluate the four geographic markets examined in the output gap analysis above.

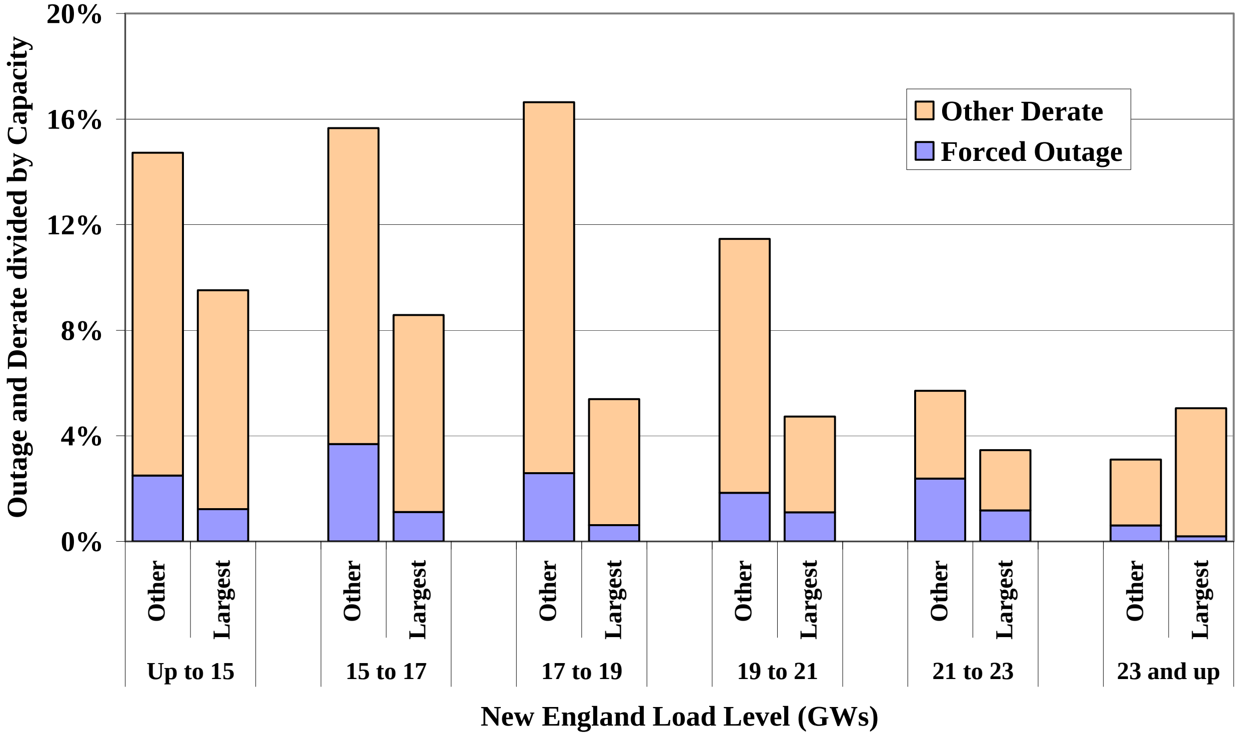
In each market, we examine forced outages and other derating by load level. The "Other Derate" category includes reductions in the hourly capability of a unit from its maximum seasonal capability that are not logged as forced outages or planned outages. These deratings can be the result of ambient temperature changes or other factors that affect the maximum capability of a unit.

1. Potential Physical Withholding in Boston

Figure 48 shows declarations of forced outages and other deratings in Boston by load level. Based on the pivotal supplier analysis, the capacity of the largest supplier can be expected to be pivotal in most hours when New England load exceeds 17 GW. We compare these statistics for the largest supplier to all other suppliers in the area.

The figure shows the largest supplier's physical deratings as a percentage of its portfolio. These deratings are generally close to 10 percent at low load levels, but consistently decrease as load levels increase. The average physical deratings of other suppliers are generally higher than that of the largest supplier.

Figure 48: Forced Outages and Deratings by Load Level and Supplier Boston, 2007

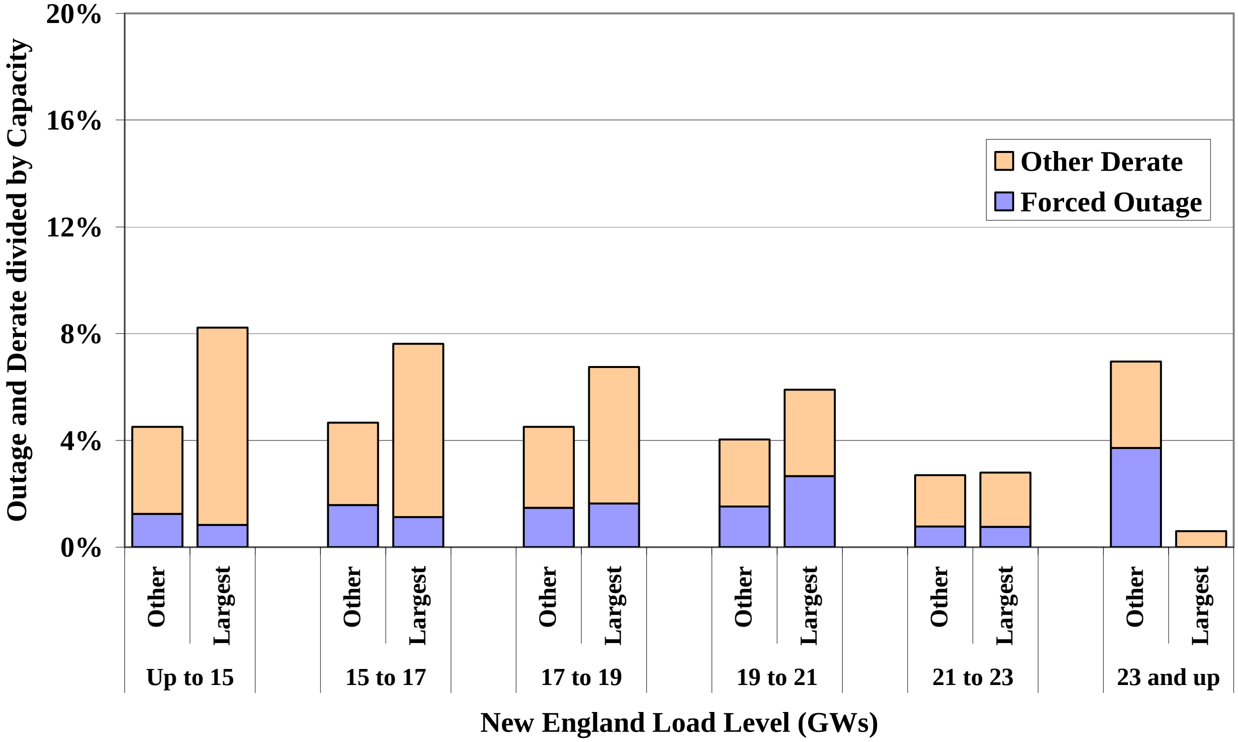


Overall, Figure 48 suggests that the pattern of deratings and outages is consistent with a competitive market. First, the large supplier shows levels of outages and deratings that are generally lower than for other suppliers. Second, the large supplier shows a general decline in the level of outages and deratings 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 shown in the figure suggest that the largest supplier increased the availability of its capacity available during periods of high load when capacity was most valuable to the market.

2. Potential Physical Withholding in Lower SEMA

Figure 49 summarizes declarations of forced outages and other deratings in the Lower SEMA area by load level in 2007. These statistics are shown for the largest supplier compared with the other suppliers in the area. Based on the pivotal supplier analysis for Lower SEMA, the largest supplier can be expected to be pivotal in 88 percent of the hours. This result indicates a potential market power concern in Lower SEMA even under moderate load conditions.

Figure 49: Forced Outages and Deratings by Load Level and Supplier Lower SEMA, 2007



While the largest supplier has a higher rate of forced outages and other deratings than the other suppliers in Lower SEMA, the rates of the largest supplier are comparable to suppliers in New England more broadly. As load levels rise, forced outages and other deratings decline. These patterns suggest efforts to increase unit availability as load rises rather than any attempt at physical withholding. Overall, the outage and deratings results for Lower SEMA do not raise concerns of strategic withholding.

3. Potential Physical Withholding in Southwest Connecticut

We analyze potential physical withholding separately in Southwest Connecticut and then in the Norwalk-Stamford load pocket. Figure 50 and Figure 51 summarize declarations of forced outages and other deratings in these areas by load level. Both figures show these statistics for the largest supplier of capacity in the area and for other suppliers.

Figure 50: Forced Outages and Deratings of the Largest Supplier by Load Level Southwest Connecticut, 2007

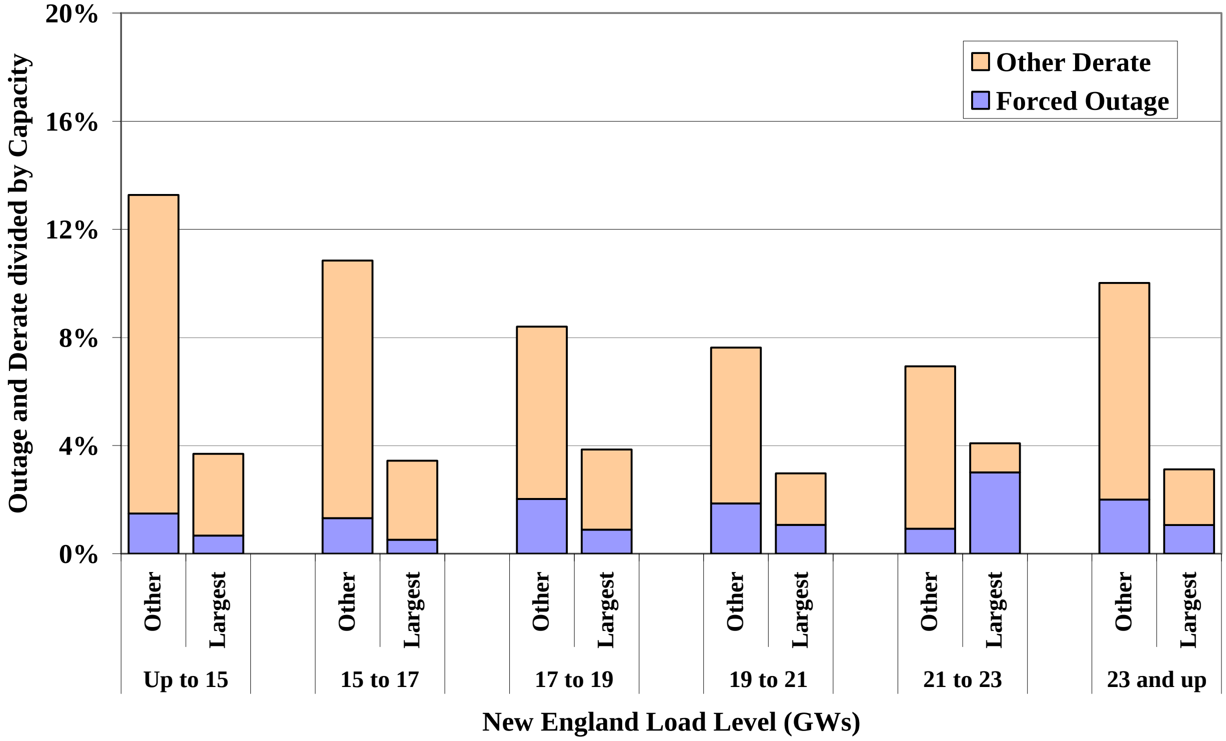
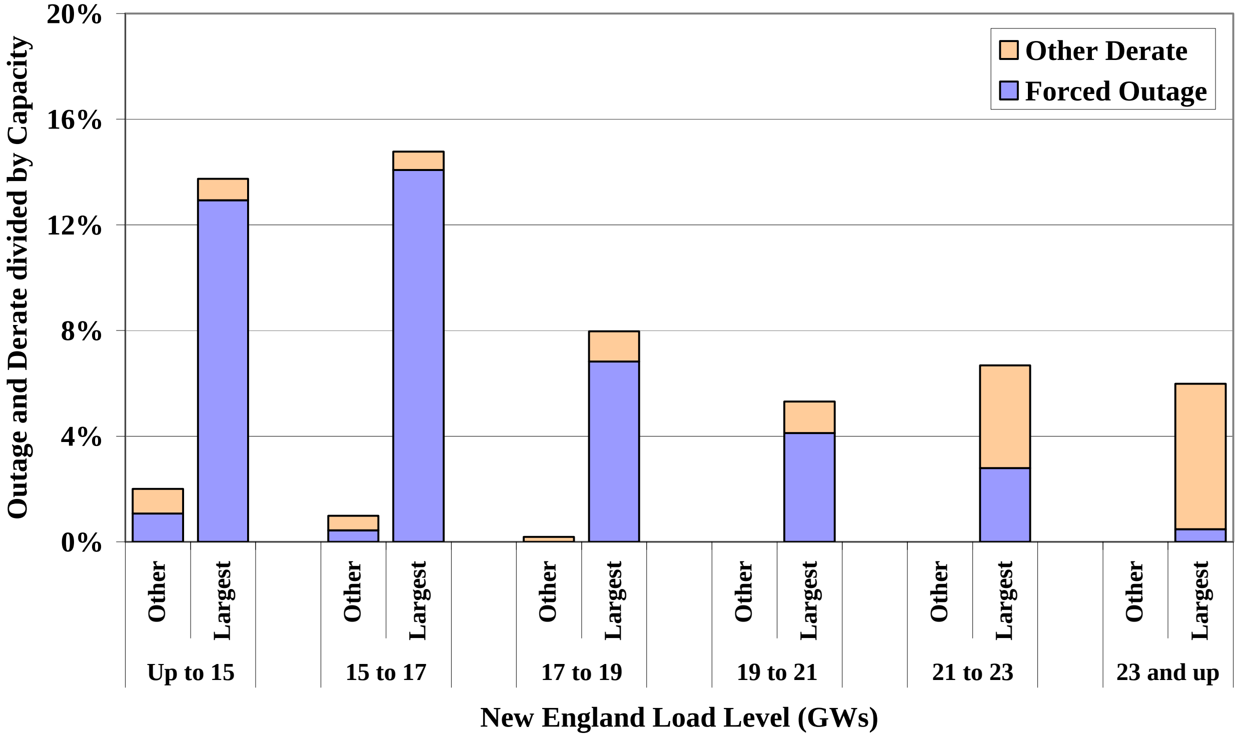


Figure 50 shows that the physical derating and forced outage quantities for the largest supplier in Southwest Connecticut is low under all load conditions. The other suppliers exhibited relatively high levels of forced outages and other derates under all load conditions. We examined the underlying data and found that these occurrences of deratings and outages were not correlated with periods of congestion. Hence, these deratings and outages do not raise concerns about physical withholding in Southwest Connecticut.

Figure 51 summarizes the potential physical withholding results for the Norwalk-Stamford area by load level for the largest supplier and for other suppliers.

Figure 51: Forced Outages and Deratings by Load Level and Supplier
Norwalk-Stamford, 2007

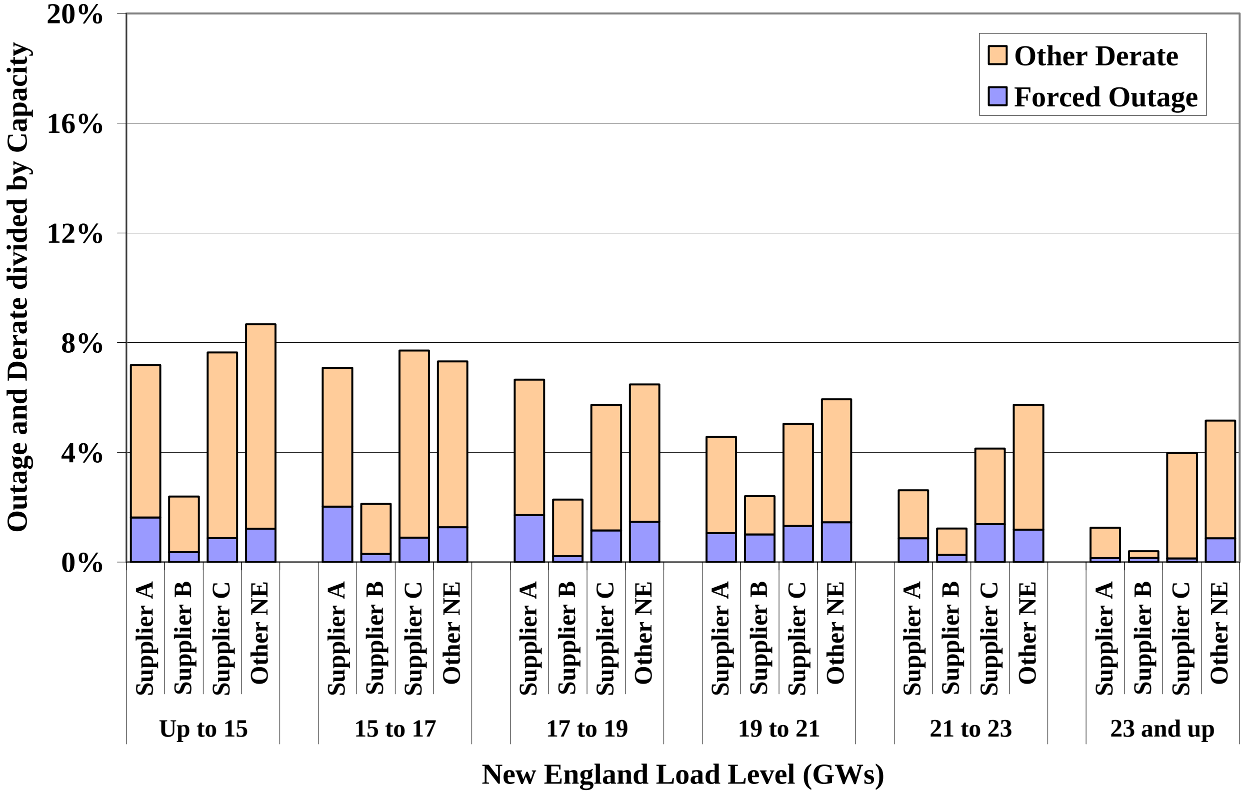


The largest supplier in Norwalk-Stamford exhibited relatively high levels of forced outages and other derates under all load conditions, although they are substantially reduced when load is greater than 17 GW. We examined the underlying data and found that these deratings and outages were not concentrated during periods with congestion into Norwalk-Stamford. Thus, the quantities shown in the figure do not provide evidence of systematic physical withholding.

4. Potential Physical Withholding in All New England

Having analyzed each of the constrained areas in New England, Figure 52 summarizes the physical withholding analysis for all of New England by load level. The results of this analysis are shown for three groups of supply. Supplier A has the largest portfolio in New England and was pivotal in approximately 13 percent of the hours during 2007 (excluding capacity under reliability agreements). Suppliers B and C were also pivotal during approximately 5 percent and 4 percent of the hours, respectively. All other suppliers are shown as a group for comparison purposes.

Figure 52: Forced Outages and Deratings by Load Level and Supplier
All New England, 2007



Supplier A exhibited rates of forced outages and other non-planned deratings that were comparable to most other New England suppliers and, importantly, were especially low when loads exceeded 21 GWs. Supplier B had lower levels of forced outages and other non-planned deratings than the other suppliers in 2007 for all load levels. Supplier C exhibited rates of forced outages and other non-planned deratings that were comparable to other New England suppliers under all load conditions.

As a group, the other New England suppliers show higher derating levels under low load conditions, but derating levels decrease as load levels increase. These patterns generally suggest that New England suppliers have increased the availability of their resources under peak demand conditions rather than physically withholding resources. The increased availability is particularly notable when we consider the effects of high ambient temperatures on thermal generators. Naturally, ambient temperature restrictions on thermal units vary along with load and are difficult to distinguish from physical withholding through a review of market data. It is beyond the scope of this report to determine whether individual outages and other deratings were warranted. However, the overall quantity of capacity subject to the deratings was consistent with expectations for a workably competitive market, so we do not find evidence to suggest that these deratings constituted an exercise of market power.

E. Conduct Raising NCPC Payments

In addition to withholding capacity from the market to raise clearing prices, suppliers can also exercise market power by inflating the NCPC payments they receive when they are needed for local reliability. In this regard, the report finds that the largest supplier in the Boston area engaged in conduct designed to increase its NCPC payments in 2007. Beginning in early 2007, this supplier:

- Increased its day-ahead offers prices for its large, economic units, which:
  - Reduced the day-ahead commitment of the supplier's large units; and
  - This required the ISO to supplementally commit some of the supplier's other capacity;
- Self-committed the large economic units on most days in which they were not committed by the ISO.

This conduct led to substantial excess capacity in the Boston area and rendered the supplemental commitments by the ISO unnecessary in retrospect. This strategy is substantially similar to prior conduct by the supplier in 2005. However, it did not occur in 2006 because the supplier's key capacity was under a reliability agreement that stipulated that the capacity be offered at marginal cost. Hence, the large economic units were usually committed in the day-ahead market in 2006. The reliability agreements for these units expired at the beginning of 2007.

The recent modification in local reliability requirements for the Boston area (which was made possible by the new transmission capability added into the area) should remove the incentive for this conduct in 2008. Nonetheless, we have been coordinating the Internal Market Monitoring Units in an evaluation of the criteria used to mitigate offers that increase NCPC payments. We agree with the IMMU's preliminary conclusion that, with that the introduction of locational forward reserve markets and forward capacity markets, the mitigation criteria for conduct that affects NCPC payments should be modified. This is particularly true in chronically constrained areas that routinely require supplemental commitments to maintain reliability. Hence, we are consulting with the Internal Market Monitoring Unit to develop a specific modifications to the mitigation measures that should be proposed later this year.

F. Conclusions

Based on the analyses of potential economic and physical withholding in this section, we find that the markets performed competitively with little evidence of market power abuses or manipulation in 2007. The pivotal supplier analysis suggests that market power concerns exist in a number of areas in New England. However, the abuse of this market power is limited by the ISO-NE's market power mitigation measures and the large amount of capacity under reliability agreements. Nonetheless, ISO-NE should continue to monitor closely for potential economic and physical withholding, particularly in constrained areas.

While there is no substantial evidence that suppliers withheld capacity from the market in order to raise clearing prices, there is evidence that at least one supplier engaged in conduct to inflate its NCPC payments when they were needed for local reliability. We have been coordinating the Internal Market Monitoring Units to develop modifications to the mitigation measures that will more effectively address this type of conduct in the future.