2013 ASSESSMENT OF THE ISO NEW ENGLAND ELECTRICITY MARKETS

Prepared by:

David B. Patton, PhD
Pallas LeeVanSchaick, PhD
Jie Chen, PhD

EXTERNAL MARKET MONITOR FOR ISO-NE

JUNE 2014

Table of Contents

List of Figures

List of Tables

Guide to Abbreviations

ASM	Ancillary Services Market
AMP	Automated Mitigation Procedures
CONE	Cost of New Entry
CT DPUC	Connecticut Department of Public Utility Control
EMM	External Market Monitor
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
FTR	Financial Transmission Rights
GW	Gigawatt (1 GW = 1,000 MW)
HHI	Herfindahl-Hirschman Index, a measure of market concentration
ISO	Independent System Operator
ISO-NE	ISO New England Inc.
LFRM	Locational Forward Reserve Market
LMP	Locational Marginal Price
LOC	Lost Opportunity Cost, a component of the regulation price
LSR	Local Sourcing Requirement
MMbtu	Million British Thermal Units, a measure of energy content
IMM	Internal Market Monitor
MW	Megawatt
MWh	Energy associated with producing 1 MW for one hour
NCPC	Net Commitment Period Compensation
NEMA	North East Massachusetts
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council, Inc.
NYISO	New York ISO
PER	Peak Energy Rent
PPR	Performance Payment Rate
RA	Reconfiguration Auction
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

Preface

Potomac Economics serves as the External Market Monitor for ISO-NE. In this role, we are responsible for evaluating the competitive performance, design, and operation of the wholesale electricity markets operated by ISO-NE.[1] In this assessment, we provide our annual evaluation of the ISO's markets for 2013 and our recommendations for future improvements. This report complements the Annual Markets Report, which provides the Internal Market Monitor's evaluation of the market outcomes in 2013.

We wish to express our appreciation to the Internal Market Monitor and other staff of the ISO for providing the data and information necessary to produce this report.

[1] The functions of the External Market Monitor are listed in Appendix III.A.2.2 of "Market Rule 1."

Executive Summary

This report assesses the efficiency and competitiveness of New England's wholesale electricity markets in 2013. Since ISO-NE began operations in 1999, it has made significant enhancements to the energy market and introduced markets for other products that have improved overall efficiency. ISO-NE'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 generation outages or other contingencies occur;
- 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 satisfy demand in the short-term and by establishing transparent, efficient wholesale price signals that govern investment and retirement decisions in the long-term. The markets achieve the short-term benefits by coordinating the commitment and dispatch of the region's resources, which 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 level of reliability with which it is delivered.

A. Introduction and Summary of Findings

In addition to providing a summary of market outcomes in 2013, this report includes findings in two primary areas: the competitive performance of the markets and the operational efficiency of the markets. The broad findings in each of these areas are discussed below.

1. Competitive Performance of the Markets

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 2013. Although structural analyses indicate potential market power under certain conditions in some areas, our assessment raised no significant competitive concerns associated with suppliers' market conduct. In addition, the ISO's automated market power mitigation process was effective in preventing the exercise of market power under conditions when a supplier may face limited competition.

Energy prices rose 58 percent from 2012 to 2013 primarily because of increased prices for natural gas (the dominant fuel in New England), which rose 78 percent on average from 2012.[2] In a competitive market, suppliers have strong incentives to offer their supply at prices close to their short-run marginal costs of production.[3] Because fuel costs constitute the vast majority of the marginal costs of most generation, higher fuel costs translate into higher offer prices and market clearing prices in a well-functioning, competitive market. The correspondence of fuel prices and offer prices in New England is an indication of the competitiveness of ISO-NE's markets. The effects of variations in natural gas prices are discussed below in greater detail.

Besides natural gas prices fluctuations, other variations in supply and demand also contributed to the increase in energy prices:

- On the demand side, peak load levels were higher in 2013 than in 2012 both in the summer and in the winter.
- Summer loads exceeded 25 GW for 44 hours and peaked at 27.4 GW in 2013 as compared with just 18 such hours and a peak of 25.9 GW in 2012.

2 Natural gas prices are based on the day-ahead prices reported by Platts for Algonquin City Gates (which is an average of deliveries from the Algonquin pipeline to citygates in Connecticut, Rhode Island, and Massachusetts).

3 Short-run marginal costs are the incremental costs of producing additional output in a timeframe short enough to preclude expanding, retiring or converting the assets to another use. These costs include any foregone opportunity costs of producing such output. For convenience, we will refer to these costs as "marginal costs". The incentive to submit offers at prices close to marginal cost is affected by the design of the market. This incentive exists in markets that establish clearing prices paid to all sellers, as is the case in the ISO-NE markets. Markets that make payments to suppliers based on the supplier's offer (i.e., pay-as-offer markets) create incentives for suppliers to raise their offers above their marginal costs.

- Winter loads exceeded 19 GW for 77 hours and peaked at 21.5 GW in 2013, compared to just 14 such hours and a peak of 19.9 GW in 2012. Tight operating conditions in these hours added 6 percent to the average LMP at New England Hub.
- On the supply side, production from nuclear, wind, coal, and oil-fired generation, together with net imports from neighboring areas, increased by an average of 1,270 MW in 2013 and by 2,120 MW during the winter months. The additional supply helped offset the effects of higher peak demand levels and reduced natural gas supplies.

2. Operational Efficiency of the Markets

Efficient real-time prices are critically important because they:

- Provide incentives for market participants to operate in a manner that maintains reliability at the lowest overall cost;
- Facilitate efficient day-ahead scheduling, resource commitments, and the arrangement of reliable fuel supplies for those resources; and
- Contribute to efficient investment in supply and demand response resources with flexible operating characteristics in the long term.

We find that both the day-ahead and real-time markets operated relatively efficiently in 2013 as prices appropriately reflected the effects of lower fuel prices and load levels. However, we also find that real-time prices often do not fully reflect the cost of satisfying demand and maintaining reliability during tight market conditions, particularly when fast-start resources or demand response resources are deployed in the real-time market. We make several recommendations in this report to address the efficiency of real-time prices.

The electricity market performed well under tight natural gas system conditions, providing incentives for suppliers to conserve gas and switch to fuel oil. The number of days when significant amounts of fuel oil was needed due to the limitations of the natural gas system increased from none in 2012 to 22 days in 2013.[4] Although New England has adequate non-gas resources to satisfy electricity demand and reliability criteria under peak winter conditions, low oil inventories, the limits of the oil supply chain, and environmental limits on oil usage reinforce the important role of the market in ensuring that scarce fuel is used efficiently.

4 These days are defined as days when: i) natural gas price at the Algonquin City Gates was higher than $17 per MMbtu; and ii) average oil-fired generation exceeded 200 MW per hour.

Natural gas system limitations that prevent generators from responding to the ISO's commitment instructions became more frequent in 2013 during the winter months. This led the ISO to commit additional non-gas capacity for system reliability early in the year. However, such commitments were reduced in the winter of 2013/14 because of enhancements by the ISO in its tracking of gas system conditions. Such enhancements are important since reliability commitments can often lead to significant surplus capacity in real time, which tends to depress energy and ancillary services prices in the real-time market.

The ISO is proposing changes to increase the incentive for suppliers to make fuel arrangements to increase their availability in real time, and improve real-time price signals by bringing the market requirements into better alignment with its reliability requirements.

3. Recommendations

Overall, we conclude that the markets performed competitively in 2013 and were operated well by the ISO. Based on the results of our assessment, however, we offer 8 recommendations to further improve the performance of the New England markets. All but one of the recommendations were also recommended in our *2012 Annual Assessment*. This is expected since many of the recommendations require substantial resources and must be prioritized with the ISO's other projects and initiatives. Most of these recommendations are either currently being evaluated by the ISO or have been included in the Wholesale Markets Plan for implementation over the next five years. Three of the recommendations made in the 2012 report are not included in this report because the ISO has nearly completed market changes to address the recommendations.[5] A table of recommendations can be found at the end of this Executive Summary.

5 Including implementing a variable replacement reserve requirement and a sloped demand curve in the capacity market. In addition, recommendations #8 and #9 from the 2011 Annual Assessment are set for implementation by the eighth Forward Capacity Auction in February 2014. These include implementing buyer-side and supplier-side mitigation measures and modeling all eight load zones in the auction.

B. Energy Prices and Congestion

Average real-time energy prices increased 58 percent, from approximately $38 per MWh in 2012 to $60 per MWh in 2013.[6] The primary reason for the increase was substantially higher natural gas prices, which rose 78 percent from 2012.

More frequent and extreme high demand conditions also contributed to the increase in energy prices in both the summer and winter. Summer loads exceeded 25 GW for 44 hours in 2013 compared to 18 such hours in 2012. Winter loads exceeded 19 GW for 77 hours in 2013 compared to 14 such hours in 2012. Although these peak load hours accounted for just 1.4 percent of all hours during 2013, LMPs averaged $250 per MWh during these hours, so the increased frequency of such periods had a significant effect on average price levels for 2013.

Increased supply partially offset the effects of higher natural gas prices and reduced natural gas deliveries to New England. The increased supply sources in 2013 included:

- Net imports – Average net imports from neighboring areas rose by more than 700 MW in 2013, particularly from New Brunswick and New York. The increase was largest during the coldest winter months (January, February, December) when net imports increased by an average of 1,150 MW over the previous year.
  - ✓ Increased net imports from New York were due to higher New England LMPs (driven primarily by the spread in natural gas prices between New York and New England).
  - ✓ Higher imports from New Brunswick resulted partly from the return of a nuclear unit at the Point Lepreau plant (with an installed capacity of 700 MW).
- Non-fossil generation – The average output from nuclear and wind generation increased by 210 MW in 2013, reflecting fewer nuclear outages and additional wind capacity.
- Other non-gas generation – The average output from coal-fired and oil-fired generation increased by 360 MW in 2013 and 1,000 MW during the winter months because of the improved economics of these fuels relative to natural gas.

Overall, these supply increases and limited gas transmission capability into New England led to a 17 percent reduction in gas-fired generation from 2012 to an average of 5.8 GW in 2013. In the

6 The price at the New England Hub, which is representative of the New England market, is reported here. The average energy price is weighted by the New England load level in each hour.

winter months, gas-fired generation fell to an average of 4.6 GW in 2013, down 25 percent from the previous year.

1. Congestion and Financial Transmission Rights

New England has experienced very little congestion into historically-constrained areas since transmission upgrades were completed in 2009. Reductions in congestion-related Locational Marginal Price (LMP) differences result in less overall congestion revenue being collected in the day-ahead and real-time markets.

Total day-ahead congestion revenues totaled $46 million in 2013, up from $30 million in 2012. The increase in congestion revenue resulted primarily from high levels of congestion on several days in February when forced transmission outages limited flows from Connecticut to neighboring states and two days in September when planned transmission outages and unusually high loads led to severe congestion on flows through West-Central Massachusetts.

The ISO uses most of the congestion revenues to fund the economic property rights to the transmission system in the form of FTRs.[7] The congestion revenue collected by the ISO in 2013 was sufficient to fully fund the $40 million target value of the FTRs. This is important because if market participants anticipate that FTRs will not be fully funded, FTR prices will be depressed below the expected value of congestion in future FTR auctions.

The ISO operates annual and monthly auctions for FTRs, which allow participants to hedge the congestion and associated basis risk between any two locations on the network. For 2013, the ISO expanded from one annual auction to two annual auctions in order to provide more opportunity of price discovery by market participants. Given the low overall levels of congestion, this change did not have a significant effect on the valuation of congestion in the FTR auctions. Since FTR auctions are forward financial markets, efficient FTR prices should reflect the expectations of market participants regarding congestion in the day-ahead market.

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

Our analysis of FTR prices indicates that 2013 annual FTR prices were generally higher than the congestion that prevailed in the energy market. Monthly FTR prices were generally more consistent with congestion patterns. This improvement is expected because additional information becomes available regarding system conditions between the annual and monthly auctions. Overall, we conclude that the FTR markets performed reasonably well in 2013.

2. Day-Ahead to Real-Time Price Convergence

When prices in the day-ahead market converge well with the real-time market, it indicates that the day-ahead market accurately represents expected real-time market conditions. This is important because most supply and demand settlements occur in the day-ahead market and FTRs settle against day-ahead congestion prices. Additionally, most generation is committed through the day-ahead market, so good price convergence leads to a more economic commitment of resources and the arrangement of fuel supplies at lower cost.

We found that price convergence between the day-ahead and real-time markets was not optimal in 2013. Real-time prices at the New England Hub were 0.3 percent higher on average than average day-ahead prices in 2013. Average real-time prices at the New England Hub have been persistently higher than average day-ahead prices for several years, which is unusual since electricity markets typically exhibit slightly higher day-ahead prices. We do not believe this result is efficient because small day-ahead premiums generally lead to a more efficient commitment of the system's resources.

Section V shows that real-time energy prices frequently do not reflect the full costs of the marginal source of supply. For example, when high-cost peaking resources are committed to satisfy the demand during tight operating conditions, real-time prices generally do not reflect their full costs. Because the real-time prices are understated in these cases, day-ahead prices would have to be slightly higher than the actual real-time prices in order to efficiently facilitate a day-ahead commitment of resources to fully satisfy the real-time system needs.

One reason for the pattern of real-time premiums is that the average allocation of NCPC charges to virtual load is relatively large. Otherwise, virtual traders would have a strong incentive to buy at the lower day-ahead price and sell at the higher real-time price. Hence, the allocation of

NCPC charges has likely inhibited the natural market response to the sustained real-time price premiums and contributed to the tendency for the day-ahead market to schedule less than the full system load. This is discussed in the next sub-section.

3. Virtual Trading and Uplift Allocation

Virtual trading plays an important role in overall market efficiency by improving price convergence between day-ahead and real-time markets, thereby promoting efficient commitment and scheduling of resources in the day-ahead market. Virtual trading in the day-ahead market consists of purchases or sales of energy that are not associated with physical demand or physical generating resources. Since no physical energy will be supplied or consumed in real time, virtual transactions scheduled in the day-ahead market are settled against real-time energy prices and are only profitable when they contribute to price convergence between the two markets.

Virtual trading volumes have been very low for several years, partly because scheduled volumes are allocated large amounts of NCPC charges and because of heightened regulatory risks. In 2013, the average hourly scheduled volumes of virtual load and virtual supply were just 230 MW and 206 MW respectively. Virtual load and supply accounted for less than 2 percent of the total scheduled demand and supply in the day-ahead market. The allocation of Economic NCPC charges to virtual transactions averaged $2.95 per scheduled MWh in 2013, placing significant downward pressure on virtual trading volumes and hindering the day-ahead market's natural response to transitory price differences between the day-ahead and real-time market.

Most NCPC charges result from supplemental commitments for system-wide needs (known as "Economic NCPC") and are allocated to "real-time deviations" between day-ahead and real-time schedules.[8] In reality, some deviations are "harming" and tend to increase NCPC, while others are "helping" and reduce NCPC. For example, underscheduling physical load in the day-ahead market can cause the ISO to commit additional units in real-time, which are likely to increase NCPC—this is a "harming" deviation. Conversely, "helping" deviations, such as over-scheduling load (including virtual load), generally result in higher levels of resource

8 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, uninstructed generation deviations from day-ahead schedules, virtual load schedules and virtual supply schedules.

commitments in the day-ahead market and, therefore, usually decrease the ISO's need to make additional commitments, thereby avoiding NCPC. The current allocation does not distinguish between helping and harming deviations and is, therefore, not consistent with cost causation. Hence, this allocation assigns NCPC costs to transactions that actually tend to *reduce* the need for supplemental commitments, including virtual load.

Additionally, NCPC charges are caused by many factors other than real-time deviations, such as when peaking resources are dispatched but do not set LMPs or when supplemental commitments are made for forecasted needs that do not materialize. We find that the current allocation scheme allocates costs to helping deviations, which reduce NCPC charges, and over-allocates costs to harming deviations relative to the portion of the NCPC they likely cause.

→ *We recommend that the ISO modify the allocation of Economic NCPC charges to participants that cause the NCPC, which would generally involve not allocating NCPC costs to virtual load and other real-time deviations that cannot reasonably be argued to cause real-time economic NCPC.*

The ISO has recently taken steps to address this recommendation and improving the allocation of NCPC. In NCPC Cost Allocation Phase 1, the ISO proposes to remove the allocation of NCPC costs incurred for real-time 1st contingency issues and system-level operating reserve needs from from virtual load and overscheduled physical load to better align the charges with the drivers of those costs. Phase 2 will evaluate other potential improvements in the allocation of NCPC.

C. Reserve and Regulation Markets

The ISO operates a forward reserve market where reserves are procured in seasonal auctions, a real-time regulation market, and a real-time reserve market where reserves are scheduled with local requirements and co-optimized with the real-time energy market. These provide market incentives that help ISO-NE meet the reliability needs of the system and reduce the need for out-of-market actions by the operators.

1. Real-Time Reserve Market Results

Overall, the clearing prices for operating reserves have increased considerably since 2011. Outside the local reserve zones:

- The average 10-minute spinning reserve clearing price increased from $1.04 per MWh in 2011 to $1.65 per MWh in 2012 and $2.95 per MWh in 2013; and
- The average 30-minute operating reserve price rose from $0.25 per MWh in 2011 to $0.97 per MWh in 2012 and $2.27 per MWh in 2013.

Recent increases in 30-minute reserve clearing prices have resulted from changes in market conditions and market rules. The most significant rule changes are discussed in the next subsection, but the two most significant changes in market conditions are:

- More frequent peaking conditions in 2013, which led to roughly 20 hours of 30-minute reserve shortages and accounted for 50 percent of the average clearing price for 2013; and
- Increased LMPs from higher fuel prices, which lead to proportionate increases in the opportunity costs of generators that are scheduled for operating reserves.

Because the 30-minute reserves are the lowest quality class of reserves, all other reserve prices and energy prices will include the 30-minute reserve price. For example, the 10-minute reserve price will always be equal to or greater than the 30-minute reserve price because these reserves can be substituted to satisfy the 30-minute requirement. However, both local reserve zone constraints and system-level 10-minute reserve constraints were rarely binding, so the prices of 10-minute non-spinning reserves and operating reserves in local reserve zones were comparable to the prices of 30-minute reserves shown above.

Higher real-time operating reserve prices increase the operating profits ("net revenues") of generators that perform reliably and have high levels of real-time availability. Operating reserves and energy are co-optimized in the real-time market, so the opportunity cost of not providing energy is reflected in the reserve prices. Likewise, these reserve prices are embedded in the prevailing LMPs. A generator that is scheduled for energy or operating reserves in a large number of hours could earn up to an additional $20 per kW-year by being available during periods when 30-minute reserve constraints are expected to bind.[9] This would likely constitute up to 15 percent of the likely annual net revenues needed to support investment in a new combined cycle unit based on our analysis for 2013. Our net revenue analysis is discussed further in sub-section E.

---

9 This assumes that the full capability of the generator is scheduled for energy or reserves in all hours with a binding 30-minute reserve constraint, and it assumes that the marginal resource is capable of providing energy or operating reserves.

2. Real-Time Reserve Market Rule Changes

The following market rule changes have contributed to the increase 30-minute reserve prices:

- In June 2012, the RCPF for system-level 30 minute reserves was increased from $100 to $500 per MWh. This has led the real-time dispatch model to set much higher clearing prices and incur higher re-dispatch costs during tight operating conditions to schedule resources needed for reliability. Previously, the real-time model would have simply gone short of reserves in these intervals and set the clearing price at $100 per MWh, or the operators would have taken out-of-market actions to secure more reserves.
- In July 2012, the system-level 30-minute reserve requirement rose consistent with the 25 percent (350 MW) increase in the system-level 10-minute requirement. The increased requirement has contributed to more frequent binding reserve constraints and higher clearing prices.
- In June 2013, the ISO implemented new rules for auditing and modifying the 10-minute and 30-minute claimed capability of operating reserve units. This led to a 190 MW reduction in claimed capability from peaking units during the summer of 2013 (compared to the prior summer) and a modest reduction during the winter months.
- In October 2013, the ISO expanded its 30-minute reserve requirements by adding a Replacement Reserve requirement. This allows the real-time clearing prices to better account for reliability needs that lead to supplemental commitments. Typically, the Replacement Reserve requirement is 160 to 180 MW, although it can be increased to account for factors such as higher-than-normal expected generator losses.

These rule changes have been beneficial because they lead real-time prices to better reflect the reliability needs of the system, which improves incentives for generators to be available and perform reliability, and reduces the need for out-of-market actions.

3. Operating Reserves in the Day-Ahead Market

The day-ahead market coordinates the procurement of an efficient set of resources to satisfy the needs of the system over the operating day, while respecting transmission constraints and other limitations. Doing this in the day-ahead timeframe enables resources to be committed (considering start-up costs, minimum run times, and other operational inflexibilities) and arrange for fuel supply. Currently, the ISO procures only energy through the day-ahead market, although forward reserve providers have certain day-ahead obligations.

Procuring operating reserves in the day-ahead market would allow the ISO to procure the amount of reserves it needs for the following day and to set clearing prices that reflect the costs of satisfying the operating reserve obligations. Such markets would also likely help address the

ISO's concerns regarding unit availability. The day-ahead reserve schedules would be established in a timeframe in which suppliers can make arrangements for fuel and staffing to allow them to be available in real time and respond to reserve deployments.

→ *We recommend that the ISO consider introducing day-ahead operating reserve markets that are co-optimized with the day-ahead energy market.*

4. Forward Reserve Market Results

The Locational Forward Reserve Market (LFRM) is a seasonal auction held twice a year where suppliers sell reserves which they are then 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 operating reserves for All of New England, Boston, Connecticut, and Southwest Connecticut. This report evaluates the results of recent forward reserve auctions and examines how suppliers satisfied their obligations in the real-time market.

With the exception of the system 10-minute non-spinning reserve price in the Winter 2013/14 auction, only the system-wide 30-minute reserve requirement was binding so the price for all local and system-wide reserve products were equal to the 30-minute reserve price. The 30-minute reserve clearing prices (adjusted for the deduction of forward capacity payments) rose from an average of $0.40 per kW-month in the 2012/13 Capacity Commitment Period to $3.23 per kW-month in the 2013/14 Capacity Commitment Period. This increase was caused by:

- The higher forward reserve requirements and anticipated increases in the real-time 30-minute reserve clearing prices (a large component of the cost of providing forward reserves is the expected forgone revenue from real-time reserves);[10] and
- The expected cost of foregone energy revenues that result from the obligation of generators to offer at or above the Forward Reserve Threshold Price.

As in prior years, we found that 99 percent of the resources assigned to satisfy forward reserve obligations in 2013 were fast-start resources capable of providing offline reserves. This is

10 The actual forward reserve prices averaged $3.35 per kW-month in the 2012/13 Capacity Commitment Period and $6.18 per kW-month in the 2013/14 Capacity Commitment Period. However, forward reserve payments are adjusted by deducting the FCA clearing price, which was $2.951 per kW-month for both Capacity Commitment Periods.

consistent with our expectations because these resources can satisfy their forward reserve obligations at a very low cost.

The ISO should consider the long-term viability of the forward reserve market because:

- It has not achieved one of its primary objectives, which was to lower NCPC by purchasing forward reserves from high-cost units frequently committed for reliability.
- The forward procurements do not ensure that sufficient reserves will be available during the operating day. Forward reserve sellers are simply obligated to offer at prices higher than the Forward Reserve Threshold Price, but may still be dispatched for energy.
- The obligation of forward reserve suppliers to offer at prices higher than the Forward Reserve Threshold Price can distort the economic dispatch and inefficiently raise costs.

In addition, higher forward capacity prices in recent auctions may eliminate the incentive for suppliers to sell forward reserves since they are only paid the difference between the forward reserve clearing price and the forward capacity price.

In the longer-term, we recommend the ISO consider introducing day-ahead reserve markets. Such markets would allow the ISO to procure the reserves it needs for the following day and to set clearing prices that reflect the costs of satisfying the operating reserve obligations. Such markets would also likely help address the ISO's concerns regarding unit availability. The day-ahead reserve schedules would be established in a timeframe in which suppliers can make arrangements for fuel and staffing to allow them to respond to reserve deployments. This is particularly true for spinning reserve providers, since it is prohibitively costly for them to accept forward reserve obligations for an entire procurement period.

5. Regulation Market

The regulation market performed competitively in 2013, with an average of approximately 670 MW of available supply competing to serve an average of 60 MW of regulation demand.[11] The significant excess supply generally limited competitive concerns in the regulation market. However, regulation supply was sometimes tight in low-demand periods when many regulation-

11 The average available supply is the average of offered regulation capabilities from committed resources in each hour.

capable resources were offline, leading to transitory periods of high regulation prices.[12] Regulation market expenses rose from $11.6 million in 2012 to $20.4 million in 2013. This increase was driven partly by the increase in natural gas prices over the same period and partly by the market design changes made in July 2013 to comply with Order 755.

In October 2011, FERC issued Order 755 on Frequency Regulation Compensation, which requires ISO-NE and other ISOs to operate regulation markets that compensate generators for "actual service provided, including a capacity payment that includes the marginal unit's opportunity costs and a payment for performance that reflects the quantity of frequency regulation service provided."[13] After several compliance filings by ISO-NE and NEPOOL, the Commission accepted: (a) a temporary market rule change that incorporated opportunity costs into the capacity payment under the current design in July 2013, and (b) permanent proposed regulation market rule changes to be effective in October 2014. It will be important to evaluate the performance of this market after the full changes are implemented. It is likely that the regulation market will continue to perform competitively given the large amount of supply in the market relative to the demand.

D. Real-Time Pricing and Market Performance

The goal of the real-time market is to coordinate the use of resources to efficiently 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. 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. In addition, to the extent that efficient price signals during shortages and tight operating conditions exceed most generators' costs, the reliance on revenue from the capacity market to maintain resource adequacy is reduced.

---

12 These types of transitory high regulation prices are normal market outcomes and generally do not raise competitive concerns.

13 *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, Order No. 755, 76 Federal Register 67260 (Oct. 31, 2011), FERC Stats. & Regs. ¶ 31,324 (2011) (Order 755).

We evaluated three aspects of the real-time market related to pricing and dispatch in 2013 and make the following conclusions and recommendations:

1. Real-Time Pricing of Fast-Start Resources

Fast-start generators are routinely deployed economically, but the resulting costs are often not fully reflected in real-time prices. In 2013, 60 percent of the fast-start capacity that was started in the real-time market did not recoup its offer. This leads fast-start resources with flexible characteristics to be substantially under-valued in the real-time market, despite the fact that they provide significant economic and reliability benefits. If the average total offers of these units were fully reflected in the energy price, the average real-time LMP would increase approximately $3.34 per MWh in 2013. If these price increases were reflected in the calculation of NCPC uplift charges, we estimate that they would have been $9.3 million lower in 2013.

Such price increases would also increase the net revenues earned by generators with high levels of real-time availability and performance during tight operating conditions by up to $25 per kW-year or 17 percent of the net revenue needed to support investment in a new combined cycle unit. These effects would be partially offset to the extent that higher real-time LMPs would encourage increased commitment of lower-cost resources in the day-ahead market.

→ *We recommend that the ISO evaluate potential changes in the pricing methodology that would allow the deployment costs of fast-start generators to be more fully reflected in the real-time market prices.*

2. Real-Time Pricing During Demand Response Activations

Participation by demand response in the market has been beneficial in many ways, contributing to reliable system operations, long-term resource adequacy, lower costs, decreased price volatility, and reduced supplier market power. Even modest reductions in consumption by end-users during high-price periods can significantly reduce the costs of committing and dispatching generation to satisfy the needs of the system. These benefits underscore the value of designing wholesale markets that provide transparent economic signals and market processes that facilitate demand response.

However, the inflexibility of demand response resources presents significant challenges for efficient real-time pricing. When demand response resources are on the margin, prices should reflect the marginal cost of the foregone consumption by the demand response resources. Because they are generally not dispatchable, they do not set real-time energy prices and tend to lower prices by reducing the apparent demand in the market. In 2013, emergency demand response resources were activated for a total of 16 hours on three days because of capacity deficiencies. Market outcomes during half of these hours were depressed by this pricing issue.

→ *We recommend that the ISO develop rules for allowing the costs of activating non-dispatchable demand response resources to be reflected in clearing prices when there would have been a shortage without the activation of demand response resources.*

3. Ex Ante and Ex Post Pricing

ISO-NE re-calculates prices after each interval (i.e., "ex post pricing") rather than using the "ex ante" prices produced by the real-time dispatch model. Our evaluation of ISO-NE's ex post pricing results indicates that it (i) creates a small upward bias in real-time prices in uncongested areas when reserve constraints are not binding, (ii) substantially understates the ex ante prices in uncongested areas when reserve constraints are binding, especially during reserve shortages; and (ii) sometimes distorts the value of congestion into constrained areas.

→ *We recommend that the ISO consider discontinuing the current ex post pricing model and establish prices that are more consistent with ex ante prices.*

E. Analysis of Long-Term Economic Signals

The ISO-NE markets play a critical role in governing investment, retirement, and other long-term decisions made by market participants. The expected net revenues from ISO New England's energy, ancillary services, and capacity markets are the primary means by which this occurs. Therefore, it is important to evaluate the net revenues produced by these markets, which are defined as the total revenues (including energy, ancillary services, Winter Reliability Program and capacity revenues) that a generator would earn in the ISO-NE markets less its variable production costs. These net revenues serve to cover a supplier's fixed costs and the return on its investment.

If there is not sufficient net revenue in the short-run from these markets to justify entry of a new generator, then one or more of the following conditions exist:

- New capacity is not needed because sufficient generation is already available;
- Load conditions are below expectations due to mild weather or reduced demand, leading to lower energy prices than expected; and
- Market rules or conduct are causing revenues to be reduced inefficiently.

Alternatively, if prices provide excessive revenues in the short-run, this would indicate a shortage of capacity, unusually high load conditions, or market rules or conduct resulting in inflated prices. Evaluating the net revenues produced from the ISO-NE's markets allows us to assess the design and performance of the market in providing efficient long-run economic signals.

1. Net Revenues for New Resources

Net revenues have increased considerably since 2012, which is due in part to the increase in operating reserve prices in 2013. Nonetheless, the estimated net revenues for new units were much lower than the cost of new entry (CONE) for all the technology types. This is expected in part because of the capacity surplus that has prevailed in New England in recent years. However, it will be very important for these net revenues to rise efficiently as capacity margins fall in New England to ensure that new investment is sufficient to maintain adequate resources. In this regard, the sloped capacity demand curve filed by ISO New England will play an important role in achieving this objective.

2. Net Revenues for Existing Resources

The energy and reserve markets provide significant incentives for generators to be flexible and available in real-time when clearing prices are likely to be high. This is illustrated by the fact that an older 10-minute gas turbine, which can start quickly and provide off-line reserves, would earn 20 to 65 percent more net revenue per kW-year than an older steam turbine, which has slower and longer operating times. This differential is large enough to influence decisions about the maintenance and/or retirement of older generation (or decisions to build more flexible new resources). The additional returns to being flexible and available highlight the benefits of the real-time pricing enhancements that would improve price efficiency during tight conditions, which are discussed in sub-section D.

In addition to flexibility, the ability to switch fuels away from natural gas can substantially affect a unit's net revenues in some years. The incremental net revenues a supplier earned from having dual fuel capability were de minimis in 2012 because of low natural gas prices. In 2013, dual fuel capability generated modest incremental net revenues for combined-cycle units (~$9 per kW-year) and steam turbines (~$4 per kW-year).[14] However, for the 12 months ending February 28, 2014, the incremental revenue from dual fuel capability increased sharply:

- Combined cycle net revenues increased to $32 per kW primarily because of higher energy revenues attributable to high natural gas prices in January 2014;
- Steam turbine net revenues rose to $19 per kW, half of which is attributable to the winter reliability program and half to higher natural gas prices; and
- Since gas-only combustion turbines can provide reserves during tight gas supply conditions, their increase in net revenues from dual-fuel capability was small.

These dual fuel net revenues for the combined-cycle and steam turbines are sizable, constituting 20 to 30 percent of the annual net revenues a new unit would require to break even. However, these estimates assume that units have sufficient fuel on-site to operate when economic. During the winter of 2013/14, some units ran less because of low oil inventories even with the winter reliability program. Hence, the actual net revenues from dual-fuel capability were likely lower in reality for many dual-fueled units. Finally, given the temporary nature of the winter reliability program, suppliers considering investing in dual fuel capability would likely discount this source of incremental net revenue for dual fuel capability. Nonetheless, periods of natural gas price volatility generate substantial energy net revenues for dual-fueled units.

Forward reserve sales are also a significant source of revenue for peaking units in this analysis because of the high premium on forward reserve clearing prices relative to average real-time reserve prices. Forward reserve sales are less profitable for peaking units with better heat rates because forward reserve providers are obligated to increase their offer prices substantially and,

---

14 This analysis does not include all of the additional costs necessary to maintain an inventory of fuel oil, and that the use of fuel oil may be limited by low inventories and air permit restrictions.

therefore, must forego some profitable energy sales. Combined-cycle units and steam turbines rarely find it profitable to sell forward reserves because they would need to run in a large number of unprofitable hours.

Finally, our analysis shows that peaking units can earn high net revenues by providing reserves. This indicates the importance of programs that audit or otherwise ensure that off-line peaking units are capable of responding as scheduled. If the response capability of reserve units is over-estimated, it will inflated reserve payments to poor performers and depressed reserve clearing prices for good performers. This is particularly important during winter operating conditions when some off-line reserve providers may be less reliable than at other times of year.

F. External Interface Scheduling

Efficient scheduling of the interfaces between New England and its neighbors can have a significant effect on the ISO-NE market outcomes. Hence, we evaluate transaction scheduling between New England and the three adjacent regions: Quebec, New Brunswick, and New York.

1. Quebec and New Brunswick Interfaces

Net imports from Quebec averaged 1,635 MW during peak hours 2013, up slightly from 2012. Quebec generally has significant surplus energy that it sells into neighboring control areas. In 2013, New England experienced the highest energy prices of Quebec's immediate neighbors, so a large share of transmission capability from Quebec was used to import energy to New England in most hours. However, during very cold weather, Quebec reduced flows to New England in order to serve its own native load. Consequently, imports from Quebec fell to an average of 1,545 MW on the 22 winter days with gas prices above $20 per MMbtu.

Net imports from New Brunswick increased significantly to an average of 425 MW during peak hours in 2013 because of the return of a 700 MW unit at the Point Lepreau nuclear plant. New Brunswick has little natural gas-fired generation, so flows into New England were maintained at high levels on the 22 winter days with gas prices above $20 per MMbtu, averaging 400 MW.

2. New York Interfaces

New England and New York are connected by one large interface between northern New England and eastern upstate New York, and by two small interfaces between Connecticut and Long Island. Exports are usually scheduled from Connecticut to Long Island over the smaller interfaces (averaging roughly 345 MW during peak hours in 2013), while participants schedule power flows that can alternate directions on the larger interface depending on the relative prices. On average, New England imported roughly 465 MW from New York across the larger interface in 2013.

The spread in natural gas prices between New England and New York is an important driver of the variations in interchange between the two markets, particularly in the winter. The spread averaged $3.90 per MMbtu in four months (January, February, November, and December) of 2013 compared to an average of $0.07 per MMbtu in the other eight months. Accordingly, New England imported an average of 745 MW *from* New York during peak hours in these four winter months, compared to an average of 190 MW *to* New York in other eight months.

On an hourly basis, market participants should arbitrage the prices between New York and New England 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. This has caused large real-time price differences to frequently occur between the two markets, even when the interfaces are not fully utilized. This results in substantial inefficiencies and higher costs in both areas. It also degrades reliability because the interchange does not adjust predictably to changes in supply or demand changes in New England.

To address this issue, ISO-NE and NYISO are implementing the Coordinated Transaction Scheduling (CTS) process to improve the efficiency of the interchange between the two control areas. CTS will allow intra-hour changes in the interchange between control areas and is scheduled to be effective in the fourth quarter of 2015. Under CTS, the ISOs will schedule interchange based on short-term forecasts of market conditions and new bidding procedures that allow firms to submit bids that are jointly evaluated by the ISOs.

→ *We continue to recommend that the ISO place a high priority on the implementation of CTS.*

G. System Operations

The wholesale market should provide efficient incentives for participants to make resources available to meet the ISO's reliability requirements. When the wholesale market does not meet all of these requirements, the ISO will commit additional generation or take other actions to maintain reliability. In addition to the NCPC costs that result from these actions, these commitments result in surplus supply that lowers real-time prices and reduces scheduling incentives in the day-ahead market. Hence, such actions should be undertaken only when necessary. In this section, we evaluate several aspects of the ISO's operations and processes for satisfying reliability requirements in 2013.

1. Accuracy of Load Forecasting

The day-ahead load forecast is important 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-NE's daily peak load forecasts, we found that the average day-ahead load forecast was slightly higher than the average real-time load in the peak load hour of each day in 2013. Overall, load forecasting was relatively accurate and generally superior to load forecasting in other RTO markets.

2. Supplemental Commitment

Supplemental commitment for local reliability has been low since mid-2009 when significant transmission upgrades in historically import-constrained areas were completed. These upgrades have allowed additional imports to these areas, reducing the amount of online and quick start capacity that must be available internally. In 2013, the amount of capacity committed for local reliability issues averaged just 140 MW.

Most supplemental commitments have been made to satisfy system-wide reserve needs in recent years. This category of supplemental commitment decreased 18 percent to average 300 MW in 2013. Our evaluation shows that supplemental commitment during winter conditions was lower in late 2013 than early 2013. Supplemental commitment during the non-winter months was also lower. These reductions were partly due to the following changes in market operations:

- The ISO changed the timing of the day-ahead market and the RAA process on May 23 to allow the initial RAA process to be completed five hours earlier (by 5 pm) on the day before the operating day. This provides additional time for generators to make fuel arrangements, reducing the risk that generators will be unavailable because of a lack of natural gas and, thus, reducing the need for the ISO to make supplemental commitments.
- The ISO implemented several improvements to the real-time reserve market rules that have provided better incentives for market-based commitment of generation, which are discussed in sub-section C.
- The ISO has developed analytical tools to track supply and usage of natural gas on New England generators. More timely and accurate information regarding gas system conditions and availability from these tools enables the ISO to better determine how much supplemental commitment is necessary.

In addition, day-ahead load scheduling increased from an average of 93 percent of actual load in 2012 to 95 percent in 2013. This reduces supplemental commitments because it allows the day-ahead market to facilitate commitments that more completely satisfy the system's real-time needs. The increase was partly due to higher and more volatile real-time energy and reserve clearing prices, which were driven partly by more frequent shortages and high and volatile natural gas prices.

After reviewing the supplemental commitments and the surplus capacity levels that resulted from real-time operating conditions, we found that more than 60 percent of the capacity that was supplementally committed in 2013 was actually needed to maintain system level reserves in retrospect.[15] This was a notable improvement from 45 percent in 2012. Some amount of over-commitment is not avoidable because resource commitments are "lumpy" (i.e., the market cannot commit exactly the quantity it needs) and commitment decisions are often made well in advance when there is significant uncertainty regarding the necessity of the supplemental commitments.

15 This is a simple evaluation that treats any surplus capacity (i.e., the amount of online and available offline capacity in excess of the demand for energy and reserve requirements) as "not needed" for the system. This simple evaluation tends to understate the necessity of supplemental commitments because: 1) the evaluation is based on hourly integrated peak rather than the higher instantaneous peak, and 2) the ISO cannot commit just a portion of a unit. For example, suppose the ISO needs an additional 200 MW of capacity to satisfy system reliability needs and commits the most economic unit with a capacity of 300 MW. In this evaluation, 100 MW of capacity would be deemed as "not needed".

3. Fuel Usage Under Tight Gas Supply Conditions

When transmission bottlenecks on the natural gas pipeline system limit the availability of gas, the wholesale electricity market plays an the important roles of:

- Allocating the available gas between generators;
- Determining how much electricity to import; and
- Conserving and managing available oil inventories other limited non-gas resources.

Uncertainty about natural gas prices and the availability of other fuels contribute to electricity price volatility. These factors make it more challenging for suppliers to offer their resources efficiently and for the ISO to maintain reliability while minimizing out-of-market actions.

Our evaluation of winter operations shows widespread use of oil on a small number of cold-weather days when natural gas supplies were limited because of high core demand. A single seven-day period accounted for 41 percent of the fuel oil used during the Winter of 2013/14 This highlights the difficulty in predicting (before the winter) how much oil-fired generation will be needed for reliability. During this week, much of the oil was used in response to the decrease in electricity imports when natural gas prices were higher in New York than New England. Overall, the ISO and participants have coped reasonably well with challenging fuel supply conditions by effectively conserving and allocating the available supply of natural gas. Nonetheless, the market results from the recent winters highlight two significant market issues.

First, generators currently must submit a single daily offer curve ten hours before the start of each operating day. This creates significant challenges for suppliers that must manage limited fuel in order to produce when it is most valuable. Volatile intraday natural gas market conditions lead to cost uncertainties that cannot be accurately reflected in a daily offer. Likewise, scarce oil inventories lead to opportunity costs that change as units are dispatched more or less than anticipated. The Hourly Offer project will address these issues by allowing suppliers to update their offers through the operating day as conditions change. This will improve the efficiency of generator scheduling and LMPs considerably during peak winter conditions.

Second, although oil-fired generation increased considerably on the days of high gas prices, many oil-fired generators were not fully utilized when LMPs would enable them to recoup the variable costs of producing on oil because of low oil inventories. Before each winter, suppliers with oil-fired capacity decide how much to oil to hold in inventory after balancing the potential gains from being available when gas prices are very high against the carrying costs of storing oil and the risks of holding unused oil after the winter.

4. Uplift Charges

Uplift charges increased from $99 million in 2012 to $196 million in 2013, which included:

- First, out-of-market capacity payments to units retained for reliability (FCM reliability credits) increased $7 million to more than $18 million in 2013. The design issues in the FCM that caused inconsistency between the ISO's reliability needs and its FCM procurements have been resolved, but the payments will continue until June 2016.
- The interim Winter Reliability Program resulted in additional $25 million of uplift. Generators with oil-inventory service obligations were paid nearly $39 per MWh for maintaining the necessary oil inventory to be capable of producing a specific amount of power from oil during the winter.
- Uplift payments for local second contingency protection increased by roughly $29 million in 2013. Most of the increase occurred in February 2013 as Winter Storm Nemo caused substantial generation and transmission outages and resulted in increased local reliability commitments in Boston and Rhode Island.
- The "Economic" category of uplift payments associated with non fast-start resources rose by $30 million from 2012 to 2013. Most of the increase occurred in the three winter months (i.e., January, February, and December), which was caused by higher system-wide reliability commitments and higher natural gas prices.

5. Conclusions: System Operations

Our assessment of system operations indicates that the ISO's operations to maintain adequate reserve levels in 2013 were reasonably accurate and consistent with the ISO's procedures. In 2013, the overall amount of supplemental commitment fell 8 percent from the previous year despite more challenging weather and system conditions. This report discusses several market enhancements and improvements to the reserve adequacy assessment (RAA) procedures that contributed to the reduction. Several of these improvements were made during 2013, so the benefits were not fully reflected in the annual results for 2013.

Our evaluation of winter operations shows widespread use of oil on a relatively small number of cold-weather days when natural gas supplies were limited because of high core demand. Overall, the market performed reasonably well in managing the available supply of oil and natural gas under the tight gas supply conditions, although the report discusses several market changes that should improve market performance.

Limiting the Effects of Out-of-Market Actions

Our analyses show that market clearing prices are heavily dependent on the amount of surplus capacity that is available in the real-time market, especially under relatively tight operating conditions. Hence, factors that lead to artificially high levels of surplus capacity tend to:

- Reduce the incentive for units to procure the fuel necessary to be available in real time;
- Dampen economic signals to invest in better performance and availability for both new and existing resources;
- Use more of the available fuel as more generation is brought online at higher average heat rates; and
- Increase the uplift charges that can be difficult for participants to hedge and that may discourage participation in the ISO-NE market.

To ensure that these issues are minimized, it is beneficial for the ISO to regularly review its assumptions and processes for determining that additional commitments are necessary to satisfy its reliability requirements. In this regard, the ISO made significant enhancements during 2013 to the analytical tools it uses for forecasting how gas pipeline conditions and limited oil inventories will affect generator availability during the operating day, this allowed it to reduce the amount of supplemental commitment in late 2013 compared with previous periods of tight gas system conditions. Additional improvements will be possible when the ISO implements CTS because it will be able to rely on rational interchange adjustments with New York.

Recent Reserve Market Enhancements

The correlation between real-time prices and the amount of surplus capacity also reinforces the importance of:

- Fully reflecting reliability needs in the market requirements for operating reserves. Procuring less operating reserves in the real-time market than needed for reliability increases the apparent surplus capacity amounts and depresses real-time prices. Ultimately, this reduces the incentive for generators to be available in real time; and

- Allowing individual generators to sell only quantities of operating reserves that they are capable of providing. Additional sales artificially raise the apparent real-time supply of operating reserves and tend to depress real-time prices.

The ISO has promoted these two objectives by implementing several recent enhancements to the real-time reserve markets, including procuring "replacement reserves" in the real-time market beginning October 1, 2013, and revising its procedures for auditing suppliers' capability to provide operating reserves in June 2013. These changes are discussed in Section C.

Future Market Enhancements

The ISO is planning two market enhancements that will lead to more efficient scheduling and pricing during tight market conditions. The first will provide generators with additional flexibility to modify their offers closer in the real time (i.e., intraday reoffers). The ISO is planning to introduce hourly day-ahead energy offers and intraday reoffers in the fourth quarter of 2014. This will enable more efficient scheduling, particularly during periods of volatile natural gas prices and low fuel inventories. It will enable suppliers to better manage scarce fuel and will reduce the risks of resources being dispatched below its marginal cost.

Second, the ISO has proposed to modify the allocation of NCPC charges resulting from supplemental commitment for reliability. Currently, a large share of these NCPC charges are borne by virtual load and over-scheduled physical load scheduled in the day-ahead market even though both actually help *reduce* supplemental commitment by helping increase market-based commitment in the day-ahead market. Removing this disincentive to schedule virtual load and physical load in the day-ahead market will improve the day-ahead commitment and reduce the need for supplemental commitment.

We also recommend changes in sub-section D that would allow the real-time prices of energy and reserves to better reflect the costs of maintaining reliability during tight operating conditions. Since expectations of real-time prices are the primary determinant of day-ahead prices, these changes should increase the day-ahead market commitment of generators that can satisfy system's reliability criteria.

H. Forward Capacity Market

The Forward Capacity Market is designed to attract and maintain sufficient resources to satisfy ISO-NE's long-term resource planning requirements efficiently. FCM provides economic signals that supplement the signals provided by the energy and ancillary services markets. In combination, these three sources of revenue provide economic signals for new investment, retirement decisions, and participation by demand response.

Forward Capacity Auctions (FCAs) are held 39 months before the beginning of each year-long Capacity Procurement Period to provide sufficient lead time for a new generator to be built if it clears in the FCA. The first eight FCAs have facilitated the procurement of installed capacity for the period from June 2010 to May 2018. This report evaluates the results of the three most recent FCAs and discusses on-going market enhancements and other areas for potential improvement.

1. FCM Results

In FCA 6, which was held in April 2012 to procure capacity for June 2015 to May 2016, 2.8 GW of excess capacity was purchased over the requirement and all locations cleared at the price floor. This resulted in capacity payment rates of $3.13 per kW-month. However, the ISO rejected 79 MW of de-list bids by existing NEMA resources for the reliability of the NEMA load zone. These resources were retained out-of-market because the NEMA load zone was not modeled in the auction. This issue was resolved after FCA 6 because NEMA and other capacity zones are now modeled in all cases. The previous rules only modeled individual load zones when the existing capacity resources were not sufficient to satisfy the requirement.

New investment in large-scale generation was motivated by the ISO's forward capacity market for the first time in FCA 7 in order to satisfy the requirement for the NEMA load zone. This resulted in price separation between NEMA, where new resources cleared at a price of $14.999 per kW-month and existing resources received a payment rate of $6.661 per kW-month. The rest of the system cleared 3.2 GW of excess capacity at the price floor and resources received a payment rate of $2.74 per kW-month.

After seven FCAs that cleared substantial capacity surpluses at the price floor, several significant generation retirements were announced that eliminated the excess capacity margin going into FCA 8. Consequently, new resources cleared at a price of $15 per kW-month and existing resources received a payment rate of $7.025 per kW-month. The differences between compensation for new and existing resources in FCAs 7 and 8 raise significant efficiency concerns that are discussed below.

2. FCM Market Enhancements

It also become apparent that the current FCA rules have led to pricing outcomes that may undermine the incentives for efficient investment in new resources and maintenance of existing resources. The ISO has already implemented some enhancements and is currently working on additional reforms for future FCAs that will address most of the issues discussed in this section. The recent improvements implemented or proposed by the ISO include:

- First, the ISO began to model the Connecticut and NEMA local capacity zones all of the time in FCA 7. In prior auctions, failing to model local capacity zones led to out-of-market payments to maintain adequate resources. The ISO is planning to model additional local capacity zones, which will become more important in the future as retirements necessitate new entry to satisfy planning criteria in areas outside Connecticut and NEMA.[16]
- The Insufficient Competition Rule has led the effective prices for new resources being more than double the prices for existing resources in the last two auctions in some areas (throughout New England in FCA 8). Generally, it is efficient to pay new and existing resources at the same rate when they are providing the same service partly because it provides efficient incentives for maintaining on existing resources. This issue will be largely addressed when the ISO implements sloped demand curves.
- To address growing concerns regarding resource performance and its effects on reliability, ISO-NE and NEPOOL submitted proposals in January 2014 to strengthen the incentives for suppliers to perform reliably. Both proposals focused on enhancements to real-time shortage pricing as the primary means to facilitate good performance (since resources with high availability would benefit most from shortage pricing). We generally supported the ISO proposal but recommended two modifications: (i) that a lower Performance Payment

16 The Commission recently accepted an ISO proposal to model additional capacity zones whenever the excess reserve margin in a particular local region is smaller than the largest generating station in the region beginning in FCA 10. The rationale for this criterion is that if the station delisted in a particular FCA, it would be necessary to clear new capacity to satisfy the local capacity requirement. See *ISO New England Inc.*, 147 FERC ¶ 61,071 (2014), dated April 28, 2014.

Rate (PPR) be adopted and (ii) that the PPR have a slope that would distinguish between minor and major reserve shortages.[17]

3. Other Recommended Enhancements

In addition to these existing or proposed enhancements, we have identified two additional market rule changes may be beneficial. The first area is related to the market power mitigation measures for existing capacity suppliers. The high clearing prices in FCA 7 and FCA 8 resulted from falling capacity margins in recent years. Capacity margins have fallen because of retirements of older capacity, not because of peak demand growth. Hence, the recent price outcomes demonstrate that retirements can have profound effects on FCA clearing prices and costs to consumers. We have not evaluated the non-price retirements that occurred before FCA 8 and, therefore, have no evidence that would raise potential competitive concerns. Nonetheless, independent of these particular retirements, we find that the current market power mitigation rules are not adequate to ensure the capacity market outcomes are workably competitive. Hence, we recommend that the ISO:

→ *Adopt a mitigation measure that addresses the potential for retirement delist bids to be used to increase FCA prices above competitive levels.*

Second, the Capacity Commitment Period Election (i.e., "Lock-in") allows new generation and new demand response resources to elect to lock-in the auction clearing price for a period of up to five years, and the ISO recently filed to increase the period to seven years. Although the extended lock-in is likely to achieve the purpose of increasing the incentives for new entry, it results in a significant difference between the prices paid to existing resources and prices paid to new resources over the long-term. Paying systematically higher prices for new resources could lead to over-investment in new resources and under-investment in maintaining older resources that are important for reliability. The ISO acknowledge some of the concerns regarding this form of price discrimination in the Testimony of Dr. Robert Either who indicated that the ISO

17 See Motion to Intervene Out of Time and Comments of ISO New England's External Market Monitor in Commission Docket ER14-1050, dated February 13, 2014.

will "reevaluate the lock-in period after a series of successful auctions".[18] We support the ISO's intention to reconsider whether this the lock-in provision is necessary in the future.

I. Competitive Assessment

The report evaluates the market concentration and competitive performance of the markets operated by ISO-NE in 2013. Based on our evaluation of the markets in New England we find that the markets performed competitively in 2013.

This competitive assessment has two main components. First, we utilize structural analyses to identify potential market power issues. Second, we evaluate the conduct of market participants in several areas. Although the structural analyses indicate that some suppliers may possess market power under certain conditions, our analyses do not indicate that suppliers withheld resources to raise prices in the ISO-NE markets.

1. Structural Market Power

The structural component of our assessment evaluates each geographic market primarily 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"). This is most likely to occur in constrained areas that can become separate geographic markets with a limited number of suppliers when congestion arises. Based on our pivotal supplier analysis, we found that one or more suppliers were pivotal in a large number of hours in 2013 in Connecticut (11 percent of hours), Boston (52 percent of hours), and All of New England (33 percent of hours).

2. Market Participant Conduct

The behavioral component 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

18 See filing by ISO-NE and NEPOOL in Commission Docket ER14-1639, dated April 1, 2014, Testimony of Robert G. Ethier at pages 32-36.

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. Due to the substantial decline in commitments for local reliability in recent years compared to historical levels, this was not a significant concern in 2013.

3. Market Power Mitigation

High levels of structural market power are commonplace in wholesale electricity markets and are usually addressed through effective market power mitigation measures. Such measures address anticompetitive behavior by requiring generators that have the ability to affect LMPs to offer at competitive levels and by deterring generators from physically withholding with the potential for financial sanctions. Hence, it is not surprising that although there is significant structural market power in the New England wholesale market, there is no indication of attempts to exercise market power. Indeed, the market power mitigation measures are an important factor in producing competitive outcomes in the New England wholesale market.

In April 2012, the ISO automated the market power mitigation process in the real-time market. Under the new process (known as the Automated Mitigation Procedure, or "AMP"), the real-time market software performs the test of whether a generator's offer has a significant effect on the LMP in parallel with the real-time dispatch software. Hence, AMP enables the ISO to identify and prevent the abuse of market power in a more timely and accurate fashion than the previous manual process.

AMP mitigation occurred 230 times in 2013. On average, roughly 90 MW of capacity was mitigated each day, of which 86 percent was of thermal non-peaking resources, 10 percent was of thermal peaking resources, and the remaining 4 percent was for hydroelectric resources. Mitigation of hydroelectric resources became much less frequent from 2012 to 2013 because of improvements in the recognition of the opportunity costs that result from the energy limitations of these units. Mitigation of thermal units was more frequent during the cold weather months when natural gas prices were relatively volatile because volatile natural gas prices create cost uncertainty that can be difficult to reflect accurately in offers and in reference levels. The uncertainty is increased by the fact that offers and reference levels must be determined by 2 pm on the day before the operating day. This can cause some competitive offers may be mitigated inappropriately. The project to allow generators to submit hourly offers will substantially reduce this concern.

In addition, oil-fired generation becomes economic when the gas prices rise above oil prices. If an oil-fired generator has limited on-site inventory, it is efficient for the generator to conserve the available oil in order to produce during the hours with the highest LMP. Accordingly, it is competitive for such generators to raise their offer prices to reflect these opportunity costs. Not all generators to take the initiative to request reference level adjustments that reflect these costs when they arise, which can result in inappropriate mitigation.

Apart from the automated mitigation, we continue to monitor market outcomes closely for potential economic and physical withholding together with the IMM, and have found little additional conduct that would raise competitive concerns.

J. Table of Recommendations

We make the following recommendations based on our assessment of the ISO-NE's market performance in 2013. A number of these recommendations have been made previously and are now reflected in the ISO's *Wholesale Market Plan*.

Recommendation	Wholesale Mkt Plan	High Benefit[19]	Feasible in ST[20]
Energy Markets			
1. Allow the costs of fast-start units and operator actions to maintain reliability (e.g., export curtailments) to be reflected in real-time prices.	✓	✓	
2. Allow the costs of deployed demand response resources to be reflected in prices when they are needed to avoid a shortage.			
3. Develop provisions to coordinate the physical interchange between New York and New England in real-time.	✓	✓	
4. Modify allocation of "Economic" NCPC charges to make it more consistent with a "cost causation" principle.	✓	✓	✓
5. Discontinuing the current ex post pricing model and establish prices that are more consistent with ex ante prices.			✓
6. Provide suppliers with the flexibility to modify their offers closer to real time to reflect changes in marginal costs.	✓	✓	
Reserve Markets			
7. Consider introducing day-ahead operating reserve markets that are co-optimized with the day-ahead energy market.		✓	
Capacity Markets			
8. Introduce eligibility requirements governing the use of Non-Price Retirement Delist Bids		✓	

19 Recommendation will likely produce considerable efficiency benefits.

20 Complexity and required software modifications are likely limited.

II. Prices and Market Outcomes

In this section, we review wholesale market outcomes in New England during 2013. This section includes an analysis of overall price trends and a review of prices in transmission congested areas. We also provide an evaluation of the performance of the day-ahead market, which includes analyses of the convergence of day-ahead and real-time markets and of virtual trading patterns.

A. Summary of Prices and Market Outcomes

Both average day-ahead and real-time energy prices rose nearly 58 percent from 2012 to 2013. At the New England Hub, average real-time energy prices rose from approximately $38 per MWh in 2012 to $60 per MWh in 2013, while average day-ahead prices were slightly (less than one percent) lower than average real-time prices in both years.[21] The increases in energy prices from 2012 to 2013 were mostly attributable to:

- Substantially higher natural gas prices, which rose 78 percent on average from 2012 to 2013;[22] and
- An increase in load levels from 2012 to 2013. Average load rose 1.3 percent and the annual peak load rose 5.6 percent.

However, the increase was partly offset by:

- Higher levels of net imports from neighboring areas, which rose by an average of more than 700 MW from 2012 to 2013; and
- Increased production from coal-fired, nuclear, and wind generation, which rose by an average of 510 MW.

Consistent with recent years, New England experienced little congestion in 2013 into historically-constrained areas such as Boston, Connecticut, and Lower Southeast Massachusetts as a result of transmission upgrades that have been made between 2007 and 2009. As discussed more fully in Section I, ISO-NE collected day-ahead congestion revenues of $46 million in 2013,

---

21 These energy prices are load-weighted annual average energy prices.

22 Natural gas fuels the marginal generation that sets energy prices in most hours. Natural gas prices are based on the indices reported by Platts for Algonquin City Gates (i.e., the Algonquin pipeline at city gates in Connecticut, Rhode Island, and Massachusetts).

only a fraction of the congestion revenues collected in other markets (e.g., $664 million in the NYISO and $838 million in the MISO).

Differences between day-ahead and real-time prices were moderate in 2013. Average real-time prices were higher than average day-ahead prices by 0.4 percent in 2013, which was a slight improvement from 2012. Good convergence is important because it leads to efficient day-ahead resource commitment, external transaction scheduling and natural gas scheduling. The real-time price premiums that have persisted over the last few years raise efficiency concerns because real-time prices tend to be understated for reasons discussed in this report. In general, it is efficient for average day-ahead prices to exceed average real-time prices by a small margin and for net schedules in the day-ahead ahead market to be close to the actual real-time load. The normal market response to real-time premiums would lead to more efficient day-ahead outcomes. However, this response is inhibited by the allocation of significant NCPC charges to transactions that improve the day-ahead outcomes (e.g., virtual load).

B. Energy Price Trends

This subsection begins with an examination of the day-ahead prices at the New England Hub.[23] Figure 1 shows the load-weighted average price at the New England Hub in the day-ahead market for each month in 2012 and 2013. The figure also shows the monthly average natural gas price, which should be a key driver of electricity prices when the market is operating competitively.[24]

The figure shows that natural gas price fluctuations were a significant driver of variations in monthly average electricity prices in 2012 and 2013 as expected. In 2013, nearly 44 percent of the installed generating capacity in New England used natural gas as its primary fuel.[25] Low-cost nuclear resources and other baseload resources typically produce at full output, while natural

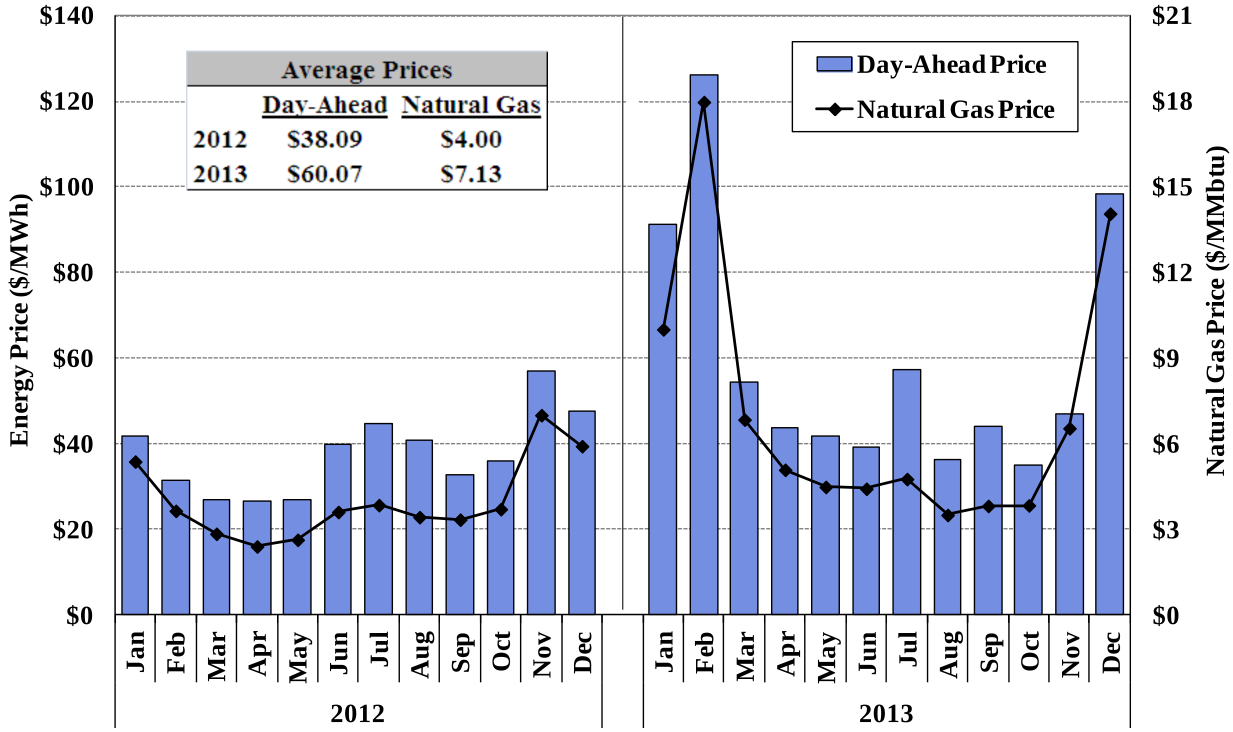
23 The New England Hub is in the geographic center of New England. The Hub price is an average of prices at 32 individual pricing nodes, which has been published by the ISO to disseminate price information that facilitates bilateral contracting. Futures contracts are currently listed on the New York Mercantile Exchange and Intercontinental Exchange that settle against day-ahead and real-time LMPs at the Hub.

24 The figure shows the gas price indices reported by Platts for Algonquin City Gates.

25 ISO-NE, "2013-2022 Forecast Report of Capacity, Energy, Loads, and Transmission (CELT) Report," May 2013.

gas-fired resources, which accounted for 45 percent of all electricity production in 2013, are on the margin and set the market clearing price in most hours.[26] Therefore, electricity prices should be strongly correlated with natural gas prices in a well-functioning competitive market. Natural gas prices are typically higher during the winter months when heating demand for natural gas increases due to colder weather. The availability of natural gas to New England generators during cold weather periods is evaluated further in Section VII.D.

Figure 1: Monthly Average Day-Ahead Energy Prices and Natural Gas Prices
New England Hub, 2012 – 2013



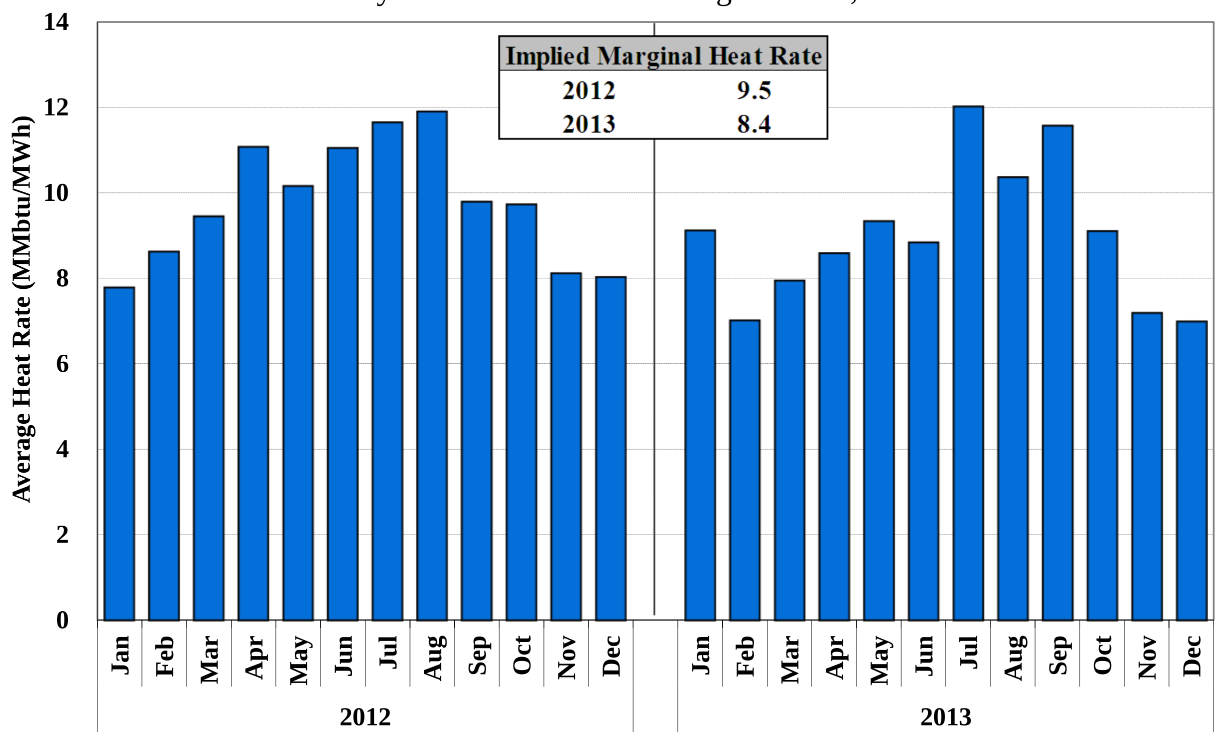
Energy prices usually increase during high load periods in the summer and winter when the demand for cooling and heating are highest. The effects of seasonal changes in demand were significant in both years during the summer months. For example, average natural gas prices increased only 8 percent in July 2013 from the prior month, while average energy prices rose more than 46 percent as demand increased sharply.

26 In 2013, 45 percent of net generation was produced from natural gas, while 32 percent was produced from nuclear fuel, 7 percent from hydroelectric, 10 percent from other renewables sources (including refuse burning), 5 percent from coal, and 1 percent from fuel oil.

Overall, the average New England Hub price in the day-ahead market increased 58 percent from 2012 to 2013. The most significant driver of the higher prices was the 78 percent increase in average natural gas prices from 2012 to 2013. Higher gas prices led to higher energy prices in most hours because natural gas-fired units were frequently on the margin. Increased load levels also contributed to the rise in prices, which is discussed in more detail subsection C.

To better identify changes in energy 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 energy price divided by the natural gas price measured in MMbtu. Thus, if the electricity price is $40 per MWh and the natural gas price is $5 per MMbtu, this would imply that an 8.0 MMbtu per MWh generator is on the margin. Figure 2 shows the load-weighted average implied marginal heat rate that is based on the day-ahead energy prices for the New England Hub in each month during 2012 and 2013.

Figure 2: Monthly Average Implied Marginal Heat Rate
Based on Day-Ahead Prices at New England Hub, 2012 – 2013



The implied marginal heat rate shows more clearly the seasonal variation in electricity prices because of factors other than natural gas prices. The implied marginal heat rates were highest in the peak summer months when high load levels lead to tight market conditions on hot days. July exhibited the highest average implied marginal heat rate and the highest load levels in 2013. The variations in load levels are discussed in more detail in the next sub-section.

Figure 2 also shows that the average implied marginal heat rate fell approximately 12 percent from 2012 to 2013. The reduction was attributable to several factors, including:

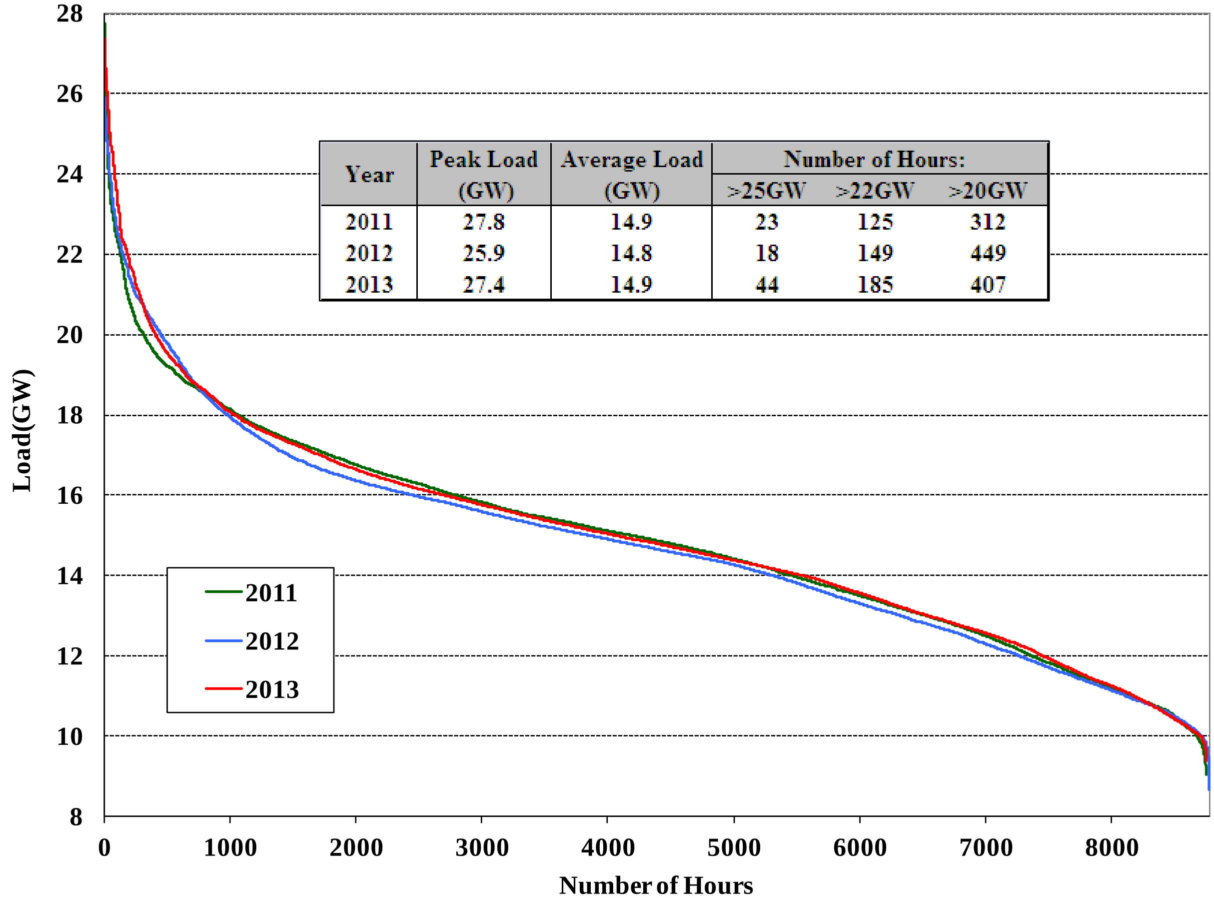
- Substantially higher natural gas prices. A small share of generation costs (e.g., variable operating and maintenance expenses) is not related to fuel prices, therefore rising fuel prices generally cause implied heat rates fall.
- Lower-cost resources set the prices more frequently in 2013 than in 2012. For example, oil-fired resources set prices more often in the winter of 2013 when natural gas prices were notably above fuel oil prices. As a result, implied heat rates calculated during these periods were lower than the actual marginal heat rates.
- Higher net imports in 2013 from neighboring areas. Total net imports averaged approximately 2,180 MW over all hours in 2013, up more than 700 MW from 2012.
- Increased generation from coal, nuclear, and wind units in 2013. Better economics for coal-fired units, fewer outages on nuclear units, and the addition of new wind turbines led the average output from these units to rise by more than 500 MW from 2012.

C. Energy Demand

In addition to fuel price changes, changes in electric supply and demand also contribute to price movements in New England. The amount of available supply changes slowly from year to year, so fluctuations in electricity demand explain much of the short-term variations in electricity prices. The hours with the highest loads are important because a disproportionately large share of the market costs to consumers and revenues to generators occur in these hours.

Figure 3 illustrates the variation in demand during the year by showing load duration curves for each of the last three years. Load duration curves show the number of hours on the horizontal axis in which the system-wide load was greater than or equal to the level shown on the vertical axis. For each of the last three years, the table in the figure shows the average load level, the peak load level, and the number of hours when the system was in high load conditions.

Figure 3: Load Duration Curves
2011 – 2013



In general, electricity demand grows slowly over time, tracking population growth and economic activity. Average load changed little from 2011 to 2013. Weather was generally milder in 2012, leading to lower average load levels than in the other two years.

Peak load conditions rose significantly in 2013 because of several short periods with extreme weather conditions in both the winter and the summer. In the winter, load peaked on December 17 at 21.5 GW, which was the highest winter peak in the past five years. In the summer, load peaked on July 19 at 27.4 GW. This was roughly 1 percent lower than the 2011 annual peak, but 6 percent higher than the 2012 annual peak. New England experienced significantly more hours with very high load conditions in 2013 because of an unusual heat wave in mid-July. Load exceeded 25 GW in 44 hours in 2013, up notably from 18 and 23 hours in 2012 and 2011, respectively. These high load levels led to very tight system conditions and more frequent operating reserve shortages.

D. Prices in Transmission Constrained Areas

ISO-NE manages flows over the network to avoid overloading transmission constraints by altering the dispatch of its resources and establishing locational marginal prices (LMPs) to establish efficient, location-specific prices that are consistent with the marginal costs of serving load at that location. Transmission congestion arises when the lowest-cost resources cannot be fully dispatched because of limited transmission capability. The LMPs can vary substantially across 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 causes LMPs to be higher in "constrained locations". In addition, transmission constraints may also require additional operating reserves in certain locations to maintain reliability. 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 I.

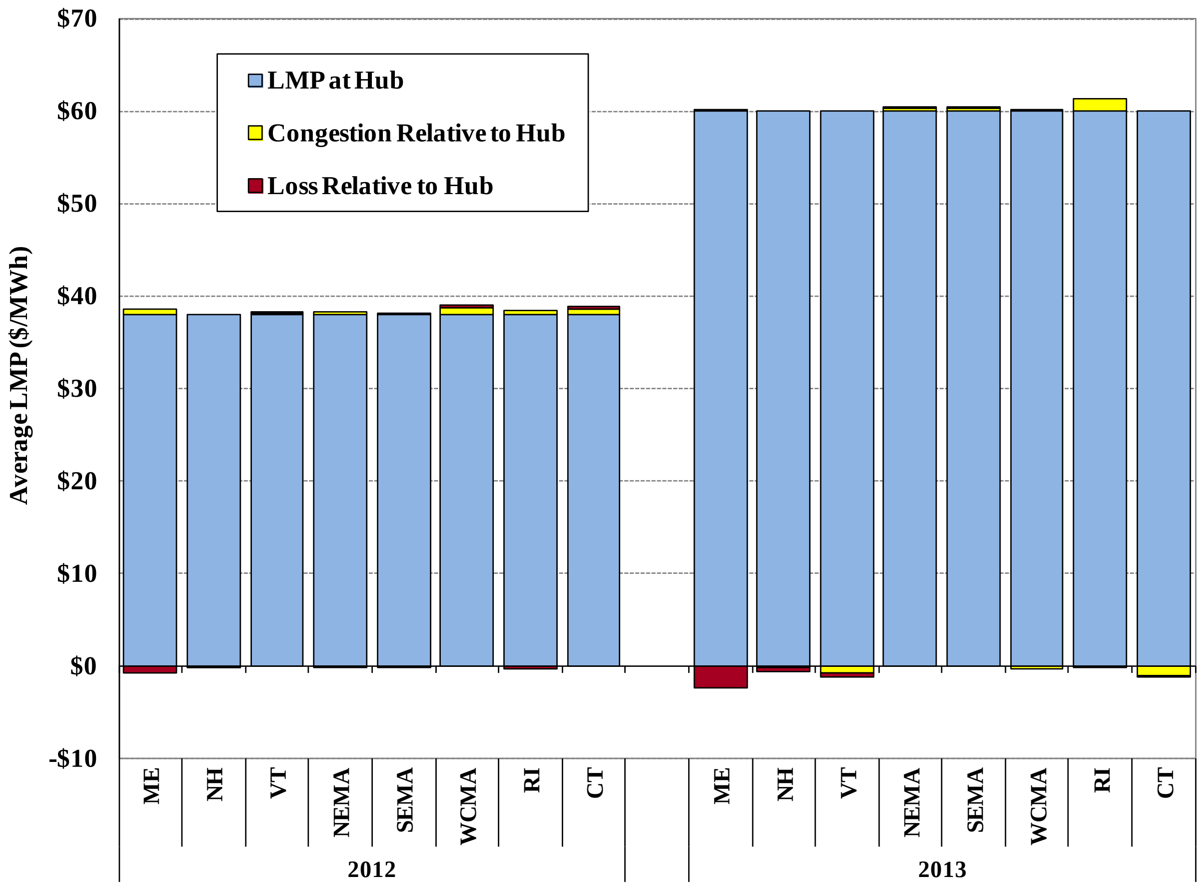
LMPs also reflect the marginal value of transmission losses. Transmission losses occur whenever power flows across the transmission network. Generally, transmission losses increase as power is transferred over longer distances or as the power flows increase, and are higher on lower voltage facilities (for a given amount of power transfer).

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 have been limited by transmission constraints at times, while Connecticut and Boston were often unable to import enough power to satisfy demand without dispatching expensive local generation in the past. However, congestion has been very limited in recent years because of the transmission upgrades made in Boston, Connecticut, and Southeast Massachusetts from 2007 to 2009. These upgrades greatly increased the transfer capability into these areas and eliminated most of the congestion into these historically constrained regions. Consequently, the current levels of LMPs do not provide significant incentives for locating new resources in net-importing regions such as Boston.

We examined the differences in energy prices across the system during the study period. Figure 4 shows load-weighted average day-ahead LMPs in 2012 and 2013 for the eight load zones in

New England.[27] The New England Hub is used as a reference location in order to illustrate the locational differences in LMPs that are caused by transmission congestion and transmission losses between the eight load zones. Positive bars indicate increased congestion and losses from the New England Hub to the location, while negative bars indicate increased congestion and losses from the location to the New England Hub.

Figure 4: Average Day-Ahead Prices by Load Zone
2012 – 2013



The figure shows that congestion levels were low in 2012 and 2013. The largest average congestion-related price differential between load zones was about 4 percent of the average LMP in 2013 (from Connecticut to Rhode Island). Congestion patterns are discussed in more detail in Section I.

---

27 New England is divided into the following eight load zones: Maine (ME), New Hampshire (NH), Vermont (VT), Rhode Island (RI), Connecticut (CT), Western/Central Massachusetts (WCMA), Northeast Massachusetts and Boston (NEMA), and Southeast Massachusetts (SEMA).

Transmission losses accounted for a comparable portion of the locational differences in LMPs in both 2012 and 2013. The largest average loss-related price differential between load zones was about 4 percent in 2013 (from Maine to Southeast Massachusetts)

E. Day-Ahead Market Performance: Convergence with Real-Time Prices

The day-ahead market allows participants to make forward purchases and sales of power for delivery in real time. This provides a valuable financial mechanism that allows participants to hedge their portfolios and manage risks associated with the real-time market. Loads can hedge price volatility in the real-time market by purchasing in the day-ahead market. Suppliers can avoid the risk of unprofitably starting their generators, because the day-ahead market will accept their offers only when they will profit from being committed. However, suppliers that sell day-ahead are exposed to some risk because they are committed to deliver energy in the real time. An outage or failure to secure fuel can force them to purchase replacement high-priced energy from the spot market. In addition to the value it provides to individual market participants, perhaps the greatest value of the day-ahead market is that it coordinates the overall commitment of resources that are used to satisfy the next day's needs at the lowest cost.

In well-functioning day-ahead and real-time markets, we expect that day-ahead and real-time prices will not systematically diverge by a substantial amount. If day-ahead prices were predictably higher or lower than real-time prices, participants should adjust their purchases and sales in the day-ahead market to bring the prices into convergence. However, day-ahead prices tend to be slightly higher than real-time prices in a well-functioning energy market because many buyers are willing to pay a small premium for day-ahead purchases to avoid the more volatile real-time prices.

The day-ahead market facilitates most of the generator commitments in New England. Good price convergence with the real-time market is important because it helps ensure that resources are committed efficiently to satisfy the anticipated real-time operating needs of the system. Additionally, most settlements occur through the day-ahead market and its results are the basis for payments to FTR holders. Persistent differences between day-ahead and real-time prices can undermine incentives for suppliers to offer their resources at marginal cost in the day-ahead market. We expect random variations resulting from unanticipated changes in hourly supply and demand between the two markets, but persistent price differences raise concerns regarding market efficiency.

Since there was little congestion in the system, price convergence between the day-ahead and real-time markets at the New England Hub provides an indication of the overall price convergence. In this section, we assess price convergence by the following two measures:

- The first measure is the simple difference between the average day-ahead price and the average real-time price. This is a very important indicator because it measures the systematic differences between day-ahead and real-time prices and examines whether the day-ahead prices reflect an accurate expectation of real-time prices.
- The second measure reports the average absolute difference between day-ahead and real-time prices on an hourly basis, which captures the overall variability of differences between day-ahead and real-time prices.

Figure 5 summarizes day-ahead prices and the convergence between day-ahead and real-time prices at the New England Hub in each month of 2012 and 2013.[28] The first measure of convergence reported in the figure, the average real-time premium, is equal to the average real-time price minus the average day-ahead price. The sum of the average day-ahead price (blue bar) and the average real-time price premium (maroon bar) is equal to the average real-time price.

The second measure of convergence, the average absolute difference between day-ahead and real-time prices, is shown by the blue line and is reported as a percentage of the average day-ahead price in the month. The figure also shows the monthly average rate of Net Commitment Period Compensation (NCPC) that is charged to real-time deviations, which is shown by the red line and is also reported as a percentage of the average day-ahead price in each month. The inset table compares these quantities on an annual basis for 2012 and 2013.

28 Day-ahead and real-time prices are averaged on a load-weighted basis.

Figure 5: Convergence of Day-Ahead and Real-Time Prices at New England Hub
2012 – 2013

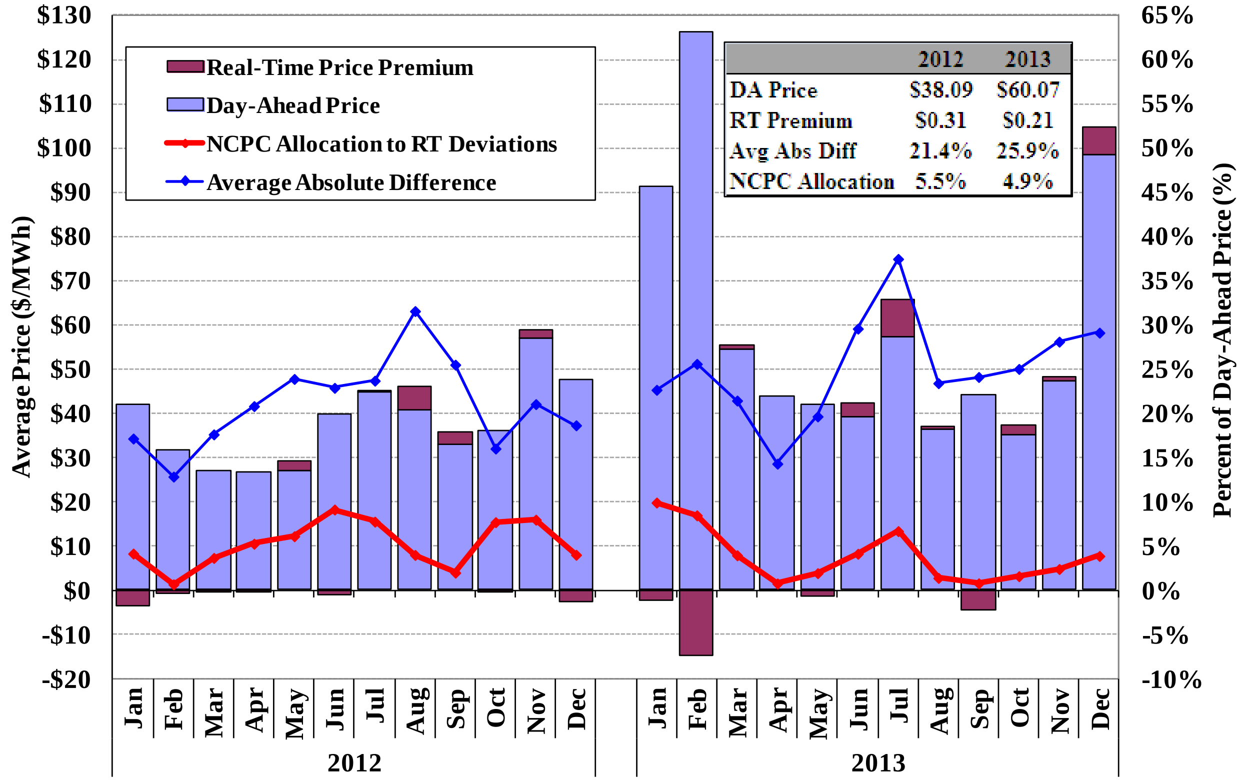


Figure 5 shows that the market exhibited a small real-time premium in both 2012 and 2013 on an annual basis, although some months exhibited a day-ahead premium. We do not believe that persistent real-time premiums are efficient because small day-ahead premiums generally lead to a more efficient commitment of the system's resources. Section V shows that real-time energy prices frequently do not reflect the full costs of the marginal source of supply. For example, when high-cost peaking resources are committed to satisfy the real-time demand, real-time prices generally do not reflect the full costs of such resources. Because the real-time prices are understated in these cases, day-ahead prices would have to be slightly higher than the actual real-time prices in order to efficiently facilitate a day-ahead commitment of resources to fully satisfy the real-time system needs.

One reason for the real-time premiums in recent years is the high average allocation of NCPC charges, which is discussed in detail in the next subsection. The increased allocation of NCPC charges (per MWh) to virtual load in particular has likely inhibited the natural market response to the sustained real-time price premiums.

The average absolute difference between day-ahead and real-time prices, the second measure of price convergence, rose from 21 percent of the average day-ahead price in 2012 to 26 percent in 2013. This increase reflects higher real-time price volatility in 2013 that was driven primarily by more volatile natural gas prices and more frequent peaking conditions (rather than a change in day-ahead market performance).

F. Virtual Trading Activity and Profits

Virtual trading plays a key role in the day-ahead market by providing liquidity and improving price convergence between day-ahead and real-time markets. Price convergence tends to produce efficient day-ahead prices, which lead to efficient commitment and scheduling of resources in the day-ahead market. Virtual transactions that are scheduled in the day-ahead market are settled against real-time energy prices. Virtual demand bids are profitable when the real-time energy price is higher than the day-ahead price, while virtual supply offers are profitable when the day-ahead energy price is higher than the real-time price. Accordingly, if prices are lower in the day-ahead market than in the real-time market, a virtual trader may purchase energy in the day-ahead market and sell it back in the real-time market. This will tend to increase day-ahead prices and improve price convergence with the real-time market. Hence, profitable virtual transactions improve the performance of the day-ahead market.[29]

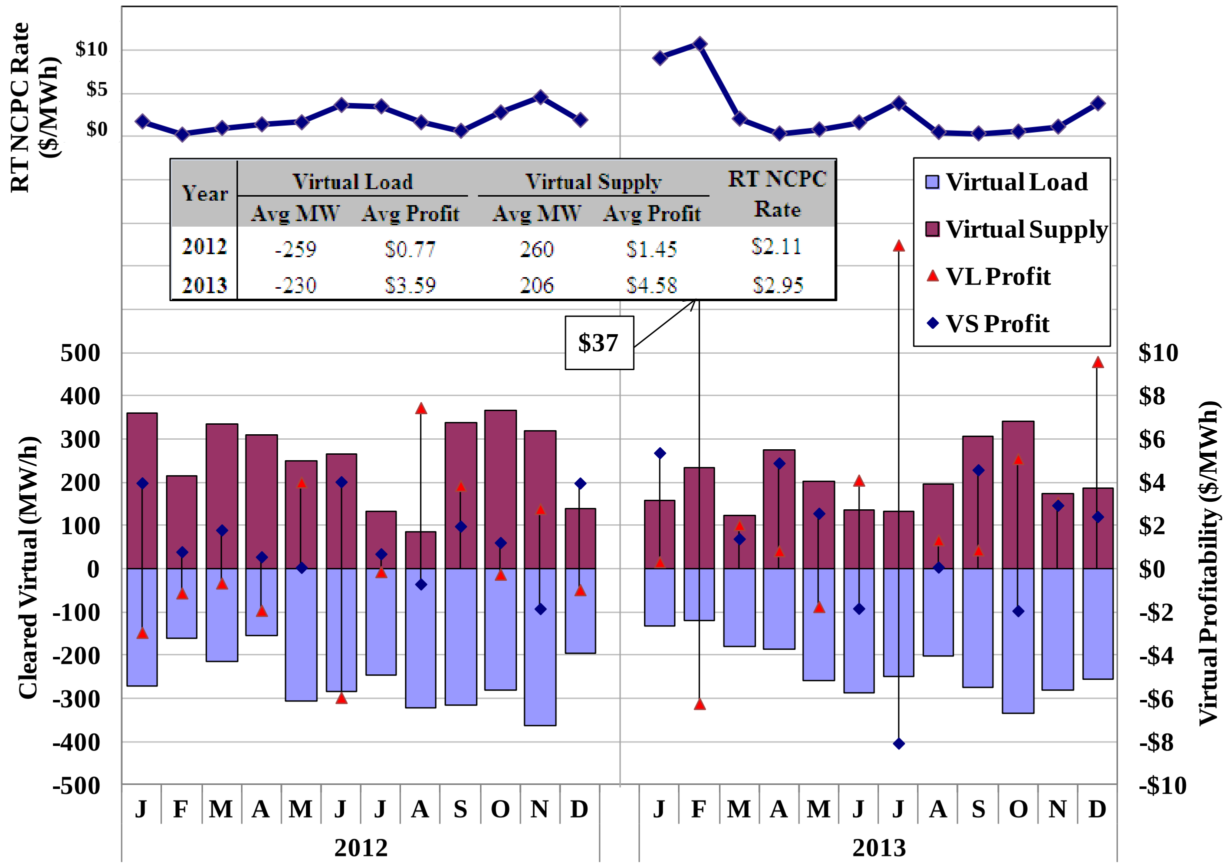
Figure 6 shows the average volume of virtual supply and demand that cleared the market in each month of 2012 and 2013, as well as the monthly average gross profitability of virtual purchases and sales. Gross profitability is the difference between the price at which virtual traders bought and sold energy between the day-ahead and real-time market. The gross profitability shown here does not account for NCPC cost allocations. The upper portion of the figure shows the average real-time NCPC rate for each month.[30]

---

29 This assumes that the model of the transmission network and certain inputs are consistent between the day-ahead and real-time markets. In some cases, a virtual transaction may be profitable because of such an inconsistency rather than because it improves the performance of the day-ahead market. It is important to modify the day-ahead and/or real-time models to eliminate or reduce such inconsistencies.

30 The monthly real-time NCPC rate is defined as the total NCPC charges allocated system wide divided by the total real-time deviations for each month.

Figure 6: Virtual Transaction Volumes and Profitability
By Month and By Location, 2012 – 2013



Virtual transactions have decreased substantially in recent years. Scheduled virtual load averaged just 230 MW in 2013, while scheduled virtual supply averaged just 206 MW. Virtual load and virtual supply each accounted for less than 2 percent of the volume in the day-ahead market. The low levels of virtual trading are likely the result of the high NCPC charges to scheduled virtual transactions and increased regulatory risk associated with enforcement activities.

Virtual Trading Profits

Figure 6 shows that virtual trading was generally profitable in 2013 (before including NCPC charges) with an overall net profit of $15 million, indicating that virtual trading improved convergence between day-ahead and real-time prices.[31] This is because virtual trades that are profitable (before including NCPC charges) generally contribute to better convergence between day-ahead and real-time prices.

However, when NCPC charges are considered, they offset approximately 60 percent (or $9 million) of the net gross profit in 2013.[32] The effects of NCPC allocations on virtual trading profits have increased in recent years. This issue is discussed in the following part of the sub-section.

NCPC Allocation and Virtual Trading

Real-time NCPC charges are allocated across virtual transactions and other Real-Time Deviations. The rate of NCPC charges allocated to virtual transactions has been high for several years, averaging roughly $2 to $4 per MWh in most months of 2012 and 2013. Supplemental commitment for system-wide reliability results in NCPC charges and it has increased in recent years, contributing to elevated NCPC rates as well. High NCPC rates provide a significant disincentive for firms to schedule virtual transactions because virtual profits tend to be small relative to day-ahead and real-time prices. Hence, the high NCPC rates contribute to the low level of virtual trading activity and the inconsistency between day-ahead and real-time prices.

ISO-NE currently allocates nearly all real-time "Economic" NCPC charges to deviations between the day-ahead and real-time schedules.[33] In reality, some deviations are "harming" and tend to increase NCPC, while others are "helping" and reduce NCPC. For example, under-scheduling physical load in the day-ahead market can cause the ISO to commit additional units in real-time, which are likely to increase NCPC—this is a "harming" deviation. Conversely, "helping" deviations, such as over-scheduling load (including virtual load), generally result in

31 Not including NCPC charges, profits can be tabulated for each category of virtual transactions in the figure by multiplying "Avg MW" and "Avg Profit" by the number of hours (8760 or 8784 for 2012) in each year.

32 For the years from 2010 to 2012, virtual transactions would net a loss on average after paying NCPC charges in each year (e.g., gross profitability of all cleared virtual transactions was $1.11 per MWh in 2012 compared to an average real-time NCPC charge rate of $2.11 per MWh in 2012).

33 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, uninstructed generation deviations from day-ahead schedules, virtual load schedules, and virtual supply schedules.

higher levels of resource commitments in the day-ahead market and, therefore, usually decrease the ISO's need to make additional commitments, thereby avoiding NCPC charges. The current allocation does not distinguish between helping and harming deviations and is, therefore, not consistent with the principle of allocating costs to actions that cause those costs. Hence, this allocation assigns NCPC charges to transactions that actually tend to *reduce* the need for supplemental commitments, including virtual load.

NCPC charges are caused by many factors other than real-time deviations, including: peaking resources not setting real-time prices, operator actions to satisfy system reliability needs, and unforeseen events such as outages. Hence, we find that the current allocation scheme over-allocates costs to deviations relative to the portion of the NCPC they likely cause. This is particularly true of virtual load transactions, which tend to increase day-ahead commitments and, therefore, decrease the need for supplemental commitments. Given that real-time price premiums prevailed for much of 2010 through 2013, allocating substantial NCPC costs to virtual load that does not cause these costs has likely degraded the performance of the day-ahead market.

Hence, we recommend that the ISO modify the allocation of Economic NCPC charges to be more consistent with a "cost causation" principle, which would generally involve not allocating NCPC costs to virtual load and other real-time deviations that cannot reasonably be argued to cause real-time economic NCPC. The ISO recently proposed to reallocate real-time economic NCPC charges from virtual load and over-scheduled physical load in the day-ahead market to real-time physical load customers.[34] This reallocation would be a significant improvement because virtual load and over-scheduled physical load in the day-ahead market are "helping" deviations, while real-time physical load tends to increase real-time economic NCPC charges because most supplemental commitments are made to maintain reliability for physical load customers.

---

34 See *NCPC Cost Allocation Phase 1* to NEPOOL Markets Committee from Catherine McDonough (ISO-NE) dated April 30, 2014.

G. Conclusion

Energy prices rose 58 percent from 2012 to 2013 as a result of substantially higher natural gas prices and more frequent peak conditions in the summer and in the winter. However, the increase was offset by other factors, including increased net imports from neighboring areas and increased production from nuclear, wind, and coal-fired generation. Transmission congestion continued to be relatively mild as a result of transmission investments made between 2007 and 2009 in historically constrained areas of Connecticut, Boston, and Southeast Massachusetts.

Differences between day-ahead and real-time prices were relatively small in 2013, but the sustained real-time price premiums have raised a potential concern that the market is unable to quickly adjust to the higher real-time prices. These market outcomes are consistent with the inefficient allocation of real-time NCPC costs to virtual load and other real-time deviations. Therefore, we continue recommend that the ISO revise the allocation methodology for economic NCPC charges, making it more consistent with cost causation principles. Accordingly, we support the ISO's NCPC Cost Allocation Phase 1 proposal because it would reallocate a significant amount of economic NCPC charges from virtual load and over-scheduled physical load in the day-ahead market, which both tend to reduce economic NCPC.

III. Transmission Congestion and Financial Transmission Rights

Congestion arises when the transmission network does not have sufficient capacity to dispatch the least expensive generators to satisfy the demands of the system. When congestion occurs, the market software establishes clearing prices that vary by location to reflect the cost of meeting load at each location. These Locational Marginal Prices reflect the economic value of binding transmission constraints that cause the dispatch of higher-cost generation in order to manage the flow over the constrained transmission facility. These prices also establish long-term economic signals that govern investment in generation, transmission, and demand response resources. Hence, it is important to evaluate locational marginal prices and associated congestion costs.

Congestion costs result from the difference in prices between the points where power is consumed and generated on the network. The price difference between two locations indicates the marginal value of additional transmission capability between the locations. The differences in locational prices that are caused by congestion are revealed in the congestion component of the LMP at each location.[35]

Most of congestion costs are incurred and collected through the day-ahead market because most of the energy that is transacted is settled in the day-ahead market. Market participants can hedge their day-ahead congestion charges by owning FTRs.[36] An FTR entitles a holder to payments corresponding to the congestion-related difference in day-ahead prices between two locations in a defined direction. For example, a participant that holds 150 MW of FTRs from point A to point B is entitled to a payment equal to 150 times the locational energy price at point 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 in the bilateral contract.

35 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.

36 FTRs can also be used as speculative investments for purchasers who forecast higher congestion revenues between two locations than the cost of the associated FTR.

Through the auctions it administers, ISO-NE sells FTRs with one-year terms (annual FTRs) and one-month terms (monthly FTRs). The annual FTRs allow market participants greater certainty by allowing them to lock-in congestion hedges further in advance. ISO-NE auctions 50 percent of the forecasted capacity of the transmission system in the annual auction, and all of the remaining capacity in the monthly auctions.[37] FTRs are auctioned separately for peak and off-peak hours.[38]

The annual auction is now conducted in two rounds beginning in 2013. Twenty-five percent of the available FTRs are auctioned in the first round, and the remaining balance of available FTRs up to 50 percent is auctioned in the second round. The annual auction was broken into two rounds to improve the efficiency of the FTR auction prices, since it allows market participants to observe FTR prices from the first round before placing their bids in the second round.[39]

The capacity of the transmission system that is estimated before the annual and monthly FTR auctions may differ from the expected capacity of the system in the day-ahead market because of unforeseen factors such as transmission outages. When the FTRs sold by the ISO collectively exceed the capacity of the constrained portions of the transmission system, the congestion revenue collected by the ISO will be less than the "target" payments to FTR holders. If target payments exceed congestion revenues for the year, the actual payments to FTR holders will be reduced proportionately to reconcile the "revenue shortfall." [40] Revenue shortfalls present an additional risk for FTR holders, particularly those that rely on the FTR as a hedge against the risk of congestion. Therefore, it is important to model the system as accurately as possible in the FTR market to avoid revenue shortfalls.

---

37 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 100 percent of the remaining predicted power transfer capability after accounting for planned transmission outages. See the ISO-NE Manual for Financial Transmission Rights, Manual M-06 for more details.

38 Peak hours include hours ending 8 to 23, Monday through Friday, not including NERC holidays. Off-peak includes all other hours.

39 See the ISO-NE Manual for Financial Transmission Rights, Manual M-06 for more details.

40 See Appendix C of Market Rule 1 for more details.

A. Summary of Congestion and FTR Market Outcomes

Total day-ahead congestion revenues totaled $46 million in 2013, up from $30 million in 2012. The increase in congestion revenue resulted primarily from high levels of congestion on two days in February when forced transmission outages limited flows from Connecticut to neighboring states and two days in September when planned transmission outages and unusually high loads led to severe congestion on flows through West-Central Massachusetts. The overall levels of congestion have been relatively low since the completion of transmission grades into historically constrained areas in 2009.

The congestion revenue collected by the ISO in 2013 was sufficient to fully fund the $40 million target value of the FTRs. This is important because if market participants anticipate that FTRs will not be fully funded, FTR prices will be depressed below the expected value of congestion in future FTR auctions.

We also compare FTR prices with congestion values in the day-ahead and real-time markets. Since FTR auctions are forward financial markets, FTR prices should reflect the expected day-ahead congestion by market participants. In 2013, FTR prices in the monthly auctions were more consistent with congestion values in the day-ahead and real-time markets than FTR prices in the annual auction. The improvement in consistency of FTR prices and congestion values from the annual auction to the monthly auctions is expected because market participants gain more accurate information about market conditions as the lead time for the auction decreases.

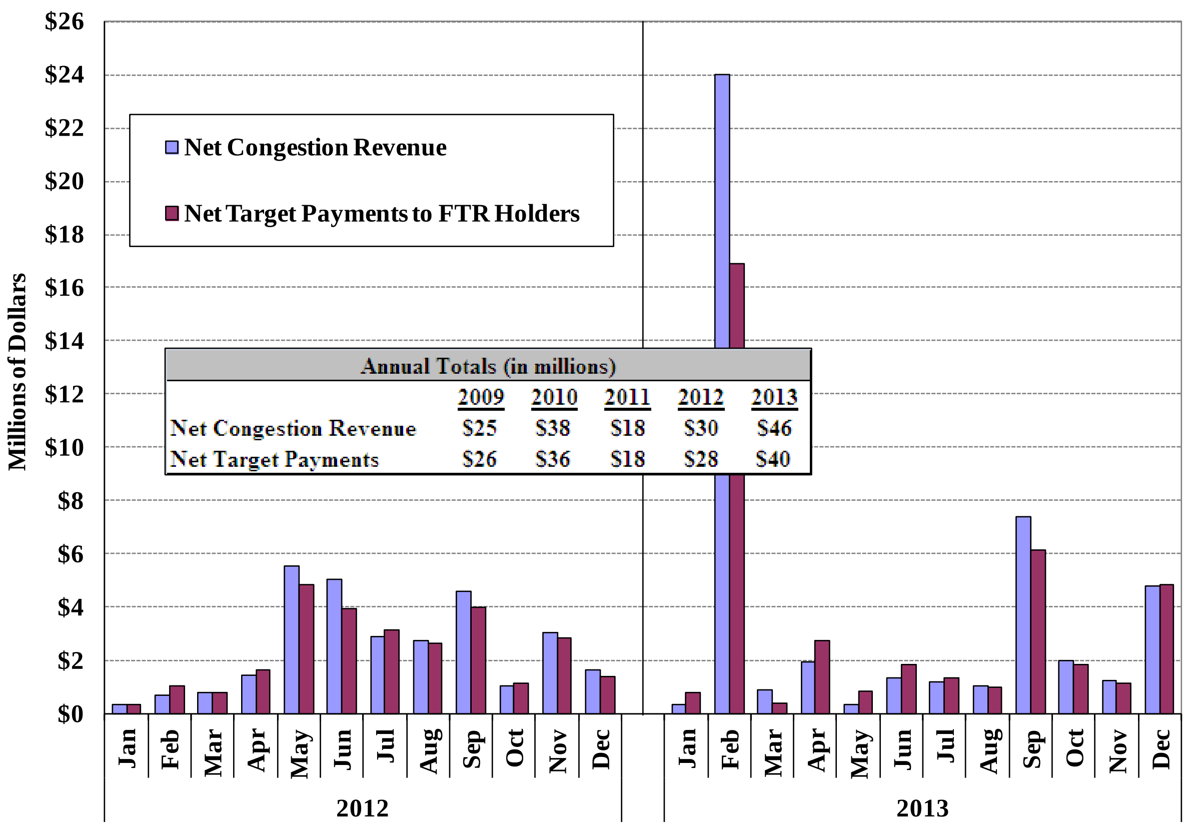
B. Congestion Revenue and Payments to FTR Holders

As discussed above, the holder of an FTR from point A to point B is 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 revenues collected in the day-ahead market.

Day-ahead congestion revenue is equal to the megawatts scheduled to flow across a constrained transmission path times the day-ahead shadow price (i.e., the marginal economic value) of the transmission path. Real-time congestion revenue is equal to the *change* in scheduled flows (relative to the day-ahead market) across a constraint times the real-time shadow price of the constraint. When the real-time constraint binds at a limit less than the scheduled flows in the day-ahead market, it results in *negative* congestion revenue must incur redispatch costs to reduce the flow from the day-ahead scheduled level to the lower real-time limit. Because most flows have already settled through the day-ahead market (e.g., net load in congested areas) these costs are generally recovered as a form of uplift.

When the total congestion revenue collected by the ISO-NE is not sufficient to satisfy the targeted payments to FTR holders, it implies that the quantities sold in the FTR auctions exceeded the actual capability of the transmission system. Figure 7 compares the net congestion revenue collected by the ISO-NE with the net target payments to FTR holders in each month of 2012 and 2013. The inset table compares the two quantities in the past five years. *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 and negative target payments to and from FTR holders.

Figure 7: Congestion Revenue and Target Payments to FTR Holders
2012 – 2013



Although overall congestion remained low in 2013, it increased significantly in percentage terms. The net congestion revenue rose by 53 percent to $46 million in 2013. Likewise, the net target payments to FTR holders increased from $28 million in 2012 to $40 million in 2013. Three months accounted for most of the increase in congestion in 2013:

- February accounted for more than 50 percent (or $24 million) of congestion revenue in 2013 primarily because of the effects of Winter Storm Nemo. This storm dropped record snow across New England on February 8 and 9. It led to significant transmission outages and a total loss of more than 6,000 MW of generating capacity. These outages contributed to high congestion, particularly in Northeast Massachusetts, Southeast Massachusetts, and Rhode Island.
- September had the second largest monthly congestion revenues because of the effects of a brief heat wave on September 11 and 12. The combined effects of high load levels and two planned transmission outages led to unusally high congestion into vicinity of the New England Hub (which is physically located within West-Central Massachusetts).
- Congestion rose notably in December as a result of high natural gas prices which increased redispatch costs and associated congestion-related price differences. As a result, congestion costs were higher than in the same month of 2012.

The figure also shows that net congestion revenues exceeded net target payments to FTR holders in half of the months in both 2012 (6 months) and 2013 (6 months). As a result, the total net congestion revenues for the 12 months in both 2012 and 2013 were sufficient to fund 100 percent of the net target payments. The correspondence of FTR obligations and day-ahead congestion indicates two things. First, ISO-NE has modeled the transmission system consistently in the FTR market and day-ahead markets. This consistency can be difficult to achieve because transmission outages and network flows caused by those on other areas (i.e., "loop flows") can be difficult to predict when the FTR auctions are being run. Second, in February and September, transmission outages led to significant congestion on transmission paths that were not fully sold in the FTR auctions. Because not all of the capacity was subscribed, the reduction in transmission capacity from these outages did not lead to significant congestion revenue shortfalls (which occurs when the FTRs exceed the capability of the system).

C. Congestion Patterns and FTR Prices

In this section, we evaluate the performance of the FTR markets by comparing 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 market. When the market is performing well, the FTR prices should converge over time with the actual congestion on the network.

Figure 8 shows day-ahead and real-time congestion prices and FTR prices for each of the eight ISO-NE load zones in 2012 and 2013. The congestion prices shown are calculated for peak hours relative to the New England Hub. Hence, a congestion price of $1 per MWh is the average cost of congestion to transfer power from the New England Hub to the location during peak hours. The figure shows the auction prices in chronological with the annual FTR auctions that occur first on the left and then the day-ahead market that occurs last on the right.

Starting in 2013, the annual auction is conducted in two rounds, so the chart shows the auction prices separately for each round in 2013. The monthly clearing prices are monthly auction prices averaged over 12 months in each year.

Figure 8: FTR Auction Prices vs. Day-Ahead and Real-Time Congestion
Average Difference from New England Hub in Peak Hours, 2012-2013

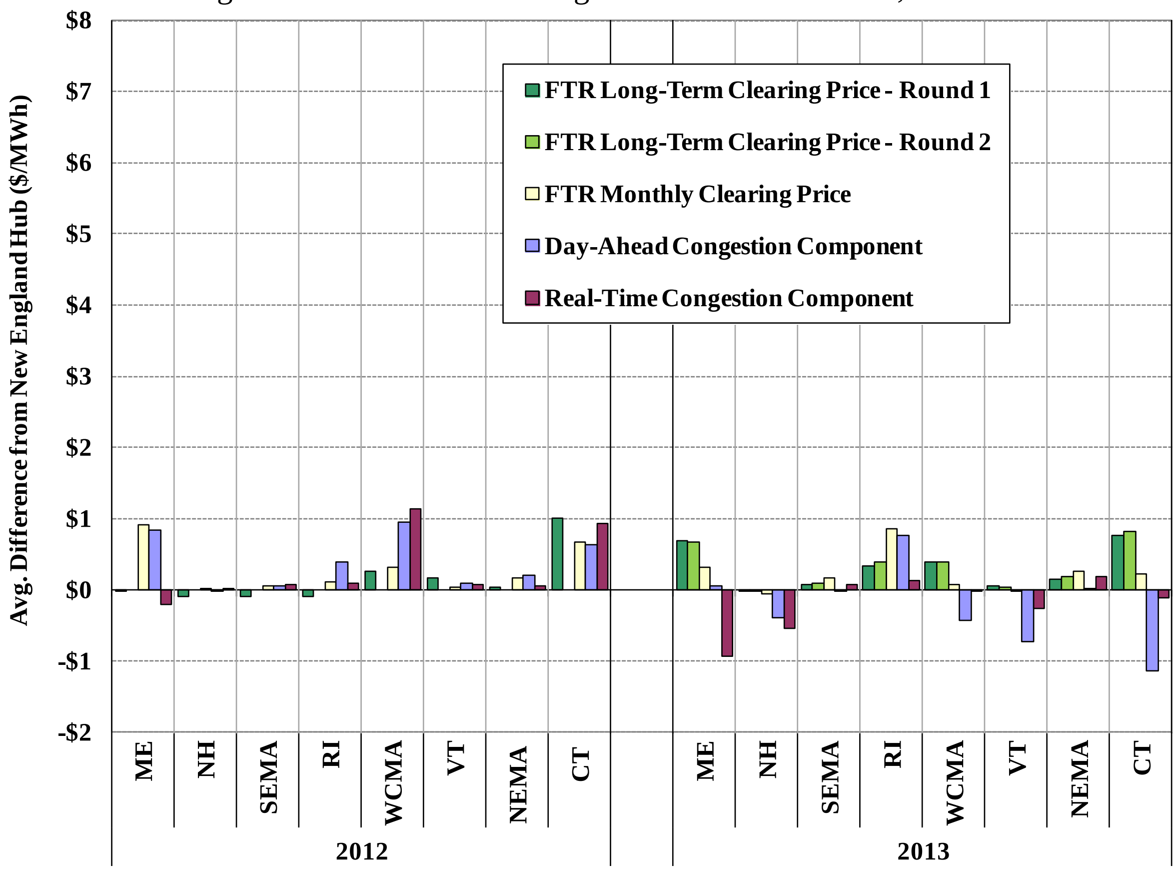


Figure 8 shows that in most areas during 2012 and 2013, monthly FTR prices were more consistent with congestion prices in the day-ahead market than were annual FTR prices. For example, the annual FTR prices from the New England Hub to Rhode Island were $0.40 per MWh lower than the corresponding day-ahead congestion values in 2013, while the monthly FTR prices were more consistent and were only $0.09 per MWh higher. This pattern is generally expected because market participants face greater uncertainty and have less information in the annual auction regarding likely congestion levels than they do at the time of monthly auctions.

The figure also shows that monthly FTR auction prices were still significantly different than the day-ahead congestion prices in some areas in 2013. For example, Connecticut exhibited a negative average day-ahead congestion from the New England Hub in 2013, which was attributable to several factors:

- In February, Winter Storm Nemo caused significant transmission and generation outages, leading to congested transmission paths *from* Connecticut to Rhode Island and Massachusetts.
- In September, rare high congestion occurred at the New England Hub, partly because of two planned transmission outages.
- In December, frequent congestion occurred on the West-to-East interface because of larger natural gas price spreads between Western Connecticut and other areas in Southern New England.[41]

However, the figure shows positive average monthly FTR auction prices from the Hub to Connecticut, which suggests that market participants did not fully anticipate the effects of the severe winter weather, large price spreads between natural gas pipelines, and transmission outages. Participants likely based their expectations more on the congestion that occurred in prior periods. Nonetheless, given that variations in congestion patterns can be difficult to anticipate in advance and the very low levels of overall congestion, we find that FTRs were reasonably valued in the FTR auctions. The FTR market responded to changes in patterns of day-ahead congestion, which was particularly evident by the changes in the pricing of FTRs in the monthly auctions.

41 Much of generation in Western Connecticut is served with gas from the Iroquois pipeline, while most of generation in other areas of Southern New England is served with gas from Tennessee and Algonquin pipelines. During these periods, average Tennessee Zn6 and Algonquin gas indexes were notably higher than the Iroquois Zn2 gas index.

IV. Reserve and Regulation Markets

This section evaluates the operation of the markets for operating reserves and regulation. The real-time reserve market has system-level and locational reserve requirements that are integrated with the real-time energy market. The real-time market software co-optimizes the scheduling of reserves and energy, which enables the real-time market to reflect the redispatch costs that are incurred to maintain reserves in the clearing prices of both energy and reserves. Energy-only markets (i.e., markets that do not co-optimize energy and reserves) do not recognize the economic trade-offs between scheduling a resource for energy rather than 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 requirement, 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).

The forward reserve market enables suppliers to sell reserves into a forward auction on a seasonal basis. Similar to the real-time reserve market, the forward reserve market has system-level and locational reserve requirements. Suppliers that sell in the forward auction satisfy their forward reserve 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 that can start within 10 or 30 minutes). The forward reserve market is intended to attract investment in capacity that is able to provide reserves at relatively low cost, particularly fast-start generation.

ISO-NE runs a market for regulation service, which is the capability of specially-equipped generators to increase or decrease their output every few seconds in response to signals from ISO-NE. Regulation is used to balance actual generation with load on a moment-to-moment basis in New England. The regulation market provides a market-based system for meeting ISO-NE's regulation needs. Unlike many other ISO-run markets, the ISO-NE markets currently do not co-optimize the scheduling of regulation with reserves and energy.

This section of the report evaluates market outcomes in the real-time reserve, the forward reserve market, and the regulation market.

A. Real-Time Reserve Market Results

This subsection evaluates the following four areas related to real-time reserve market performance: reserve requirements, reserve market design, market outcomes, and recent market rule changes.

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 ISO-NE reserve zones to protect the system in case contingencies (e.g., generator outages) occur. The ISO used to hold an amount of 10-minute reserves (i.e., TMSR plus TMNSR) at the system level equal to the size of the largest generation contingency on the system. However, the ISO increased this requirement by 25 percent effective July 23, 2012, (i.e., now 125 percent of the largest generation contingency of the system) due to generator performance issues during past reserve activation events.[42] Based on system conditions, the operator determines how much of the 10-minute reserve requirement to hold as spinning reserves.

The ISO holds an amount of 30-minute reserves that includes the system's 10-minute reserve (TMSR and TMNSR) requirements plus an incremental quantity of 30-minute reserves (TMOR). This total used to equal the size of the largest generation contingency on the system plus half of the size of the second-largest contingency on the system. However, the increase in the 10-

42 The 10-minute reserve requirement was increased 25 percent to account for poor observed performance in the deployment of reserve units relative to their claimed capability. See Agenda Item 16: "http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2012/jul1112132012/index.html"

minute reserve requirement on July 23, 2012 resulted in a corresponding increase in the 30-minute reserve requirement by 25 percent of the size of the largest contingency.

In October 2013, the ISO began procuring additional 30-minute reserves above the minimum TMOR requirement that are called "Replacement Reserves." The additional reserve requirement provides incentives for additional resources to be committed by the market, which reduces the need to use supplemental commitments under normal operating conditions. Higher quality reserves may always be used to satisfy requirements for lower quality products, the entire 30-minute reserve requirement (i.e., the minimum TMOR requirement plus the replacement reserve requirement) can be satisfied with either TMSR or TMNSR.

In 2013, the average system-wide reserve requirements were as follows:

- 10-Minute Reserves: 1,740 MW.
- Minimum 30-Minute Reserves: 2,430 MW.
- Replacement 30-Minute Reserves: 160 MW during Daylight Savings Time periods and 180 MW during Eastern Standard Time periods.
- An average of 32 percent of the 10-minute reserve requirement was held in the form of spinning reserves during intervals with binding TMSR constraints in 2013.[43]

In each of the three local reserve zones, ISO-NE 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, ISO-NE must dispatch sufficient energy in the local area to prevent cascading outages if the largest transmission line contingency occurs. Second, ISO-NE 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. Additional energy can be produced within the local area in order to unload transmission into the area, thus permitting the import of reserves if needed. Although ISO-NE is not the first RTO to co-optimize energy and reserves in the real-time market, it remains the only

43 The TMSR requirement is binding when a non-zero cost is incurred by the market to satisfy the requirement. This occurred in 2.2 percent of the intervals in 2013.

RTO that optimizes the level of imported reserves to constrained load pockets. As a result, ISO-NE is able to satisfy the local reserve requirements at a lower cost.

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 redispatch 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 redispatch cost is $10 per MWh and the reserve clearing price will not be lower than $10 per MWh. The marginal system cost that is reflected in the reserve clearing prices is equal to the marginal redispatch cost of the resources. 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 additional TMOR and set the clearing prices of both 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 (i.e., $3 plus $5 plus $7) because a megawatt of TMSR would help satisfy all three constraints. Likewise, the TMNSR clearing price would be $12 per MWh (i.e., $5 plus $7) because a megawatt of TMNSR would help satisfy two of the constraints.

Currently, ISO-NE is the only RTO that counts imported reserves towards satisfying the local reserve requirements in the co-optimization of energy and reserves. Since local reserve requirements can be met with reserves on internal resources or import capability into the load pocket that is not fully utilized, 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 fulfills a significant share of its local area reserve requirements with imported reserves. For example, roughly 18 percent of the NEMA/Boston reserve requirement was met by internal resources in 2013, while imported reserves satisfied the remaining 82 percent.

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 RCPFs are:

- $500 per MWh for the system-level minimum 30-minute reserve constraint and $250 per MWh for the system-level replacement 30-minute reserve constraint; [44, 45]
- $850 per MWh for the system-level 10-minute reserve constraint;
- $50 per MWh for the system-level 10-minute spinning reserve constraint; and
- $250 per MWh for the 30-minute reserve constraints in local reserve zones.

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 the system-level 30-minute reserve requirement were $550 per MWh, the real-time market would not schedule sufficient reserves to meet the requirement and the reserve clearing price would be set to $500 per MWh. Hence, RCPFs should be set at levels that reflect the values of the reserves and the reliability implications of a shortage of each class of reserves.

44 The RCPF for the system-level 30-minute reserve constraint was $100 per MWh before June 1, 2012.

45 This is a two-tiered demand curve for the total 30-minute reserve requirement. The $500 RCPF is set at the MW level that equals the minimum 30-minute reserve requirement, and the $250 RCPF is set at the MW level that equals the minimum 30-minute reserve requirement plus the replacement 30-minute reserve requirement.

Additionally, these values are additive when there are shortages of more than one class of reserves. Since energy and operating reserves are co-optimized, the shortage of operating reserves is also reflected in energy clearing prices.[46] For example, shortages of both minimum 30-minute reserves and 10-minute reserves would produce a clearing price of $1,350 per MWh for the system-level 10-minute reserves ($500 plus $850 per MWh) and energy prices likely exceeding $1,400 ($1,350 plus the marginal production cost 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 exceeding the ISO-NE 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 has been endorsed by FERC.[47] By providing significant amounts of revenue to resources that perform during operating reserve shortages, efficient shortage pricing reduces the level of capacity prices necessary for New England to maintain adequate resources and provides incentives for resources to be available when needed. This is also the theoretic basis for the ISO's Performance Incentive proposal that seeks to substantially increase real-time shortage pricing, which is discussed in Section VIII.C.

3. Market Outcomes

Figure 9 summarizes average reserve clearing prices in each quarter of 2012 and 2013. The left side of the figure shows prices outside the local reserve zones for three service types. The right side shows prices in the three local reserve zones for TMOR only. Each price is broken into components for each underlying requirement. 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 total 30-minute reserve requirement (i.e., including the 30-minute reserve and replacement reserve requirements). Likewise, the system-level 10-minute spinning reserve price is based on the costs

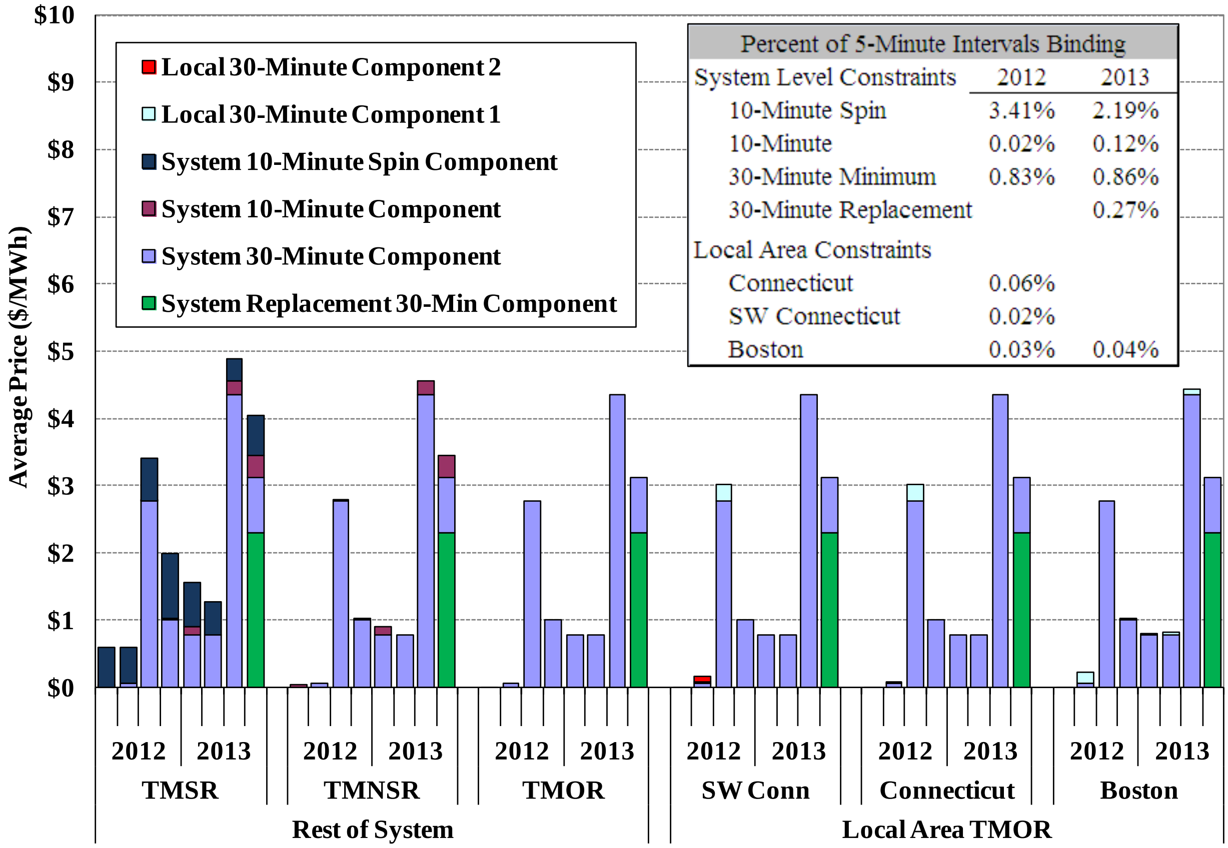
---

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

47 *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, 73 Fed. Reg. 64100 (October 28, 2008), FERC Stats. & Regs. ¶ 31,281 (2008) (Order No. 719).

of meeting three requirements: the 10-minute spinning reserve requirement; the 10-minute non-spinning reserve requirement; and the total 30-minute reserve requirement.

Figure 9: Quarterly Average Reserve Clearing Prices by Product and Location
2012 – 2013



The figure shows that reserve constraints bound infrequently in New England in 2012 and 2013. In both years, the most frequent binding constraints were the system-level 10-minute spinning reserve requirement and the system-level 30-minute reserve requirement. In 2013, the system-level 10-minute spinning reserve requirement was binding in slightly more than 2 percent of market intervals, the system-level 30-minute reserve requirement (including minimum and replacement 30-minute reserve requirements) was binding in slightly more than 1 percent of market intervals, and other reserve requirements were rarely binding.

The average clearing prices for operating reserves increased notably from 2012 to 2013. Outside the local constrained areas, the average prices for each reserve product increased significantly:

- TMSR prices increased from $1.65 per MWh in 2012 to $2.95 per MWh in 2013;

- TMNSR prices increased from $0.98 per MWh in 2012 to $2.43 per MWh in 2013; and
- TMOR price increased from $0.97 per MWh in 2012 to $2.27 per MWh in 2013.

Because the price of higher quality reserve products will always include the price of the lower quality products, nearly all of the increases shown above are by the increase in TMOR prices that were reflected in the prices for all of the 10-minute reserves and the local TMOR prices. The local TMOR clearing prices were almost identical to the system-wide TMOR prices because the local requirements were rarely binding in the real-time market in 2013 (never in Connecticut and Southwest Connecticut, and less than four hours in Boston).[48]

The increases in reserve clearing prices in late 2012 and 2013 were due to several factors:

- Higher energy prices led to concomitant increases in the opportunity cost of providing reserves (i.e., not providing energy when it otherwise would be economic to do so).
- More frequent peaking conditions because of extreme weather conditions led to more frequent shortages in 2013. The system was short of minimum 30-minute reserves in 239 market intervals during 2013, compared to only 22 market intervals in 2012.
- Four important market rule changes in 2012 and 2013 led the real-time market to set much higher clearing prices during tight operating conditions. These are discussed below.

4. Recent Real-Time Reserve Market Rule Changes

The following market rule changes have contributed to the increase in 30-minute reserve prices in 2012 and 2013:

- In June 2012, the RCPF for system-level 30 minute reserves increased from $100 to $500 per MWh to better reflect reserve shortage conditions;
- In July 2012, the 10-minute total reserve requirement was raised by 25 percent to account for under-performance expected from off-line reserve providers. Because the 10-minute requirement is a component of the 30-minute reserve requirement, the 30-minute requirement increased by an average of 340 MW;
- In June 2013, the ISO implemented tariff provisions for auditing the non-spinning reserve capability of fast start resources, resulting in an overall 190 MW reduction in claimed 30-minute reserve capability; and
- In October 2013, the ISO started to procure replacement reserves in addition to the minimum 30-minute reserve requirement.

48 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 Boston was $2.98 per MWh in 2013 ($2.95 per MWh for market-wide TMSR plus $0.03 per MWh for TMOR in Boston).

These four market rule changes have significantly improved market efficiency for a number of reasons. First, the new RCPF (#1) provides more appropriate price signals during reserve shortages. Previously, the ISO had to take more frequent out-of-market actions to maintain reserves, including curtailing exports to neighboring areas, manually dispatching online generators with available capacity, and manually committing slow-start generators to bring additional capacity online. Out-of-merit actions undermine the efficiency of the market because: (a) they artificially lower energy and operating reserve prices below levels that reflect the costs of maintaining reliability, and (b) they are generally more costly than dispatching the available resources in the real-time market.

Second, the other three rule changes (#2, #3, and #4) listed above have modified the market requirements and the claimed capability of individual generators. These changes allow the real-time market to schedule a sufficient quantity of reserve capability to satisfy the reliability needs of the system without relying as heavily on out-of-merit actions.[49] Additionally, the increased demand for operating reserves resulting from these changes will allow the real-time market prices to more accurately reflect true shortages when available resources are insufficient to satisfy the system's needs.

Taken together, all of these changes improve the ISO's shortage pricing, which provides better incentives for resources to be available and perform reliably under high load conditions and tight gas market conditions in at least two ways:

- Higher shortage prices will provide better incentives for imports from New York and other areas with available capacity.

49 The following example illustrates the effect of supplemental commitment and other out-of-merit actions on reserve prices and performance incentives. Assume the ISO makes supplemental commitments to achieve operating reserve levels that exceed the 10 and 30-minute reserve requirements by 400 MW. If a supplier fails to start or cannot obtain fuel and the ISO is only able to achieve an additional reserve level of 300 MW, the ISO is effectively 100 MW short of the operating reserves it has deemed necessary for reliability. In this case, the real-time market will perceive a 300 MW surplus and will likely price its reserves at $0 per MWh and its energy in the range of $40 to $70 per MWh. However, if the shortage in replacement reserves were perceived and priced at $250 per MWh, all classes of reserves would clear at $250 per MWh or above, and energy would likely clear above $300 per MWh. In this case, the generator that failed to start would lose substantial profit (~$250) that it would have earned by running (or if it had a day-ahead schedule, it would have to buy-back its energy at the prevailing real-time price).

- Second, more efficient shortage prices will improve the incentives for slow-starting generators to be committed in the day-ahead market and schedule the fuel necessary for operating, thereby increasing the availability of resources in real-time.

Higher real-time reserve pricing has also improved investment incentives by rewarding resources that provide energy and operating reserves during tight conditions. *Net revenue* is the operating revenue a generator receives net of its operating costs, which contributes to recouping a supplier's capital investment. For a resource with a high level of availability in 2013, the 30-minute reserve clearing prices likely increased net revenue by as much as $20 per kW-year (roughly 15 percent of the revenues needed to break-even on a new combined cycle unit). Increasing the rewards for resources that perform reliably during tight conditions reduces the revenues that generated by the capacity market in order to satisfy resource adequacy requirements and other planning criteria. Net revenue is evaluated further in Section VI.

In summary, the incentive to be available in the short-run and to invest in resources in the long-run is improved by more fully specifying and pricing the ISO's true reliability needs. This is particularly important now as concerns regarding the availability of generation and natural gas supplies have grown substantially over the past two years. These concerns prompted the ISO and NEPOOL to propose better Performance Incentives to increase incentives for suppliers to be online or provide reserves during reserve shortage conditions.[50] These reliability concerns and recommendations to address them are discussed more fully in Section VIII.C.

B. Forward Reserve Market

Each year, ISO-NE 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 fast-start resources (i.e., peaking resources). This section evaluates the forward reserve auction results and examines how suppliers satisfied their obligations in real time.

50 See Motion to Intervene Out of Time and Comments of ISO New England's External Market Monitor in Commission Docket ER14-1050, dated February 13, 2014.

1. Background on Forward Reserve Market

ISO-NE purchases two products in the Forward Reserve Market auction: 10-minute non-spinning reserves (TMNSR) and 30-minute reserves (TMOR). The forward reserve market also currently has four geographic zones: Boston, Southwest Connecticut, Connecticut, and the entire system (i.e., all of New England). Hence, the products procured in the forward reserve market are consistent with reserves in the real-time market except that the forward reserve market has no TMSR requirement.

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.

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.[51]

One of the obligations of forward reserve resources is to submit energy offers at price levels equal to or above the Forward Reserve Threshold Price. This can cause them to incur opportunity costs in the energy market if their marginal costs are less than the Forward Reserve Threshold Price. This influences supplier offers for forward reserves because suppliers will rationally include the expected value of these opportunity costs in their offers. This obligation also affects the real-time dispatch of the system.

51 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 real-time price difference between Boston TMSR and Boston TMOR.

2. Forward Reserve Auction Results

Forward Reserve 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 2013/14 Procurement Period (October 2013 to May 2014) was held in July 2013. Prior to each auction, ISO-NE sets minimum purchase requirements as follows:

- For the system-level, the minimum TMNSR requirement is based on 50 percent of the forecasted largest contingency, and the minimum TMOR requirement is based on 50 percent of the forecasted second largest contingency. [52, 53, 54]
- 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 like Forward Reserve Procurement Periods. The TMOR requirement is also 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 per kW-month price cap.[55]

The following figure summarizes the market outcomes in the last four forward reserve auctions. For each procurement period, Figure 10 shows:

- Forward reserve clearing price for each requirement,
- Reserves procured inside local reserve zones or outside the zones (i.e., Rest of System),
- Forward reserve requirement for each product, and
- The quantity of excess offers that was not cleared in the auctions.

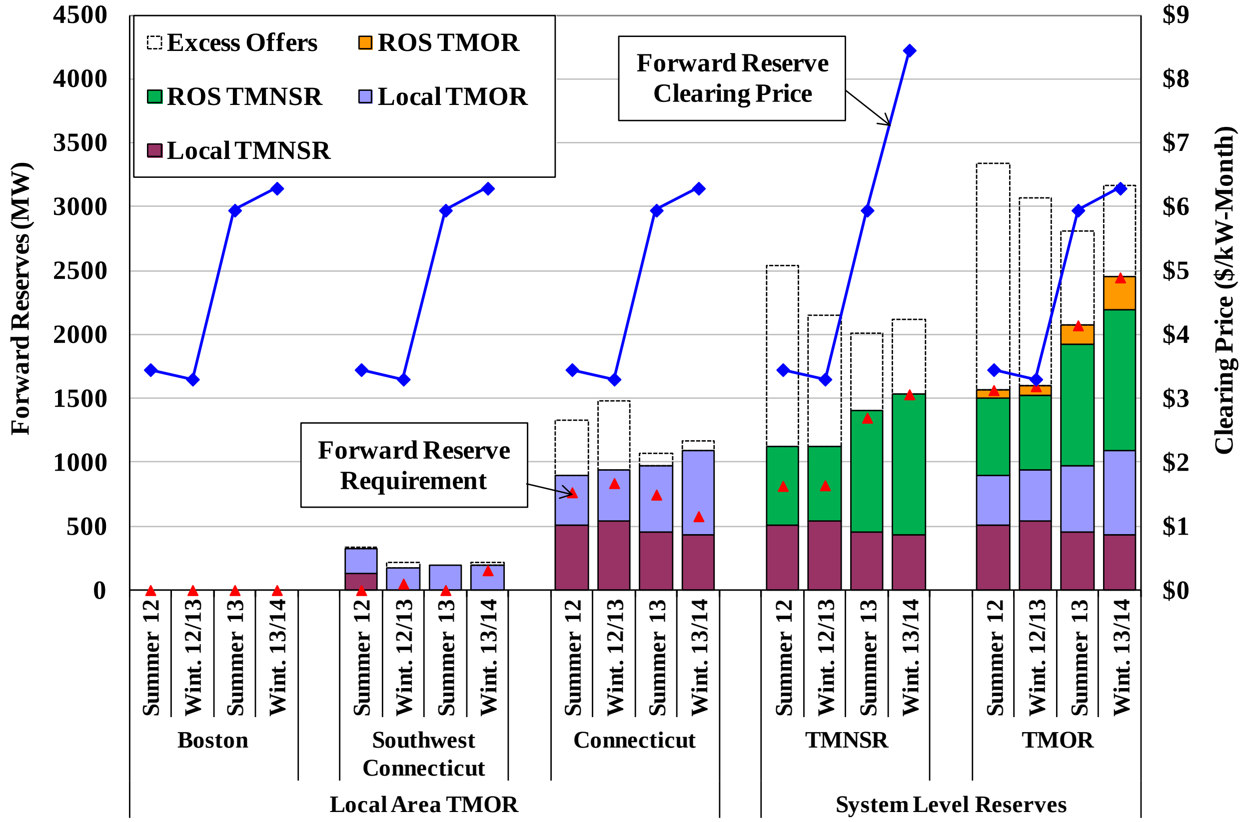
52 Usually, the forecasted largest contingency is the HQ Phase II Interconnection, and the forecasted second largest contingency is the combination of the Mystic 8 and Mystic 9 generating units.

53 An amount is added to the minimum TMNSR to account for: (a) any historical under-performance of resources dispatched in response to contingencies, and (b) the likelihood that more than one half of the forecasted 10-minute reserve requirement will be met using TMNSR.

54 An amount is added to the minimum TMOR requirement to account for replacement reserves.

55 For instance, 1 MW of TMNSR sold in Boston contributes to meeting three requirements: system-level TMNSR, system-level TMOR, and Boston TMOR. The Boston TMNSR clearing price equals the system-level TMNSR clearing price (which incorporates the price of system-level TMOR) plus the difference between the Boston TMOR clearing price and the system-level TMOR clearing price.

Figure 10: Summary of Forward Reserve Auctions
Procurement for June 2012 to May 2014



The TMNSR and TMOR requirements have increased as a result of rule changes that affected real-time reserve requirements. Starting in the Summer 2013 auction, an additional amount was added to the minimum system TMNSR requirement to reflect the 25 percent increase in the real-time TMNSR requirement. Starting in the Winter 2013/14 auction, incremental TMOR was added to the minimum system TMOR requirement to account for the scheduling of replacement reserves in the real-time market. The minimum TMNSR requirement was also increased starting in Summer 2013 to account for the likelihood that more than 50 percent the real-time 10-minute reserve requirement would be satisfied by using TMNSR (rather than TMSR).[56]

56 For example, the Summer 2013 Forward Reserve Auction assumed a first contingency of 1,740 MW at the HQ Phase II interface and that TMNSR would be used to satisfy 62 percent of the requirement. This translates to a forward reserve system TMNSR requirement of 1,349 MW (i.e., 1,740 MW × 62 percent share for TMNSR × 125 percent to as adjust for holding additional 10-minute reserves = 1349 MW).

The figure shows that the TMOR prices in the three local areas cleared at the same levels as the system TMOR prices in all of the four auctions because none of the local requirements were binding. This has been the case in the past few years because transmission upgrades between 2007 and 2009 have substantially increased the transfer capability into the local zones and caused the local requirements to fall sharply. Nonetheless, forward reserves that were procured in the local areas were used to satisfy the system-level requirements for TMNSR and TMOR and were paid the system-wide price for these products.

Outside of the local reserve areas, the clearing prices were the same for all forward reserve products with one exception. In the first three auctions, only the system TMOR requirement was binding. The TMNSR was not binding in these auctions because this requirement was satisfied at no additional cost by resources cleared for TMOR. This was not the case in the last auction (i.e., the Winter 2013/14 auction), in which the TMNSR requirement bound and caused the TMNSR prices to exceed the system TMOR prices in that auction. We believe that this deviation in the last auction is due to the effects of the Forward Reserve Threshold Price. A larger share of the TMNSR resources have marginal energy costs that are much lower than the Forward Reserve Threshold Price. Hence, they may forego significant energy revenues when they provide forward reserves, the expected costs of which would rationally be included in the forward reserve offers.

The TMOR clearing price rose significantly from an average of $3.35 per kW-month in the 2012/13 Capability Period to $6.18 per kW-month in the 2013/14 Capability Period. Forward reserve suppliers are paid according to the differential between the forward reserve clearing price and the forward capacity price.[57] After deducting the forward capacity prices, the effective forward reserve TMOR clearing prices rose from 0.40 per kW-month in the 2012/13 Capability Period to $3.23 per kW-month in the 2013/14 Capability Period.

Over the same period, the real-time TMOR clearing prices rose from an average of $3.35 per kW-month in the 2012/13 Capability Period to $6.18 per kW-month in the 2013/14 Capability Period. Hence, the large increase in the effective forward reserve TMOR clearing prices is

57 See Market Rule 1 III.9.8

consistent with the increase in the real-time TMOR clearing prices. This is appropriate given that a large component of the cost of providing forward reserves for a fast start generator is the expected forgone revenue from selling real-time reserves.

3. Forward Reserve 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 (excluding NERC holidays). 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.[58] Resources assigned to provide forward reserves forfeit any NCPC payments that they would otherwise receive. Forward reserve providers can also arrange bilaterally for other suppliers to meet their obligations. Suppliers that do not meet their forward reserve obligations incur a Failure to Reserve Penalty.[59]

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 their resources fail to deploy during a reserve pick-up.[60] 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

---

58 This level, known as the "Forward Reserve Threshold Price," is equal to the daily fuel index price posted prior to each Operating Day multiplied by a Forward Reserve Heat Rate in MMbtu per MWh, which is based on the 2.5 percentile value of a historical analysis of "implied heat rates". For example, the daily fuel index price was $3.64 per MMbtu and the forward reserve heat rate was 16.01 MMbtu per MWh for July 1, 2013. Hence, it resulted in a Forward Reserve Threshold Price of approximately $58 per MWh for this Operating Day. The daily fuel index price is based on the lower of the natural gas or diesel fuel index prices in dollars per MMbtu. The implied heat rate analysis is based on the real-time hub LMP and the lower of the distillate or natural gas fuel price indices for New England.

59 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.

60 The Failure to Activate penalty is equal to the MW quantity 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.

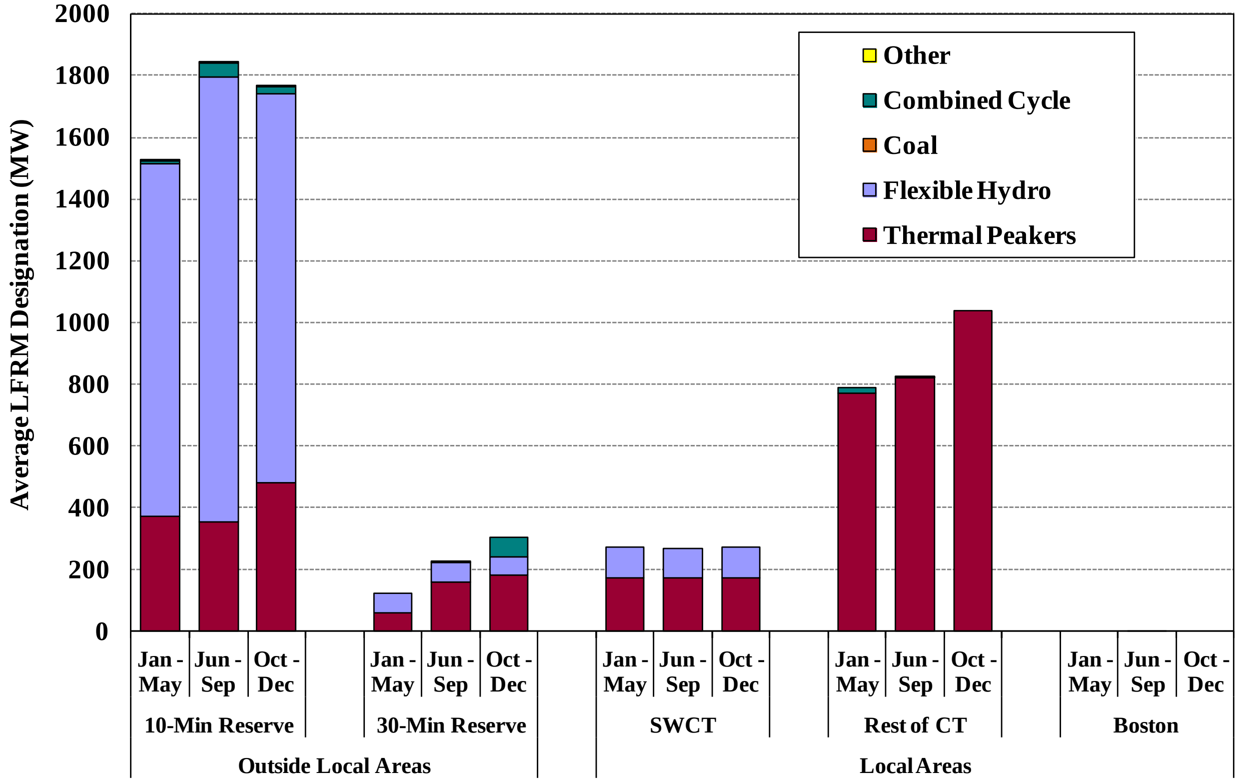
TMNSR. A supplier that has TMOR obligations would not be paid if scheduled for TMOR or would be paid $5 per MWh (i.e., the price difference between TMNSR and TMOR) if scheduled for TMNSR. Hence, the foregone reserve revenues are the same regardless of whether the supplier is ultimately scheduled for 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 Forward Reserve Threshold Price. For instance, suppose the Forward Reserve Threshold Price is $100 per MWh and a supplier assigns a generator that has incremental costs of $60 per MWh to provide forward reserves. Because the supplier is required to offer at $100 per MWh, the supplier will not be scheduled to sell energy when the LMP is between $60 per MWh and $100 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 Forward Reserve Threshold Price).

The previous three kinds of costs may be incurred by all units that provide forward reserves, but there are additional costs that are faced only by units that must be online to provide reserves. In order to provide reserves from a unit that is not a 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, they are generally most economic to meet forward reserve obligations.

The following analysis evaluates how market participants satisfied their forward reserve obligations in 2013 by procurement period. The figure shows the average amount of reserves assigned in each region by type of resource.

Figure 11: Forward Reserve Assignments by Resource Type
2013



Approximately 98 percent of the capacity assigned to provide forward reserves was hydro and thermal peaking capacity 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 slower-starting resources. Combined cycle units were assigned to provide a small portion (1.7 percent) of the forward reserves in 2013. Some of these units were ones that are capable of providing offline reserves within 30 minutes.

In summary, the vast majority of forward reserves were provided by fast-start units. This suggests that many slower-starting resources did not sell forward reserves because the expected costs of providing forward reserves exceeded the clearing prices in the forward reserve auctions. However, slower-starting units that could provide forward reserves at a cost below the forward reserve clearing price may be discouraged from participating because units that are frequently committed for reliability and receive substantial NCPC payments have disincentives to provide forward reserves (they would be required to forgo the NCPC payments). Some had expected that the Forward Reserve Market would lower NCPC costs because high-cost units committed for reliability would sell Forward Reserves. However, this has not occurred. Given that the forward reserve market increases the overall costs of scheduling energy and operating reserves by requiring providers to offer energy at or above the Forward Reserve Threshold Price, it is important to evaluate on an on-going basis whether the Forward Reserve Market contributes to overall market efficiency.

C. Regulation Market

Regulation service 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 deploys regulation to maintain the balance between generation and load in the control area. The regulation market provides a market-based system for meeting the system's regulation needs.

The ISO determines the quantity of regulation capability required to maintain the balance between generation and load based on historical performance and ISO-NE, NERC and NPCC control standards. The ISO schedules an amount of regulation capability that ranges from 30 MW to 150 MW depending upon the season, time of day, and forecasted operating conditions. Historically, the ISO has scheduled 15 to 20 MW more regulation capability in the summer and winter than it has acquired in the spring and fall. During emergency conditions, the ISO may adjust the regulation requirement to maintain system reliability. The ISO periodically reviews regulation performance against the applicable control standards. The high level of performance in recent years has permitted a steady decline in the average quantity of regulation scheduled over the last eight years: from 143 MW in 2005 to 60 MW in 2013.

1. Regulation Market Design Changes

On October 20, 2011, FERC issued Order 755 on Frequency Regulation Compensation, which requires ISO-NE and other ISOs to modify their market designs.[61] Specifically, Order 755 requires ISOs to operate regulation markets that compensate generators for "actual service

61 See Frequency Regulation Compensation in the Organized Wholesale Power Markets, Order No. 755, 137 FERC ¶ 61,064 (2011).

provided, including a capacity payment that includes the marginal unit's opportunity costs and a payment for performance that reflects the quantity of frequency regulation service provided."

After several filings by ISO-NE and NEPOOL containing market rule and tariff changes to comply with Order 755, the Commission accepted proposed changes to be implemented in October 2014.[62,63] As the ISO continues to work on the full implementation of the proposed changes, it implemented an interim market design change on July 1, 2013 that includes opportunity costs in the regulation clearing price.[64] Prior to this change, compensation for energy market opportunity costs was accomplished by separate resource-specific payments, which can be problematic because they create incentives for suppliers to not offer at their marginal costs (i.e., pay-as-bid incentives). Hence, this interim rule change addresses this issue by including energy opportunity costs in the regulation clearing price.[65] It will be important to evaluate the performance of this market after the full changes are implemented in late 2014.

2. Regulation Market Expenses

Competition is robust in ISO-NE's regulation market in most hours because the available capability generally far exceeds the ISO's requirements. This excess supply generally limits competitive concerns in the regulation market because demand can easily be supplied without the largest regulation supplier. We focus our evaluation on the overall expenses from procuring regulation. Resources providing regulation service receive the following payments:[66]

- 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 (including energy market opportunity costs since July 1, 2013).

62 See http://www.iso-ne.com/regulatory/ferc/filings/ 2013/feb/er12-1643-001_order_755_2-6-2013.pdf and 6-20-13_ordr_reg_mkt_ordr755_compliance.pdf.

63 See http://www.iso-ne.com/regulatory/ferc/orders/2013/jul/er12-1643-002_7-29-13_ordr_ext_ordr_755.pdf.

64 See Docket No. ER13-1259-000 at http://www.iso-ne.com/regulatory/ferc/filings/2013/apr/er13-1259-000_4-11-2013_reg_mkt_opp_cost_chg.pdf.

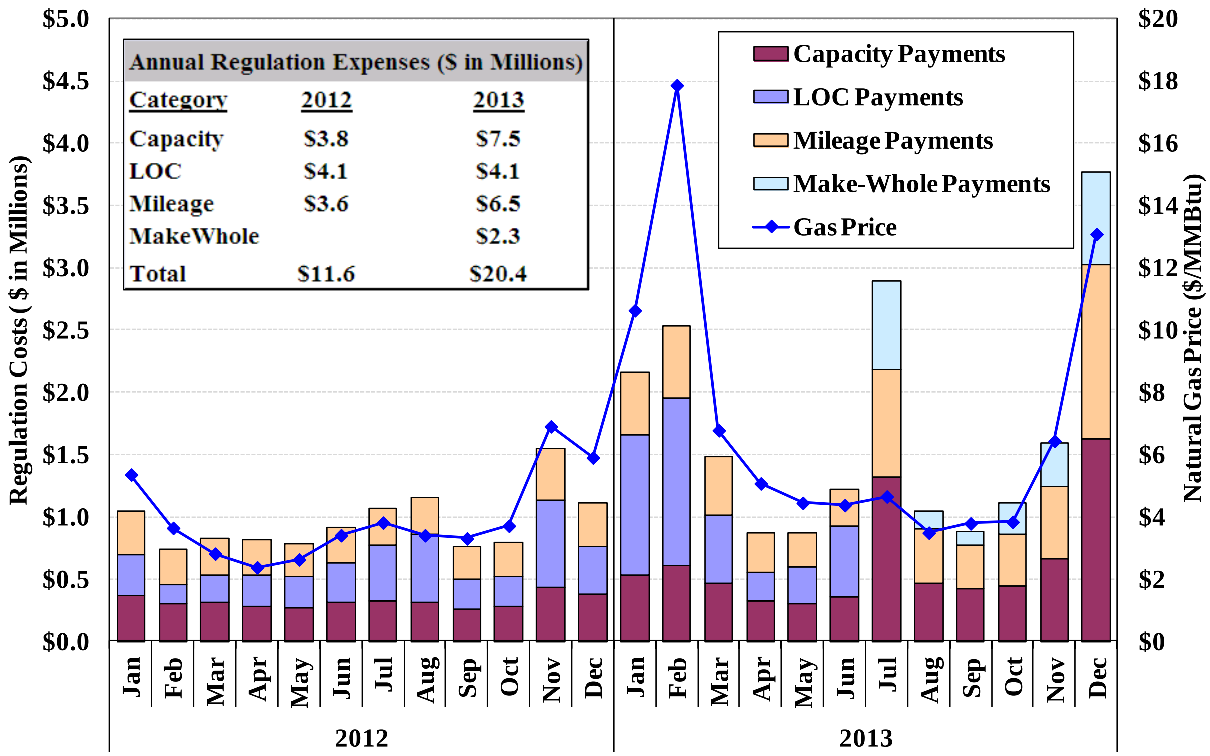
65 See ISO-NE Manual M-REG Regulation Market for more details on regulation selection and pricing.

66 In ISO-NE Manual M-REG, Capacity Payment is the "Time-on-Regulation Credit," Mileage Payment is the "Regulation Service Credit," and the Lost Opportunity Cost Payment is the "Regulation Opportunity Cost."

- 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.
- Lost Opportunity Cost (LOC) Payment – This is the opportunity cost of not providing the optimal amount of energy when the resource provides regulation service. This category of payment was eliminated following the market rule change on July 1, 2013.
- Make-Whole Payment – This is the additional payment to regulation providers when the revenues from the regulation clearing price are insufficient to cover their actual costs for providing regulation. This became effective following the market rule change on July 1, 2013.

A summary of the market expenses for each of the four categories is shown in Figure 12 by month for 2012 and 2013. The figure also shows the monthly average natural gas price.

Figure 12: Regulation Market Expenses
2012 – 2013



Total regulation expenses rose 77 percent from $11.6 million in 2012 to $20.4 million in 2013, which were driven partly by the market design change in July 2013 and partly by the increase in natural gas prices. The figure shows that variations in monthly regulation market expenses were generally correlated with changes in the monthly average natural gas price.

Input fuel prices can affect regulation market expenses in several ways. First, generators may consume more fuel to produce a given amount of electricity when they provide regulation. Market participants reflect these costs in their regulation offer prices, which directly affect both the Capacity Payments and Mileage Payments. Second, natural gas-fired combined cycle generators are usually committed less frequently during periods of high gas prices. This decreases the availability of low-priced regulation offers and leads to higher regulation expenses. Third, higher fuel prices normally increase the opportunity costs for units to provide regulation service, which is consistent with the general decrease in regulation opportunity cost expenses in the summer months compared to the winter months.

D. Conclusions and Recommendations

In the real-time reserve market, average clearing prices for all reserve products rose substantially from in 2013, reflecting:

- Higher energy prices that increased the opportunity cost of providing reserves;
- More frequent shortages in 2013 because of more frequent peaking conditions; and
- Four important market rule changes in 2012 and 2013 that increased the ISO's demand for operating reserves and its shortage pricing when it does not satisfy its 30-minute reserve requirement:

These market rule changes improve the efficiency of real-time prices by allowing the ISO's true reliability needs to be more fully specified and priced. As described in this section, efficient shortage pricing:

- Improves suppliers' incentives to be available and perform reliably under high load conditions and tight gas market conditions;
- Increases the incentives to invest in new resources with high availability;
- Reduces the revenues required from the FCM to satisfy the ISO's planning requirements;
- Encourage efficient imports from New York and other areas with available capacity; and
- Improve incentives for slow-starting generators to be committed in the day-ahead market and schedule the necessary fuel.

These improvements are particularly important now as concerns regarding the availability of generation and natural gas supplies have grown substantially over the past two years. These concerns prompted the ISO to propose Performance Incentives to further increase incentives for suppliers to be online or provide reserves during reserve shortage conditions, which we discuss in Section VIII.C.

In the forward reserve market, clearing prices rose more than 80 percent from the 2012/13 Capability Periods to the 2013/14 Capability Period. The increase was due primarily to the expected changes in real-time energy and reserves prices during tight system conditions, since forward reserve providers must forego some energy and operating reserve profits in order to meet their forward reserve obligations. Similar to prior years, we also found that 99 percent of the resources assigned to satisfy forward reserve obligations in 2013 were fast-start resources capable of providing offline reserves.

The ISO may wish to consider the long-term viability of the forward reserve market because:

- It has not achieved one of its primary objectives, which was to lower NCPC by purchasing forward reserves from high-cost units frequently committed for reliability.
- The Locational Forward Reserve Market is largely redundant with the locational requirement in the Forward Capacity Market.
- The forward procurements do not ensure that sufficient reserves will be available during the operating day. Forward reserve sellers are simply obligated to offer at prices higher than the Forward Reserve Threshold Price, but may still be dispatched for energy.
- The obligation of forward reserve suppliers to offer at prices higher than the Forward Reserve Threshold Price can distort the economic dispatch of the system and inefficiently raise costs.

In addition, increasing forward reserve prices recent forward capacity auctions may create issues in future years because forward reserve suppliers are paid according to the difference between the forward reserve clearing price and the forward capacity price. For example, the clearing price in the forward capacity auction for the 2016/17 Capability Year (i.e., FCA 7) is $14.999 per kW-month for the Boston area. This creates disincentives for Boston resources to provide forward reserves to satisfy the system requirements.

In the longer-term, we recommend the ISO consider introducing day-ahead reserve markets. Such markets would allow the ISO to procure the reserves it needs for the following day and to set clearing prices that reflect the costs of satisfying the operating reserve obligations. Such markets would also likely help address the ISO's concerns regarding unit availability. The day-ahead reserve schedules would be established in a timeframe in which suppliers can make arrangements for fuel and staffing to allow them to respond to reserve deployments. This is particularly true for spinning reserve providers, since it is prohibitively costly for them to accept forward reserve obligations for an entire procurement period.

Finally, the regulation market performed competitively in 2013 overall. On average, approximately 670 MW of available supply competed to provide 60 MW of regulation service. The significant excess supply generally limits competitive concerns in the regulation market. ISO-NE's latest proposal for complying with the Order 755 will become effective on or after October 1, 2014. It is likely that the regulation market will continue to perform competitively given the large amount of supply in the market relative to the average demand.

V. Real-Time Pricing and Market Performance

The goal of the real-time market is to efficiently procure 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. This tends to distort the real-time prices and may indicate that there are reliability needs that are not fully priced. Both of these issues are significant because they undermine the efficiency of the real-time price signals. Efficient real-time price signals are essential because they encourage reliable performance and increased availability by generators and demand response, and investment in new resources or transmission where it is needed most.

Indeed, the recent efforts to introduce additional Performance Incentives recognize that efficient price signals during shortages motivate resources to be available when needed. Furthermore, to the extent that efficient price signals during shortages or tight operating conditions exceed generators' costs, the revenues needed from the forward capacity auctions to maintain adequate installed capacity margins will fall.[67] 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 2013. This section examines the following areas:

- Prices during the deployment of fast-start generators;
- Prices during the activation of real-time demand response;
- Efficiency of real-time ex post prices; and

At the end of this section, we provide a list of our conclusions and recommendations regarding the efficiency of real-time prices.

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

Fast-start generators are capable of starting from an offline status and ramping to their maximum output within 30 minutes of notification, which enables them to provide valuable offline

67 Section VI evaluates the amounts of net revenue that new and existing generators earn from the capacity and energy markets.

reserves. 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 can ramp more quickly than most baseload units, better enabling the system operator to respond rapidly to unexpected changes in operating conditions. During such conditions, it is particularly important to operate the system efficiently and to set prices that accurately reflect the cost of satisfying demand and reliability requirements.

This section of the report discusses the challenges related to efficient real-time pricing when fast-start generators are the marginal supplier of energy in the market. It also evaluates the efficiency of real-time prices when fast-start generators were deployed by the real-time market in 2013. This can be an issue because fast-start peaking units are relatively inflexible once they are started. This causes them to frequently not set the real-time price, even when they are the marginal source of supply).

1. Treatment of Fast-Start Generators by the Real-Time Dispatch Software

This subsection describes how fast-start peaking units are committed by the real-time market dispatch software. The ISO's real-time dispatch software, called Unit Dispatch System (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.[68] Most commitment decisions are made in the day-ahead timeframe prior to the operation of UDS. UDS' primary function is to adjust the output levels of online resources. The only resources that UDS can commit (i.e., start from an offline state) are fast-start generators.[69] It is more efficient to allow UDS to start fast-

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

69 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.

start generators than to rely exclusively on operators to manually commit such units because UDS performs an economic optimization.[70]

When determining dispatch instructions for most online generators, UDS considers only incremental offers. However, for fast-start generators, UDS also considers commitment costs (since they must be committed from an offline state) and uses various assumptions regarding the dispatchable range of the generator. The treatment of commitment costs and the dispatchable range have important implications for price setting by the real-time software (i.e., how real-time LMPs are determined).

UDS schedules fast-start generators using the following criteria:

- Offline fast-start generators – UDS considers commitment costs by adding the start-up offer (amortized over 1 hour) and "no-load" offers to the incremental offer. UDS treats the generator as having a dispatchable range from 0 MW to its maximum output level.
- Online fast-start generators during the minimum-run time – UDS considers only the incremental offer. UDS treats the generator as having a dispatchable range from its minimum output level to its maximum output level.
- Online fast-start generators after the minimum-run time has elapsed – UDS considers only the incremental offer. UDS treats the generator as having a dispatchable range from 0 MW to its maximum output level.

In the first phase of commitment listed above (when the unit is offline), real-time LMPs usually reflect the full cost of deploying the fast-start generator, partly because UDS considers the no-load offer and the start-up offer of the generator. Furthermore, UDS allows the fast-start generator to "set price" when the generator is economic to be online by treating the generator as dispatchable between 0 MW and the maximum output level.

However, in the second and third phases of commitment (i.e., once the unit is online), real-time LMPs frequently do not reflect the full cost of deploying the fast-start generator, even if the generator is still economic to be online. Since UDS does not consider the start-up and no-load offers, the real-time price-setting logic incorporates only the incremental offer. Furthermore, since the minimum output level of most fast-start generators is within 90 percent of their

70 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.

maximum output level, fast-start generators are frequently dispatched at their minimum output levels where they do not set price during the second phase of commitment. In such cases, the resulting LMP may be lower than the incremental offer of the fast-start generator.

The following example illustrates the pricing challenges when fast-start generators are deployed economically by the real-time market. Suppose UDS needs to schedule an additional 15 MW in an import-constrained area and the lowest cost supply is an offline fast-start generator with an incremental offer price of $75 per MWh, a no-load offer of $300 per hour, a start-up offer of $500 per start, a minimum output level of 18 MW, and a maximum output level of 20 MW. In this case, the average total offer of the offline unit is $115 per MWh ($75 per MWh + $300/hour ÷ 20 MW + $500/hour ÷ 20 MW) when it runs at full output for one hour. This total offer is used in the price-setting logic during the first phase of commitment.

In the start-up interval, UDS treats the fast-start generator as flexible and schedules 15 MW from the fast-start generator. This generator is the marginal generator and, therefore, sets the LMP at $115 per MWh. Since 15 MW is lower than the minimum output level of the generator, the generator is instructed to produce at its minimum output level. Once the generator is running (but before its minimum run period has expired) it is no longer possible to schedule 15 MW from the fast-start generator since the minimum output level (18 MW) is enforced. As a result, the fast-start generator is dispatched at 18 MW rather than 15 MW, and the output level of the next most expensive generator is reduced by 3 MW to compensate for the additional output from the fast-start generator. In this case, the fast-start generator is no longer eligible to set the LMP since it is at its minimum output level, so the next most expensive generator sets the LMP at a price lower than the incremental offer of the fast-start generator ($75 per MWh).

After the minimum run time elapses, UDS can schedule 15 MW from the fast-start generator if that is most economic, because the minimum output level is not enforced in this phase. In this case, the fast-start generator sets the LMP at its incremental offer of $75 per MWh. However, when the UDS solution reduces the output of the unit below its economic minimum, the operator must decide whether to decommit the resource.

In this example, the fast-start generator is dispatched in merit order, although the full cost of the decision is not reflected in real-time LMPs. The fast-start generator costs $115 per MWh to operate in the first hour and $90 per MWh thereafter; however, the LMP is set to $115 per MWh in the first UDS interval (usually approximately 10 minutes), less than $75 per MWh for the remainder of the first hour, and $75 per MWh thereafter. This issue is worse when an operator commits a fast-start generator for reliability. In this case, the unit will generally operate at its economic minimum and not set prices because they tend to be higher cost than the units committed economically. In both cases, the owner of the fast-start unit would receive NCPC payments to make up the difference between the total offer and the real-time market revenue.

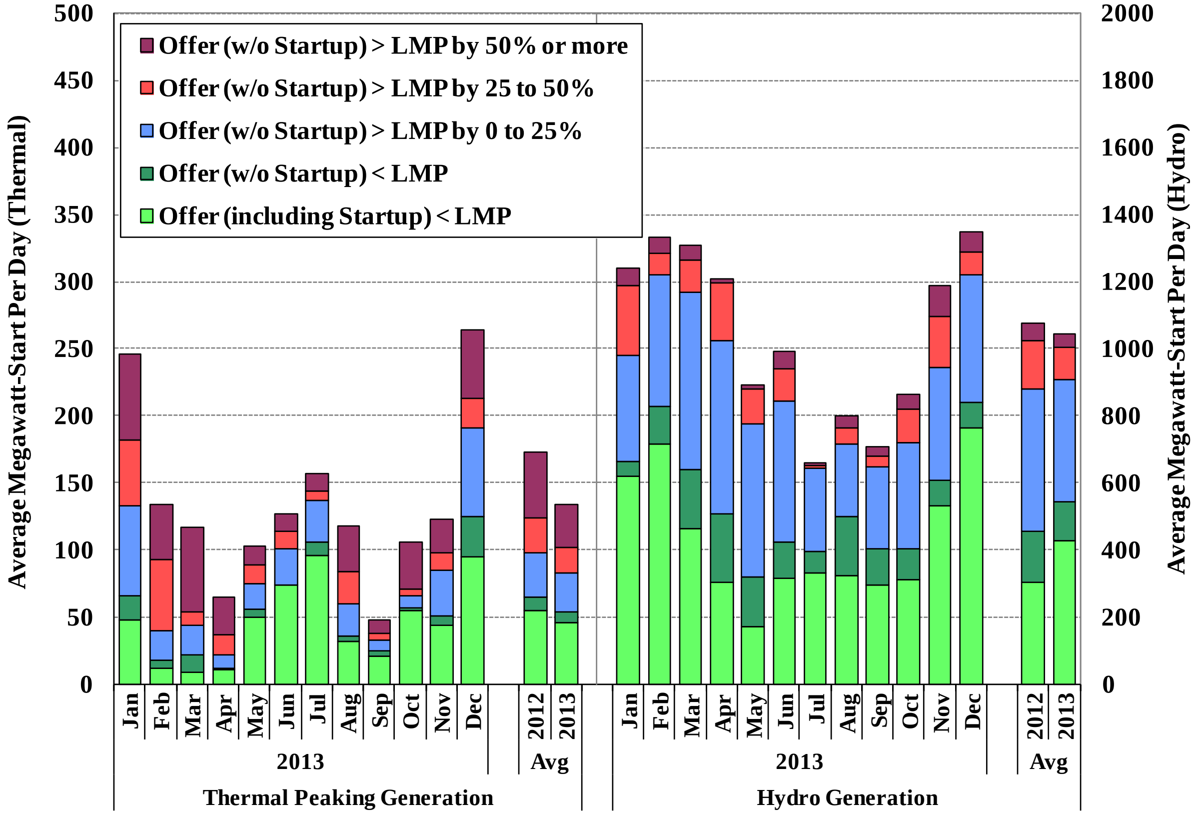
2. Evaluation of Fast-Start Deployments by UDS in 2013

The following two analyses assess the efficiency of real-time pricing during periods when fast-start units were deployed in merit order. The first analysis summarizes how consistent the real-time prices are with the offer costs of the fast-start resources. The second analysis evaluates how LMPs would be affected if the average total offers were fully reflected in real-time prices.

Figure 13 summarizes the consistency of the real-time LMP with the average total offer for fast-start units committed economically by UDS. The average total offer includes no-load and start-up costs amortized over one hour and the comparison is made over the units' over the initial commitment period, which is usually one hour. When the average real-time LMP is greater than the average total offer, the figure shows the associated capacity in the category labeled "Offer (including Startup) < LMP". However, when the average real-time LMP is less than the average total offer, LMPs do not fully reflect the cost to the system of deploying the fast-start generator. Figure 13 shows hydroelectric and thermal units separately, and categorizes such occurrences in five categories based on the relative economics of the units.

Figure 13 shows that flexible hydro generation accounted for over 85 percent of fast-start generation that was started in merit order by UDS in 2012 and 2013. This indicates that hydro generators are generally less costly and have sufficient water to operate on a daily basis. Many of the thermal peaking units in New England have low capacity factors because of their high production costs. The amount of thermal peaking generation that was started in merit order by UDS fell modestly from 2012 to 2013.

Figure 13: Comparison of Real-Time LMPs to Offers of Fast-Start Generators
First Hour Following Start-Up by UDS, 2013



Overall pricing efficiency during hours when fast-start resources are committed by UDS improved modestly from 2012 to 2013. Including both thermal peaking and hydro generation resources, the average total offer (including start-up costs) was lower than the real-time LMP in 40 percent of starts in 2013, up from 29 percent in 2012. The improvement in 2013 was mostly associated with hydro generation resources. Nonetheless, real-time prices still did not reflect the full cost of satisfying load in most periods when fast-start resources were deployed.

Although thermal peaking generators are deployed in a relatively limited number of hours, they are frequently the marginal source of supply in the hours that they run. This makes it particularly important to reflect the full cost of their deployment in real-time LMPs when they are deployed efficiently in merit order. Even when start-up costs are excluded, 61 percent of the thermal peaking generation exhibited offers greater than the real-time LMP. Hence, even though these units were dispatched in economic merit order, they often relied on NCPC payments to recoup their full as-bid operating costs. More importantly, these results indicate that real-time prices do not accurately reflect the marginal cost of serving real-time demand, which affects the economic signals provided by the day-ahead and forward markets in New England. The following analysis examines how real-time energy prices would be affected if the average total offers of such units were reflected in real-time LMPs.[71]

Figure 14 summarizes the portion of the fast-start units' costs that were not fully reflected in real-time LMPs in 2013. The lower portion of Figure 14 shows how frequently thermal and hydro fast-start units were started economically by UDS when their average total offers were greater than the LMP during the minimum run time in 2013.[72] The figure excludes fast-start units that were started in import-constrained areas since these LMPs would be representative of only a limited area of New England.[73] The upper portion of the figure shows the difference between the annual average total offer and the real-time LMP from such periods by time of day. The figure also shows the impacts separately for hydro and thermal fast-start units by dividing all examined market intervals into: (a) "Hydro Only" intervals if only flexible hydro resources are started and running in that interval; and (b) "Thermal & Hydro" intervals if at least one thermal fast-start unit is started and running in that interval.[74] The inset table summarizes our estimates of the reduction in NCPC if these average total offers were fully reflected in real-time LMPs.

Figure 14 shows that fast-start units were deployed economically by UDS when their average total offer was greater than the real-time LMP in a substantial portion of hours. Such hours were most frequent from hours-ending 7 to 22, particularly around the morning peak (hours-ending 7 to 9) when load picks up rapidly and the evening peak (hours-ending 18 to 21). Ramping needs are highest on the system during these periods, so fast-start generation is sometimes needed to satisfy load during these periods.

---

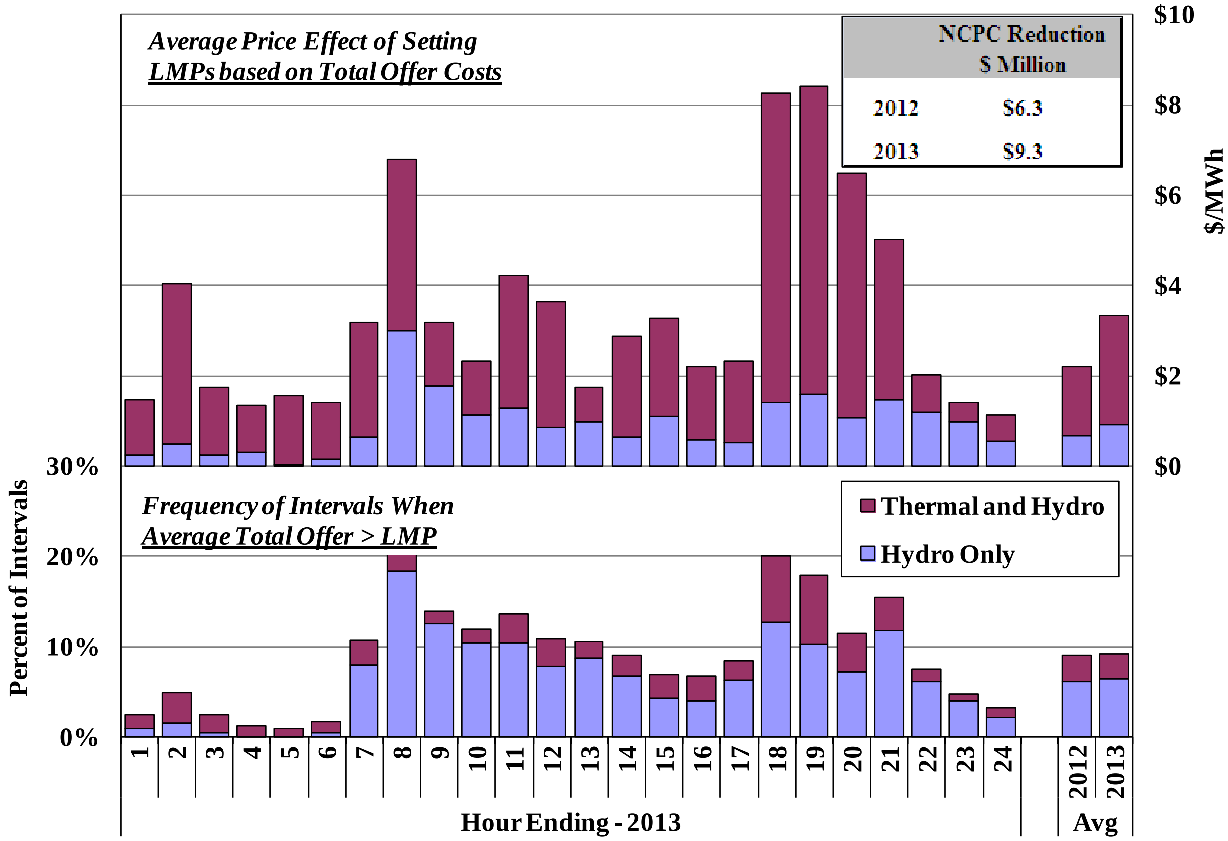
71 If a gas turbine was started with a total offer of $115/MWh when the LMP was $75/MWh, this analysis would assume the unit would increase the LMP by $40 per MWh. Other lower-cost gas turbines or hydro resources started in the same hour would not affect prices because they are inframarginal.

72 If multiple fast-start units are started at one time, the analysis uses the one with the largest difference between the average total offer and the real-time LMP, which is usually the highest-cost unit.

73 The area is treated as import-constrained if the congestion component of the LMP at the fast-start unit's node is greater than the congestion component at New England Hub by $1 per MWh or more.

74 Since thermal fast-start units typically have higher offer costs, lower-cost hydro fast-start units started in the same hour would generally not affect prices because they are inframarginal.

Figure 14: Difference Between Real-Time LMPs and Offers of Fast-Start Generators
First Hour Following Start-Up by UDS, 2013



Overall, fast-start units were started economically by UDS when their average total offer exceeded the real-time LMP during the minimum run time in 9 percent of all hours in 2013, comparable to the previous year. Hydro-only fast-start units were started during two-thirds of these hours (i.e., 6 percent of all hours in 2013), while at least one thermal fast-start unit was started in the remaining one-third of these hours.

If the average total offers of these units were fully reflected in the energy price in these hours, the average real-time LMP would increase approximately $3.34 per MWh in 2013. More than 70 percent of this increase would be attributable to allowing thermal peaking generators to set prices, even though these units would be started much less frequently than the hydroelectric units. Overall, the estimated price increase would be largest in hour-ending 19 when the average LMP would rise by $8.44 per MWh. If the estimated price increases were reflected in the calculation of NCPC uplift charges, we estimate that they would be reduced by $6.3 million in 2012 and $9.3 million in 2013.

However, these differences likely overstate the impact from more efficient real-time pricing during fast-start resource deployments because they do not consider the likely market responses to the higher real-time prices:

- Incentives to purchase more in the day-ahead market would increase, which would increase the amount of lower-cost generation committed in the day-ahead market.
- Net imports would increase from neighboring control areas, particularly from New York during the morning and evening peak hours.

Hence, the actual effect on real-time LMPs from more efficient pricing during fast-start deployments and resulting reductions in NCPC uplift charges would be smaller than the results shown in Figure 14. However, these responses would substantially improve efficiency because higher-cost peaking generation would be displaced by lower-cost intermediate generation and net imports. Allowing peaking resources to set prices when marginal would also improve:

- Incentives for reliable performance during the relatively tight operating conditions, since fast start units are dispatched primarily when operating reserve margins are smallest during the morning and evening peaks; and
- Incentives governing longer-term investment and retirement decisions by participants, since it would provide increased net revenues to generators that are available during tight operating conditions.[75] This would, in turn, reduce the required net revenues from the capacity market.

Therefore, we continue to 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 NYISO has a methodology for allowing fast-start resources to set the real-time LMP, and the Midwest ISO is preparing to implement a similar methodology. We recommend ISO-NE consider using a similar mechanism to improve the efficiency of real-time pricing when fast-start resources are the marginal sources of supply.[76]

75 Suppose that allowing fast start resources to set the LMP when economic would raise the average LMP by 50 percent of the potential $3.34 per MWh shown in Figure 14. This would increase the net revenue of a generator with high availability by up to $14 per kW-year. Net revenue is evaluated further in Section VI.

76 The MISO is currently planning to implement this methodology (known as “ELMP”) in late 2014.

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

Price-responsive demand has the potential to enhance wholesale market efficiency in theory. 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. Indeed, a large share of new capacity procured in the Forward Capacity Auctions has been composed of demand response capability rather than generating capability. 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.

The rise in demand response participation over the past several years is beneficial in many ways, but it also presents significant challenges for efficient real-time pricing. Active demand resources procured in the forward capacity market (i.e., Real-Time Demand Response and Real-Time Emergency Generation) are currently not dispatchable within the real-time dispatch software and cannot, therefore, set real-time energy prices. Instead, they are dispatched as part of the OP-4 procedures under Actions 2 and 6. [77,78]

The activation of demand response in real time can inefficiently depress real-time prices substantially below the marginal cost of the foregone consumption by the demand response resources, particularly during shortages or near-shortage conditions. Although there is little information available on the marginal cost of foregone consumption for demand response resources, the marginal costs of most demand response resources are likely to be much higher than the marginal costs of most generators. Hence, real-time prices should be very high when demand response resources are activated.

In 2013, there were three occasions when emergency demand response resources were activated. On January 28, the ISO activated a total of 373 MW of Real Time Demand Response resources

---

77 "Dispatchable" 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.

78 Loads that are dispatchable in the real-time market are able to participate in the Asset Related Demand (ARD) programs. ARDs are paid according to day-ahead and real-time LMPs. ARDs are not paid for capacity, however, they are also not charged for capacity obligations.

for three and half hours (17:28 to 21:00). On July 19, the ISO activated a total of 193 MW of Real Time Demand Response resources for seven and half hours (13:00 to 20:30). On December 14, the ISO activated a total of 248 MW of Real Time Demand Response resources for three and half hours (17:07 to 20:45). All three events were caused by a system-wide capacity deficiencies that resulted in part from unexpected high load.[79] Table 1 summarizes the following average quantities for each hour during the three events:

- The day-ahead and real-time LMPs at the New England Hub;
- The amount of real-time demand response that was activated;
- The net imports from other control areas in real-time;
- The day-ahead net scheduled load and real-time load; and
- The amount of shortages or surpluses of system-level 30-minute reserves.

Table 1: Resource Availability and Prices During Activation of RT Demand Response
2013

Date	Hour Ending	NE Hub LMP DAM ($/MWh)	NE Hub LMP RTM ($/MWh)	RT DR Deployment (MW)	Net Imports NY (MW)	Net Imports Canada (MW)	DAM Sched Load (GW)	RT Load (GW)	30-Min Reserves Shortage(-)/Surplus(+) (MW)
28-Jan	18	$209.21	$780.89	373	870	1544	17.4	19.8	(58)
	19	$206.01	$270.68	373	827	1624	17.2	19.5	364
	20	$191.85	$147.50	373	958	1654	16.7	18.8	544
	21	$182.77	$144.28	373	870	1739	16.4	17.9	799
19-Jul	14	$196.25	$868.79	193	454	2418	25.5	27.3	(1062)
	15	$206.73	$709.27	193	365	2418	25.5	27.3	(2677)
	16	$209.18	$630.36	193	343	2418	25.5	27.3	(1016)
	17	$219.34	$585.06	193	386	2418	25.2	27.4	(719)
	18	$199.24	$440.56	193	501	2418	24.9	27.1	(206)
	19	$152.70	$79.56	193	404	2418	24.2	26.4	112
	20	$146.72	$58.09	193	507	2418	23.2	25.6	422
	21	$141.13	$85.89	193	90	2418	23.1	25.2	603
14-Dec	18	$275.09	$1,289.93	248	1316	1391	18.4	20.1	(806)
	19	$217.13	$264.61	248	1555	1703	18.1	19.8	255
	20	$207.11	$177.33	248	1600	1918	17.4	19.2	599
	21	$203.30	$216.43	248	1428	1660	16.8	18.5	579

The table shows seven hours across three days with significant shortages of 30-minute reserves (i.e., one hour each on January 28 and December 14, and five hours on July 19) when real-time

79 On the three days, the Real Time Demand Response resources were activated via OP-4 Action 2.

demand response resources were activated. As a result, the reserve clearing price for 30-minute reserves was $500 per MWh (the RCPF) during these shortages and real-time LMPs were generally higher than $500 per MWh.

However, the results from these events also highlight two market issues. First, there was a significant amount of available import capability from neighboring areas that could have been used to import power into New England during the seven hours with operating reserve shortages. However, the current rules require that real-time external transactions be scheduled in advance of each hour. Implementation of CTS between New York and New England will allow for much more timely responses from imports to unforeseen changes in conditions that lead to reserve shortages in New England. [80]

Second, a demand response activation can depress real-time prices when the activation eliminates the shortage of operating reserves (i.e., when the response is larger than the magnitude of the shortage). This occurred for roughly three hours during these events. For example, in hour-ending 19 of July 19, there would have been a reserve shortage without the real-time demand response activation, so the demand response resources were effectively the marginal resources during this hour. It would be efficient for real-time prices to reflect the value of foregone consumption of the demand response resources in such cases, which is not currently possible because demand response resources do not submit bids and are not activated based on economic criteria. The actual real-time prices in these cases were inefficient because the foregone value of consumption for most demand response resources was likely much higher than the LMPs in these hours.

If the foregone value of consumption for demand response resources was better reflected in real-time LMPs, it would provide more efficient scheduling incentives in the day-ahead market. The table shows that the amount of energy scheduled in the day-ahead market was roughly 2 GW lower than the amount of real-time load during these events. Raising the real-time price in these cases would provide incentives to purchase more energy in the day-ahead market. Increased

80 CTS is scheduled to be effective by the end of 2015 and it is discussed in Section I.C.

purchases would, in turn, likely lead additional lower cost resources to be scheduled and reduce the likelihood of the reserve shortages and emergency demand response activations.

Hence, it is important to consider ways to appropriately reflect the value of foregone consumption in real-time prices. To this end, ISO-NE is moving forward with a proposal to enable demand response resources to participate fully in the day-ahead and real-time markets by June 2017. This would allow active demand response resources to submit multi-part offers into the day-ahead and real-time markets and for the ISO to schedule demand response resources in merit order as it would for a generating resource.[81] Since the new demand response programs will allow resources to offer based on their marginal willingness to consume and be scheduled in economic merit order (rather than be activated based on an operating procedure), it should have a better basis for allowing demand response resources to set prices. However, most demand response resources will still be relatively inflexible on a five-minute basis, so market developments that allow fast start resources to set prices should be applicable to demand response resources as well. To the extent that a portion of the demand response resources continue to be available only during emergencies (i.e., not economically through the ISO markets), the ISO should consider additional provisions to allow these resources to set prices.

C. Ex Ante and Ex Post Pricing

Ex ante prices are produced by the real-time dispatch model (UDS) when it determines dispatch instructions, although the ISO uses ex post prices to settle with market participants in the real-time market. In this section, we examine inconsistencies between the ex ante and ex post prices, and we identify several factors that can undermine the efficiency of the ex post prices.

Ex ante prices are produced by the real-time dispatch model and are consistent with the cost-minimizing set of dispatch instructions produced by UDS. They are consistent in the sense that the offer prices of dispatched resources are less than or equal to the LMP and the offer prices of un-dispatched resources are greater than or equal to the LMP. Hence, ex ante prices are set to levels that give generators an incentive to follow their dispatch instructions (assuming they are

81 See presentation *Full Integration of Demand Response Resources into the Energy and Reserves Markets*. by Henry Yoshimura (ISO-NE) to NEPOOL Markets Committee, May 6-7, 2014.

offered at marginal cost). Because these prices are consistent with the optimized dispatch, they are an efficient reflection of the prevailing market conditions.

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 resource, a "real-time offer price" is used in place of its offer curve.[82] 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 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. This is intended to improve the incentives of generators to follow dispatch instructions.

The evaluation in this section identifies three inconsistencies between ex ante and ex post prices:

- A small (roughly 0.3 percent in 2013) but persistent upward bias in real-time prices during the vast majority of intervals when reserve constraints are not binding;
- Significantly understated real-time prices when reserve constraints are binding (particularly during reserve shortages), resulting in frequent price corrections; and
- Occasional distortions in the ex post prices lead to inefficient pricing in congested areas.

These inconsistencies tend to undermine the incentives of generators to follow dispatch instructions and be available during operating reserve shortages. The end of this section provides a summary of the conclusions and recommendations from the evaluation of ex post pricing.

82 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.

1. Persistent Differences Between Ex Ante and Ex Post Prices

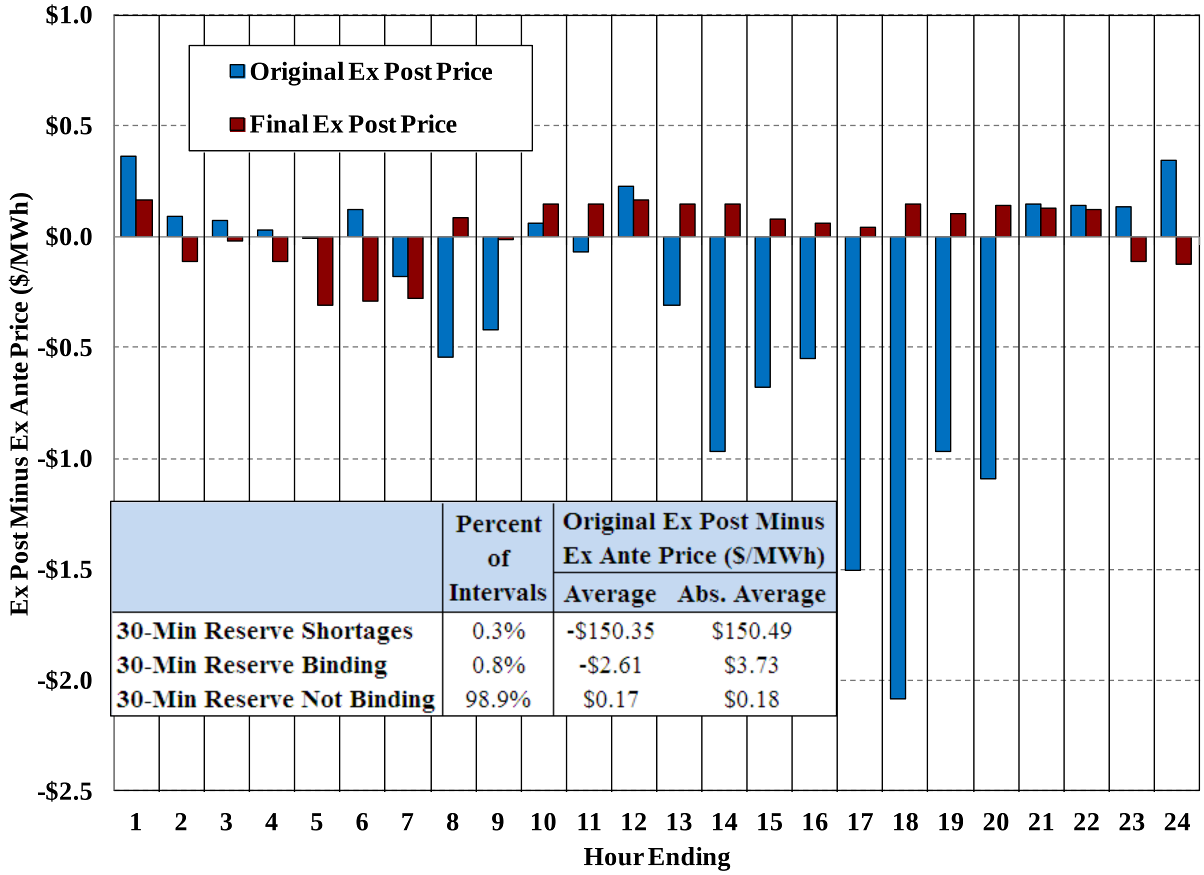
The first analysis highlights two issues with the current implementation of ex post pricing. First, it leads to a small but persistent upward bias in real-time prices in the vast majority of intervals when reserve constraints are not binding (see #1 in the list above). Second, it significantly understates real-time prices (relative to the ex ante dispatch rates) when reserve constraints are binding, particularly during reserve shortages (see #2 in the list above).

Figure 15 summarizes differences between ex ante and ex post prices in 2013 at a location close to the New England Hub.[83] This location is relatively uncongested, making it broadly representative of prices throughout New England. The blue bars show the average original ex post price (i.e., prices produced directly by the LMP Calculator) minus the average ex ante price by the time of day. The maroon bars show the average final ex post price minus the average ex ante price. The final ex post price equals the original ex post price in more than 99 percent of market intervals but differs in the remaining intervals because of administrative price corrections. The table in the figure summarizes the average difference and the average absolute difference between original ex post prices and ex ante prices under the following system conditions:

- 30-Min Reserve Not Binding – When UDS procures more 30-minute reserves than the requirement;
- 30-Min Reserve Binding – When UDS procures the same amount of 30-minute reserves as the requirement; and
- 30-Min Reserve Shortages – When UDS procures less 30-minute reserves than the requirement.

83 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 15: Average Difference Between Five-Minute Ex Post and Ex Ante Prices
2013



The table in the chart shows a persistent small bias that caused the original ex post prices to be slightly higher than ex ante prices in nearly 99 percent of intervals during which system-level 30-minute reserve constraints were not binding.[84] These original ex post prices were normally used as final real-time prices. As a result, average final ex post prices were $0.17 per MWh higher than ex ante prices at this location during these intervals in 2013.

This persistent small bias is the result of the interaction between the following two factors. First, loss factors change slightly due to the time lag between the calculation of the ex ante and ex post prices. 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 offer costs

84 The persistent bias is implied by the fact that the average difference is almost identical to the average absolute difference.

of some resources relative to others, which causes the ex post pricing model to move resources. Second, the dispatchable range of each resource is generally 20 to 40 times larger in the downward direction than the upward direction.

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 model to the ex post model, resources will appear most costly and be ramped downward in the ex post model. 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 typical interval without congestion, four or five units are ramped down and 100 or so units are ramped up. As units that are ramped up in the ex post model reach their maximums, increasingly expensive units set 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.

The difference between original ex post prices and ex ante prices was much larger in the remaining 1 percent of intervals when system conditions were relatively tight. The table shows that the original ex post prices understated the ex ante prices by an average of $2.60 per MWh during the intervals when the system-level 30-minute reserve constraint was binding and by an average of over $150 per MWh during the intervals when the system was short of 30-minute reserves. Although this occurred only during a small number of intervals, the large magnitude of differences resulted in a sizable impact on average.

The figure shows that the impact was greatest during afternoon peak hours because shortages occur more frequently during these periods. In 2013, the hour ending 18 exhibited the largest average price impact of over $2 per MWh. Nonetheless, when such large differences occur, the ISO has a process to administratively correct these ex post prices to be in line with their ex ante levels. The figure shows that final ex post prices were generally consistent with ex ante prices after the correction, which ensured that final real-time prices were not distorted on average. These results suggest that the current implementation of ex post pricing does not properly reflect reserve costs in real-time prices, especially during reserve shortages.

2. Theoretical Problems with Ex Post Pricing

Proponents have justified ex post pricing partly 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 because very little of their output is settled at real-time prices. Second, with the exception of the episodic price effects in congested areas, which are discussed in Part 3 of this subsection, 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 that are very close to the offer price of the unit failing to following dispatch. Further, any slight change in the ex post price will not affect the unit failing to follow dispatch in a manner that has any relationship to the cost to the system of its actions. 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.[85]

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 because the marginal unit loses its eligibility to set prices. Due to the specific implementation in New England, this theoretical concern is rarely manifested.

85 Uninstructed deviation penalties are penalties applied to suppliers that are not within a specified range of the dispatch instruction sent by ISO-NE.

3. Ex Post Pricing in Congested Areas

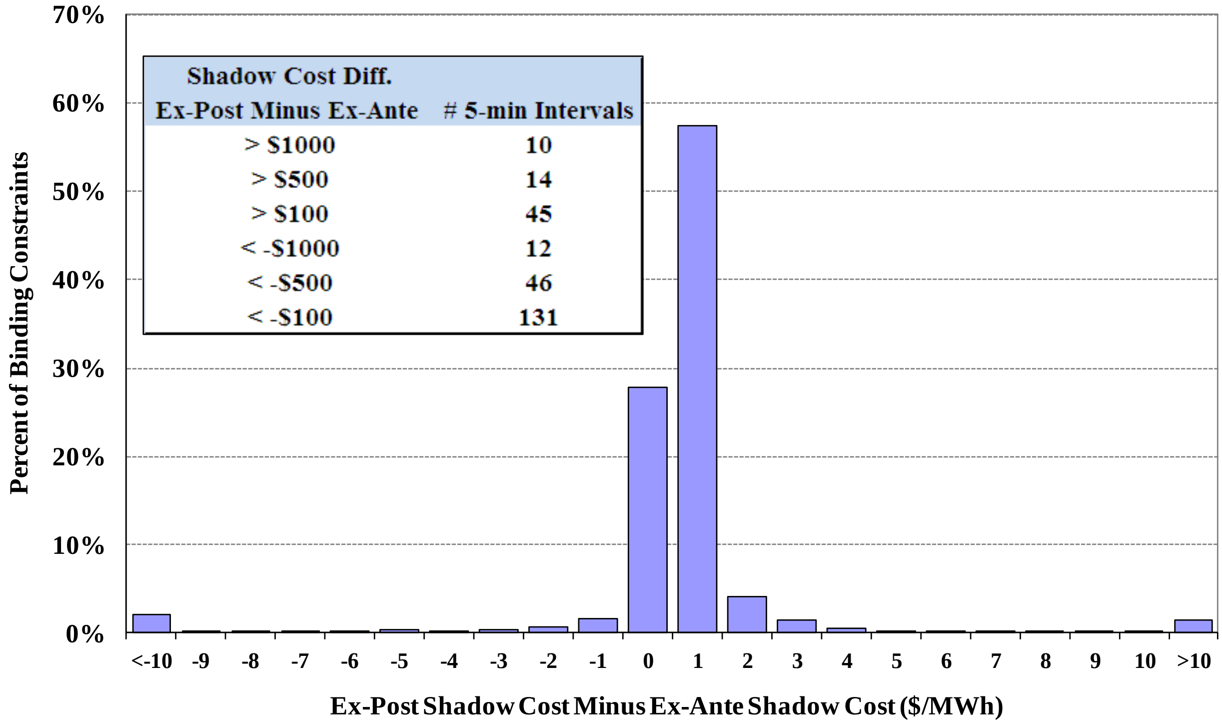
On occasion, there are large differences between ex ante prices and ex post prices in congested areas. Such occasions arise when the marginal unit for the binding constraint becomes inflexible or flexible but with a reduced offer price in the ex post pricing.[86]

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 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 16 summarizes differences in constraint shadow prices between ex post and ex ante calculations in 2013. A positive value indicates a higher shadow cost in the ex post calculation. For example, the value "2" on the x-axis means the ex post shadow cost is $1-$2 per MWh higher than the ex ante cost.

86 When a fast-start unit is committed by UDS, its combined offer that adds its start-up and no-load offers on top of its incremental energy offer is used. In the ex post pricing, however, when the unit's offer is used, the start-up and no-load offers are not included.

Figure 16: Difference in Constraint Shadow Costs Between Ex Post and Ex Ante
All Binding Constraints, 2013



The average difference was not significant in 2013. About 97 percent of all differences were within $10 per MWh. However, there were a small number of intervals with substantial differences in congestion costs between the ex ante and ex post calculations. In particular, there were 45 intervals during which ex post shadow prices were at least $100 per MWh higher than ex ante prices, and 131 intervals during which ex post shadow prices were at least $100 per MWh lower than ex ante prices. These accounted for 1.5 percent of the intervals that had at least one binding transmission constraint (which accounted for roughly 0.2 percent of all market intervals) during 2013. The relatively mild price impact can be attributed partly to the very low levels of congestion that currently prevail in the ISO-NE markets. However, as load grows and transmission congestion increases, we expect that these instances will also increase.

4. Conclusions regarding Ex-Post Pricing

Our evaluation of the ex post pricing results indicates that the real-time ex post prices:

- Are slightly biased in the upward direction in uncongested areas when reserve constraints are not binding;

- Are substantially lower than ex ante prices in uncongested areas when reserve constraints are binding, especially when reserves are scarce;
- Introduce small potential inefficiencies when they are not consistent with dispatch instructions; and
- Sometimes distort the value of congestion into constrained areas.

The primary 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 that ex post prices are sometimes set at inefficient levels, particularly when the system is under shortage conditions, we recommend that the ISO consider discontinuing the current ex post pricing model and set prices consistent with its ex ante pricing.

D. Conclusions and Recommendations

Efficient price formation is an important function of real-time market operations. Efficient real-time price signals provide incentives for generators to be available, for demand response to participate in the wholesale market, and for investors to build capacity in areas where it is most valuable. Furthermore, to the extent that efficient price signals during shortages and tight operating conditions exceed most generators' costs, the reliance on revenue from the capacity market to maintain resource adequacy is reduced. Hence, efficient real-time prices provide market participants with incentives that are compatible with the ISO's mandate to maintain the reliability of the system at the lowest possible cost.

This section evaluates several aspects of real-time pricing in the ISO-NE market during 2013. Our evaluation leads to the following conclusions and recommendations:

- Fast-start generators are routinely deployed economically, but their costs are often not fully reflected in real-time prices. This frequently leads to inefficiently low real-time prices during tight operating conditions when thermal peaking generators are needed to satisfy real-time demand. Efficient price signals in these cases will provide better incentives for suppliers to make sufficient capacity available to meet the system's needs.
  - ✓ We recommend that the ISO evaluate potential changes in the pricing methodology that would allow the deployment costs of fast-start generators to be more fully reflected in the real-time market prices.
- Demand response programs help 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.

- ✓ Hence, we recommend that the ISO allow the costs of non-dispatchable demand response resources to be reflected in clearing prices when there is a capacity deficiency or when a deficiency is avoided by the activation of the demand response resources.

- During normal operating conditions, ex post prices are set slightly higher than the efficient level. During shortage conditions, issues with the pricing software lead to ex post prices that are set far below the efficient level, requiring real-time price corrections,

  - ✓ We recommend that the ISO consider discontinuing the current ex post pricing model and develop an alternate pricing model that is more consistent with ex ante pricing.

VI. Long-Run Price Signals

The ISO-NE markets play a critical role in governing investment, retirement, and other long-term decisions made by market participants. The expected net revenues from ISO New England's energy, ancillary services, and capacity markets are the primary means by which this occurs. Therefore, it is important to evaluate the net revenues produced by these markets, which are defined as the total revenues (including energy, ancillary services, Winter Reliability Program and capacity revenues) that a generator would earn in the ISO-NE markets less its variable production costs. These net revenues serve to cover a supplier's fixed costs and the return on its investment.

If there is not sufficient net revenue in the short-run from these markets to justify entry of a new generator, then one or more of the following conditions exist:

- New capacity is not needed because sufficient generation is already available;
- Load conditions are below expectations due to mild weather or reduced demand, leading to lower energy prices than expected; and
- Market rules or conduct are causing revenues to be reduced inefficiently.

Alternatively, if prices provide excessive revenues in the short-run, this would indicate a shortage of capacity, unusually high load conditions, or market rules or conduct resulting in inflated prices. Evaluating the net revenues produced from the ISO-NE's markets allows us to assess the design and performance of the market in providing efficient long-run economic signals.

In this section, we estimate the net revenues for three types of new technologies and the types of older technologies in recent years. Estimated net revenues are shown separately by revenue category (i.e., capacity versus energy and ancillary services). The results are also shown separately for dual-fuel and gas-only generators to evaluate the potential returns to dual-fuel capability.

A. Description of Net Revenue Analysis Methodology

We estimate the net revenues the markets would have provided to the three types of new units and three types of older existing units that have constituted most of the new generation in the ISO-NE region over the past few years:

- *Hypothetical new units*: (a) a 2x1 Combined Cycle ("CC") unit, (b) a LMS 100 aeroderivative combustion turbine ("LMS") unit, and (c) a frame-type F-Class simple-cycle combustion turbine ("Frame 7") unit; and
- *Hypothetical existing units*: (a) a Steam Turbine ("ST") unit, (b) a 10-minute Gas Turbine ("GT-10") unit, and (c) a 30-minute Gas Turbine ("GT-30") unit.

We estimate the net revenues that would have been received by the generators at the New England hub. The method we use to estimate net revenues uses the following assumptions:

- All units are scheduled before each day based on day-ahead prices, considering commitment costs, minimum run times, minimum generation levels, and other physical limitations.
- CC and ST units may sell energy, 10-minute spinning reserves, and 30-minute reserves; while combustion turbines may sell energy and 10-minute or 30-minute non-spinning reserves. Each gas-only and dual-fueled unit is assumed to offer reserves, limited only by its ramp rate and commitment status.
- Combustion turbines (including older gas turbines) are committed in real-time based on hourly real-time prices. Combustion turbines settle with the ISO according to real-time market prices and the deviation from their day-ahead schedule.
- Online units are dispatched in real-time consistent with the hourly integrated real-time LBMP and settle with the ISO on the deviation from their day-ahead schedule. However, to account for the effect of the slower ramp rate of the ST unit in this hourly analysis, the unit is assumed to operate within a certain margin of the day-ahead energy schedule. The margin is assumed to be 25 percent of the maximum capability.
- All technology types are evaluated under gas-only and dual-fuel scenarios to assess the incremental profitability of dual-fuel capability. ST units are assumed to use low sulfur residual oil. All other units are assumed to use ultra-low sulfur diesel oil.
- Combustion turbines (including older gas turbines) are also evaluated for their profitability based on the generator's decision to participate in the Forward Reserve Auctions for each of the capability periods. It is assumed that generators anticipate when selling forward reserves will be more profitable than selling real-time reserves before each capability period.
- All the dual-fuel units are assumed to offer into the Winter Reliability Program (WRP). The revenues from WRP were estimated based on the weighted average of accepted bids from each type of unit in the most recent auction.

- Fuel costs assume transportation and other charges of 27 cents/MMbtu for gas and $2/MMbtu for oil on top of the day-ahead index price (Algonquin City Gates for gas). Intraday gas purchases are assumed to be at a 10% premium due to gas market illiquidity and balancing charges, while intraday gas sales are assumed to be at a 10% discount for these reasons.
- The minimum generation level is 440 MW for CCs and 90 MW for ST units. The heat rate is 7,639 btu/kWh at the minimum output level for CCs, and 13,000 btu/kWh for ST units. The heat rate and capacity for a unit on a given day are assumed to vary linearly between the summer values on August 1 and the winter values on February 1. The summer and winter values are shown in the following two tables.
- Regional Greenhouse Gas Initiative (RGGI) compliance costs are included.
- We also use the modified operating and cost assumptions listed in the following tables:

Table 2: New Unit Parameters for Net Revenue Estimates [87]

Characteristics	CC	LMS 100	Frame 7
Summer Capacity (MW)	715	188	417
Winter Capacity (MW)	754	202	450
Summer Heat Rate (Btu/kWh)	7469	9260	10806
Winter Heat Rate (Btu/kWh)	7405	9041	10383
Min Run Time (hrs)	4	1	1
Variable O&M ($/MWh)	2.4	5.4	3.7
Startup Cost ($)	18402	0	18328
Startup Cost (MMBTU)	3376	430	900
EFORd	2.5%	2.0%	2.0%

87 These parameters are based on technologies studied as part of the ISO's recent sloped demand curve filing.

Table 3: Existing Unit Parameters for Net Revenue Estimates

Characteristics	ST	GT-10	GT-30
Summer Capacity (MW)	360	32	16
Winter Capacity (MW)	360	40	20
Heat Rate (Btu/kWh)	10000	15000	17000
Min Run Time (hrs)	16	1	1
Variable O&M ($/MWh)	8.0	4.0	4.5
Startup Cost ($)	6000	1200	519
Startup Cost (MMBTU)	2000	50	60
EFORd	5%	10%	20%

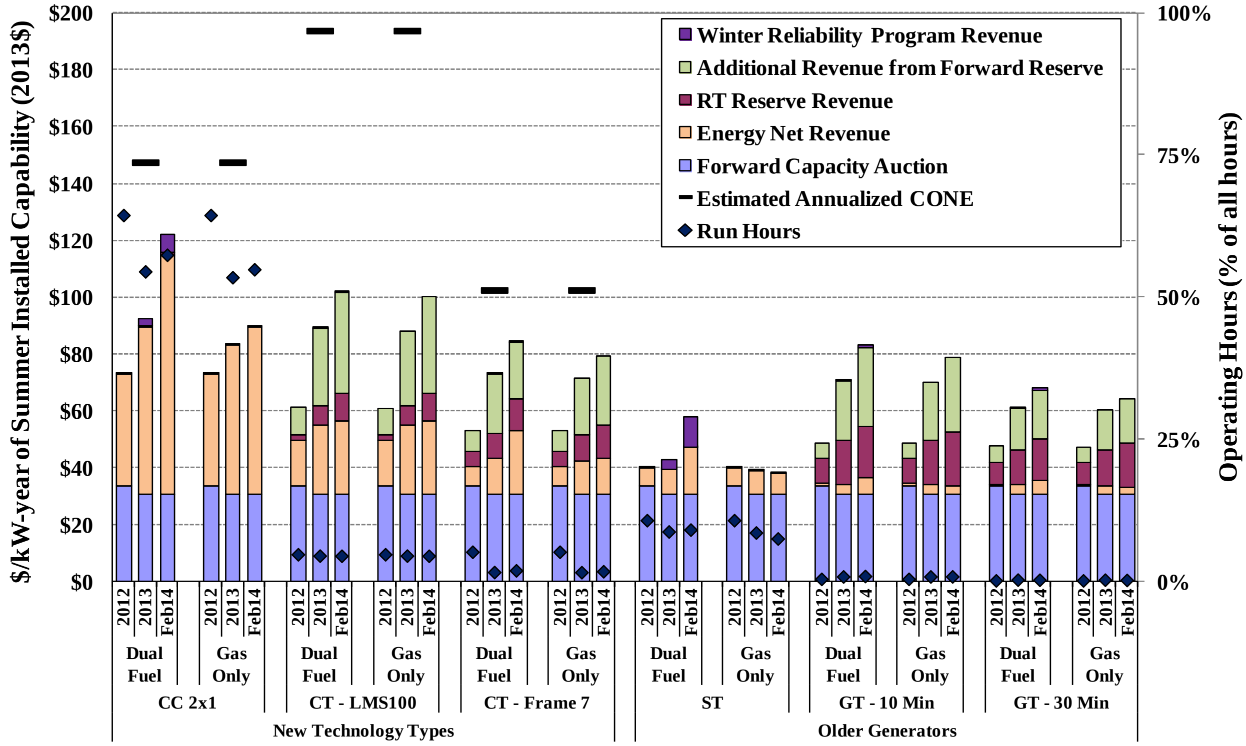
B. Net Revenue Results

The following figure summarizes net revenue estimates using our method. All values are shown per kW-year of summer installed capability. Figure 17 shows annual estimated net revenues for 2012, 2013, and the year-ended February 28, 2014 (“Feb14”) in order to highlight the variation in net revenues across recent winters. The figure also shows the levelized Cost of New Entry (CONE) estimated in the ISO’s recent sloped demand curve filing for the three new technologies. Net revenues are shown for each of the following categories:

- Forward Capacity Auction – This category is based on payment rates in the forward capacity auctions.
- Energy Net Revenue – This category is based on net LMP revenue from energy sales (and purchases) in the day-ahead and real-time markets minus variable production costs.
- RT Reserve Revenue – This category is based on revenue from operating reserve sales in the real-time market (assuming no participation in the forward reserve market).
- Additional Revenue from Forward Reserve – This category shows the additional revenue that would be earned from selling in the forward reserve auctions when it would have been more profitable than simply selling energy and real-time operating reserves.
- Winter Reliability Program Revenue – This category shows the average additional revenue that was earned by generators that participated in the program in the winter of 2013/14.

Figure 17 also shows the estimated number of run hours for each type of technology in each period assuming the generator participates in the forward reserve market when profitable.

Figure 17: Annual Net Revenue for Generators
New England Hub, 2012, 2013, & Year-Ended February 2014



Total net revenues increased from 2012 to 2013 for all technologies mainly because:

- Energy prices rose from 2012 to 2013, more than offsetting the effects of higher natural gas prices for most types of units;
- More frequent high load conditions led to higher net revenues from electricity sales and the summer and winter; and
- Operating reserve revenues rose because of higher forward and real-time reserve prices. It was profitable for all types Combustion Turbine units to participate in the forward reserve auction in almost all of the capability periods. Revenues from these reserves are significant even though newer CTs have lower heat rates than the threshold price.
- ISO-NE implemented the Winter Reliability Program before December 2013 so many dual-fuel units received additional revenues.

Net revenues were higher for the year-ended February 28, 2014 than for 2013 for every type of technology except gas-only steam turbines. The increases were attributable to the effects of the Winter Reliability Program, more frequent winter peak load conditions, and the effects of higher gas prices.

Despite the net revenue increases described above, the estimated net revenues for new units were much lower than the cost of new entry for all the technology types. This is expected in part because of the capacity surplus that has prevailed in New England in recent years. Estimated net revenues were highest for a new CC unit because of its low heat rate, followed by an LMS100 unit, then a Frame 7 unit because of its relatively high heat rate and start-up costs. The annualized levelized capital costs of a new Frame 7 unit are the lowest. When compared to other new units, the CC and Frame 7 units were closest to being economic with net revenues that were 17 percent lower than their respective annualized CONE values. The LMS100 and Frame 7 units earn large amounts of net revenue from selling reserves, while the combined cycle earns the majority of its net revenue from energy sales because it is rarely economic to provide operating reserves.

For older existing units, the estimated net revenues were likely higher than the annualized "going-forward costs" in areas where such units are in operation. This is because retirements would occur if net revenues fell below going-forward costs for a significant period. Among older technologies, the estimated net revenues were highest for the gas turbines because of the increased reserve prices. Steam turbines earned the majority of their net revenue from selling capacity, although energy net revenues and winter reliability program revenue were significant for the dual-fueled steam turbine.

The ability to switch fuels away from natural gas can substantially affect a unit's net revenues in some years. The incremental net revenues a supplier earned from having dual fuel capability were *de minimis* in 2012 because of low natural gas prices. In 2013, dual fuel capability generated modest incremental net revenues for combined-cycle units (~$9 per kW-year) and steam turbines (~$4 per kW-year).[88] However, for the 12 months ending February 28, 2014, the incremental revenue from dual fuel capability increased sharply:

- Combined cycle net revenues increased to $32 per kW primarily because of higher energy revenues attributable to high natural gas prices in January 2014;

88 This analysis does not include all of the additional costs necessary to maintain an inventory of fuel oil, and that the use of fuel oil may be limited by low inventories and air permit restrictions.

- Steam turbine net revenues rose to $19 per kW, half of which is attributable to the winter reliability program and half to higher natural gas prices; and
- Since gas-only combustion turbines can provide reserves during tight gas supply conditions, their increase in net revenues from dual-fuel capability was small.

These dual fuel net revenues for the combined-cycle and steam turbines are sizable, constituting 20 to 30 percent of the annual net revenues a new unit would require to break even. However, these estimates assume that units have sufficient fuel on-site to operate when economic. During the winter of 2013/14, some units ran less because of low oil inventories even with the winter reliability program. Hence, the actual net revenues from dual-fuel capability were likely lower in reality for many dual-fueled units. Finally, given the temporary nature of the winter reliability program, suppliers considering investing in dual fuel capability would likely discount this source of incremental net revenue for dual fuel capability. Nonetheless, periods of natural gas price volatility generate substantial energy net revenues for dual-fueled units.

Forward reserve sales are a major source of revenue for peaking units in the this analysis because of the high premium on forward reserve clearing prices relative to average real-time reserve clearing prices. Forward reserve sales are somewhat less profitable for peaking units with better heat rates because forward reserve providers are obligated to increase their offer prices to be consistent with the cost of a high heat rate unit, so they must forego some energy sales as a result. CCs and steam turbines never find it profitable to sell forward reserves because they would need to be online in a large number of unprofitable hours.

C. Conclusions – Net Revenue

Net revenues have increased considerably since 2012, which is due in part to the increase in operating reserve prices in 2013. Nonetheless, none of the new technologies studied in our evaluation would have earned sufficient net revenues to recoup the annualized cost of an investment in a new unit. This is expected because there is currently a substantial amount of excess installed capacity in New England. However, it will be very important for these net revenues to rise efficiently as capacity margins fall in New England to ensure that new investment is sufficient to maintain adequate resources. In this regard, the sloped capacity demand curve filed by ISO New England will play an important role in achieving this objective.

The energy and reserve markets provide significant incentives for generators to be flexible and available in real-time when clearing prices are likely to be high. This is illustrated by the fact that an older 10-minute gas turbine, which can start quickly and provide off-line reserves, would earn 20 to 65 percent more net revenue per kW-year than an older steam turbine, which has slower and longer operating times. This differential is large enough to influence decisions about the maintenance and/or retirement of older generation. Likewise, it is sufficient to induce some investors to build new assets with more flexible operating characteristics (e.g., a new investor may build a combined cycle that is configured to run as a baseload unit or as a quick start unit). The additional returns to being flexible and available highlight the benefits of the real-time pricing enhancements that would improve price efficiency during tight conditions, which are discussed in Section V.

Our net revenue estimates indicate high returns from dual-fuel capability for a new CC unit and an older steam turbine unit for the year-ended in February 2014. For the CC unit, the majority of net revenues derive from increased energy margins. For the steam turbine unit, approximately half came from increased energy margins and half came from the winter reliability program. However, these estimates assume that units have sufficient fuel on-site to operate whenever it is economic. During the winter of 2013/14, many generators ran less because of low oil inventories, so the actual net revenues from dual-fuel capability were likely much lower for many CCs and steam turbines in New England. The Winter Reliability Program provided incentives for higher inventory levels and increased the net revenues for participating units. However, given the temporary nature of the winter reliability program, it is unlikely that potential investors would be induced to build a new resource or add dual-fuel capability based primarily on such a revenue stream.

Finally, our analysis shows that peaking units can earn high net revenues by providing reserves. This indicates the importance of programs that audit or otherwise ensure that off-line peaking units are capable of responding as scheduled. If the response capability of reserve units is over-estimated, it will inflated reserve payments to poor performers and depressed reserve clearing prices for good performers. This is particularly important during winter operating conditions when some off-line reserve providers may be less reliable than at other times of year.

VII. External Interface Scheduling

This section examines the scheduling of imports and exports between New England and adjacent regions. ISO-NE 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 can flow in either direction depending on market conditions, although ISO-NE imported more power from NYISO than it exported in 2013. 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 demand in New England. The ability to draw on neighboring systems for emergency power, reserves, and capacity also lowers the costs of meeting reliability needs 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 NYISO, TransEnergie (Quebec), and the New Brunswick System Operator. ISO-NE and NYISO are interconnected by three interfaces:

- The Roseton Interface, which is the primary interface and includes several AC tie lines connecting upstate New York to Connecticut, Massachusetts, and Vermont;
- The 1385 Line, a controllable AC interface between Norwalk, Connecticut and Long Island; and
- The Cross-Sound Cable, a DC interface between New Haven, Connecticut and Long Island.

New England and Quebec are interconnected by two interfaces: Phase I/II (a large DC interconnection), and the Highgate Interface (a smaller AC interconnection between Vermont and Quebec). New England and New Brunswick are connected by a single interface.

This section evaluates the following aspects of transaction scheduling between ISO-NE and adjacent control areas. Section A summarizes scheduling between New England and adjacent areas in 2013. Section B evaluates the efficiency of scheduling by market participants between New York and New England. Section C discusses ISO England’s on-going efforts to improve the utilization of its interfaces with New York. Section D provides a summary of our conclusions and recommendations.

A. Summary of Imports and Exports

The following two figures provide an overview of imports and exports by month for 2012 and 2013. Figure 18 shows the average net imports across the three interfaces with Quebec and New Brunswick by month, for peak and off-peak periods.[89] The net imports across the two interfaces linking Quebec to New England are combined.

Figure 18: Average Net Imports from Canadian Interfaces
2012 – 2013

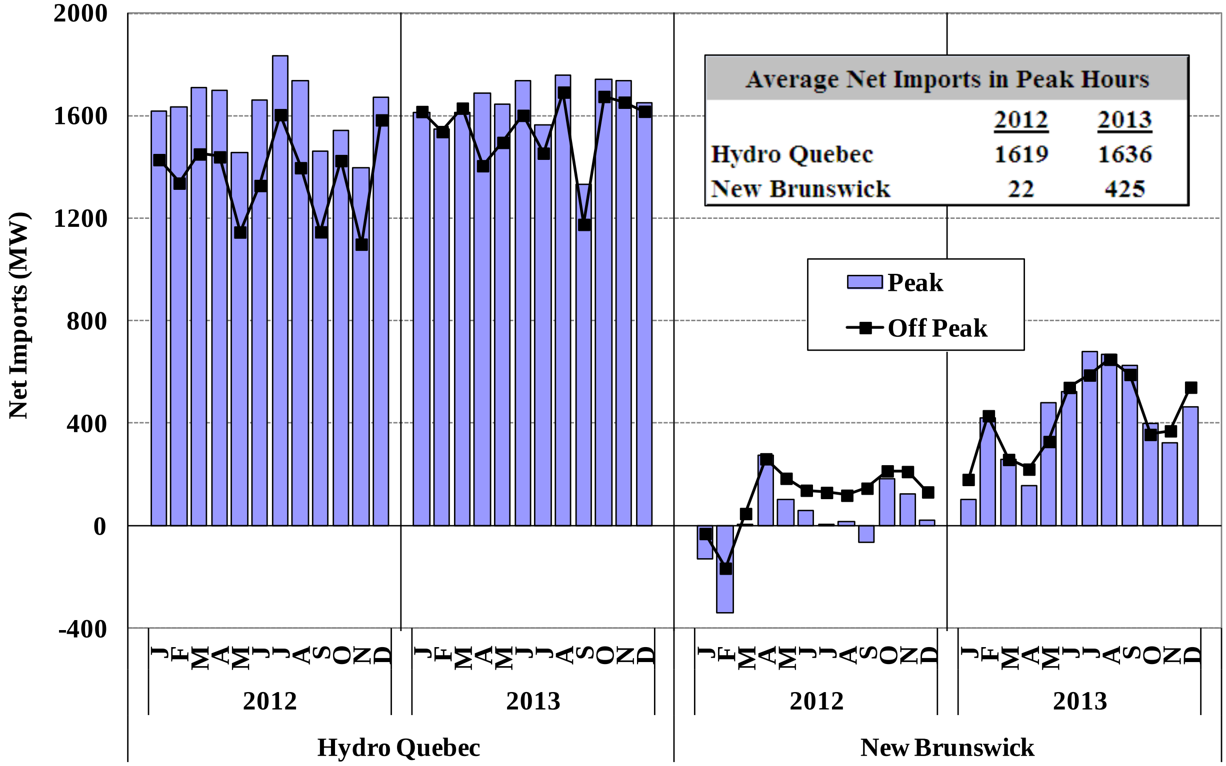


Figure 18 shows that the interfaces with Quebec are often fully utilized to import to New England. Average net imports from Quebec were higher during peak hours than during off-peak hours by roughly 250 MW in 2012 and by 90 MW in 2013. This reflects the tendency for hydro resources in Quebec to store water during low demand periods in order to make more power

89 Peak hours include hours ending 8 to 23, Monday through Friday (not including NERC holidays), and the remaining hours are included in Off-Peak.

available during high demand periods. In the same way that the imports vary from peak to off-peak hours, imports also vary seasonally with imports rising during periods when energy prices are the highest. This was evident in both 2012 and 2013, when average net imports generally rose in the summer months and in periods with high natural gas prices (i.e., typically the winter months). This pattern is beneficial to New England because it tends to smooth the residual demand on New England internal resources.

Average net imports from New Brunswick rose considerably in 2013, up 400 MW from 2012 during peak hours. The increase was largely attributable to the return of the Point Lepreau nuclear unit (with an installed capacity of 700 MW) in New Brunswick in late November 2012.

Figure 19 shows average net imports across the three interfaces with New York by month in 2012 and 2013 for peak and off-peak periods. The net imports across the Cross-Sound Cable and the 1385 Line are combined.

Figure 19: Average Net Imports from New York Interfaces
2012 – 2013

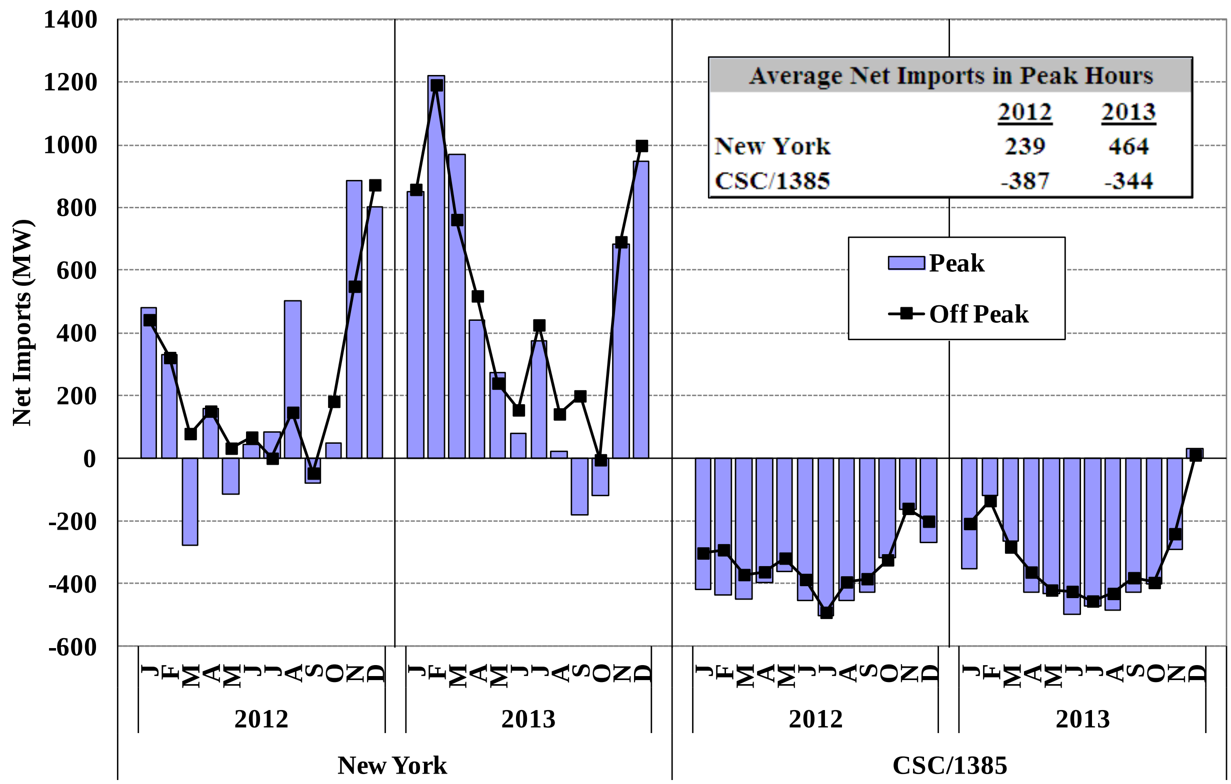


Figure 19 shows that the direction and the level of flows varied considerably across the primary interface with New York (i.e., the Roseton interface) during the past two years, reflecting the variations in relative prices in the two markets. New England tends to import more power from (or export less power to) New York in the winter months for several reasons. First, New England is more reliant on natural gas generation, which is typically most expensive in the winter months.

Second, the spread in natural gas prices between New England and New York tends to increase in the winter months when demand for heating rises. For example, ISO-NE imported an average of 925 MW from New York across the primary interface during peak hours in four months (January, February, November, and December) of 2013, compared to an average of 235 MW in other eight months. During these four winter months, the spread in natural gas prices between New England and New York averaged $3.90 per MMBtu. In the other eight months of 2013, the spread averaged only $0.07 per MMBtu.[90]

New England was a net importer from New York across the primary interface in both 2012 and 2013. Net imports averaged approximately 490 MW over all hours in 2013, up roughly 255 MW from 2012. The increase was consistent with the increased spread in natural gas prices between New England and New York, which rose from an average of $0.30 per MMBtu in 2012 to $1.35 per MMBtu in 2013.

The figure also shows that flows were more consistent from New England to Long Island across the Cross-Sound Cable and the 1385 Line. Both lines are often fully utilized during peak hours to export power to Long Island, especially in the summer. However, the average level of exports across the two interfaces fell substantially in the winter months of both 2012 and 2013. In December 2013, New England actually imported more than it exported to Long Island. These variations were driven by increased natural gas price spreads between New England and Long Island as well.

90 The spread is based on the difference between the Algonquin City Gates index, which is representative of natural gas prices in most of New England, and the Iroquois Zone 2 index, which is representative of natural gas prices in eastern upstate areas of New York and in Long Island.

B. Interchange with New York

The performance of ISO-NE's 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 sub-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. In this sub-section, we evaluate the extent to which the interface is scheduled efficiently.

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. It is especially important to schedule flows efficiently between control areas during peak demand conditions or shortages when flows between regions have the largest economic and reliability consequences.

However, one cannot expect that trading by market participants alone will optimize the use of the interfaces. Several factors prevent real-time price differences between New England and New York from being fully arbitraged.

- Market participants do not operate with perfect foresight of future market conditions (e.g., may not be able to predict which side of the interface will have a higher real-time price) at the time when transaction bids and offers must be submitted.
- Differences in the procedures and timing of scheduling in each market serve as barriers to full arbitrage.
- There are transaction costs associated with scheduling imports and exports that diminish the returns from arbitrage. Participants will not schedule additional power between regions unless they expect a price difference greater than these costs.
- The 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 alone will fully optimize the use of the interface. Nevertheless, we expect trading to improve the efficiency of power flows between regions.

1. Price Convergence Between New England and New York

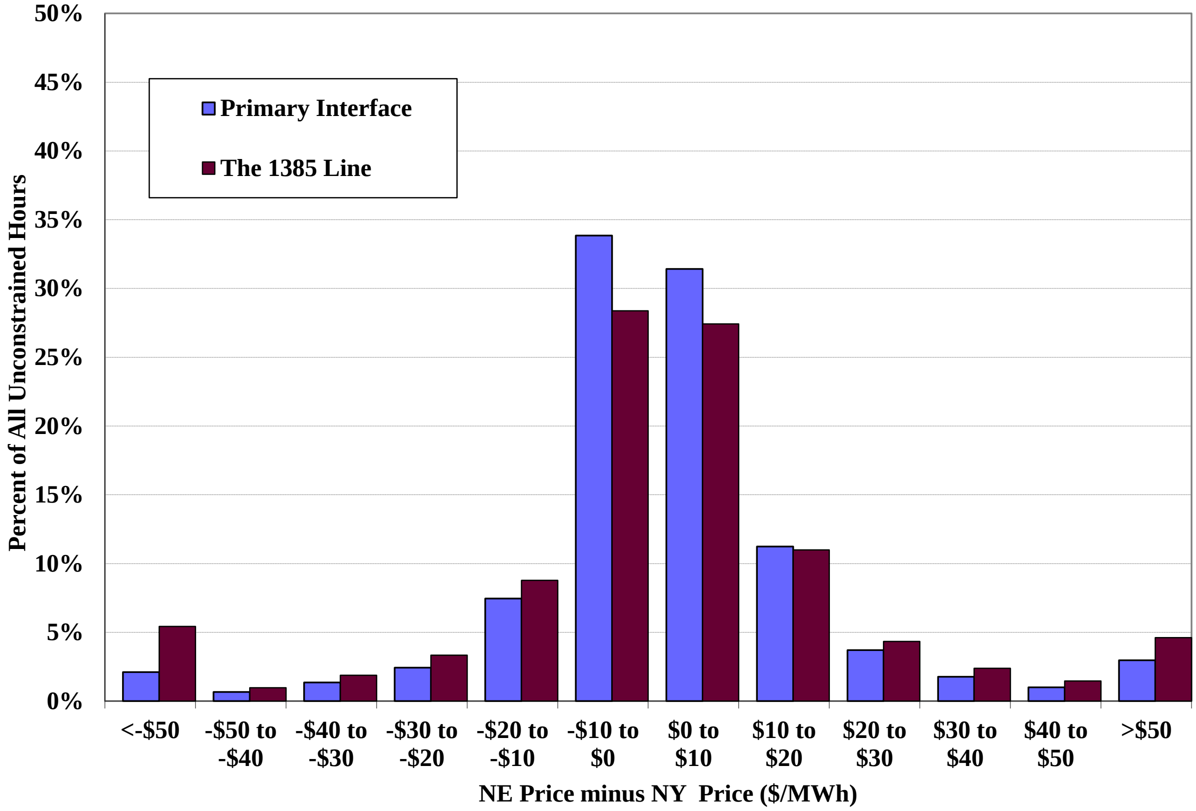
The following figure evaluates scheduling between New England and New York across the primary interface and the Northport Norwalk Scheduled Line (i.e., the 1385 Line). The Cross-Sound Cable is omitted because it is scheduled under separate rules.[91] Figure 20 shows the distribution of real-time price differences across the primary interface between New England and New York and the 1385 Line in hours when the interfaces were not constrained.[92]

While the factors described above prevent complete arbitrage of price differences between regions, trading should help keep prices in the neighboring regions from diverging excessively. Nonetheless, Figure 20 shows that although the price differences were relatively evenly distributed around $0 per MWh, a substantial number of hours had price differences more than $10 per MWh for each interface. In 2013, the price difference between New England and New York exceeded $10 per MWh in 35 percent and 44 percent of the unconstrained hours for the primary interface and the 1385 Line, respectively. Additionally, the price difference was greater than $50 per MWh in 5 percent of the unconstrained hours for the primary interface and in 10 percent of the unconstrained hours for the 1385 Line.

91 Service over the Cross-Sound Cable is provided under the Merchant Transmission Facilities provisions in Schedule 18 of ISO-NE's Tariff, which 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 ISO-NE and NYISO market systems. Scheduling limits restrict the ability to use the CSC interface for short-run arbitrage transactions between Connecticut and Long Island.

92 The prices used in this analysis are the prices at the New England proxy bus in the New York market (i.e., New York price) and the prices at the New York proxy bus in the New England market (i.e., New England price).

Figure 20: Real-Time Price Difference Between New England and New York
Unconstrained Hours, 2013



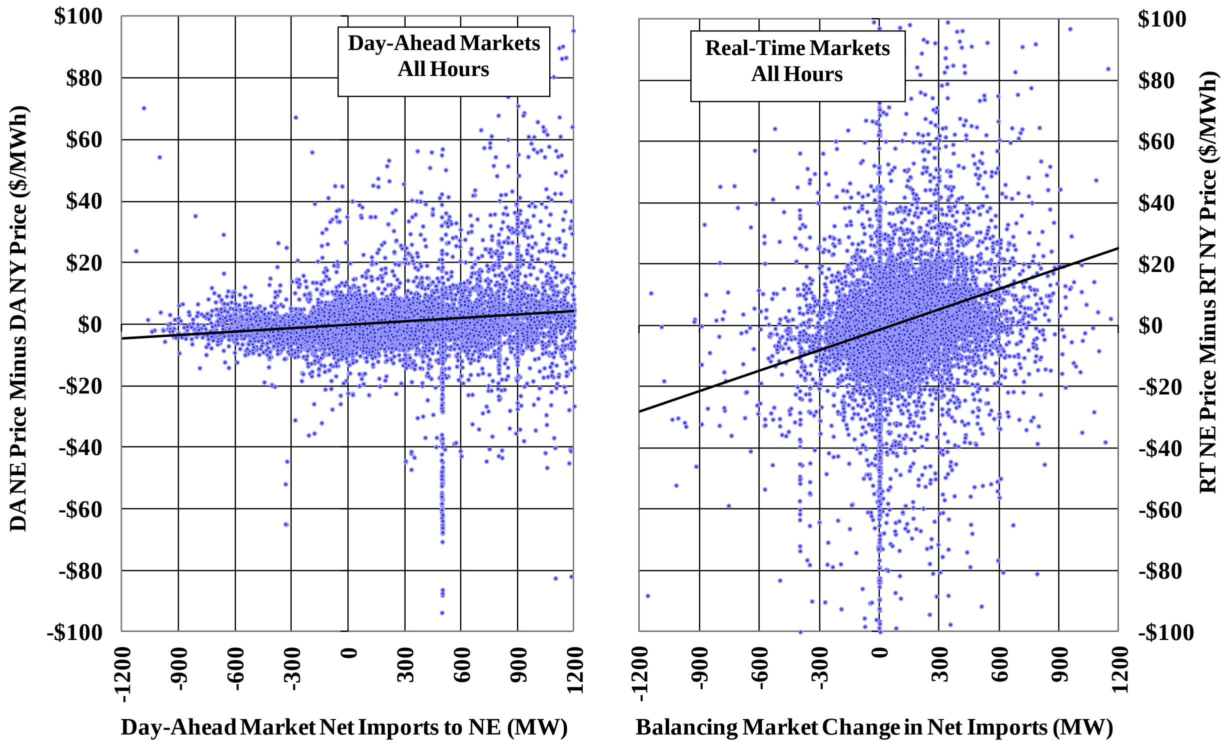
These results indicate that the current process does not fully utilize the interface. Given the pattern of price differences shown, there are many hours when increasing flows from the lower priced region to the higher priced region would have significantly improved the efficiency of clearing prices and production in both regions. This failure to fully arbitrage the interfaces leads to market inefficiencies that could be remedied if the ISOs were to coordinate interchange.

2. Efficiency of Scheduling Between New England and New York

Although market participants have not fully arbitraged the interface between New York and New England, the following analyses evaluate whether the direction of participants' transaction schedules have been consistent with the relative prices in the two regions and have, therefore, improved price convergence and efficiency.

The following analysis focuses on whether the incremental changes in participants' schedules (i.e., real-time adjustments from day-ahead schedules) have been consistent with the relative prices in the two regions. Figure 21 shows a scatter plot of net scheduled flows across the primary interface versus the difference in prices between New England and upstate New York for each hour in 2013. 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 (= 500 – 300).

Figure 21: Efficiency of Scheduling in the Day-Ahead and Real-Time
Primary Interface Between New England and New York, 2013



The trend lines in the left and right panels show statistically significant positive correlations between the price difference and the direction of scheduled flows in the day-ahead and real-time markets. However, the correlation in the day-ahead market is relatively weak, which indicates the difficulty participants have in scheduling transactions efficiently. The correlation is much stronger in the real-time market, reflecting larger price variations in each real-time market. These positive relationships indicate that the scheduling of market participants generally respond to price differences by increasing net flows scheduled into the higher-priced region. However, this response is incomplete and the interface remains substantially under-utilized as a result.

The difficulty of predicting changes in market conditions in real-time is reflected in the wide dispersion of points on the right side of Figure 21. Approximately 45 percent of the points in the real-time market panel are in inefficient quadrants – upper left and lower right – indicating hours when the net real-time adjustment by market participants shifted scheduled flows in the unprofitable direction (from the high-cost market to the low-cost market). Although market participant scheduling has helped converge prices between adjacent markets, Figure 21 highlights that considerable room for improvement remains.

Although the arbitrage is not complete, the positive correlation between the price differences and the schedule changes indicate that participants generally respond rationally to the price differences in the real-time market. Additionally, total net revenues from cross-border scheduling in 2013 were $12.6 million in the day-ahead market and $13.6 million in the real-time market (not accounting for transaction costs).[93] The fact that significant profits were earned from the external transactions provides additional support for the conclusion that market participants generally help improve market efficiency overall by facilitating the convergence of prices between regions.

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

93 This likely underestimates the actual profits from scheduling because it assumes that day-ahead exports from one market are matched with day-ahead imports in the other market. However, market participants have other options such as matching a day-ahead export in one market with a real-time import in the other market. This flexibility actually allows participants to earn greater profits from more efficient trading strategies than those represented in the figure.

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 the interchanges by the ISOs.

In July 2010, ISO-NE and NYISO commenced a joint effort known as the Inter-Regional Interchange Scheduling project to address the issue of inefficient scheduling between the two markets. The RTOs proposed two solution options:

- Tie Optimization- The ISOs exchange information 15 minutes in advance and optimize the interchange based on a prediction of market conditions. The interchange would be adjusted every 15 minutes.
- Coordinated Transaction Scheduling (CTS)- Identical to Tie Optimization, except the interchange schedule is only adjusted to the extent that market participants have submitted intra-hour Interface Bids priced below the predicted price difference between the markets.

We employed simulations to estimate the benefits of these two initiatives. 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 in both regions as additional production from lower-cost generators one ISO displaces production from higher-cost generators in the other ISO. The net consumer savings arise because improved coordination between the ISOs tends to lower prices on average in both regions.

The simulation results indicated significant potential benefits from fully optimizing the interchange, including roughly $17 million per year in production cost savings and $200 million per year in consumer savings. Both proposals would capture a large share of these potential benefits (60 to 70 percent). The Tie Optimization proposal performed only slightly better in our simulations than the CTS proposal.[94]

Through their respective stakeholder processes, ISO-NE and NYISO decided to move forward with the CTS proposal to improve coordination between markets.[95] Accordingly, a market design project for CTS is currently under way and is scheduled to be effective by the end of

94 For a detailed description of simulation models and results, see our *2010 Assessment of Electricity Markets in New England*, Section IV.C.

95 ISO-NE and NEPOOL filed the proposed tariff changes on February 24, 2012 in Docket ER12-1155-000. These were accepted by FERC on April 19, 2012.

2015.[96] Given the potential benefits from more efficient coordination with other control areas, we recommend that the ISO-NE continue to place a high priority on this initiative.

D. Conclusions and Recommendations

Efficient use of transmission interfaces between regions allows customers to be served by lower-cost external 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 either direction between New England and New York, depending on market conditions in each region. Overall, New England imported a net average of 2.0 GW in the summer months and 2.8 GW in the winter months, reducing the use of more costly internal generation resources and scarce fuel supplies.

The external transaction scheduling process has functioned adequately and scheduling by market participants has improved convergence of prices between New England and adjacent areas. However, sizable savings can be achieved by improve scheduled interchange between regions to more fully utilize the external interface capability. 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.

The Coordinated Transaction Scheduling (CTS) process is under development to coordinate the interchange between control areas more efficiently. Under CTS, the ISOs will schedule interchange based on short-term forecasts of market conditions and new bidding procedures that will allow market participants to submit bids that are jointly evaluated by the ISOs. The estimated benefits of this initiative are high, therefore we continue to recommend that ISO-NE and the NYISO place a high priority on implementing CTS.

96 See the 2014 *ISO-NE Wholesale Markets Project Plan*, page 20.

VIII. System Operations

To maintain the reliability of the system, sufficient resources must be available in the operating day to satisfy forecasted load and reserve requirements without exceeding the capability of the transmission system. The day-ahead market is intended to provide incentives for market participants to make resources available to meet these requirements at the lowest cost.

The day-ahead market clears physical and virtual load bids and supply offers, and produces a coordinated commitment of resources. When the day-ahead market does not satisfy all forecasted reliability requirements for the operating day, the ISO performs the Reserve Adequacy Assessment (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. Out-of-market commitments can also indicate that there are important reliability requirements that are not fully reflected in the wholesale market requirements, so the cost of satisfying these requirements is not fully reflected in market clearing prices.

The rising demand for natural gas in recent years has reduced the availability of gas to electricity generators during severe winter weather conditions, creating new challenges for the design of wholesale electric markets. The primary challenge is for the market to coordinate the scheduling of electric resources in a manner that satisfies the system's reliability needs and leads to efficient procurement and scheduling of natural gas and other fuels, both for electric generation and other uses. During severe winter weather, the amount of installed capacity is more than adequate, but the limited supply of natural gas reduces the availability of installed capacity. Moreover, the ISO has limited information about the availability of gas to individual generators (beyond their nominations), increasing uncertainty about whether the available capacity will be adequate under tight conditions. When the market does not have mechanisms to fully reflect the limited availability of generating capacity, market prices will be depressed and, therefore, will not provide efficient incentives for generation to be available. This leads the ISO to make additional resources available through supplemental commitment and other out-of-market actions, which further depress prices and undermine the market incentives for reliable generator performance.

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;
- Surplus Generation – The amount of capacity from online or available offline fast-start resources in excess of the system's energy and operating reserve requirements;
- Reliability Commitment – Reliability commitments make additional resources available to operate in real time, and they increase the amount of generation that runs out-of-merit in real time;
- Fuel Usage Under Tight Gas Supply Conditions – This evaluates the supply mix on cold-weather days when gas supply was limited; and
- Uplift Expenses – This examines the financial charges that result from out-of-market procurements and NCPC payments.

Our conclusions and recommendations in these areas are provided at the end of the section.

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 important 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, or short-term outage scheduling.

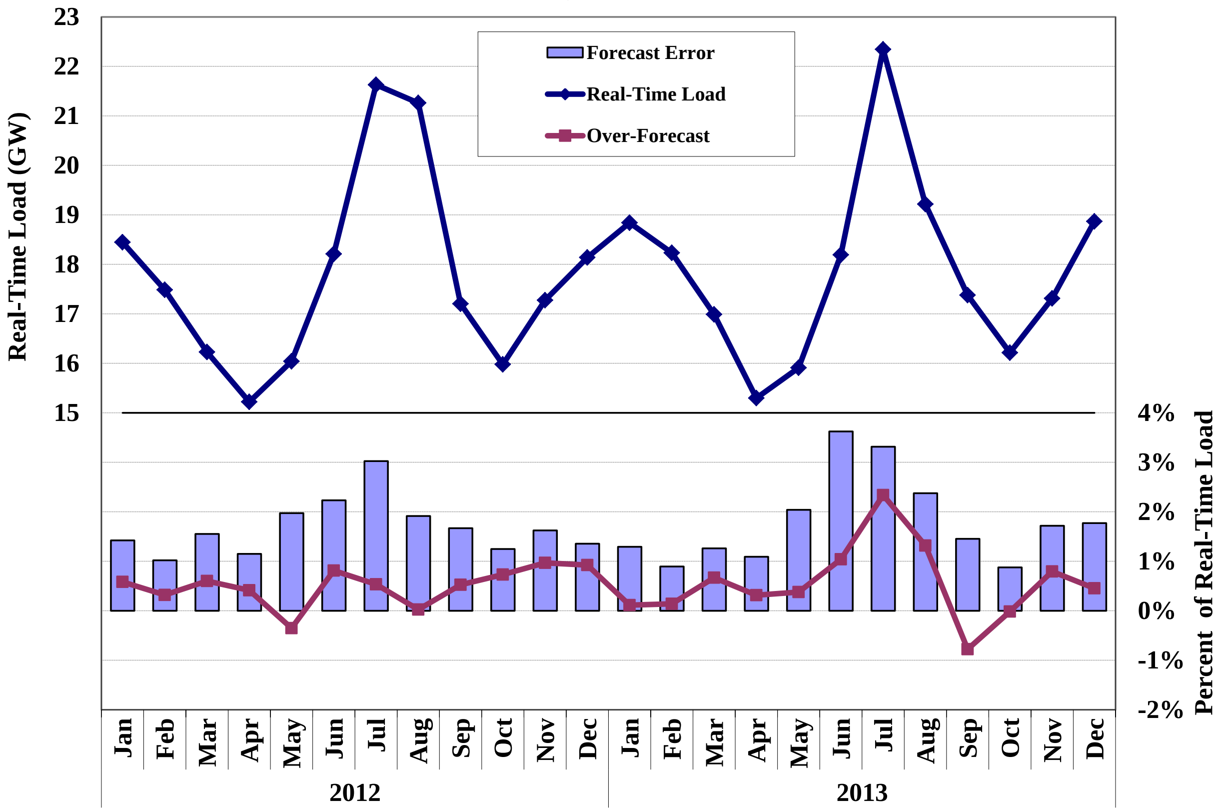
In addition, the ISO uses the forecast to estimate the amount of resources that will be needed to satisfy load and reserve requirements without exceeding the capability of the transmission system. The day-ahead forecast is most important because most scheduling and unit commitment takes place on the 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 22 summarizes daily peak loads and two measures of forecast error on a monthly basis during 2012 and 2013. 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. [97] 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 22: Average Daily Peak Forecast Load and Actual Load

Weekdays, 2012 – 2013



97 The real-time daily peak load is based on the average load in the peak load hour of each day. Thus, the instantaneous peak load of each day is slightly higher than the values used in Figure 22..

The figure shows a seasonal pattern of high loads during the winter and summer and mild loads during the spring and fall. Overall, load increased modestly from 2012 to 2013. The annual peak load of 27.4 GW occurred on July 19, 2013, up approximately 6 percent from the peak load of 25.9 GW in 2012.[98] The average load increased by roughly 1 percent, from 14.8 GW in 2012 to 14.9 GW in 2013.

The ISO's day-ahead load forecasts are very consistent with actual load, although the ISO tends to slightly over-forecast load on average. The average over-forecast was comparable in the two years: 0.5 percent in 2012 and 0.6 percent in 2013. The ISO regularly evaluates the performance of its load forecasting models to ensure there are no factors that bias the forecast unjustifiably.[99]

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. The average forecast error was roughly 1.8 percent in 2013, consistent with 2012. The forecast error tends to increase during the summer months. In 2013, the forecast error averaged 3.1 percent in the summer months (June to August) and just 1.4 percent in other months. Nonetheless, these levels of forecast error are still relatively small, and the load forecasting performance of the ISO remains good overall.

B. Surplus Capacity and Real-Time Prices

Under normal operating conditions, the available online and fast-start capacity is more than sufficient to satisfy load and reserve requirements, which suggests that some surplus capacity will exist in almost every hour. This is a normal outcome in a properly functioning market.

---

98 New England's all-time peak is 28,130 MW, recorded on August 2, 2006.

99 A small bias toward over-forecasting may be justifiable because the costs of under-forecasting (i.e., under-commitment and potential for shortages) are likely larger than the costs of over-forecasting. Furthermore, it may be appropriate when the instantaneous peak load is expected to be substantially higher than the hourly average peak load.

Surplus capacity does not raise concerns unless inflated by inefficient commitments by the ISO or market participants.

Surplus capacity is also important because it constitutes the resources that are available to respond to unexpected changes in real-time operating conditions. Accordingly, the quantity of surplus capacity exhibits a strong negative correlation with real-time energy prices. This section evaluates the pattern of surplus capacity and real-time energy prices. In this report, we define "Surplus Capacity" as the amount of capacity that is online or capable of starting within 30 minutes in excess of the amount required to meet load and reserve requirements. Hence, surplus capacity is equal to:

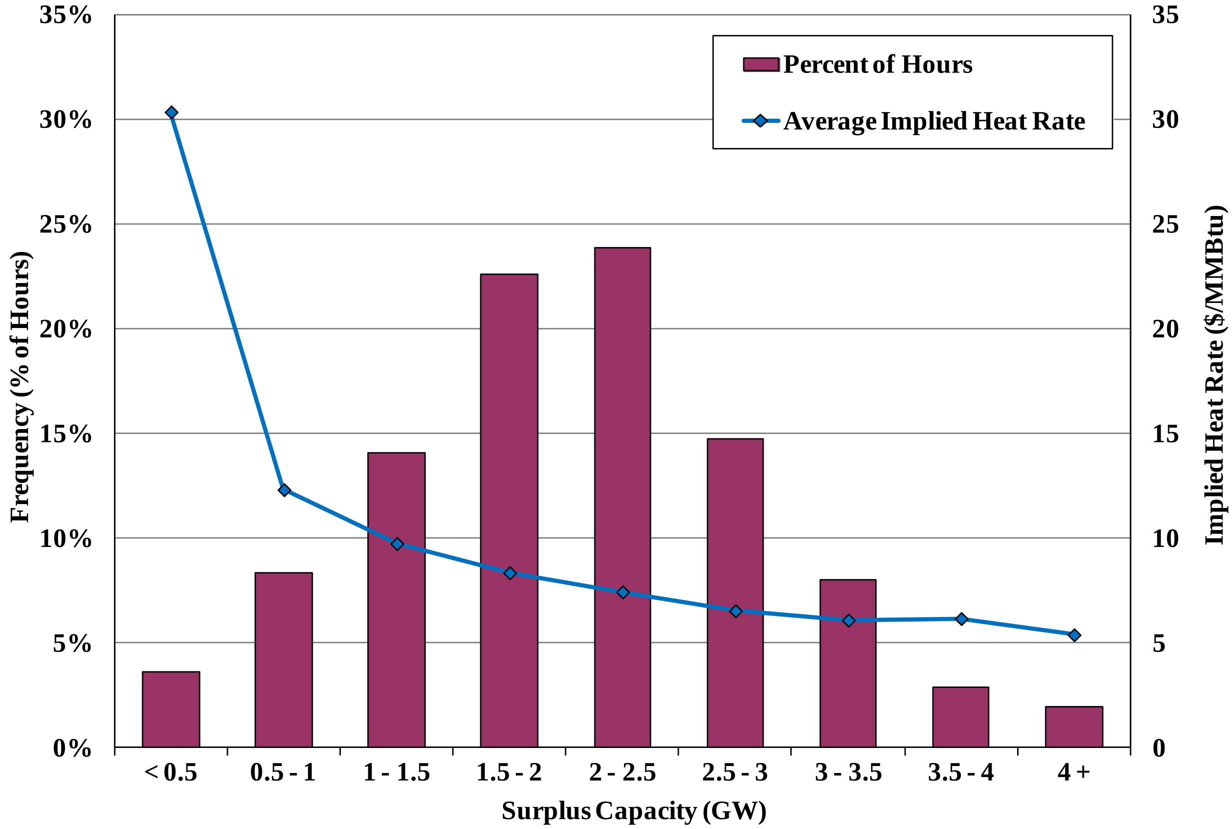
Online Reserves + Offline Reserves Deployable in 30 minutes – TMOR Requirement [100]

Figure 23 summarizes the relationship of surplus capacity to real-time energy prices at ISO-NE Hub in each peak hour of 2013. Each bar shows the frequency of peak hours when Surplus Capacity was in the range of values shown on the horizontal axis. For example, there was 0.5 GW to 1.0 GW of surplus capacity in approximately 8 percent of hours in 2013. The lines show the average real-time implied marginal heat rate at New England Hub in the hours that correspond to each range of surplus capacity. For example, in hours when there was 0.5 GW to 1.0 GW of surplus capacity, the average real-time implied marginal heat rate was 12.3 MMbtu per MWh in 2013. The implied marginal heat rate is shown in order to normalize real-time energy prices for changes in natural gas prices during 2013.[101]

100 The TMOR requirement includes the minimum 30-minute reserve requirement and the replacement reserve requirement, where applicable.

101 In this section, the implied marginal heat rate in a particular hour is equal to (the real-time LMP minus a $3 VOM) divided by (the natural gas index price plus a $0.40 adder).

Figure 23: Surplus Capacity and Implied Marginal Heat Rates
Based on Real-Time LMPs at the Hub in Peak Hours, 2013 [102]



The figure shows a strong correlation between the quantity of surplus capacity and the implied marginal heat rate in real time. In general, the implied marginal heat rate increases as the surplus capacity decreases, and the rate of increases accelerates sharply when the surplus approaches zero. The figure shows that the average implied marginal heat rate ranged from 5.4 to 12.3 MMbtu per MWh in hours with more than 500 MW of surplus capacity but rose sharply to 30.4 MMbtu per MWh in hours with less than 500 MW of surplus capacity (which include shortage hours, i.e., hours with negative surplus capacity). This sharp increase reflects the tendency for prices to rise rapidly during tight operating conditions. [103]

---

102 In this figure, “peak hours” includes hours-ending 7 through 22 on weekdays.

103 In general, LMPs are higher than $500 per MWh when the system was short of minimum 30-minute reserves and are higher than $250 per MWh when the system was short of 30-minute replacement reserves.

This analysis highlights two important aspects in the energy market. First, it reinforces the importance of minimizing out-of-market commitment for reliability, since the commitment of even one additional generator has substantial effects on the amount of surplus capacity, market clearing prices, and the resulting NCPC charges. Second, to the extent that reliability criteria require additional resources to be online beyond the quantities reflected in the market rules, it leads to an upward bias in the amount of surplus capacity in the real-time market. This increased surplus depresses real-time prices below efficient levels.

In 2013, the ISO implemented the following two market enhancements that improved the recognition by the market of the amount of capacity that is required to maintain reliability:

- Replacement Reserves Procurement – When it has concerns regarding certain large contingencies and the reliability of individual generators, the ISO sometimes requires higher quantities of operating reserves than are explicitly reflected in the 30-minute minute reserve requirement. The ISO started to reflect these needs in an additional Replacement Reserve requirement beginning October 1, 2013, which resulted in the procurement of additional 30-minute reserves using an RCPF that reflects the reliability value of the additional reserve needs (e.g., $250 per MWh).
- Generator Audit Revisions – The ISO improved its auditing process to better recognize generator's capability to provide generation and reserves, which became effective June 1, 2013 and included:
  - ✓ Changes to the auditing of the fast-start capabilities of off-line reserve resources (i.e., off-line reserve auditing);
  - ✓ Tariff provisions that memorialize the procedures for auditing the maximum claimed capability of generation resources (i.e., claimed capability auditing); and
  - ✓ Audits of a number of generator operating parameters that ISO-NE relies on in making generator commitment and operational decisions (i.e., on-line reserve auditing).

These enhancements led to more accurate calculation of the amount of available resources relative to the amount of resource required for reliability. This is also expected to result in higher real-time clearing prices for energy and reserves during tight operating conditions when reliable generator performance is most important for system reliability. This should, in turn, reduce NCPC uplift charges, improve the incentives for generator commitment in the day-ahead market, and provide signals for investments to improve performance by both new and existing resources.

C. Supplemental Commitments and Surplus Capacity

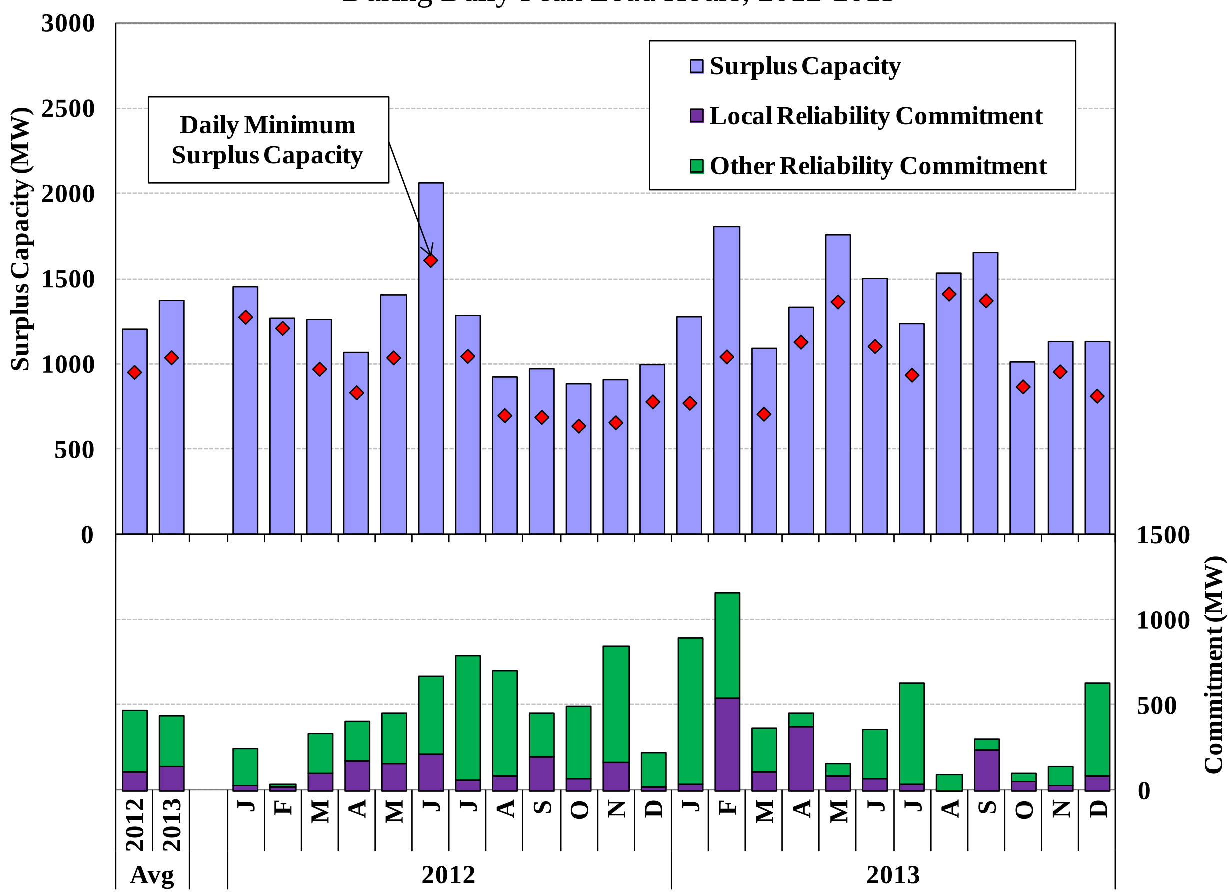
Given the effect of surplus capacity on prices, it is important to evaluate the supplemental commitments made by the ISO after the day-ahead market, since they can increase system surplus capacity, depress real-time prices inefficiently, and lead to increased uplift costs.

Sufficient resources must be available to satisfy local and system reliability requirements. After the day-ahead market, the ISO may need to commit additional generators with high commitment costs to meet local and system-level reliability requirements. Once the commitment costs have been incurred, these generators may be inexpensive providers of energy and reserves. Because these commitment costs are not reflected in the market prices, the real-time LMPs frequently do not reflect the full value of online and fast-start capacity when generators are committed for reliability. Like any other forward financial market, the day-ahead market LMPs tend to converge with the real-time LMPs, Therefore, the day-ahead LMPs do not reflect the full value of online and fast-start capacity, which can cause the day-ahead market-based commitment to not fully satisfy 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 reliability requirements in the real-time market, reducing the need for supplemental commitment. Nonetheless, supplemental commitments are still needed to meet reliability requirements, so it is important to continue evaluating potential market improvements.

Figure 24 shows the average amount of capacity committed after the day-ahead market to satisfy local and system-level requirements in the daily peak load hour in each month of 2012 and 2013. Local Reliability Commitment shows capacity committed to: (i) ensure that reserves are sufficient in local constrained areas to respond to the two largest contingencies; (ii) support voltage in specific locations of the transmission system; and (iii) manage constraints on the distribution system that are not modeled in the market software (known as Special Constraint Resources (SCRs)). Other Reliability Commitment shows capacity committed for local first contingency protection and for system-level reserve requirements together since the ISO does not maintain data that distinguishes between these two reasons for commitment. 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. In the upper panel of the figure, the blue bars show average surplus capacity in the peak load hour and the red diamonds indicate average daily minimum surplus capacity (i.e, the minimum surplus capacity in any hour of each day).

Figure 24: Supplemental Commitments and Surplus Capacity
During Daily Peak Load Hours, 2012-2013



The figure shows that supplemental commitment by the ISO averaged 435 MW during daily peak load hours in 2013, down modestly from 470 MW in 2012. Local reliability commitment accounted for 31 percent of total reliability commitment in 2013 and averaged nearly 140 MW, which was up 28 percent from 2012. The increase occurred primarily: (a) in February when Winter Storm Nemo caused substantial generation and transmission outages and resulted in increased reliability needs in Boston and Rhode Island; and (b) in April when multiple planned outages led to more frequent reliability commitments in Maine.

Other reliability commitment included mostly commitments for system-wide reserves and a small amount for local first contingencies. This category decreased 18 percent from an average of 365 MW in 2012 to 300 MW in 2013. July accounted for 16 percent of these commitments in 2013, most of which occurred during the heat-wave week when high temperatures led to high load levels and very tight system conditions. The three winter months (January, February, and December) accounted for 56 percent of this category as most commitments occurred on days with very high natural gas prices and increased uncertainty regarding the availability of fuel to both gas-fired and oil-fired generators. Supplemental commitment in the remaining eight months was low, averaging just 130 MW and falling substantially from the same periods in 2013.

Overall, supplemental commitment during winter conditions were lower in December 2013 compared with early 2013, as were supplemental commitments during the non-winter months of 2013 compared to 2012. These improvements are partly due to several changes in market operations during 2013:

- The ISO changed the timelines of the day-ahead market and the RAA process on May 23, 2013. This change allows an earlier completion of the initial RAA process by 17:00, which is 5 hours earlier than the previous timeline.[104] This provides more time for market participants to make fuel arrangements. This has likely led to fewer instances of market participants declaring their gas-fired resources unavailable and reduced the need for the ISO to make supplemental commitments.
- The ISO implemented several revisions to its generator audit process on June 1, 2013 (which are discussed in the prior sub-section) to improve the reliability of reserve schedules. In the past, the ISO sometimes committed additional capacity in the RAA

104 Prior to May 23, 2013, the day-ahead market bidding window closes at 12:00 noon and the ISO clears the market and posts results at 16:00. There is a re-offer period between 16:00 and 18:00, during which market participants may submit changes to their original supply offers. Following the re-offer period, the ISO conducts the initial RAA process to determine whether it is necessary from a reliability perspective to commit more resources in addition to those that were committed through the day-ahead market. The initial RAA process is completed at 22:00 and market participants are notified if any of their resources have been committed through the RAA process to operate for the upcoming Operating Day that starts at 12:00 midnight. While after May 23, 2013, the day-ahead market bidding window closes at 10:00, the ISO clears the market and posts results no later than 13:30, the re-offer period closes at 14:00, and the initial RAA completes by 17:00.

process because it discounted the reserve capability because of inconsistent past performance. These enhancements allow the ISO to have more accurate information on resource capability and reduce the need for such over-commitment.

- The ISO has developed analytical tools to track supply and usage of natural gas on New England generators. Reliability commitment was lower in December than in January and February of 2013. More timely and precise information regarding gas availability from these tools enables the ISO to better determine how much supplemental commitment is necessary.

Another factor that likely contributed to the reduction in supplemental commitments was the increase in day-ahead load scheduling from an average of 93 percent in 2012 to 95 percent in 2013. The increase was partly due to higher and more volatile real-time LMPs in 2013 that were driven primarily by more frequent shortages and high and volatile natural gas prices.

Despite the improvements, there were still days when relatively large quantities of supplemental commitments resulted in large surplus capacity levels, which raise costs to ISO-NE's customers and distort real-time prices. After reviewing the supplemental commitments and the surplus capacity levels that resulted from real-time operating conditions, we found that more than 60 percent of the supplemental resource commitments in 2013 were needed to maintain system level reserves in retrospect.[105] This was a notable improvement from 45 percent in 2012. The fact that some of the reliability-committed capacity was not needed in retrospect is typically due to the following factors.

- The size of the unit committed may exceed the forecast capacity shortfall, contributing to the amount that is not needed (e.g., if a 250 MW unit is committed to resolve a 170 MW shortfall);
- The "desired capacity surplus" that operators have the discretion to determine to account for concerns regarding generator availability, load forecast errors, or other factors; [106] and

---

105 This is a simple evaluation that treats any surplus capacity (online and available offline capacity less the need to meet system load and reserve requirements) as "not needed" for the system. This simple evaluation tends to understate the necessity of supplemental commitments because: 1) the evaluation is based on hourly integrated peak rather than the higher instantaneous peak, and 2) the ISO cannot commit just a portion of a unit. For example, if the ISO needs an additional 200 MW of capacity to satisfy system reliability needs and commits the most economic unit with a capacity of 300 MW. In this evaluation, 100 MW of capacity would be deemed as "not needed".

106 The operators have the discretion to commit surplus generation when they believe it is necessary to deal with uncertainty as stated in the System Operating Procedure, Perform Reserve Adequacy Assessment, Section 5.3.2.3, "The Forecaster may commit additional Generators as needed for reliability (anticipated storms, hurricanes or other conditions that affect Bulk Power System reliability)."

- The assumed level of imports and exports. When evaluating the need for commitments in advance, the ISO generally assumes day-ahead scheduled transactions will flow.

In general, the desired capacity surplus should be minimized since the operating reserve requirements are set at levels that should ensure reliability. Adding a non-zero desired capacity surplus introduces an inconsistency between the market requirements and the operating requirements, although we recognize that conditions can sometimes arise that would justify an increase in the desired capacity surplus. The procurement of Replacement Reserves starting in October 2013 has better aligned the market requirements with the desire for additional surplus capacity on some days.[107] We would go further in this regard and allow operators to vary the quantity of the replacement reserve requirement based on their concerns regarding load and fuel supply uncertainty.

With regard to the import and export assumptions, we believe that substantial improvements are possible. In general, the assumptions regarding imports and exports are that the day-ahead scheduled transactions will flow in real time. By committing generation to support day-ahead exports, they are treated as firm and we understand from the ISO that the operators generally do not curtail day-ahead exports. This treatment of the day-ahead exports in the capacity evaluation process raises potential efficiency concerns because:

- The participants are not obligated to schedule the exports in real time, which could render the units committed to support them unnecessary;
- The value of the day-ahead exports may not justify the costs of the supplemental commitments made to support them; and
- Assuming a fixed schedule substantially understates the ability of adjustments in interchange to help maintain reliability.

This is particularly true when exports are scheduled to New York when the difference in price on the New York side of the border is not significantly higher than on the New England side (which represents the value of the export).

107 For example, suppose that the desired capacity surplus would have been 300 MW on a particular day. If the ISO procures 180 MW of Replacement Reserves, it will be able to reduce the desired capacity surplus to 120 MW without reducing reliability.

Hence, the ISO should consider whether its assumptions regarding imports and exports in its capacity evaluation process could be improved. The ISO-NE is moving forward with the NYISO in implementing Coordinated Transaction Scheduling (CTS), which should rationalize the physical flow between the two markets in real-time. This should, in turn, allow the ISO to rely more heavily on the markets to cause power to flow in the efficient direction, making it unnecessary to commit generation to support day-ahead exports.

D. Fuel Usage Under Tight Gas Supply Conditions

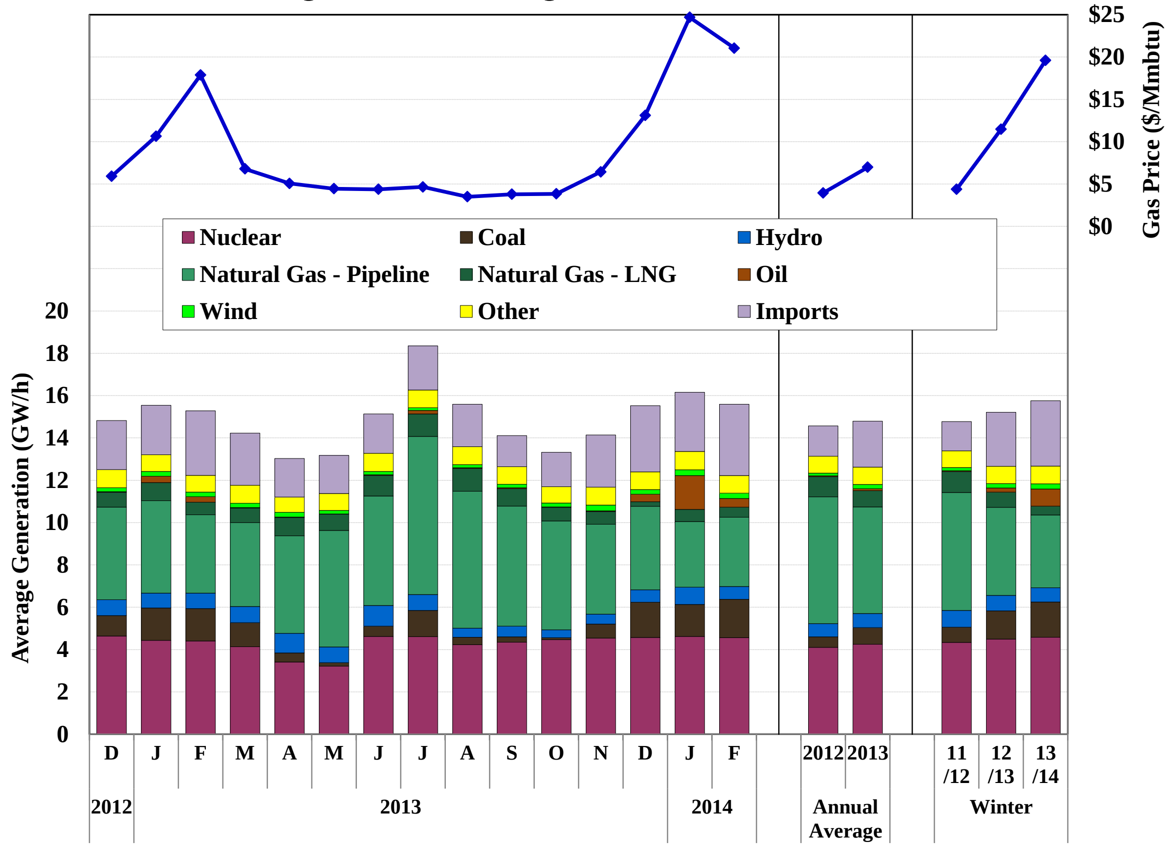
In recent years, fuel price fluctuations have been the primary driver of changes in wholesale power prices because most of the marginal production costs of fossil fuel generators are fuel costs. Although much of the energy is generated from hydroelectric, nuclear, and coal-fired generators, natural gas units are usually the marginal source of generation. Hence, natural gas prices affect wholesale power prices more directly than other fuel prices.

When bottlenecks on the natural gas pipeline system limit the availability of gas, the wholesale electricity market has the important role of determining which generators burn the available gas, how much electricity to import, and how to utilize the available fuel inventories of internal oil-fired generation and other non-gas resources. Uncertainty about natural gas prices and the availability of other fuels make it challenging for suppliers to offer their resources efficiently and for the ISO to maintain reliability. The following two analyses evaluate the efficiency of fuel usage in New England, especially during periods of tight natural gas supply.

Figure 25 summarizes the general pattern of fuel usage by showing the average: a) day-ahead natural gas price index for Algonquin City Gates; b) internal generation by fuel type; and c) net imports to New England in each month from December 2012 to February 2014.[108]

108 The figure also compares these quantities on an annual basis for the past two years and on a seasonal basis for the past three winters. The fuel type for each fossil fuel generator (i.e., gas, oil, or dual-fuel unit) in the figure is based on its actual fuel consumption reported to the U.S. Environmental Protection Agency ("EPA") and the U.S. Energy Information Administration ("EIA"). The fuel type for each non-fossil fuel generator is based on information in the 2014 CELT report (i.e., 2014-2023 Forecast Report of Capacity, Energy, Loads, and Transmission).

Figure 25: Fuel Usage and Natural Gas Prices



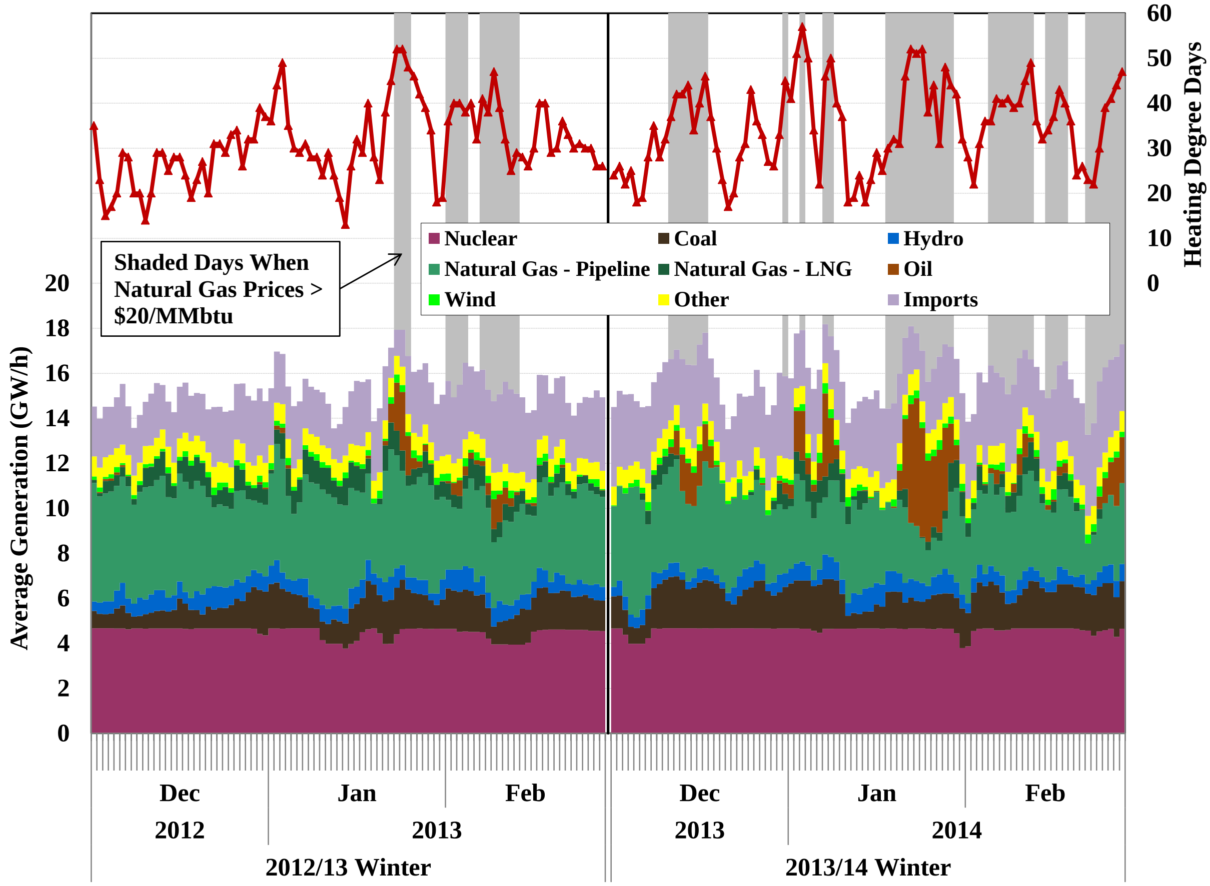
Most of the fluctuations shown in the figure result from changes in natural gas prices, outages, or fuel availability (e.g., water and wind conditions) for non-fossil resources:

- Non-fossil fuel-fired generation (including nuclear, hydroelectric, and renewable generation) did not vary much from month to month. Taken together, the average amount of non-fossil fuel fired generation rose from almost 5 percent in 2013, reflecting fewer nuclear outages and the installation of additional wind resources.
- Oil-fired generation averaged less than 30 MW per hour in most months, but increased substantially when gas prices rose sharply. Average oil production rose from 30 MW in the winter of 2011/12 (i.e., December 2011 to February 2012) to nearly 200 MW in the winter of 2012/13 and over 800 MW in the winter of 2013/14 as average natural gas prices rose from roughly $4.40 to $11.50 and $19.60 per MMbtu over the same periods.
- Coal production increased from an average of 720 MW in the winter of 2011/12 to 1,660 MW in the winter of 2013/14 because of the low cost of coal relative to natural gas.
- Gas-fired generation during the winter fell from an average of 6,580 MW to 3,860 MW from 2011/12 to 2012/13.
- Net imports increased from 2012 to 2013 and from the winter of 2011/12 to the winter of 2013/14. These increases were largely driven by increased natural gas prices and higher

spreads in natural gas prices between New England and neighboring markets in these periods (changes in net imports are discussed in more detail in Section I.A).

The next analysis focuses on the winter months when supply of natural gas is usually tightest. Figure 26 evaluates fuel usage daily over the last two winters. The bottom portion of the figure shows average internal generation by fuel type and average net imports to New England. The top portion of the figure shows the Heating Degree Days (HDD) in the upper portion. [109] The figure also highlights the days during which natural gas prices exceeded $20 per MMbtu.

Figure 26: Fuel Usage Under Tight Gas Supply Conditions
Winter 2012/13 & 2013/14



Cold weather conditions (indicated by high HDD) caused natural gas prices to rise above $20 per MMbtu on 14 days in the winter of 2012/13 and on 42 days in the winter of 2013/14. Oil-fired

109 The heating degree days are based on average outside air temperature at Boston and a base temperature of 65 Fahrenheit. For example, if the average air temperature is 15 Fahrenheit, the HDD will be (65-15) = 50.

generation increased sharply on these days, especially during a seven-day period in late January 2014 (i.e., from January 22 to January 28). During this seven-day period, natural gas prices averaged $53 per MMbtu and oil-fired generation averaged 4,280 MW per hour, which accounted for 41 percent of total generation from oil during the entire three-month period. The large amount of oil used in a single week illustrates the difficulty in predicting (before the winter) how much oil-fired generation will be needed over the winter season.

The figure also shows that oil-fired generation totaled 1.75 million MWh in the winter of 2013/14, significantly higher than 0.42 million MWh in the winter of 2012/2013. The sharp increase occurred because:

- Extreme cold weather conditions were more frequent in the winter of 2013/14, which led to more frequent natural gas price spikes and increased demand for oil-fired generation. For instance, HDD exceeded a value of 42 almost three times more often in the winter of 2013/14 than the prior winter. Cold weather also reduced imports from Quebec (a winter-peaking system) on several days with very gas prices.
- Higher oil inventories coupled with high gas prices outside New England contributed to high oil-fired production on some days in the winter of 2013/14. From January 22 to 28, natural gas price for the Transco pipeline (downstate NY) were $5 to $60 per MMbtu higher than the Algonquin Citygate index (NE), leading to reduced imports and a corresponding increase in oil-fired generation in New England.

The ISO implemented Winter Reliability Program before the winter of 2013/14 as an interim solution to mitigate the reliance on natural gas-fueled generation and maintain system reliability under tight gas supply conditions. This program procured an oil inventory service that is equivalent to a total of 1.95 million MWh of oil-fired generation for the three winter months, leading to higher starting inventories than before the previous winter.[110]

The widespread use of oil on the cold-weather days indicates that the ISO and market participants have been able to cope with challenging fuel supply conditions reasonably well in managing available supply of natural gas under the tight gas supply conditions. Nonetheless, the market results from the recent winters highlight two significant market issues. First, the current rule that requires each generator to submit a single daily offer curve ten hours before the start of

110 See Appendix K in Market Rule 1: Winter 2013-2014 Reliability Solutions for more details.

each operating day that is binding for the entire day creates significant challenges for generators that must manage limited fuel in order to produce when it is most valuable. Volatile natural gas prices and inelastic intraday supply conditions lead to cost uncertainties that cannot be accurately reflected in a daily offer. Likewise, limited oil inventories lead to significant opportunity costs that change as a generator is dispatched more or less than anticipated. The Hourly Offer project will allow generators to update their costs throughout the operating day as conditions change and address these concerns. This should improve the efficiency of generator scheduling and LMPs considerably during peak winter conditions.

Second, although oil-fired generation increased considerably on the days of high gas prices, many oil-fired generators were not fully utilized when LMPs would enable them to recoup the variable costs of producing on oil because of low oil inventories. Before each winter, suppliers with oil-fired capacity decide how much to oil to hold in inventory after balancing the potential gains from being available when gas prices are very high against the carrying costs of storing oil and the risks of holding unused oil after the winter.

The Winter Reliability Program was instituted to ensure that oil-fired generators would have adequate oil on-site to maintain reliability when natural gas supply was limited during winter peak conditions. However, it is an interim solution that does not provide consistent market incentives to all generators that reduce New England's dependence on the natural gas system. A more comprehensive solution is needed to provide efficient incentives for maintaining a fleet of resources that can satisfy the system's summer and winter reliability needs in the years ahead.

E. Uplift Costs

To the extent that the wholesale market does not satisfy ISO-NE's reliability requirements, the ISO takes additional steps to ensure sufficient supplies are available. The ISO primarily makes supplemental commitments of resources that were not economic in the day-ahead market to ensure it satisfies the reliability needs of the system. Such generators receive 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 figure summarizes several categories of uplift by month in 2013, including:

- FCM Reliability Credits – The uplift from these out-of-market capacity payments are allocated to Network Load in the zone where the unit is located.[111] Units prevented from delisting for reliability reasons receive Reliability Credits under FCM, which are equal to the difference between their rejected delist bid and the FCA clearing price.
- Local Second Contingency Protection Resources – In 2013, 82 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.[112] 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 is allocated to Network Load throughout New England, export transactions, and wheel-through transactions.
- Economic and First Contingency Protection Resources – In 2013, 70 percent of this uplift was allocated to Real-Time Deviations throughout New England.[113] The remaining uplift for units committed in the day-ahead market is allocated to day-ahead scheduled load throughout New England. Non-fast-start units are typically started in the RAA process to maintain adequate reserves, while the fast-start units are typically started in economic merit order by the real-time dispatch model but do not recover the full as-offered cost (i.e., start-up, no-load, and incremental offer costs).[114]
- Winter Reliability Program – The ISO implemented an interim solution to mitigate the reliance on natural gas-fueled generation and maintain system reliability during the winter of 2013/14 (i.e., from December 2013 to February 2014). Under this program, market participants provided the equivalent of nearly 2 million MWh of energy in oil inventory and demand response for three months in exchange for total payments of $25 million.

When uplift charges are incurred to address local supply inadequacies, it is generally appropriate to allocate these charges to the local customers who benefit directly from the service. For this reason, the first three of these categories are allocated to local customers, while the uplift charges for Voltage Support Resources, the Winter Reliability Program, and other supplemental commitment are allocated to customers throughout New England.

---

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

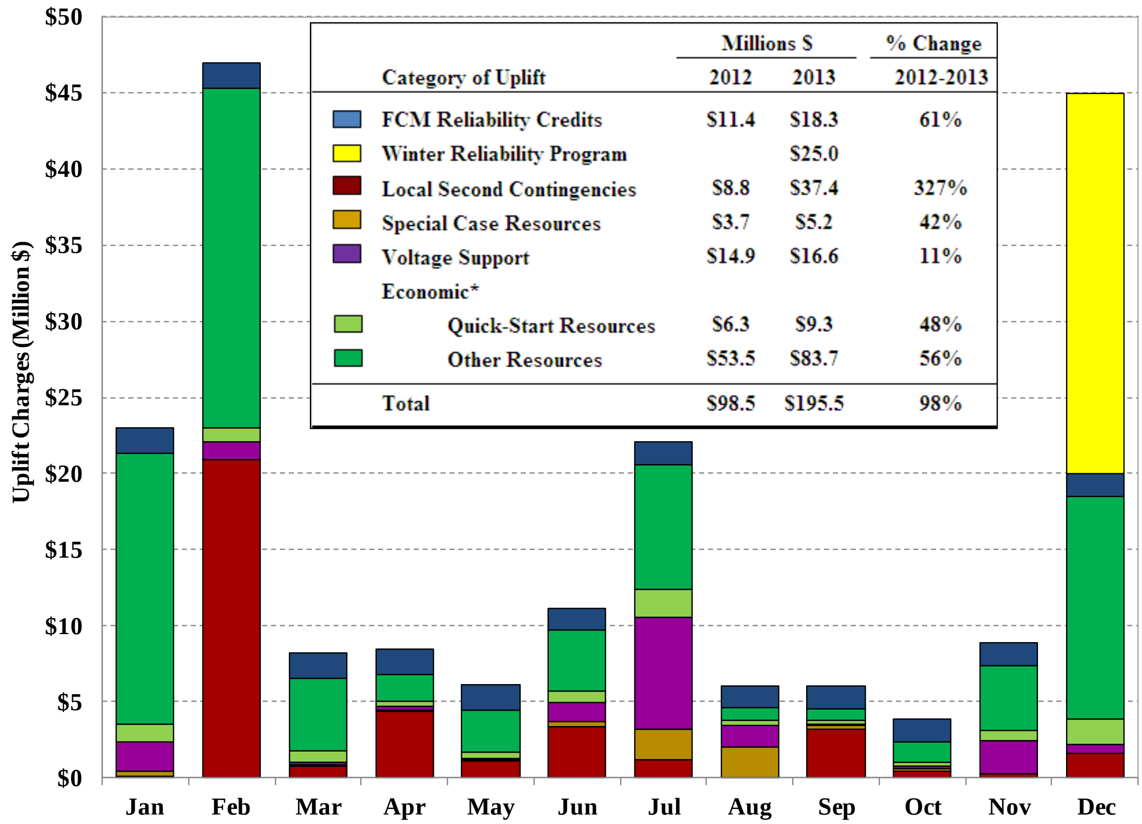
112 Real-Time Load Obligations include load customers that are served by the Load Serving Entity.

113 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, uninstructed generation deviations from day-ahead schedules, virtual load schedules, and virtual supply schedules.

114 Section V.A discusses further the tendency for fast start units to be committed in economic merit order but not set the LMP during most of the period for which they are committed.

The following figure summarizes the total costs of uplift associated with NCPC charges and out-of-market capacity payments under FCM and Winter Reliability Program in each month of 2013.[115] The "Economic" category includes uplift for commitments made for system-wide reserve requirements and first contingency requirements, and the category is broken into NCPC charges for quick-start resources versus non-quick-start resources (which are primarily committed for reliability). The table in the figure shows the year-over-year changes in these uplift categories from 2012 to 2013.

Figure 27: Uplift Costs by Category by Month
2013



Category of Uplift	Millions $ 2012	Millions $ 2013	% Change 2012-2013
FCM Reliability Credits	$11.4	$18.3	61%
Winter Reliability Program		$25.0	
Local Second Contingencies	$8.8	$37.4	327%
Special Case Resources	$3.7	$5.2	42%
Voltage Support	$14.9	$16.6	11%
Economic*			
Quick-Start Resources	$6.3	$9.3	48%
Other Resources	$53.5	$83.7	56%
Total	$98.5	$195.5	98%

The figure shows that total uplift charges increased from $99 million in 2012 to $196 million in 2013. Several factors contributed to the increase:

- Out-of-market capacity payments rose by $32 million in 2013, which include FCM reliability credits and payments under the Winter Reliability Program.

115 The numbers in the table are based on information available at time of reporting, which may be different from the numbers in final settlements.

- FCM reliability credits were paid to two units in Boston because their de-list bids were rejected for reliability in the third and fourth Forward Capacity Commitment Period (i.e., June 2012 to May 2013, June 2013 to May 2014).[116] Therefore, reliability credits were paid only in the last seven months of 2012, while they were paid in each month of 2013.
- The interim Winter Reliability Program resulted in additional $25 million of uplift in December 2013. Generators with program obligations were paid $38 per MWh for maintaining the necessary oil inventory to be capable of producing a specific amount of power from oil during the winter.
- Uplift payments for local second contingency protection increased by roughly $29 million in 2013. Most of the increase occurred in February 2013 as Winter Storm Nemo caused substantial generation and transmission outages and resulted in increased local reliability commitments in Boston and Rhode Island.
- The “Economic” category of uplift associated with non fast-start resources increased by roughly $30 million in 2013. The three winter months (i.e., January, February, and December) accounted for most of the increase, which was driven partly by increased system-wide reliability commitments (which is quantified and discussed in more detail in Subsection C above) and higher production costs as a result of higher natural gas prices.

Overall, the increase in uplift charges associated with NCPC payments was consistent with the increase in natural gas prices in 2013 that led to higher commitment costs of gas-fired resources. This is also one reason that the “Economic” NCPC payments associated with fast-start resources rose by 50 percent in 2013 although the economic dispatch of such resources by UDS fell modestly from 2012. As described above, fast-start resources dispatched economically by the real-time dispatch model (i.e., the UDS) can require NCPC payments to cover their costs because they generally do not set the LMP at the level of their total offer cost.[117] This underscores the importance of efforts to modify the real-time pricing and dispatch software to allow fast start resources to set the clearing price when they are the marginal source of supply (i.e., when their deployment enables the real-time model to avoid scheduling more expensive resources).[118]

F. Conclusions and Recommendations

When the market does not schedule sufficient resources to maintain reliability, the ISO must take out-of-market actions to make additional reserves available, such as supplemental commitments.

116 There were no such rejections in the second Forward Capacity Commitment Period.

117 See Section V.A. for a detailed analysis and discussion of this issue.

118 See Section V.A. for a discussion of this recommendation.

Some out-of-market actions are necessary, but they tend to undermine the market incentives for resources to be available and perform reliably. Hence, it is important to minimize out-of-market actions and to make enhancements that enable the market to reward resources for helping satisfy reliability criteria, particularly under tight conditions.

In 2013, the overall amount of supplemental commitment fell 8 percent from the previous year despite more challenging weather and system conditions. This report discusses several market enhancements and improvements to the reserve adequacy assessment (RAA) procedures that contributed to the reduction. Several of these improvements were made during 2013, so the benefits were not fully reflected in the annual results for 2013. Higher and more volatile natural gas prices and the Winter 2013/14 Reliability Program caused uplift charges from out-of-market payments to generators in 2013 to nearly double from the previous year.

Our evaluation of winter operations shows widespread use of oil on a relatively small number of cold-weather days when natural gas supplies were limited because of high heating demand. A single seven-day period accounted for 41 percent of the fuel oil used during the Winter of 2013/14, which illustrates the difficulty in predicting (before the winter) how much oil-fired generation will be needed for reliability. During this week, much of the oil was used in response to the fall in electricity imports when natural gas prices were higher in some areas of New York than in New England. Overall, the market performed reasonably well in conserving the available supply of oil and natural gas under the tight gas supply conditions, although the report discusses several market changes that should improve market performance.

Out-of-Market Actions

Our analysis of surplus online and fast-start capacity shows that market clearing prices are highly dependent on the amount of surplus capacity that is available in the real-time market, especially under relatively tight operating conditions.[119] Hence, factors that lead to artificially high levels of surplus capacity tend to:

- Reduce the incentive for units to procure the fuel necessary to be available in real time;

119 In this section, Surplus Capacity refers to the amount of available on-line reserves plus available off-line reserves on fast-start resources minus the 30-minute operating reserve requirement.

- Dampen economic signals to invest in better performance and availability for both new and existing resources.
- Increase large and volatile uplift charges that can be difficult for participants to hedge and which may discourage participation in the ISO-NE market.

To ensure that these issues are minimized, it is beneficial for the ISO to regularly review its assumptions and processes for determining that additional commitments are necessary to satisfy its reliability requirements. In this regard, the ISO made significant enhancements during 2013 to the analytical tools it uses for forecasting how gas pipeline conditions and limited oil inventories will affect generator availability during the operating day. This allowed it to reduce the amount of supplemental commitment in late 2013 as compared with previous periods of tight gas system conditions.

Recent Market Enhancements

The correlation between real-time prices and surplus capacity quantities reinforces the importance of:

- Fully reflecting reliability needs in the market requirements for operating reserves. Procuring less operating reserves in the real-time market than needed for reliability increases the apparent surplus capacity amounts and depresses real-time prices, which reduces the incentives for generators to be available and perform reliably; and
- Allowing individual generators to sell only quantities of operating reserves that they are capable of providing. Additional sales artificially raise the apparent real-time supply of operating reserves and tend to depress real-time prices.

The ISO implemented two market enhancements in 2013 to address these issues. First, the ISO started procuring “replacement reserves” in the real-time market beginning October 1, 2013. This better enables the real-time prices to reflect reliability concerns regarding the availability of generators with limited or uncertain fuel supplies. Although the ISO has the capability to modify the quantity of replacement reserves based on its concerns regarding load and fuel supply uncertainty, it normally procures a fixed quantity. It would be beneficial for the ISO to vary the procurement amount more frequently to more accurately reflect changing system conditions.

Second, the ISO revised its procedures for auditing generator capability in June 2013. This has improved the accuracy of 10-minute and 30-minute reserve schedules from off-line and on-line resources, ensuring that the real-time market procures a sufficient quantity of operating reserves and that real-time prices more accurately reflect the cost of maintaining reliability.

Future Market Enhancements

The ISO is working on two market enhancements that will lead to more efficient scheduling and pricing during tight market conditions. The first will provide generators with additional flexibility to modify their offers closer in the real time (i.e., intraday reoffers) to reflect changes in marginal costs. This will enable more efficient scheduling decisions during periods of volatile natural gas prices and low fuel inventories, which will enable supplier to conserve scarce fuel and will reduce the risks for generators to be available in the day-ahead and real-time market (at an offer price that is lower than its marginal cost). The ISO is planning to introduce hourly day-ahead energy offers and intraday reoffers in the fourth quarter of 2014.[120]

Second, the ISO has proposed to modify the allocation of NCPC charges resulting from supplemental commitment for reliability. Currently, a large share of these NCPC charges are borne by virtual load and over-scheduled physical load scheduled in the day-ahead market even though both actually help *reduce* supplemental commitment by helping increase market-based commitment in the day-ahead market. The proposed changes would reallocate these charges based on real-time physical load, since such commitments are made to maintain the reliability of physical load.[121] Removing this disincentive to schedule virtual load and physical load in the day-ahead market will improve the day-ahead commitment of resources, thereby reducing the need for supplemental commitment.

We also recommend changes in Section V that would allow the real-time prices of energy and reserves to better reflect the costs of maintaining reliability during tight operating conditions. Since expectations of real-time prices are the primary determinant of day-ahead prices, these changes should increase the day-ahead market commitment of generators that can satisfy system's reliability criteria.

120 See 2014 Wholesale Markets Project Plan.

121 The effects of NCPC charges and the ISO's proposal are discussed in Section I.F.

IX. Forward Capacity Market

The Forward Capacity Market (FCM) is designed to attract and maintain sufficient resources to satisfy ISO-NE's long-term resource planning requirements efficiently. FCM provides economic signals that supplement the signals provided by the energy and ancillary services markets. In combination, these three sources of revenue provide economic signals for new investment, retirement decisions, and participation by demand response.

Forward Capacity Auctions are held 39 months before the beginning of each year-long Capacity Procurement Period to provide sufficient lead time for a new generator to be built if its offer is accepted in an FCA. The first eight FCAs have facilitated the procurement of installed capacity for the period from June 2010 to May 2018.

This section provides background on the FCM rules and evaluates the outcomes of FCAs 6, 7, and, which were held in April 2012, February 2013, and February 2014 to procure capacity for the three years from June 2015 to May 2018. This section also discusses certain market reform proposals and rule changes that are underway. A summary of our conclusions and recommendations is at the end of the section.

A. Forward Capacity Market Design

ISO-NE is responsible for ensuring that there will be sufficient resources to satisfy the one-day-in-ten-year resource adequacy standard and other reliability criteria for New England over the ten-year planning horizon. Energy-only markets do not usually produce sufficiently high prices to facilitate the levels of investment needed to satisfy resource adequacy requirements and other planning criteria. This is known as the "missing money" problem. Capacity markets are designed to solve the missing money problem by providing an amount of supplemental revenue to suppliers that is sufficient to satisfy these planning criteria.

Capacity markets are generally designed to provide incentives for efficient investment in new resources. A prospective investor estimates the cost of investment minus the expected "net revenues" from providing energy and ancillary services (i.e., the variable profits after netting the associated variable production costs).[122] This difference between investment costs and net revenue, which is known as net cost of new entry ("net CONE"), is the estimated capacity revenue that would be necessary for the investment to be profitable.[123]

In an efficient market, the investments with the lowest net CONE will be the first to occur. The capacity price should clear at a level that is higher than the net CONE of the investments that are needed and lower than the net CONE of investments that are not needed. In this manner, the market facilitates investment in efficient capacity resources to meet the system's planning requirements. The resulting clearing price provides a signal to the market of the marginal value of capacity.

1. Key Market Design Elements

FCM was designed to efficiently satisfy ISO-NE's resource adequacy and transmission security requirements by using competitive price signals to retain existing resources and attract new supply. FCM has several key elements discussed in this section that are intended to work together to accomplish this goal.

Installed Capacity Requirement – The Net Installed Capacity Requirement (NICR)[124] is the capacity needed to satisfy New England's reliability standards in the Capacity Commitment Period, which begins three years after the auction.

Local Sourcing Requirement – The LSR is the minimum amount of capacity needed in the load zone to satisfy Resource Adequacy criteria (i.e., to reduce the probability per year of firm load shedding below 10 percent) and Transmission Security Analysis criteria (i.e., to have sufficient capacity such that the system can be restored to a normal state after the largest two

122 Section VI analyzes the estimated cost of new entry relative to the estimated net revenues that would be earned by generators in recent years. Net revenues include the total revenues from capacity, energy, operating reserves, and other ISO markets minus the resulting variable production costs.

123 Although the term "net cost of new entry" is used here in a generic sense, the meaning of Net Cost of New Entry in the context of FCM has evolved. Net CONE in the context of FCM is defined in Market Rule 1, Section 13.2.4. This report uses "net CONE" when discussing the concept generically and "Net CONE" when using the Tariff-defined meaning.

124 The NICR is equal to the Installed Capacity Requirement minus the HQICC. This treats a portion of the capacity from Hydro Quebec as a load reduction rather than as supply.

contingencies). Until FCA 7, LSRs were not modeled in the auction if the existing resources in total were sufficient to satisfy the LSR. Since FCA 7, LSRs are always modeled for Connecticut and NEMA.[125] The Commission recently accepted an ISO proposal for modeling additional capacity zones whenever the excess reserve margin in a particular local region is smaller than the largest generating station in the region beginning in FCA 10.[126]

New Capacity Treatment – Existing capacity participates in the FCM each year and receives only a one-year commitment. New capacity resources can choose an extended commitment period from one to five years at the time of qualification. The ISO has filed to extend this "lock-in" period to seven years beginning in FCA 9. Both new and existing capacities are generally paid the same market clearing price in the first year. [127] The price paid to new capacity after the first year is indexed for inflation.

Demand Curve & Price Floor – The demand curve in a capacity auction defines the price the ISO will pay for various sales quantities. The demand curve and participants' offer prices determine the market clearing price(s), subject to the restriction that they be no lower than the applicable price floor. These rules have undergone recent changes:

- FCA 1 to 7 – Vertical Demand Curve & Price Floor – The ISO used a vertical demand curve at the level of the NICR/LSR extending from the price floor up to $15 per KW-month. The price floor constituted a horizontal segment of the demand curve from the NICR/LSR to higher sales quantities. The price floor was originally conceived as a temporary measure and was eliminated after FCA 7.
- FCA 8 – Vertical Demand Curve – The ISO used a vertical demand curve from approximately $15 per kW-month and the level of the NICR/LSR down to $0 per kW-month. The vertical demand curve is flawed because it implies that incremental capacity above the minimum requirement has no value. To address this flaw, the Commission ordered the ISO to use sloped demand curves after FCA 8.[128]

---

125 The determination of the Local Sourcing Requirements, including the modeling assumptions used to determine the Local Resource Adequacy Requirement and the Transmission Security Analysis Requirement are described in Tariff Section III.12.2.

126 The rationale is that if the station delisted in a particular FCA, it would be necessary to clear new capacity to satisfy the local capacity requirement. See *ISO New England Inc.*, 147 FERC ¶ 61,071 (2014), dated April 28, 2014.

127 This was provided that the Insufficient Competition Rule and Inadequate Supply Rule are not invoked.

128 See *ISO New England Inc.*, 146 FERC ¶ 61,038 (2014), PP. 30.

- FCA 9 – System-wide Sloped Demand Curve & Vertical Demand Curve for Zones – The ISO has filed to create a sloped demand curve for the system from:
  - ✓ The Price Cap of 1.6 x Net CONE of $11.08 per kW-month, which corresponds to the quantity where the LOLE is 0.2; to
  - ✓ The price of $0 at a quantity corresponding to an LOLE of 0.012.[129]
- The ISO anticipates this is expected to result in an average LOLE that meets the standard of 0.1. The ISO will temporarily continue to use vertical demand curves for the local zones in FCA 9.
- FCA 10 – Sloped Demand Curves – The ISO intends to file a proposal for sloped demand curves in individual load zones for implementation in FCA 10.

<u>Insufficient Competition Rule</u> – This rule is designed to limit clearing prices for existing capacity under conditions when the FCA results might be affected by the exercise of market power. However, the rule does not result in an efficient price under some circumstances, which prompted a complaint to the Commission before FCA 8. In response to this complaint, the Commission ultimately approved an ISO proposal to establish a payment rate of $7.025 per kW-month (rather than risk having such an inefficient result) for existing capacity if the Insufficient Competition Rule was invoked in the auction. This rule is being replaced by the sloped demand curve, and the potential for anti-competitive conduct will be addressed by the market power mitigation measures discussed below.[130]

<u>Capacity Carry Forward Rule</u> – This rule is designed to avoid volatile prices in local load zones when the scale of new investment results in "lumpy" additions that are not necessary every year. Under certain circumstances, this carries forward a clearing price from one FCA with new entry to a subsequent FCA. This is retained for FCA 9, but it will not be necessary when the sloped demand curve is implemented for individual zones.

2. Market Power Mitigation Measures

The FCM is a forward procurement market, so it allows new and existing suppliers to compete, reducing the potential incentives to exercise market power. The FCM design also includes

---

129 See filing by ISO-NE and NEPOOL in Commission Docket ER14-1639, dated April 1, 2014, filing letter page 6.

130 The Commission found the results of the Insufficient Competition Rule was unjust and unreasonable because it led to prices that were not reflective of supply conditions. See *New England Power Generators Association, Inc. v. ISO New England Inc.*, 146 FERC ¶ 61,039 at PP. 47 (2014).

several provisions that are intended to guard against the abuse of market power by large sellers and/or large buyers. A large seller might have an incentive to withhold capacity in order to raise the auction clearing price, while a large buyer might have an incentive to contract with a developer to build new capacity at an above-market cost in order to reduce capacity prices below competitive levels.[131]

On the supply-side, the Internal Market Monitor (IMM) conducts a process to review de-list bids to ensure that large suppliers cannot exercise market power by withholding in the FCA. Most de-list bids exceeding $1 per kW-month are reviewed and must be justified by the resource-owner as consistent with the Going Forward Costs of the resource or some other competitive rationale. However, retirement de-list bids are not subject to any mitigation measures, which raises potential competitive concerns.[132]

On the buyer-side, the IMM conducts a process to review new capacity offers to ensure they are consistent with the resource's net CONE. Specifically, if the owner intends to offer the resource below the Offer Review Trigger Price that corresponds to the technology of the resource, the owner must demonstrate that the project's offer is not lower than the net CONE of the project.[133]

B. Analysis of Forward Capacity Auction Results

Six FCAs were held before 2013, FCA 7 was held in February 2013 for the commitment period of 2016/2017 (i.e., June 2016 to May 2017), and FCA 8 was held in February 2014 for the commitment period of 2017/2018 (i.e., June 2017 to May 2018). This section summarizes and evaluates the overall results of FCA 6, FCA 7, and FCA 8, first for individual load zones and second for the overall system.

131 Comparable concerns arise when public entities subsidize investment in resources that are not economic.

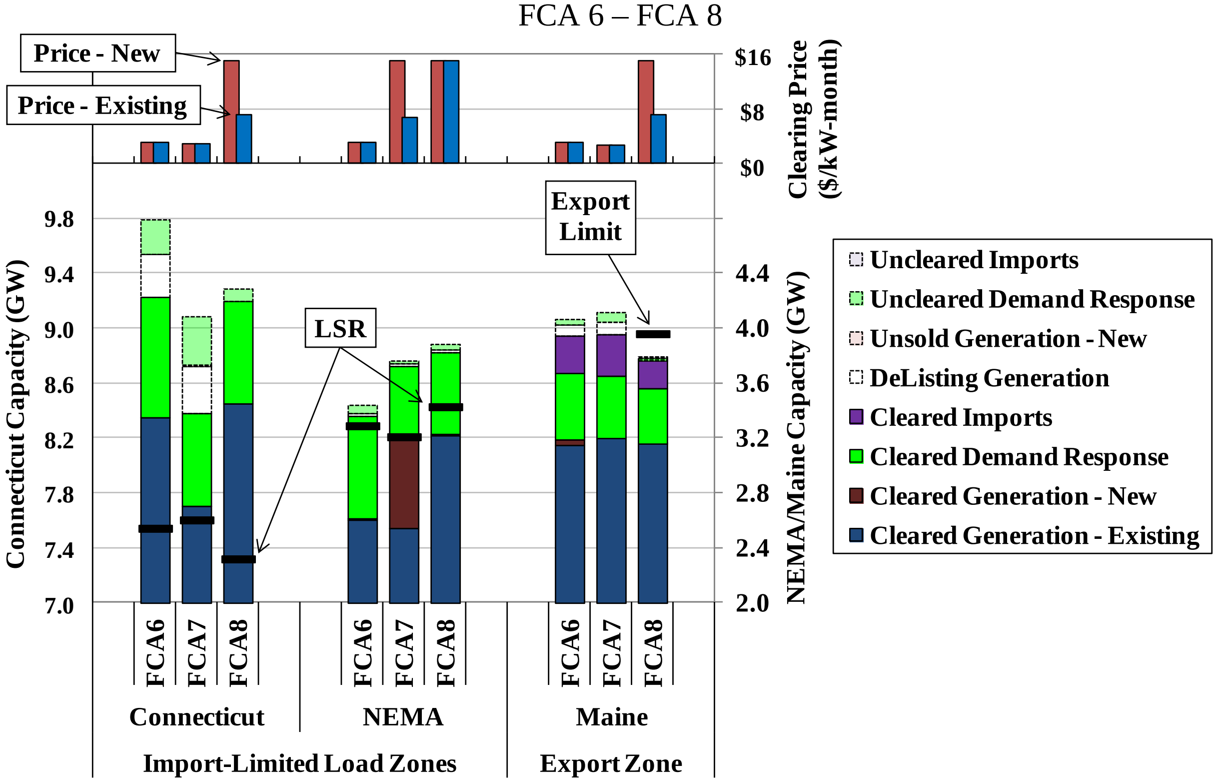
132 The de-list review process is set forth in Market Rule 1 Section III.13.1.2.3.2.

133 For FCA 9, the Offer Review Trigger Prices will be $13.424 per kW-month for a combustion turbine and $8.866 per kW-month for a combined cycle. They are defined for other generation and demand response types. The the Offer Review Trigger Prices and the process for reviewing offers from New Resources is set forth in Market Rule 1 Section III.A.21.

1. Summary of Capacity Auction Results – Local Areas

Figure 28 summarizes the outcomes from FCA 6, FCA 7, and FCA 8 for three local load zones, showing the distribution of cleared and un-cleared capacity by location. Cleared resources are divided into existing generation, new generation, demand response resources, and imports from external areas. The amounts of cleared resources are shown relative to the LSRs for Connecticut and NEMA. The amounts of cleared resources are shown relative to the Maximum Capacity Limit ("Export Limit") for Maine, since it can be export-constrained. The amounts of un-cleared resources are divided into new unsold generation, de-listing generation, demand response resources, and imports. Clearing prices for new and existing resources at each location are shown in the top panel of the figure.

Figure 28: FCM Auction Results for Local Areas
FCA 6 – FCA 8



The results from FCAs 6, 7, & 8 for NEMA provide useful insights regarding efficient capacity market design.

FCA 6

Figure 28 shows that the amount of excess capacity in NEMA was very low based on the existing resources that were qualified to participate, but the NEMA zone was not modeled in the auction because the existing resources were adequate to satisfy the LSR. Consequently, the ISO rejected 79 MW of de-list bids in NEMA for reliability rather than accepting offers from a new capacity resource. This would have required a higher clearing price for NEMA. This problem delayed economic entry by some resources, led to out-of-market payments to maintain adequate capacity levels, and resulted in capacity prices that did not properly reflect the benefits of additional capacity for reliability. This was resolved after FCA 6 by requiring that NEMA and other capacity zones be modeled, regardless of whether existing resources are adequate to satisfy the LSR.

FCA 7

Price separation between NEMA and other areas occurred for the first time in FCA 7. A large new resource submitted an offer to leave the auction in NEMA at $14.998 per kW-month. Because NEMA would not have met its LSR without this new capacity, its offer set the clearing price for new resources. However, the Insufficient Competition Rule was invoked partly because the new resource was pivotal for NEMA, which led to a clearing price of $6.661 per kW-month for existing capacity. This was 1.1 times the value of CONE as defined in the Tariff at that time.[134] These results raise several issues.

First, the vertical demand curve tends to produce volatile prices when the existing supply of resources is close to the LSR. Prices are very low until new entry is needed, and then tend to increase dramatically. More stable price expectations would reduce the risks for new investors and would provide better incentives for maintaining the reliability of existing resources. The ISO is addressing these issues by proposing sloped demand curve for the system by FCA 9 and for the load zones by FCA 10.

---

134 CONE was a value negotiated before FCA 1 and escalated annually using the Handy-Whitman index.

Second, the Insufficient Competition Rule does not set efficient prices for existing resources when additional resources are needed for reliability. Existing resources provide reliability benefits that are comparable to new resources, but existing resources received less than half the clearing price paid to new resources. Pricing rules that favor new resources over existing resources undermine incentives for maintaining existing resources and tend to inefficiently encourage the retirement of existing resources. The ISO is addressing this issue by eliminating the Insufficient Competition Rule along with the vertical demand curve for the system by FCA 9 and for load zones by FCA 10.

FCA 8

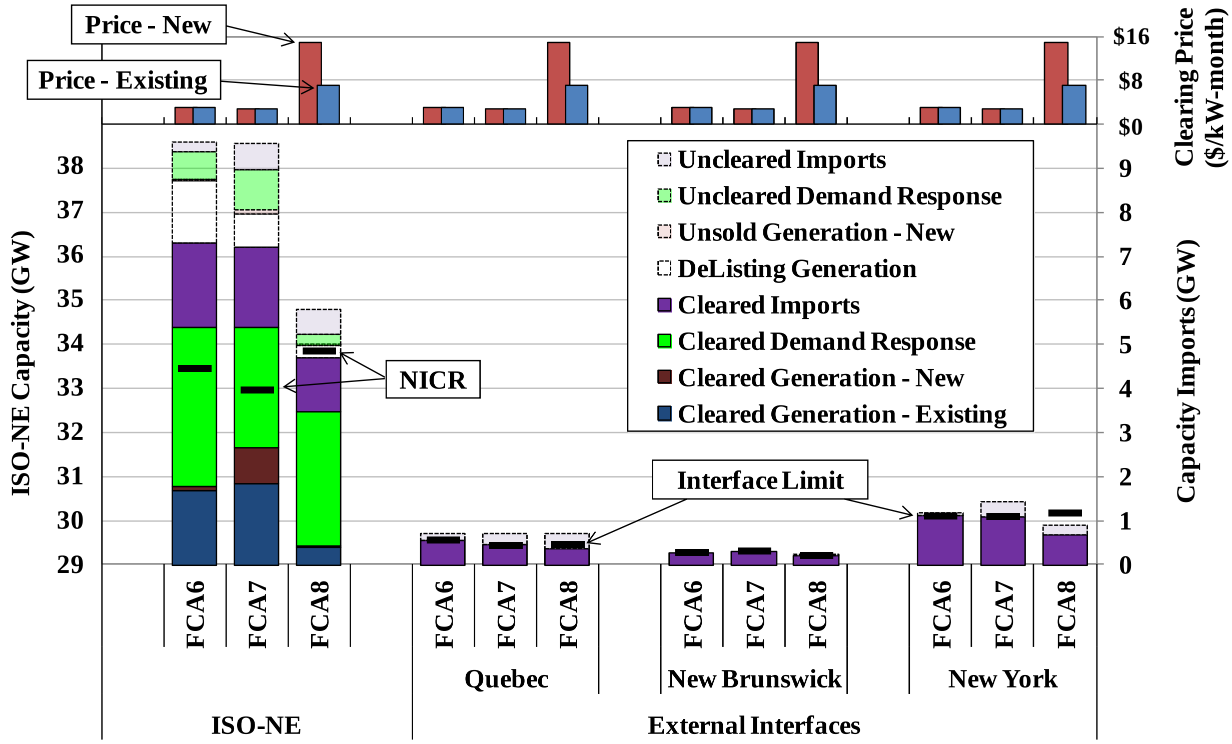
Although there was substantial excess capacity in FCA 8 in Boston, the clearing price rose to $15 per kW-month because of the Capacity Carry Forward Rule, which is designed to prevent "lumpy" new investment from causing a steep drop in subsequent FCA clearing prices. The price in an efficient market should be lower after the entry of a large new supplier than after the entry of a small new supplier. However, the Capacity Carry Forward Rule tends to maintain higher price levels following large new investments than small new investments. This issue can be addressed by eliminating the Capacity Carry Forward Rule when the sloped demand curve is implemented in FCA 10.

2. Evaluation of Capacity Auction Results – System Level

Figure 29 summarizes the outcomes from FCA 6, FCA 7, and FCA 8 for the overall system and for the external interfaces, showing the distribution of cleared and un-cleared capacity by control area. Cleared resources are divided into existing generation, new generation, demand response resources, and imports from external areas. The quantities of cleared resources are shown relative to the system NICR, while the cleared imports are shown relative to the import limits for the external interfaces. The amounts of un-cleared resources are divided into new unsold new generation, de-listing existing generation, demand response resources, and imports.[135] Clearing prices for new and existing resources at each location are shown in the top panel of the figure.

135 The figure does not show 100 MW of Administrative De-Listed capacity in each auction. Administrative De-Lists are used when a New England resource exports capacity to another control area.

Figure 29: FCM Auction Results for the System and External Interfaces
FCA 6 – FCA 8



From FCA 1 to FCA 7, ISO-NE cleared substantial capacity surpluses and prices cleared at the price floor. The external interfaces were generally utilized to import the maximum amount under the interface capabilities.

In FCA 8, qualified supply resources were reduced considerably by generation retirements that had been announced before the auction, and the Insufficient Competition Rule was invoked. Clearing prices increased dramatically for all resources. New resources cleared at a price of $15 per kW-month, while existing resources were paid $7.025 per kW-month in accordance with the Insufficient Competition Rule. The results from FCA 8 highlight several areas for improvement in the capacity market design.

First, the auction results reinforced the observation that the vertical demand curve tends to produce volatile prices as compared with a sloped demand curve. The sloped demand curve that was filed by the ISO will lead to more stable price expectations going forward, which will reduce the risks for new investors and provide better incentives for existing resource owners to maintain their resources.

Second, the outcome of FCA 8 also highlighted that the Insufficient Competition Rule does not set efficient prices for existing resources when additional resources are needed for reliability. In this case, existing resources provide comparable reliability benefits to new resources. Pricing rules that favor new resources over existing resources undermine incentives for efficient maintenance of existing resources and encourage older resources to retire sooner than would be efficient for satisfying resource adequacy needs. Furthermore, such rules favor imported capacity over internal resources, since import resources are more readily able to participate as new resources each year. Consequently, the share of resources that qualified as "new" and received the higher clearing price in FCA 8 included 0.1 percent of generation, 12 percent of demand response, and 93 percent of imports. This issue will be addressed with the elimination of the Insufficient Competition Rule along with the vertical demand curves.

Third, the small capacity margin in FCA 8 was driven by several significant Non-Price Retirement Delist Bids that occurred before the auction. Although such retirements can have substantial effects on clearing prices and overall costs for consumers, these retirements are not subject to any review under the market power mitigation rules. We have not evaluated the non-price retirements that occurred in FCA 8 and, therefore, have no evidence that would raise potential competitive concerns. Nonetheless, independent of these particular retirements, we find that the current market power mitigation rules are not adequate to ensure the capacity market outcomes are workably competitive. The conclusion of this section discusses our recommendation to address this issue.

C. Forward Capacity – Conclusions

The primary goal of deregulated wholesale markets is to facilitate market-based investment in new resources where the investment risks (and potential rewards) are borne by private firms rather than regulated investment where the risks are borne by captive consumers. Another goal of these markets is to facilitate the orderly departure of existing resources that are no longer economic to remain in service. This section discusses recent market outcomes that have led the

ISO to propose four significant enhancements to the FCM rules. It also discusses two additional recommendations for the ISO to consider.

Recent Proposed Market Rule Enhancements

For the first time, new investment in large-scale generation was motivated by the ISO's forward capacity market in FCA 7 in NEMA. However, it has also become apparent that the current pricing rules may undermine the incentives for efficient investment in new resources and maintenance of existing resources. The ISO has already implemented some enhancements and is working on additional reforms for future FCAs to address most of the issues discussed in this section. The ISO has taken steps to improve the FCM design in the following four areas.

First, the ISO began modeling the Connecticut and NEMA local capacity zones all the time in FCA 7. In previous auctions, not modeling local capacity zones led to out-of-market payments to maintain adequate local capacity levels and resulted in capacity prices that did not efficiently reflect the benefits of additional capacity for reliability. The ISO is planning to model additional local capacity zones, which will become more important as retirements necessitate new entry in order to satisfy local planning criteria in areas outside Connecticut and NEMA.[136]

Second, ISO New England has filed to create a system level sloped demand curve for use in FCA 9 and is preparing to create sloped demand curves for the local zones by FCA 10. The new sloped demand curves will provide more stable price expectations, reduce the risks for new investors, and provide better incentives for existing resource owners to keep them well-maintained.

Third, the Insufficient Competition Rule led to large differences between the prices for new resources and the prices for existing resources in the last two auctions. In FCA 7, new NEMA resources were paid 125 percent more than existing resources. In FCA 8, new resources in other locations were paid 114 percent more than existing resources. Generally, it is most efficient to

136 The Commission recently accepted an ISO proposal to model additional capacity zones whenever the excess reserve margin in a particular local region is smaller than the largest generating station in the region beginning in FCA 10. The rationale for this criterion is that if the station delisted in a particular FCA, it would be necessary to clear new capacity to satisfy the local capacity requirement. See *ISO New England Inc.*, 147 FERC ¶ 61,071 (2014), dated April 28, 2014.

pay new and existing resources at the same rate when they are providing the same service. This provides efficient incentives to govern retirement and maintenance decisions on existing resources. This issue will be addressed when the ISO implements the sloped demand curves.

Fourth, to address growing concerns regarding resource performance and its effects on reliability, ISO-NE and NEPOOL submitted proposals to strengthen the incentives for suppliers to perform reliably in January 2014. Both proposals focused on enhancements to real-time shortage pricing as the primary means to facilitate good performance, since shortage pricing channels more revenue towards resources with high levels of availability and reliability. We generally supported the ISO proposal but recommended two modifications: (i) that a lower Performance Payment Rate (PPR) be adopted and (ii) that the PPR have a slope that would distinguish between minor and major reserve shortages.[137] These changes would improve the ISO's proposal by providing real-time price signals that are more consistent with the marginal reliability value of resources during shortage conditions.

Other Recommended Enhancements

We have identified two additional areas in which market rule changes may be beneficial. The first area is related to the market power mitigation measures for existing capacity suppliers. The high clearing prices in FCA 7 and FCA 8 resulted from falling capacity margins in recent years. Capacity margins have fallen not because of peak demand growth, but because of retirements of older capacity. The recent price outcomes demonstrate that retirements can have profound effects on FCA clearing prices. In general, market power mitigation measures are necessary to ensure that the market based rates in wholesale electricity markets are just and reasonable. The current supply-side market power mitigation measures guard effectively against anticompetitive conduct by existing resources participating in the auction, but there are no provisions that guard against the use of Non-Price Retirement De-List Bids to withhold economic capacity resources to raise prices. Further, when the desire to retire emanates from an economic concern, there is no reason why such a concern should not be embodied in a delist bid. Hence, we recommend the

137 See Motion to Intervene Out of Time and Comments of ISO New England's External Market Monitor in Commission Docket ER14-1050, dated February 13, 2014.

ISO consider adopting appropriate eligibility rules for resources' use of the Non-Price Retirement De-List bid (i.e., that it be reserved for cases where the factor driving the decision to retire cannot reasonably be reflected in a de-list offer). This would allow the ISO's supply-side mitigation measures to be appropriately applied to most retirement decisions.

Second, the Capacity Commitment Period Election (i.e., "Lock-in") allows new generation and new demand response resources to elect to lock-in the auction clearing price for a period of up to five years. The ISO recently filed to increase the period to seven years in conjunction with the sloped demand curve. Although the extended lock-in is likely to achieve the purpose of increasing the incentives for new entry, it is likely to result in significant differences between the prices paid to existing resources and prices paid to new resources over the long-term. Paying systematically higher prices for new resources could lead to over-investment in new resources and under-investment in maintaining existing resources that are important for reliability. Also, in areas where the efficient scale of investment is in a larger resource, it could contribute to price volatility.

In its recent proposal, the ISO recognized these concerns stating: "The Commission and others have expressed concern that lock-in periods result in short-term price discrimination. We acknowledge this concern, but the perceived risks in the FCM are currently unnaturally high and reflect more than the normal volatility that the initial five-year lock-in period was designed to ameliorate…many investors say they perceive the New England market as being riskier than other markets." For this reason, the ISO has stated that it will "reevaluate the lock-in period after a series of successful auctions."[138] We support the ISO's intention to reconsider whether this the lock-in provision is necessary and beneficial in the future.

138 See filing by ISO-NE and NEPOOL in Commission Docket ER14-1639, dated April 1, 2014, Testimony of Robert G. Ethier at pages 32-36.

X. Competitive Assessment

This section evaluates the competitive performance of the ISO-NE wholesale markets in 2013. 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 limited generation resources or transmission capability. Most market power in wholesale electricity markets is dynamic, existing only in certain areas and under particular conditions. The ISO has market power mitigation measures that are employed to prevent suppliers from exercising market power under these conditions. Although these measures have generally been effective, it is still important to evaluate competitive structure and conduct in the ISO-NE markets because participants with market power may still have the incentive to exercise it at levels that would not warrant mitigation.

Based on the analysis presented in this section, 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 ISO-NE markets.[139]

We address five main areas in this section:

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

A summary of our conclusions regarding the overall competitiveness of the wholesale market is included at the end of this section.

139 See, e.g., Section VIII, "2012 Assessment of Electricity Markets in New England", Potomac Economics.

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 into 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 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 ability and 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.[140, 141] 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 such that when demand is high, a given quantity of withholding has a larger price impact because the supply is substantially less elastic in the higher cost ranges. Thus, large suppliers are more likely to possess market power during high demand periods than at other times.

140 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.

141 However, some incentive still exists because spot prices will eventually affect prices in the forward market.

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 subsection of the report examines structural 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 match demand in real time on a moment-to-moment basis. The lack of economic storage options limits inter-temporal substitution in spot 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) online and fast-start capacity available for deployment in the real-time spot market, and (ii) offline and slower-starting 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 online and fast-start capacity is available for deployment. The value of energy in all forward markets, including the day-ahead market, is derived from the expected 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 recognized as being historically 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:[142]

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

This subsection analyzes the six geographic areas listed above using the following structural market power indicators:

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

142 Lower SEMA was evaluated in prior reports, but is excluded from recent reports because the transmission constraints into the area was virtually eliminated since July 2009 when network upgrades were completed.

The findings from the structural market power analyses in this section are used to focus the analyses of potential economic and physical withholding in Subsections 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. The analysis in this subsection shows several categories of supply and import capability relative to the load in each of the six regions of interest.

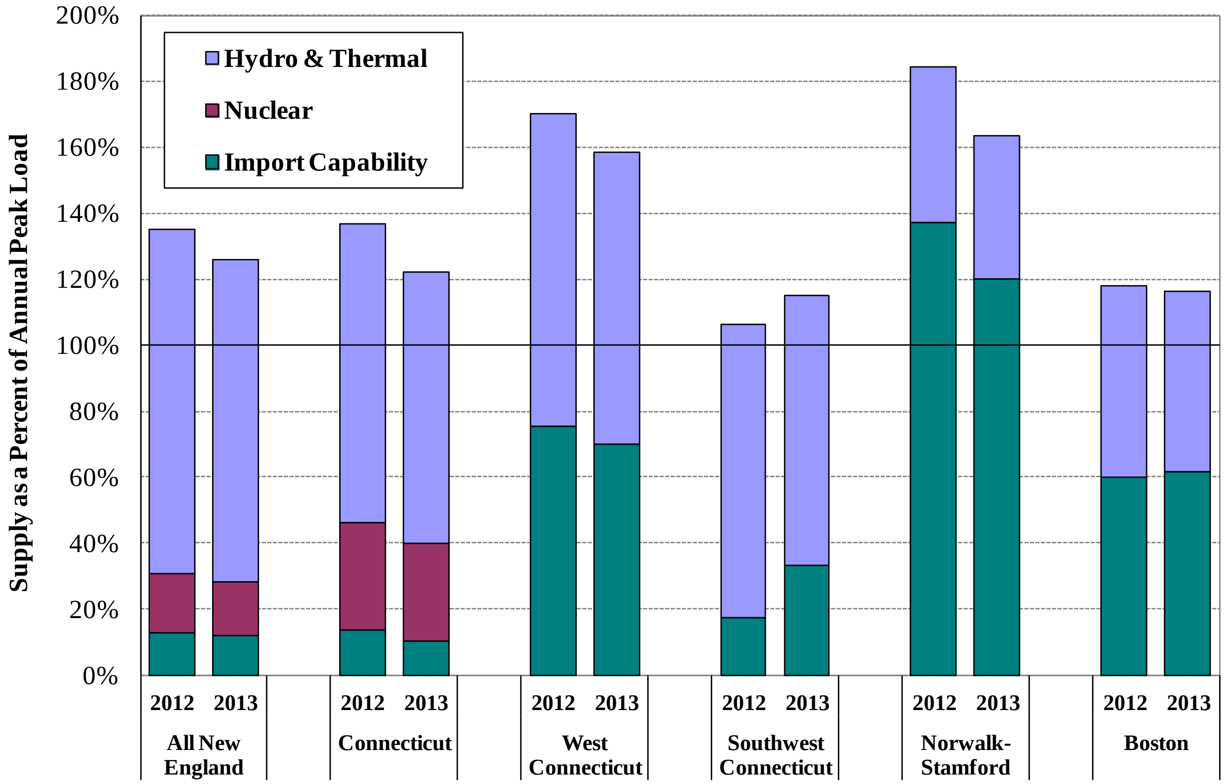
We differentiate between different types of supply because some types cannot feasibly be withheld to exercise market power. For convenience, the table below shows different categories of supply and provides comments regarding the feasibility of withholding them.

Table 4: Withholding by Type of Resource

Type of Resource	Comment
Nuclear	Nuclear resources pose fewer market power concerns than other types of resources because they typically cannot be dispatched down substantially. This limits their owner's ability to withhold once a unit is online. They also generally have the lowest marginal production costs making them costly to withhold.
Hydroelectric	Hydroelectric resources that can vary their output (i.e., reservoir and pump storage units) may be able to withhold. Smaller "run-of-river" hydroelectric facilities are generally more limited in their ability to change output level.
Fossil-Fired	Fossil-fired units have relatively wide dispatch ranges and marginal production costs that are closer to the prevailing LMP. Hence, they are generally the easiest and least costly resources to withhold.

Figure 30 shows import capability and two categories of installed summer capability for each region: nuclear units and all other generators in 2012 and 2013.[143] These supplies are shown as a percentage of 2012 and 2013 peak loads, respectively, although a substantial quantity of additional capacity is also necessary to maintain operating reserves in New England.[144] The figure shows that while imports from neighboring control areas can be used to satisfy 12 to 13 percent of the load in the New England area under peak conditions in 2012 and 2013, the five 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 100 percent of its load under peak conditions in both 2012 and 2013. This effectively eliminates it as an area of significant market power concern.

Figure 30: Supply Resources versus Summer Peak Load in Each Region
2012 – 2013



143 The import capability shown for each load pocket is the transfer capability during the peak load hour, reduced to account for local reserve requirements.

144 Roughly 2,050 to 2,100 MW of additional capacity was needed to maintain operating reserves in New England prior to July 23, 2012. After that, close to 2,500 MW of additional capacity was needed (due to the increase of 10-minute reserve requirement).

Figure 30 shows that the internal supply as a share of peak load fell modestly from 2012 to 2013 in all regions. This is because the summer peak load rose 6 percent from 2012 to 2013, while there were very few changes to the supply of internal resources in these regions. The amount of import capability into each region did not change significantly from 2012 to 2013.[145] The variations in import capability were primarily attributable to the differences in network topology (e.g., line outages), generation patterns, and load patterns during the peak load hours in the two years.

Therefore, supply conditions were generally consistent in most areas from 2012 to 2013. Figure 30 also shows the margin between peak load and the total available supply from imports and native resources. In 2013, the total supply exceeded peak load in each region, ranging from 15 percent in Southwest Connecticut to 64 percent in Norwalk Stamford. Areas with lower margins may be more susceptible to withholding than other areas.

3. Market Shares and Market Concentration

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 31 shows the market shares of the largest three suppliers in the annual peak load hours in 2012 (on July 17) and in 2013 (on July 19). 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 tends to understate the true level of concentration, because, in reality, the market outside of the area is not perfectly competitive, and because suppliers inside the area may be affiliated with resources in the market outside of the area.

145 The transmission system in New England has evolved significantly over the past decade, particularly from 2006 to 2009 when several major transmission upgrades were completed in the historically constrained areas such as Boston, Connecticut, and Lower SEMA. These upgrades significantly improved the transmission system infrastructure and increased the transfer capability into affected regions.

Figure 31: Installed Capacity Market Shares for Three Largest Suppliers [146]
July 17, 2012 and July 19, 2013

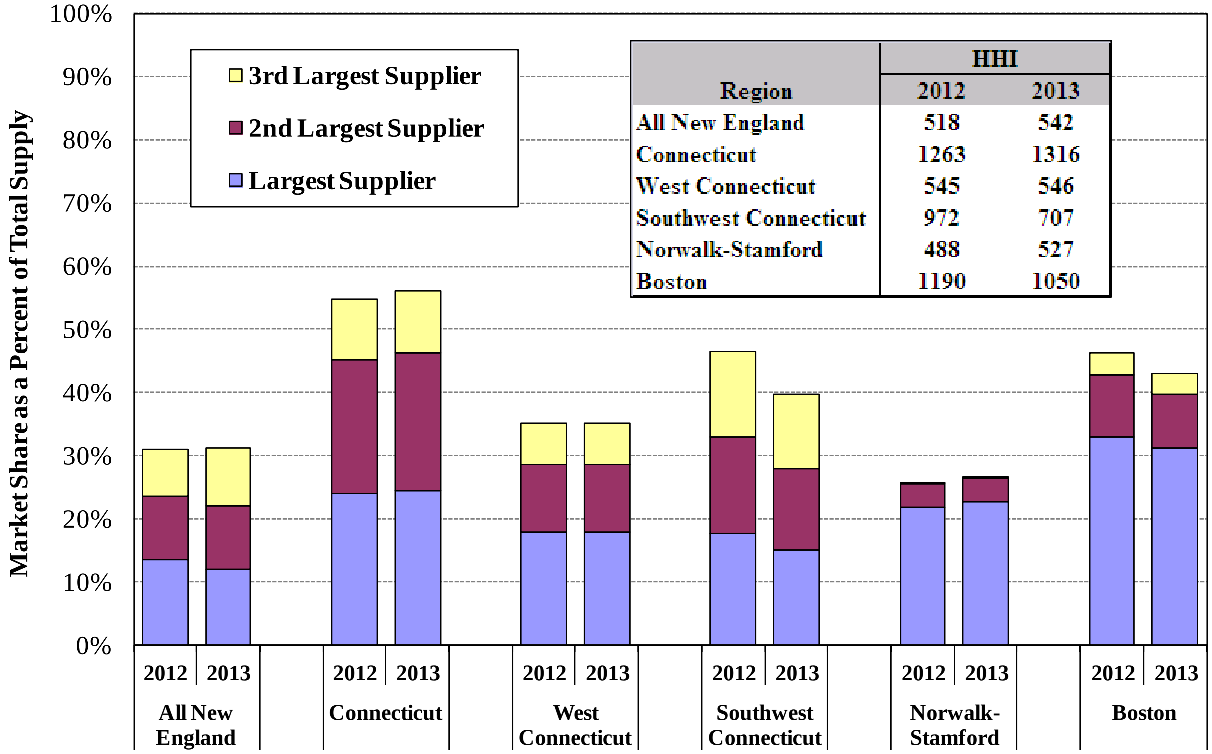


Figure 31 indicates a substantial variation in market concentration across New England. In all New England, the largest supplier had a 12 percent market share in 2013. In the load pockets, the largest suppliers had market shares ranging from 15 percent in Southwest Connecticut to 31 percent in Boston in 2013. Likewise, there is variation in the number of suppliers that have significant market shares. For instance, Norwalk-Stamford had just two native suppliers with very different market shares in 2013, while Southwest Connecticut had three native suppliers with more comparable market shares.

The figure shows that market shares of the largest three suppliers in New England did not change significantly from 2012 to 2013, although the identity of the largest three suppliers changed.[147,]

146 The market shares of individual firms are based primarily on the Lead Participant that is identified in the 2013 CELT Report.

147 The merger of NRG and Genon made the new company one of the top three suppliers in New England. This occurred at the end of 2012.

[148] Otherwise, there were very few changes to the supply of internal resources in each region, and the import capability into each region remained similar. The modest differences in market shares on the peak load day between 2012 and 2013 in some of the local areas were generally attributable to the variations in the import capability associated with differences in network topology, generation patterns, and load patterns on the two days.

The HHI figures suggest that no areas in New England were highly concentrated in 2013.[149] The HHI for Norwalk-Stamford is 527, which is low for most product markets. This is counter-intuitive since there are only two major suppliers in the area. However, because its load can be entirely served by imports, the need for local suppliers is very limited. Of the remaining areas, Connecticut and Boston had the highest HHI statistics in 2013, with 1316 and 1050, respectively.

4. 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.[150] 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 in large volumes, production needs to match demand in real time on a moment-to-moment 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.

---

148 Dominion reduced its portfolio by 1,500 MW by selling the Brayton Point power plant to Energy Capital Partners in August 2013. However, Dominion was still one of the largest three suppliers in New England.

149 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.

150 The DOJ and FTC evaluate the change in HHI as part of their 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. Also, the HHI analysis employed by the antitrust agencies is not intended to determine whether a supplier has market power.

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 capacity of some of its resources is needed to meet demand and reserve requirements in the market. A pivotal supplier has the ability to unilaterally raise the spot market prices to very high levels by offering its energy at a very high price level. Hence, the market may be subject to substantial market power abuse when one or more suppliers are pivotal and 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.[151] This section of the report identifies the frequency with which one or more suppliers were pivotal in various areas within New England.

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.

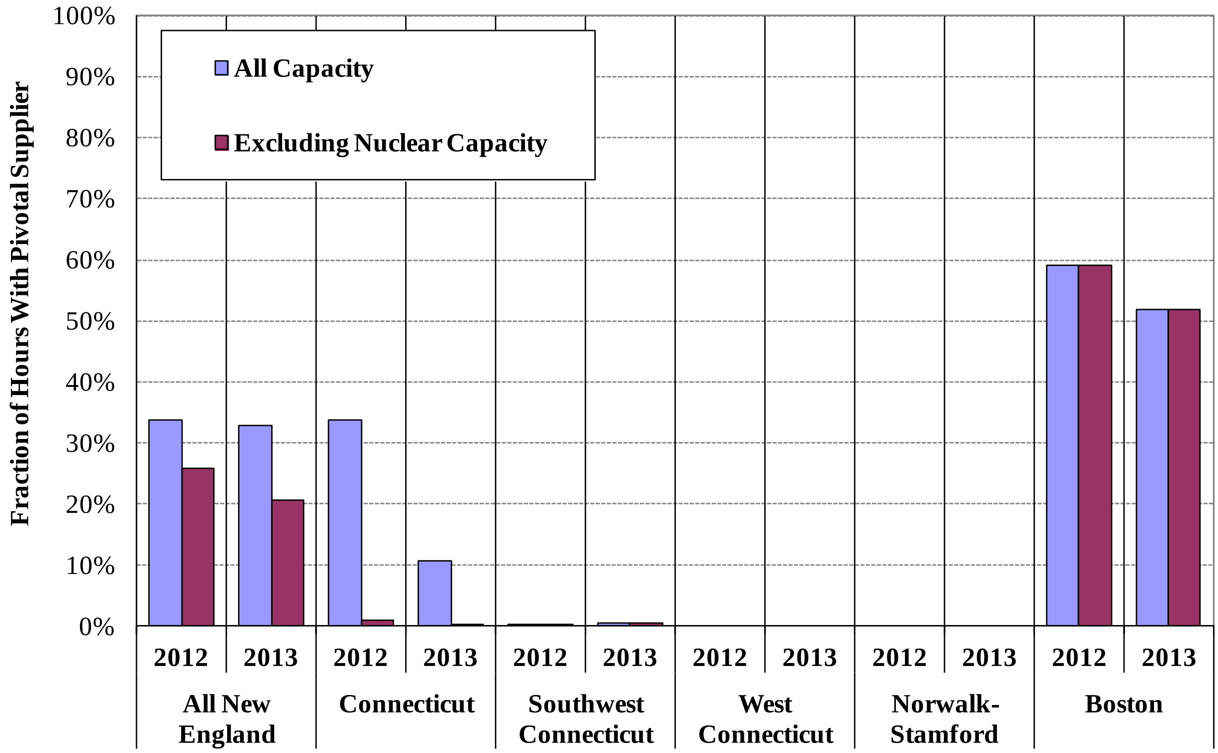
To identify the areas where market power is a potential concern most frequently, Figure 32 shows the portion of hours where at least one supplier was pivotal in each region during 2012 and 2013.[152] The figure also shows the impact of excluding nuclear units. As discussed above, owners of nuclear units are less likely to engage in economic or physical withholding.

---

151 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.

152 The IMM also does a pivotal supplier assessment in its Annual Market Report. Compared with our assessment, the IMM's pivotal supplier assessment produces lower frequencies of one or more pivotal supplier due to differences in the underlying objectives of each assessment. Our analysis is a real-time test, focusing on capacity that is online (i.e., committed) or capable of starting within 30 minutes (i.e., available offline quick-start) in the real-time market, since this indicates when a single supplier could cause a shortage by withholding in the real-time market. The IMM's assessment includes capacity that is available to the day-ahead market, including longer lead time units, since this assessment is used in the execution of the market power mitigation measures for the day-ahead market,

Figure 32: Frequency of One or More Pivotal Suppliers by Type of Withheld Capacity
2012 – 2013



Including all categories of capacity, the pivotal supplier analysis raises potential concerns regarding three of the six areas shown in Figure 32. The areas that do not raise potential concerns are Norwalk-Stamford, Southwest Connecticut, and West Connecticut, where imports typically serve a large share of load and the ownership of internal capacity is much less concentrated than the other load pockets.

The figure shows that potential local market power concerns were most acute in Boston, where one supplier owns nearly 70 percent of the internal capacity in 2013 and was pivotal in over 50 percent of hours. In addition, none of the capacity in Boston was nuclear capacity.

Although Connecticut had a pivotal supplier in 11 percent of hours in 2013 and 34 percent of hours in 2012, the largest supplier in Connecticut owns only nuclear capacity. In order to exercise market power, the largest supplier would need to withhold from non-nuclear resources in order to raise the clearing prices paid for its nuclear production. Therefore, it is appropriate to exclude the nuclear capacity from the pivotal supplier frequency for Connecticut. This leaves very few hours (< 1 percent) when a supplier was pivotal in Connecticut in the past two years.

For the entirety of New England, excluding nuclear capacity from the pivotal supplier analysis would reduce the pivotal frequency (from 33 percent to 21 percent of hours in 2013 and from 34 percent to 26 percent of hours in 2012). 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 frequency declined (but with varying degrees) in all areas from 2012 to 2013. The reduction was attributable to several factors:

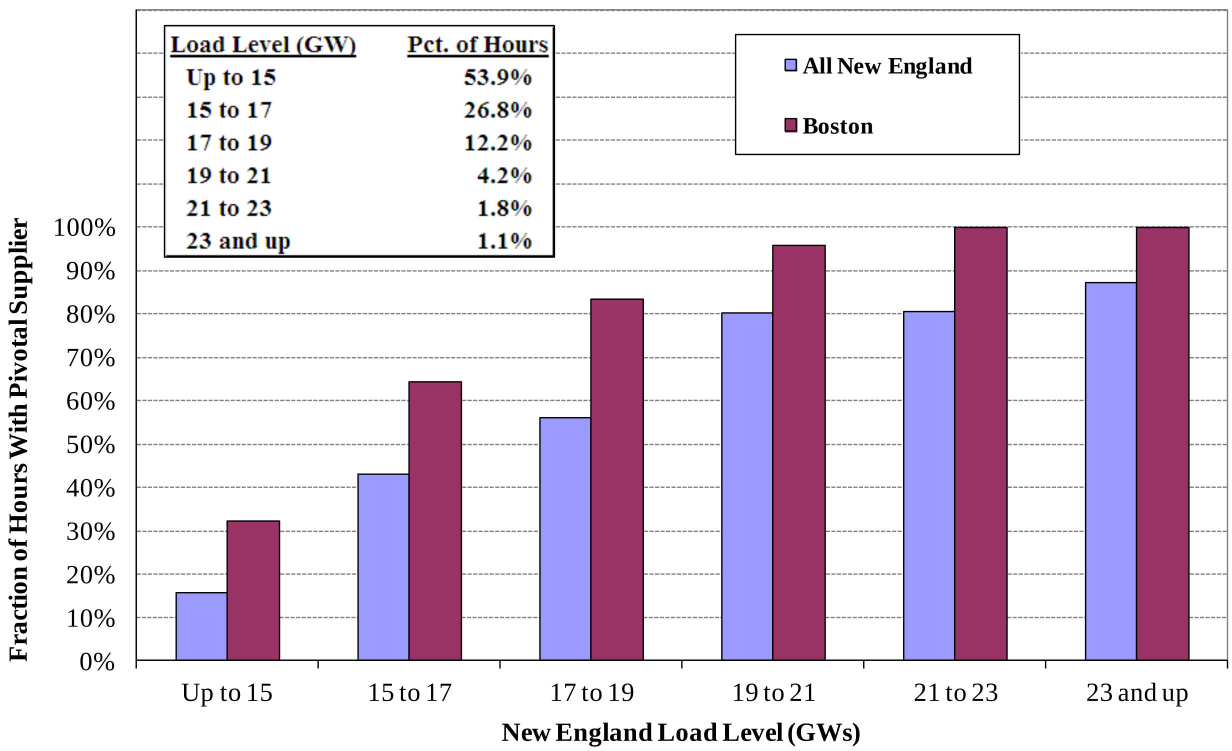
- In all of New England, the size of the largest supplier decreased by several hundred MW in mid-2013, since the supplier that previously had the largest portfolio sold 1,500 MW of its generating capacity to another firm. As a result, a different firm became the largest supplier in New England.
- Net imports from neighboring areas rose substantially in 2013, which offset the increase in load levels. From 2012 to 2013, average net imports rose more than 700 MW, while average load rose only about 200 MW. So, internal resources in New England served less demand on average in 2013 than in 2012.
- Coal-fired capacity was economically committed more frequently in 2013 because of higher natural gas prices, and this coal-fired capacity was not held by the largest suppliers in 2013. The largest supplier in Boston and Connecticut do not have coal-fired generators, while the largest supplier in all of New England sold its coal-fired capacity to in mid-2013.
- However, these factors were offset by increased peak load conditions and increased system-wide 30-minute reserve requirements in 2013. The 30-minute reserve requirement was raised: a) in July 2012 to conform with the increased 10-minute reserve requirement; and b) in October 2013 to reflect the procurement of replacement reserves.

These changes led top suppliers to have lower shares of real-time dispatchable capacity (i.e., online and offline fast-start capacity) and consequently to be pivotal less frequently in 2013.

The pivotal supplier summary in Figure 32 indicates the greatest potential for market power in Boston. A close examination is also warranted for all of New England, while Connecticut raises less concern. Each area had a single supplier that was most likely to have market power. Accordingly, Sections C and D closely examine the behavior of the largest single supplier by geographic market.

As described above, market power tends to be more prevalent as the level of demand rises. In order to strategically withhold, a dominant supplier must be able to reasonably foresee its opportunities to raise prices. Since load levels are relatively predictable, a supplier with market power could focus its withholding strategy on periods of high demand. To assess when withholding is most likely to be profitable, Figure 33 shows the fraction of hours when a supplier is pivotal at various load levels. The bars in each load range show the fraction of hours when a supplier was pivotal in All of New England and Boston. West Connecticut, Southwest Connecticut, and Norwalk-Stamford are not shown because there were very few instances of a supplier being pivotal during 2013. Connecticut is not shown because the largest pivotal supplier had exclusively nuclear capacity, which is not expected to provide that supplier with an incentive to withhold.

Figure 33: Frequency of One or More Pivotal Suppliers by Load Level
2013



The figure shows that a supplier in Boston was pivotal in at least 64 percent of hours when the load exceeded 15 GW in New England. In all of New England, the largest supplier was pivotal in at least 40 percent of the hours when load exceeded 15 GW. The pivotal frequency fell to 32 percent in Boston and 16 percent in all of New England during hours when load was below 15 GW in New England.

In 2013, based on the pivotal supplier analysis in this subsection, market power was most likely to be a concern in Boston and all of New England when load exceeded 15 GW. However, 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 reality, there would likely 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 Monitor calculates generator cost reference levels pursuant to Appendix 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 IMM 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 real-time market outcomes for fast-start units and day-ahead market outcomes for slower-starting 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 we use is:

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

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

By using the greater of actual production or the output level offered at the clearing price, 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 hydroelectric 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. They attempt to do this by raising their offer prices so their units will be dispatched only during the highest-priced periods of the day. However, the owners of such units submit offers prior to 2 pm on the previous day based on their expectations of market conditions. 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 that would indicate significant attempts to exercise market power.

We have observed that some units that expect to be committed for local reliability and receive NCPC payments also produce above average output gap. One explanation is that these units raise their offers in anticipation of receiving higher NCPC payments and are not dispatched as a result. Such instances are flagged as output gap, even though the suppliers are not withholding in an effort to raise LMPs.

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 subsection, 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 separately in Boston and all of New England. Our analyses apply the most stringent thresholds that are used in the current market power mitigation measures, which are: a) the lower of $25 per MWh or 50 percent over the reference level for the energy offer; and b) 25 percent over the reference level for the no-load and startup offers.

2. Output Gap in Boston

The pivotal supplier analysis raises concerns regarding the potential exercise of market power in Boston where one supplier owns the majority of capacity. Figure 34 shows output gap results for Boston by load level. Output gap statistics are shown as the percentage of the portfolio size for the largest supplier compared with all other suppliers in the area. Based on the pivotal supplier analysis in the previous subsection, the largest supplier can expect that its capacity will be pivotal in most hours when load exceeds 15 GW.

Figure 34: Average Output Gap by Load Level and Type of Supplier
Boston, 2013

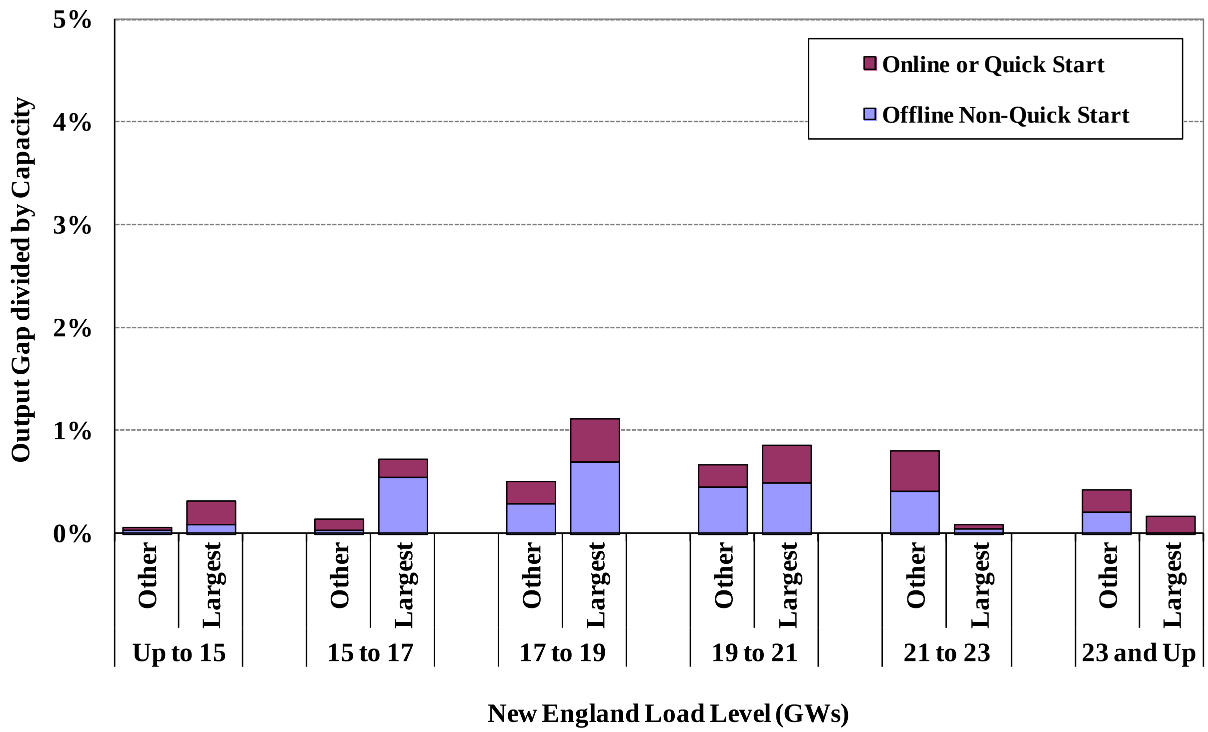


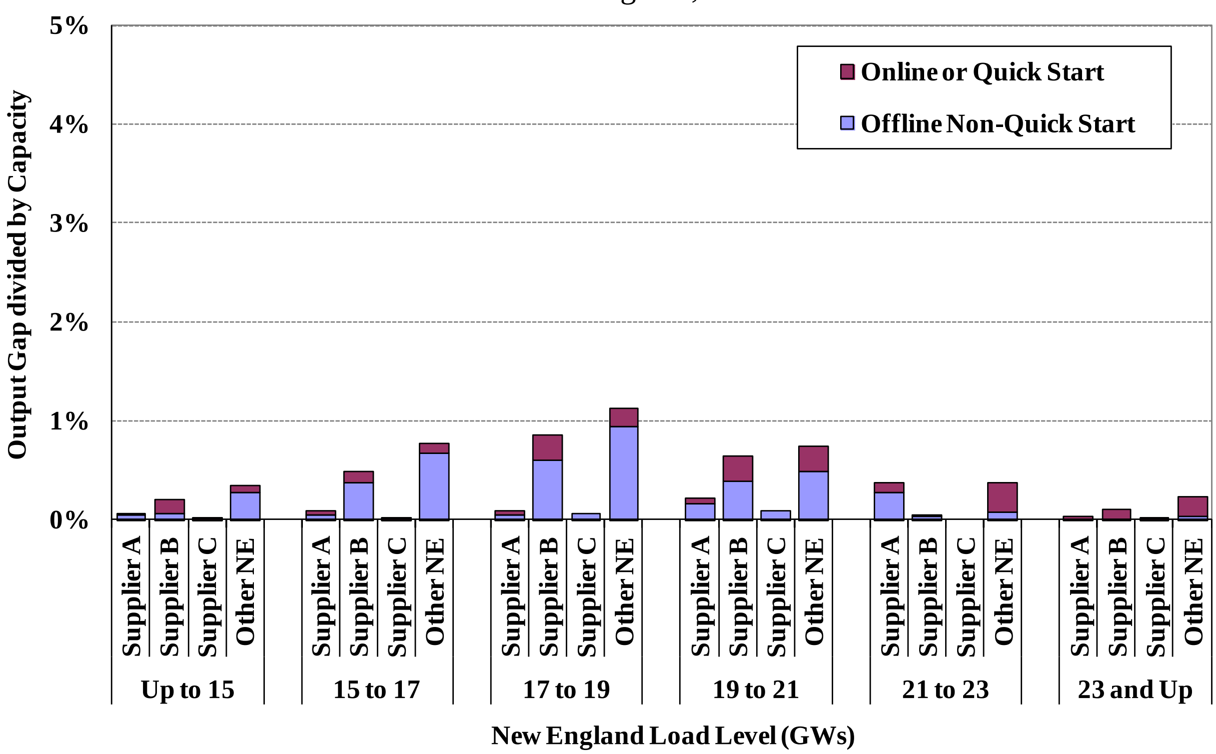
Figure 34 shows that the overall amount of output gap for the largest supplier in Boston was small as a share of its total capacity in 2013, less than 1 percent in the majority of hours. In particular, the amount of output gap for the largest supplier was very low when the load exceeded 21 GW. This is a positive indication that the largest supplier, which accounts for nearly 70 percent of generating capacity in Boston, did not economically withhold its capacity when the need for its capacity was the greatest.

Nonetheless, the amount of output gap rose modestly when load was between 17 and 21 GW. The increase occurred mostly in the winter months for at least two reasons. First, natural gas prices were very high in the winter months, which made the $25 per MWh threshold much tighter as a percentage of LMP levels. Second, the output gap assumes the lower-cost fuel is used by dual-fuel units. Some of these units must sometimes must burn the higher-cost fuel (e.g., units might still burn gas on high-gas-price days due to low oil inventory). The increase in output gap was not a significant concern given that the ISO has an automated mitigation process in place and participants have used the consultation process more frequently to update the fuel cost used in the reference levels in order to avoid inappropriate mitigation. In summary, these results do not raise significant competitive concerns.

3. Output Gap in All New England

Figure 35 summarizes output gap results for all of New England by load level for four categories of supply. Suppliers A, B, and C have the largest portfolios in New England. All other suppliers are shown as a group for reference. In 2013, at least one top supplier was pivotal in 33 percent of the hours and at least three top suppliers were pivotal in 9 percent of the hours.

Figure 35: Average Output Gap by Load Level and Type of Supplier
All New England, 2013



The figure shows that the region-wide output gap was generally low for each of the four categories of supply. The largest three suppliers in New England exhibited small output gap levels (< 1 percent of their portfolio sizes) under all load conditions in 2013, especially at high loads when withholding is most likely to occur and be profitable. Although the amount of output gap rose modestly in the middle load range, it was not a significant concern for the reasons discussed earlier. Additionally, the output gap levels for the three largest suppliers were lower than the output gap levels of all other suppliers, which serve as a benchmark for conduct of smaller suppliers that are much less likely to have market power. Therefore, economic withholding was not a significant concern in New England in 2013.

D. Physical Withholding

This section of the report examines declarations of forced outages and other non-planned deratings to determine if there is any evidence that the suppliers are exercising market power. In this analysis, we evaluate the two geographic markets examined in the output gap analysis above: Boston and all of New England.

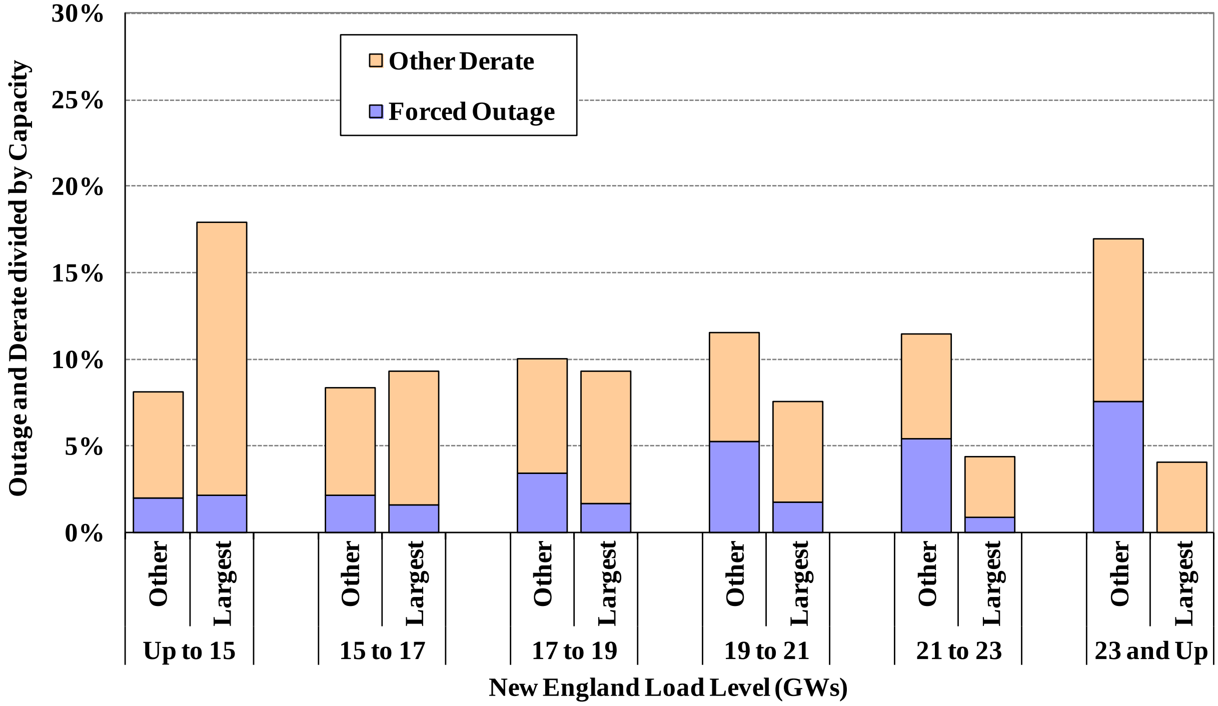
In each market, we examine forced outages and other deratings by load level. The "Other Derate" category includes any reduction in the hourly capability of a unit from its maximum seasonal capability that is not logged as a forced outage or a planned outage. These deratings can be the result of ambient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

1. Potential Physical Withholding in Boston

Figure 36 shows declarations of forced outages and other non-planned 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 15 GW. We compare these statistics for the largest supplier to all other suppliers in the area. The figure shows the supplier's physical deratings as a percentage of its portfolio.

Figure 36 shows that the rate of other non-planned outages ('Other Derate' Category) of the largest supplier in Boston was high at low load levels in 2013, especially when load was less than 15 GW. This was primarily driven by units that were frequently online in special operating modes (where a portion of the capacity is not available) in early morning hours. Under low load conditions, this operating practice does not raise competitive concerns and is consistent with competitive conduct.

Figure 36: Forced Outages and Deratings by Load Level and Supplier
Boston, 2013



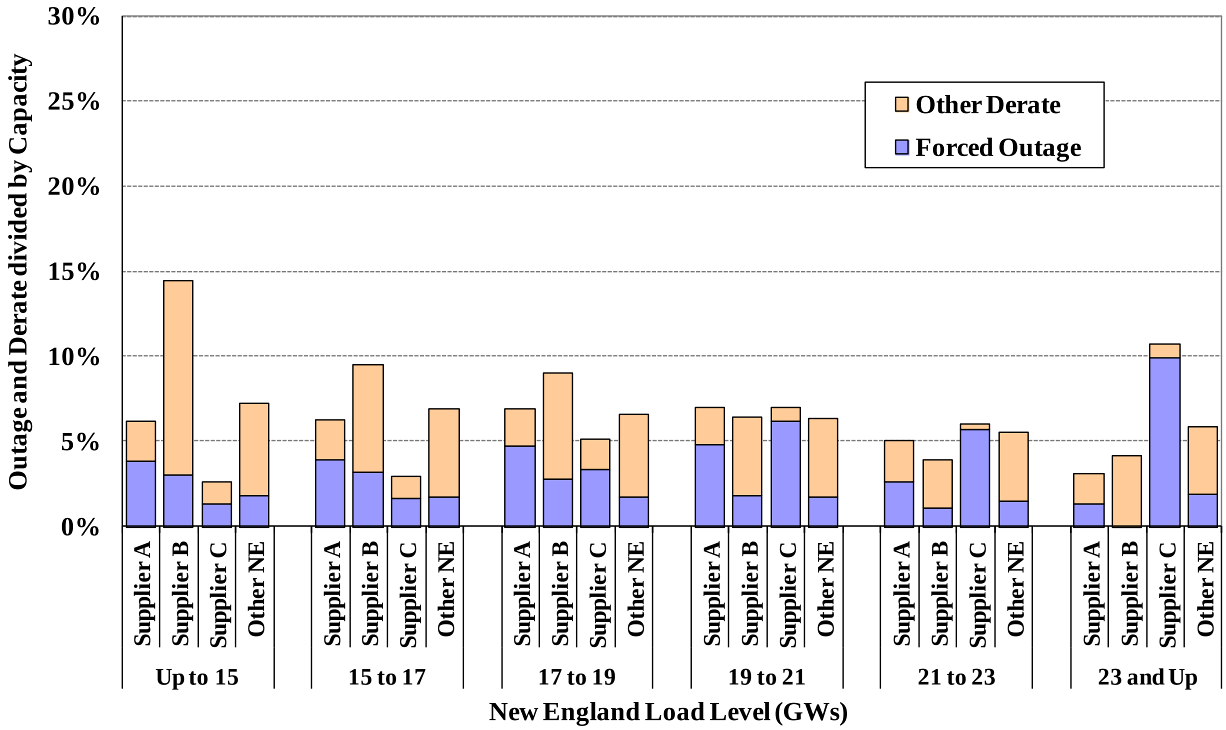
The largest supplier exhibited a pattern of deratings and outages that is generally consistent with expectations in a competitive market. Although levels of outages and deratings for the largest supplier were high at low load levels, they were lower than other suppliers when load exceeded 15 GW (when withholding is most likely to be profitable). Furthermore, the largest supplier showed a relatively low level of outages and deratings as load increased to the highest load levels.

However, the amount of outages and deratings for other suppliers rose at high load levels. The increase was associated with older steam turbine capacity that experienced outages on high load days. This capacity ran more frequently under peak demand conditions, increasing the probability of being on outage during the higher load portion of the year. Given the higher utilization of these resources during the high demand portion of the year, the increased frequency is reasonable. The overall results of outage and deratings for Boston do not raise concerns of strategic withholding in 2013.

2. Potential Physical Withholding in All New England

Figure 37 summarizes the physical withholding analysis for all of New England by load level in 2013. The results of this analysis are shown for four groups of supply. Suppliers A, B, and C have the largest portfolios in New England. All other suppliers are shown as a group for comparison purposes. In 2013, the largest supplier was pivotal in 33 percent of the hours and the three top suppliers were all pivotal in 9 percent of the hours.

Figure 37: Forced Outages and Deratings by Load Level and Supplier
All New England, 2013



Supplier A exhibited rates of forced outages and other non-planned deratings that were moderate under all load conditions. Supplier B exhibited rates of forced outages and other non-planned deratings that were comparable to other New England suppliers when loads exceeded 17 GW, but were substantially higher at lower load levels, especially when load was less than 15 GW. Supplier B is also the largest supplier in Boston, so the pattern for Supplier B was explained earlier by factors that do not raise competitive concerns. Supplier C exhibited a small rate of forced outages and other non-planned deratings when load was below 23 GW but an increased rate of forced outages rose as load increased to the highest level. The increase was associated with older steam turbine capacity that had more frequent forced outages during the hottest days of year as a result of higher utilization. As a group, the other New England suppliers' derating levels generally decreased as load levels increased.

These results generally suggest that New England suppliers increased the availability of their resources under peak demand conditions 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. Market Power Mitigation

Mitigation measures are intended to mitigate abuses of market power while minimizing interference with the market when the market is workably competitive. The ISO-NE applies a conduct-impact test that can result in mitigation of a participant's supply offers (i.e., incremental energy offers, start-up and no-load offers). The mitigation measures are only imposed when suppliers' conduct exceeds well-defined conduct thresholds and when the effect of that conduct on market outcomes exceeds well-defined market impact thresholds. This framework prevents mitigation when it is not necessary to address market power, while allowing high prices during legitimate periods of shortage. The mitigation measures are designed to allow prices to rise efficiently to reflect legitimate supply shortages while effectively mitigating inflated prices associated with artificial shortages that result from economic withholding, particularly in transmission constrained areas.

When a transmission constraint is binding, one or more suppliers may be in the position to exercise market power due to the lack of competitive alternatives in the constrained area. For this reason, more restrictive conduct and impact thresholds are used for import-constrained areas. The ISO has two structural tests (i.e., Pivotal Supplier Test and Constrained Area Test) to determine which mitigation thresholds are applied to a supply offer in the following five categories:[153]

- Market-Wide Energy Mitigation ("ME") – ME mitigation is applied to any resource that is in the portfolio of a pivotal Market Participant. The conduct test is applied to all offer blocks that are greater than $25 per MWh and uses a threshold of the lower of $100 per MWh or 300 percent over the reference level. The impact test uses a slightly different threshold, which is the lower of $100 per MWh or 200 percent of the LMP.
- Market-Wide Commitment Mitigation ("MC") – MC mitigation is applied to any resource whose Market Participant is determined to be a pivotal supplier. The conduct test is applied to all individual start-up (including cold, intermediate, and hot starts) and no-load offers and has a threshold of 200 percent over the reference level.
- Constrained Area Energy Mitigation ("CAE") – CAE mitigation is applied to a resource that is determined to be within a constrained area. The conduct test is applied to all offer blocks and has a threshold of the lower of $25 per MWh or 50 percent over the reference level. The impact test uses the same threshold relative to the LMP.
- Constrained Area Commitment Mitigation ("CAC") – CAC mitigation is applied to a resource that is determined to be within a constrained area. The conduct test is applied to all individual start-up and no-load offers and has a threshold of 25 percent over the reference level.
- Local Reliability Commitment Mitigation ("RC") – RC mitigation is applied to a resource that is committed or kept online for local reliability. [154] The conduct test is applied to all individual start-up and no-load offers and has a threshold of 10 percent or $80 per MWh over the low-load commitment reference level. [155]

There are no impact tests for the three types of commitment mitigation (i.e., MC, CAC, and RC), so suppliers are mitigated if they merely fail the conduct test in these three categories. On the other hand, for the other two categories (i.e., ME and CAE), suppliers are mitigated only if they fail both the conduct and impact tests. Once a generator is mitigated, all the financial parameters of the supply offer (i.e., including all energy offer blocks, all types of start-up, and no-load offers) are set to their reference levels from the time when the mitigation decision is made until the end of the day or the end of the minimum run time, whichever is greater.

---

153 See Market Rule 1 Appendix A Section III.A.5.2 for more details of these two structural tests.

154 This includes local first or second contingency protection, voltage support, or special constraint resource service.

155 The low-load commitment reference level is based on the start-up See Market Rule 1 Appendix A Section III.A.5.5.5 for more details of the calculation of the low load commitment reference and the formulation of the conduct threshold.

The ISO preformed mitigation manually until April 2012 when the real-time mitigation process was automated and incorporated into the market software.[156] The automated mitigation process (AMP) allows for a more timely and accurate assessment of the estimated price impact of offers that violate the conduct test in real-time for the following reasons:

- Before the mitigation process was automated, only resources that were "on the margin" and setting the LMP were identified as candidates for mitigation.[157] After automation, all suppliers failing the conduct test and affecting prices by more than the impact threshold are mitigated, even if they are extra-marginal.
- Before automation, a consultation between the resource and the ISO was required before making mitigation decisions. In some cases, the resource was no longer marginal when the consultation process was complete, so mitigation would not be implemented. After automation, consultation must occur before the hour.

Under the new automated-mitigation rules, the mitigation is effective without delay. The automated new process uses a parallel dispatch model to measure the price impact of supply offers that fail conduct, which is a great improvement from the usage of an overly-simplified model in the manual process.[158]

Since there is no manual review of offers and reference levels before mitigation is imposed, it is more important to ensure that the inputs to mitigation, especially the generators' cost reference levels, are complete and accurate when the process is automated. This can be challenging for generators that have opportunity costs that change from day-to-day. Hydroelectric units may have sufficient storage capacity for a limited number of run hours over a given period of time, natural gas-fired units may have quantity limitations related to its nominations and/or directions from the pipeline, and coal-fired and oil-fired units may have limited fuel inventories on site. It is important for the owners of such units to proactively request reference level adjustments to reflect the opportunity costs that result from such limitations.

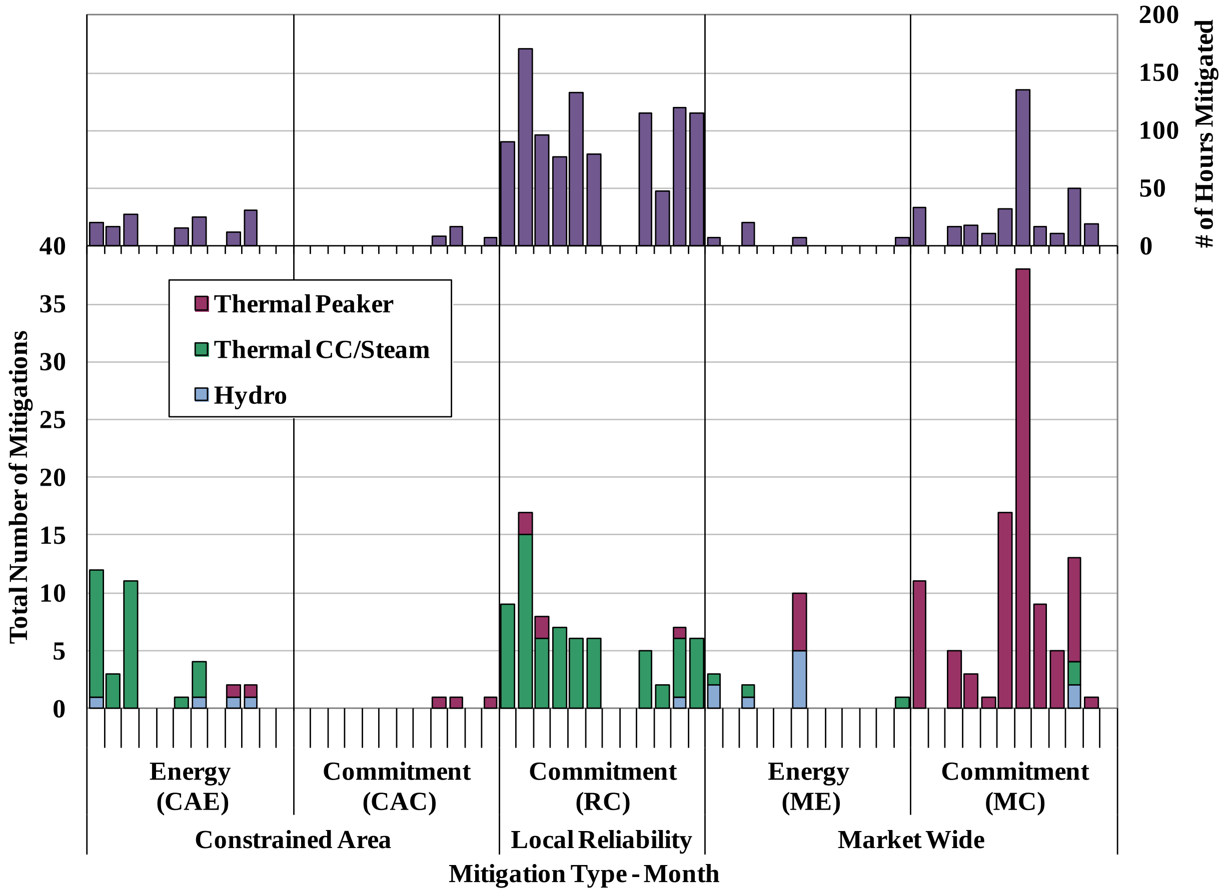
156 The day-ahead mitigation is still a manual process.

157 Hence, a $50 resource that caused an increase in the LMP from $75 to $150 by offering $500 would not be mitigated before April 2012.

158 The parallel dispatch model (SSPD) uses the same inputs and the same network model as in the actual dispatch model (UDS), except that UDS uses original supply offers while SSPD uses references to replace the supply offers that fail conduct. The LMPs calculated in SSPD are compared with the LMPs from UDS. If the difference exceeds the applicable impact threshold, the supply offer is mitigated.

The following analyses examine the frequency and quantity of mitigation in the real-time energy market under the automated process. Figure 38 shows the frequency of automated mitigation for each type of mitigation in 2013 on a monthly basis. Any mitigation changes made after the automated mitigation process were not included in this analysis. The lower portion of the figure shows the total number of mitigations that occurred in each month on three categories of resources: (a) hydroelectric units; (b) thermal peaking units; and (c) thermal combined cycle and steam units. The upper portion of the figure shows the total number of hours in each month that were affected by each type of mitigation. If multiple resources were mitigated during the same hour, only one hour was counted in the figure.

Figure 38: Frequency of Real-Time Mitigation by Mitigation Type and Unit Type
2013

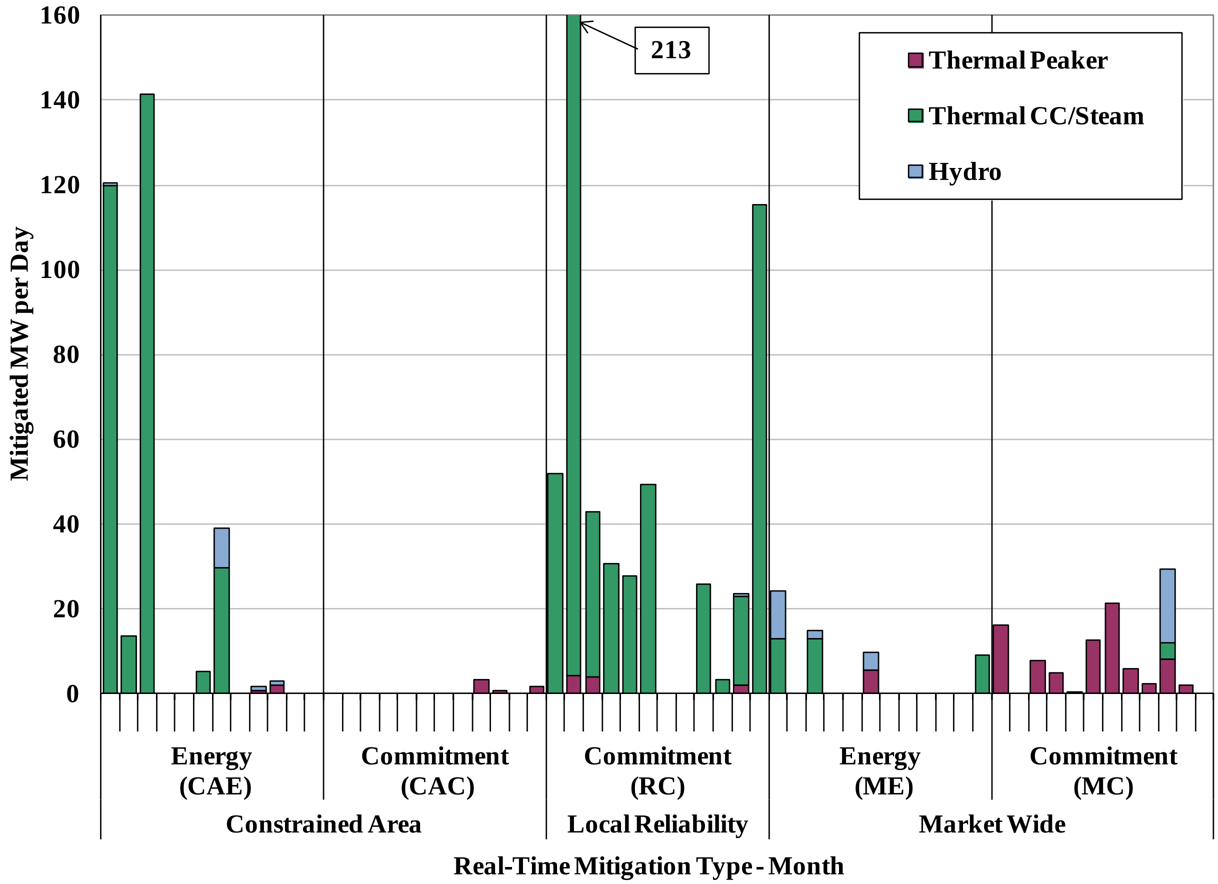


The figure shows that real-time mitigation occurred 230 times under the automated process during 2013. Commitment mitigation (i.e., CAC, MC, and RC) accounted for 78 percent of all mitigation while energy mitigation (i.e., CAE and ME) accounted for the remaining 22 percent.

In all commitment mitigations, non-peaking thermal resources (i.e., fossil-fueled combined cycle units and steam units) accounted for 93 percent of local reliability commitment mitigations, while thermal peaking resources (i.e., gas turbines) accounted for 96 percent of other commitment mitigations (i.e., CAC and MC).

Figure 39 shows the quantity of automated mitigation for each type of mitigation in 2013 on a monthly basis. The figure shows the average amount of capacity that was mitigated each day separately for hydroelectric resources, thermal peakers, and other thermal generating resources.

Figure 39: Quantity of Real-Time Mitigation by Mitigation Type and Unit Type
2013



Local reliability commitment mitigation (i.e., RC) accounted for the largest share (55 percent) of capacity that was mitigated in 2013. However, these generally affect NCPC uplift charges rather than LMPs. Constrained area energy mitigation (i.e., CAE) was the second largest mitigation category, accounting for 30 percent of total mitigated capacity in 2013. On average, roughly 90

MW of capacity was mitigated each day in 2013, of which 86 percent was for thermal non-peaking resources, 10 percent was for thermal peaking resources, and the remaining 4 percent was for hydroelectric resources.

The frequency of mitigation of hydroelectric resources became much less frequent from 2012 to 2013. Most hydroelectric resources, and energy-limited resources in general, typically formulate offers that will enable them to produce output when it is valuable to the system (normally peak hours) and consequently most profitable. Since intra-day offers are not currently allowed, when one offer curve is mitigated it remains mitigated for the rest of the day. Therefore, if a mitigation of a hydroelectric resource occurs during the early morning hours, it can potentially lead the resource to generate more than intended during off-peak hours. The mitigation of these resources became less frequent because of improvements in the recognition of the opportunity costs that result from their energy limitations.

Mitigation of thermal units was more frequent during the cold weather months of January to March and December when natural gas prices were relatively volatile. This occurred for two reasons. First, volatile natural gas prices create uncertainty regarding fuel costs that can be difficult to reflect accurately in offers and reference levels. The uncertainty is increased by the fact that offers and reference levels must be determined by 6 pm on the day before the operating day. Consequently, competitive offers may be mitigated when these uncertainties are larger than the applicable conduct thresholds. Hence, one benefit of the project to allow generators to submit hourly offers is that it will reduce the frequency of inappropriate mitigation of competitive offers.

Second, oil-fired generation becomes economic when the gas prices rise above oil prices. However, if an oil-fired generator has limited on-site inventory, it is efficient for the generator to conserve the available oil in order to produce during the hours with the highest LMP. Accordingly, it is competitive for such generators to raise their offer prices to reflect these opportunity costs when it would be more economic to run in other hours. Hence, it is important to allow reference level adjustments to reflect these costs whenever they are legitimate.

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 2013. The pivotal supplier analysis suggests that market power concerns exist in several areas in New England. However, the abuse of this market power is addressed by the ISO-NE's market power mitigation measures, which limits the ability of a generator to offer above competitive levels when would doing so would have a substantial impact on LMPs in an import-constrained area.

The new automated mitigation process helps ensure the competitiveness of market outcomes by mitigating attempts to exercise market power in the real-time market software. To ensure competitive offers are not mitigated, it is important for generators to proactively request reference level adjustments when they experience input cost variations due to fuel price volatility and/or fuel quantity limitations. It can be difficult to anticipate such cost variations by offer submission deadline at 6 pm the previous day, so the implementation of the hourly offers project will better enable generators to submit offers that reflect their marginal costs and for the ISO to set reference levels that properly reflect those costs.