2012 Annual Markets Report

Internal Market Monitor
May 15, 2013

Preface

The Internal Market Monitor (IMM) of ISO New England (ISO) publishes an Annual Markets Report (AMR) that assesses the state of competition in the wholesale electricity markets operated by the ISO. The *2012 Annual Markets Report* covers the ISO's most recent operating year, January 1 to December 31, 2012. The report addresses the development, operation, and performance of the wholesale electricity markets administered by the ISO and presents an assessment of each market based on market data, performance criteria, and independent studies.

This report fulfills the requirement of *Market Rule 1*, Section III.A.17.2.4, Appendix A, *Market Monitoring, Reporting, and Market Power Mitigation*:

> *The Internal Market Monitor will prepare an annual state of the market report on market trends and the performance of the New England Markets and will present an annual review of the operations of the New England Markets. The annual report and review will include an evaluation of the procedures for the determination of energy, reserve and regulation clearing prices, NCPC* [Net Commitment-Period Compensation] *costs and the performance of the Forward Capacity Market and FTR* [Financial Transmission Rights] *Auctions. The review will include a public forum to discuss the performance of the New England Markets, the state of competition, and the ISO's priorities for the coming year. In addition, the Internal Market Monitor will arrange a non-public meeting open to appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets, subject to the confidentiality protections of the ISO New England Information Policy, to the greatest extent permitted by law.*[1]

The IMM submits this report simultaneously to the ISO and the United States Federal Energy Regulatory Commission (FERC) per FERC order:

> *The Commission has the statutory responsibility to ensure that public utilities selling in competitive bulk power markets do not engage in market power abuse and also to ensure that markets within the Commission's jurisdiction are free of design flaws and market power abuse. To that end, the Commission will expect to receive the reports and analyses of an RTO's* [Regional Transmission Organization's] *market monitor at the same time they are submitted to the RTO.*[2]

The External Market Monitor (EMM) also publishes an annual assessment of the ISO New England wholesale electricity markets. The EMM is external to the ISO and reports directly to the board of directors. Like the IMM's report, the External Market Monitor's report assesses the design and operation of the markets and the competitive conduct of the market participants.

This report of the IMM presents the most important findings, market outcomes, and market design changes of New England's wholesale electricity markets for 2012. A summary of the outcomes and market performance is included in Section 1.1. Section 2 and Section 3 include more detailed discussions of each of the markets, market results, and the IMM's analysis and recommendations. An appendix (Section 4) provides additional data on the markets. A list of

[1] *ISO New England Inc. Transmission, Markets, and Services Tariff* (ISO tariff), Section III.A.17.2.4, *Market Rule 1*, Appendix A, "Market Monitoring, Reporting, and Market Power Mitigation" (March 13, 2013), http://www.iso-ne.com/regulatory/tariff/sect_3/index.html.

[2] FERC, PJM Interconnection, L.L.C. et al., *Order Provisionally Granting RTO Status*, Docket No. RT01-2-000, 96 FERC ¶ 61, 061 (July 12, 2001).

acronyms and abbreviations also is included. Key terms are italicized and defined within the text and footnotes. To aid the reader in understanding the report's findings, an overview of the New England electricity markets, how they function, and market monitoring is available on the ISO's website.[3]

All information and data presented are the most recent as of the time of publication. Some data presented in this report are still open to resettlement.

[3] *Overview of New England's Wholesale Electricity Markets and Market Oversight* (May 15, 2013), http://www.iso-ne.com/pubs/spcl_rpts/index.html.

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Section 1
Executive Summary

The *2012 Annual Markets Report* addresses the development, operation, and performance of the wholesale electricity markets administered by ISO New England (ISO) and presents an assessment of each market based on market data and performance criteria. This section summarizes the region's wholesale electricity market outcomes for 2012, the important market issues and the IMM's recommendations for addressing these issues, the overall competitiveness of the markets, and market mitigation and market reform activities. Section 2 and Section 3 contain a more detailed discussion of the performance of the real-time and forward markets the ISO administers, and Section 4 is an appendix of additional data. A list of abbreviations and acronyms is included at the end of the report. Key terms are italicized and defined within the text and footnotes.

1.1 Summary of Market Outcomes

Over the long run, competitive and efficient electricity markets provide the incentives to maintain an adequate supply of electric energy at prices consistent with the cost of providing it. The core responsibilities of the ISO New England Internal Market Monitor (IMM) are to review the competitiveness of the wholesale electricity markets, report on market outcomes, and recommend improvements to the market design. The IMM reviewed market outcomes and related information for 2012 and concluded that the wholesale electric markets operated competitively in 2012. Market concentration is low, and energy prices remain at levels consistent with the short-run marginal cost of production. The ISO operated through "Superstorm Sandy" without major incident. Overall market outcomes were influenced by lower natural gas prices and lower electrical energy demands compared with 2011. These factors caused energy costs in 2012 to be lower than 2011 levels.

Table 1-1 shows wholesale electricity costs (in dollars and dollars per megawatt-hour; $/MWh) by market in 2012 compared with 2011. Total costs declined by about 20% while energy costs declined by about 23%. The decline in energy costs was primarily the result of a decrease in natural gas prices.[4]

[4] The annual total cost of electric energy is approximated as the product of the annual real-time load obligation for the region and the average annual real-time locational marginal price (LMP). The real-time load obligation is the requirement that each market participant has for providing electric energy at each location (i.e., pricing node, load zone, or the Hub) equal to the amount of load it is serving, including external and internal bilateral transactions.

Table 1-1
Wholesale Market Cost Summary

Type	Annual Costs ($ Billions)			Average Costs ($/MWh)		
	2012	2011	% Change	2012	2011	% Change
Energy	4.77	6.17	-23%	37.42	48.00	-22%
Capacity	1.19	1.35	-11%	9.36	10.48	-11%
Ancillary Services	0.13	0.11	17%	1.04	0.88	18%
Total	6.10	7.63	-20%	47.81	59.36	-19%

In 2012, about 52% of the wholesale electricity generated in New England came from natural-gas-fired generators. By comparison, in 2000, less than 15% of New England's electricity was produced from natural gas. This increased consumption of natural gas for electricity generation, as well as residential and commercial space heating, has significantly increased the use of the region's gas pipeline infrastructure. The IMM has observed an increase in the number of natural gas resources unable to follow the ISO's dispatch instructions or honor the terms of their supply offers for several reasons. These reasons include differences between the gas sector and electric power sector scheduling days, insufficient gas pipeline infrastructure when the demand for natural gas has been high, and limited flexibility in submitting offers into the electric markets. The IMM's review of these events has led to several recommendations and areas for further review.

The Forward Capacity Market (FCM) continues to clear sufficient resources to meet the region's resource adequacy planning requirements. However, recent concerns about resource performance—specifically fuel-procurement decisions that adversely affect a resource's ability to deliver energy in real-time—has prompted the ISO to consider a number of market enhancements to improve generator performance and reduce reliability risks. The sixth Forward Capacity Auction (FCA #6) was held in April 2012, and, like the previous five FCAs, cleared at the auction floor price. The capacity price for FCA #6 was $3.43/kilowatt (kW)-month, resulting in a capacity surplus of 2,853 MW, a 24% reduction from FCA #5. Capacity payments made to all resources in 2012 totaled $1.19 billion, an 11% drop from 2011.

Forward Reserve Market (FRM) auction revenues decreased by 48%, totaling $9.3 million in 2012. Systemwide clearing prices in the FRM auctions for summer 2012 and winter 2012/2013 were $4,500/MW-month and $3,301/MW-month, respectively, a drop of 23% and 24% from the prior year's auctions. Real-time reserve payments totaled $29.8 million, an increase of 214% from 2011. Several factors explain the large increase in reserve payments during the third and fourth quarters:

- The total 10-minute reserve requirement increased by 25% in summer 2012.
- The Reserve Constraint Penalty Factor (RCPF) for system 10-minute operating reserve (TMOR) increased from $100/MWh to $500/MWh.
- Several days of tight system conditions, including capacity deficiencies, in August and November 2012, resulted in numerous instances when the TMOR constraint was binding.

Regulation payments decreased by 7%, totaling $11.6 million because of reductions in natural gas prices.

In 2012, Net Commitment-Period Compensation (NCPC) payments totaled $87.1 million.[5] Economic NCPC held relatively flat from last year at $59.8 million. The costs associated with providing local second-contingency protection, distribution support, and voltage support totaled $27.3 million, an increase of 79%, driven primarily by the need to commit a unit to provide voltage to a particular area.

1.2 Issues and Recommendations

The IMM has identified the following issues and makes the following recommendations, in priority order, for improving the market design. The recommendations are based on observations of participant behavior and market outcomes in 2012 and the analysis presented herein.

1.2.1 Resource Performance Issues

The region's use of natural gas for about half its electric energy has revealed both operational difficulties in coordinating the purchase and delivery of the fuel that generators need each day and the potentially insufficient infrastructure to supply all the natural gas the region's residential, commercial, industrial, and electric sectors demand during peak periods. The ISO has several proposals in differing stages of implementation to address both the operational and adequacy issues. To address the operational problems, the ISO is proposing, among other things, to (1) change the timeline for the day-ahead market, (2) increase the amount of 30-minute reserve purchased through the locational Forward Reserve Market (FRM) and simultaneously price this increased reserve in real-time operations, and (3) implement hourly offers and intraday reoffers. To address the adequacy-related issues, the ISO is proposing to change the definition of shortage events in the Forward Capacity Market and implement a new performance incentive framework for the FCM. The recommendations in this section are grouped into those that primarily address operational issues and those that primarily address adequacy issues, in order of importance within each category.

1.2.1.1 Operational Issues and Recommendations

The IMM believes that with the ISO's proposed changes to the day-ahead market timeline, the increased purchase of operating reserves, and the implementation of intraday offers, resources will less often fail to deliver energy because of a lack of fuel. The primary reason for this improvement is that the resources needed based on the Reserve Adequacy Assessment (RAA) will be notified earlier in the day so they will have more time to procure gas.[6] However, these changes do not directly address the problems with gas resources' performance between the close of the evening nomination cycle and the start of the next gas day. To address these problems, the IMM makes the following recommendations:

[5] *Net Commitment-Period Compensation* is a method of providing "make-whole" payments to market participants with resources dispatched out of economic-merit order for reliability purposes when the costs of providing energy or reserves from the resources would otherwise exceed the revenue paid to the market participant. *Economic NCPC* arises when the total cost of committing and operating a generating resource exceeds the revenues it earns from the sale of energy at the LMP.

[6] Each day after the reoffer period for the Day Ahead Energy Market, the ISO performs a Reserve Adequacy Assessment to determine whether it needs to commit additional generators to meet the load forecast plus operating reserve requirement.

- Continue to support the recommendation made in the *2011 Annual Markets Report* (AMR11) that the ISO implement software and rule changes that would allow resources to offer hourly and update incremental supply offers within the operating day to reflect changes in fuel costs during the operating day.[7] Resource owners may be more willing to provide electric energy if they can accurately reflect their costs in real time. This change will allow sellers to reflect costs more indicative of actual fuel prices, improve energy market price signals, and permit a closer match between these prices and the cost of procuring fuel in real time (see Section 2.1.3.3 and Section 3.4.4).
- Develop additional forward markets so that any resources committed by the ISO for reliability reasons has a financial obligation to provide energy. The IMM has observed that problems with resources failing to respond successfully to ISO commitment and dispatch instructions in real time because of a lack of fuel continued in 2012. This indicates that the energy revenues foregone by not procuring the fuel to operate do not provide sufficient incentives for these resources to procure fuel. Most of these instances occurred when the ISO dispatched resources to provide energy not sold in the day-ahead market, thus the resources had no financial obligation to provide the energy. The IMM recognizes that designing and implementing forward markets is complex and will require significant time and resources (see Section 2.1.3.3 and Section 3.4.4).
- Make the locational Forward Reserve Market product a "24 x 7" product rather than the current "5 x 16" product when the intraday reserves are implemented to provide incentives for locational FRM resources to make arrangements for fuel in the overnight hours (see Section 2.1.3.3).
- Increase the locational FRM penalties to assure the effectiveness of the intraday reserves (see Section 2.1.3.3).
- Have the ISO work with the natural-fired-gas generators to improve how these generators report their availability during the hours after the close of the evening nomination cycle (see Section 2.1.3.3).

1.2.1.2 Adequacy Issues and Recommendation

The IMM supports the change in the definition of shortage events and the revised FCM Performance Incentive proposal.[8] However, the FCM performance incentives will not affect system operations until at least the 2018/2019 capacity commitment period. To address the incentive issues in the FCM more promptly, the IMM recommends that the ISO implement rule changes as quickly as possible so that resources with a capacity supply obligation that fail to provide energy when dispatched lose at least a portion of their monthly capacity payment. This proposal is described in more detail in Section 3.4.3.3.

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[7] *2011 Annual Markets Report* (AMR11) (May 15, 2012), http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/index.html.

[8] ISO New England Inc., *FCM Performance Incentives—A Strategic Planning Initiative,* presentation to the NEPOOL Markets Committee (November 16, 2012), http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2012/nov162012/a02_iso_presentation_11_16_12.ppt.

1.2.1.3 Resources Failing to Meet Tariff Obligations

The ISO's *Transmission, Markets, and Services Tariff* (ISO tariff) requires resources to follow dispatch instructions and to be able to supply energy according to the terms of their supply offers when dispatched.[9] This means that instances when generators fail to operate when dispatched because of a lack of fuel may be tariff violations, which the IMM must report to the Federal Energy Regulatory Commission (FERC).

1.2.2 Other Recommendations

Additional IMM recommendations, listed in order of importance, are as follows:

- The IMM continues to support the recommendation made in the *2011 Annual Markets Report* to develop a sloped demand curve for use in the Forward Capacity Auction. A review of the shape of each FCA's capacity supply curve shows that, given the FCA's vertical demand curve, a small surplus or deficiency of resources available to meet the Installed Capacity Requirement (ICR) or local sourcing requirement (LSR) could produce a disproportionally large change in the capacity price compared with the level of reliability associated with the surplus or shortage in each zone. The need for a sloped demand curve becomes more pressing with the modeling of additional capacity zones in the auction, allowing the prices to more efficiently signal the relative surplus or shortage in each zone (see Section 1.4 and Section 3.4).

- The IMM recommends reviewing the rules defining limited-energy generator (LEG) resources to determine whether they need to be revised. The IMM believes that the use of the LEG provisions does not excuse a resource from meeting its obligation to have sufficient fuel to operate consistent with its energy offer. Fossil-fueled generators must be able to operate at their maximum physical capability for the day if needed (See Section 2.1.3.4).
- The IMM continues to support the recommendation made in the *2011 Annual Markets Report* that the ISO revise the market rules so that real-time NCPC charges do not prevent virtual transactions from improving the liquidity in the day-ahead market. The IMM is concerned with the continued decline in the volume of virtual trades where virtual transactions are needed to provide an adequate level of liquidity in the Day-Ahead Energy Market. Analysis suggests a relationship between the allocation of Net Commitment-Period Compensation charges to virtual transactions and the observed decline in trading activity (see Section 3.1.2.5).

- The IMM recommends that the locational FRM's failure-to-activate penalty not be triggered solely by the emergency version of the dispatch software ("Contingency SPD").[10] Because the Contingency SPD is used infrequently, only 13 times in 2012, the fast-start and on-line resources that the markets have reserved to provide energy when needed are rarely penalized when they fail to provide the reserves.

[9] *ISO New England Inc. Transmission, Markets, and Services Tariff* (ISO tariff), (2013), http://www.iso-ne.com/regulatory/tariff/sect_3/index.html.

[10] *Contingency SPD* is a version of the dispatch software designed specifically for response to losses of imports or supply greater than 500 MW or threats to interregional reliability that require joint action by neighboring balancing areas.

One alternative would be for the penalty to be triggered any time the ISO dispatches an FRM resource into the expensive energy reserved by the FRM but the resource does not provide the energy (see Section 3.3.5.3).

- The IMM recommends that the ISO cease identifying the bidders when announcing the results of any Financial Transmission Rights (FTR) auction. Section III.7.3.7 of the ISO tariff requires all winning bids for an annual auction to be published, including the identity of the bidder.[11] Because the auction has multiple rounds and is repeated every year, the publication of the bidders' identities risks coordinated behavior among buyers aimed at reducing the prices to acquire the valuable rights at prices below competitive levels. This is a general property of repeated auctions (see Section 3.2.2).[12]
- The IMM continues to support the recommendation made in the *2011 Annual Markets Report* that an independent party, such as the distribution utility, submit, or at the least verify, the meter data for demand-response resources. The market rules currently require owners of demand-response resources to submit and verify the integrity of the meter reads used to establish their resources' baseline consumption and demand reductions. The IMM contends that this approach introduces a conflict of interest because the party submitting the data that is used to determine payment is the party that will be paid. The reporting of data by an independent party also will address data quality issues in a timely manner (see Section 2.1.4).
- The IMM continues to support the recommendation made in the *2011 Annual Markets Report* for the ISO tariff to be modified to define "facility shutdowns" and "meter malfunctions" for real-time demand resources (RTDRs) and real-time emergency generation (RTEG) assets as situations constituting a "forced" outage or unavailability. These designations would make these assets ineligible for compensation for these outage periods and would require them to promptly report the outages to the ISO.[13] Without such provisions in place, a market participant could be paid improperly for apparent load reductions in response to an ISO's dispatch instruction (see Section 2.1.4).

1.3 Market Design Changes

The major revisions to the market design implemented in 2012 are summarized below.

1.3.1 Implementation of Automated Mitigation

On April 17, 2012, the IMM implemented automated mitigation in the electric energy markets.[14] Under automated mitigation, a separate dispatch of the electricity market is run side by side with the actual dispatch. This parallel dispatch uses all the same inputs as the actual dispatch, except resource offers that exceed the conduct thresholds of the energy market are replaced

[11] ISO tariff, Section III.7.3.7, *Market Rule 1*, "Announcement of Winners and Prices," (March 1, 2013), http://www.iso-ne.com/regulatory/tariff/sect_3/index.html.

[12] Paul Klemperer, "What Really Matters in Auction Design," *Journal of Economic Perspectives* 16, no. 1 (Winter 2002).

[13] The ISO tariff is available at http://www.iso-ne.com/regulatory/tariff/sect_3/index.html.

[14] *Market Rule 1, Revisions Relating to Real-Time Automated Mitigation of Supply Offers*, ER11-4540-000 (filed September 15, 2011), http://www.iso-ne.com/regulatory/ferc/filings/2011/sep/er11_4540_000_9-15-11_rev_auto_mitigation.pdf.

with the resources' reference offers. The prices resulting from the parallel dispatch are compared with the prices from the actual dispatch, and if the difference exceeds the mitigation thresholds, the resource is mitigated. The key advantage of automated mitigation and the comparison of the alternative dispatch with the original dispatch is a more accurate calculation of a price impact.

As expected, the number of mitigated units has increased with the implementation of automated mitigation. The number of mitigations increased because of changes in the evaluation of pivotal suppliers and in the consultation process. The IMM expects that the frequency of mitigation will stabilize at a level lower than the initial months but higher than before automated mitigation was implemented (see Section 2.1.3.6).

1.3.2 Reserve Constraint Penalty Factor Change

On March 22, 2012, the ISO and the New England Power Pool (NEPOOL) Participants Committee filed jointly to change the Reserve Constraint Penalty Factor systemwide value for 30-minute operating reserves.[15] Specifically, the filed RCPF change was to increase the systemwide RCPF value for TMOR from $100/MWh to $500/MWh with an effective date of June 1, 2012.

The ISO had observed that the $100/MWh system TMOR RCPF value was inefficiently low, resulting in instances that prevented the unit-dispatch system from redispatching resources to cure a reserve deficiency and in system operators needing to take manual actions to obtain additional reserves to lessen the deficiency. In addition, the inefficiently low system TMOR RCPF value resulted in more instances in which resource owners' financial incentives were not aligned fully with the ISO's dispatch instructions. Finally, the low TMOR RCPF value led to instances in which inefficient price signals failed to convey the true marginal cost of reserves during the intervals when it was most valuable. The change in the RCPF value was required to address these problems (see Section 2.2).

1.3.3 Minimum Offer Requirement Filing

On December 3, 2012, the ISO filed with FERC a proposed package of changes to the FCM design.[16] The ISO proposed that the associated tariff changes take effect for the eighth Forward Capacity Auction (FCA #8), which will be run in 2014. A major element of this package is the proposed implementation of a new buyer-side offer-floor mitigation mechanism. Buyer-side mitigation is designed to encourage the economic entry of new resources by restricting resources from entering the market at prices below their costs, which depresses capacity prices.

The existing mechanism (applicable up to and including FCA #7) requires the IMM to review all new resource offers below 0.75 times the cost of new entry (CONE). This will be replaced by a set of resource-specific benchmark prices, known as offer-review trigger prices (ORTPs). The IMM developed a menu of ORTPs for various resource types, which approximate the net cost of entry of each resource. The ORTP establishes a floor price for a new resource, below which it will leave the auction, absent a request submitted to the IMM to offer at a price lower than the

[15] ISO New England Inc. and New England Power Pool, *RCPF Value Change,* Docket No. ER12-___-000 (March 22, 2012), http://www.iso-ne.com/regulatory/ferc/filings/2012/mar/er12-1314-000_rcpf_value_chg_3-22-2012.pdf.

[16] ISO New England Inc., *Revisions to Forward Capacity Market Rules*, Docket No. ER12-953-001 (December 3, 2012), http://www.iso-ne.com/regulatory/ferc/filings/2012/dec/er12-953-001_12-3-12_fcm_redesign_compl.pdf.

relevant ORTP. For example, the proposed ORTP for a combustion turbine for FCA #8 is $10/kW-month. Should a new combustion turbine resource wish to remain in the FCA below this floor price, it must submit both cost data and the requested offer price to the IMM for review and approval. The key benefit of the proposed ORTPs and their recognition that different resource types can have very different cost-of-entry requirements is allowing for more efficient economic pricing in the FCM. In a February 12, 2013, letter order, FERC accepted in part and rejected in part the December 3, 2012, filing on the ORTPs for various resource types (see Section 3.4.4).[17]

1.4 Status of IMM Recommendations from the *2011 Annual Markets Report*

The status of the IMM recommendations from the *2011 Annual Markets Report* are shown in Table 1-2.

Table 1-2
Status of IMM Recommendations from the *2011 Annual Markets Report*

2011 Recommendation	Status as of the AMR12 Publication Date
Penalize resources with a capacity supply obligation that fail to deliver electric energy when requested in real time on the basis of the cost their unavailability has on the market.	Partially addressed by FCM Performance Incentives project. FERC filing planned for the end of 2013
Implement market functionality that would allow resources to offer hourly and update incremental supply offers within the operating day to reflect changes in fuel costs during the operating day.	Part of Hourly Offers, Negative Offers, and Intraday Reoffers project. In the Markets Committee. FERC filing planned for mid-2013
Adopt a penalty to levy on resources that fail to follow dispatch instructions.	Pending assessment
Implement the FERC Minimum Offer Price Rule, and eliminate the floor price.	Effective for FCA #8, pending final FERC approval
Develop a sloped demand curve for use in the market-pricing mechanism.	In assessment
Revise the market rules so that real-time NCPC charges do not prevent virtual transactions from providing the benefits of improved liquidity in the day-ahead market.	Start external stakeholder process no earlier than Q4 2013
Modify the tariff to define facility shutdowns and meter malfunctions for RTDR and RTEG assets as situations constituting a "forced" outage or unavailability, which would make the assets ineligible for compensation for these outage periods and require them to report the outages promptly to the ISO.	In assessment

[17] *Order Accepting in Part, and Rejecting in Part, FCM Compliance Filing,* Docket No. ER12-953-001 (February 12, 2013), http://www.iso-ne.com/regulatory/ferc/orders/2013/feb/er12-953-001_2-12-13_order_fcm_compliance.pdf.

Section 2
Real-Time Markets

ISO New England's (ISO) real-time markets include the Real-Time Energy Market, the Regulation Market, and real-time reserves. This section describes the 2012 outcomes of the real-time markets and the Internal Market Monitor's (IMM) recommendations for these markets. The section also summarizes the ISO's actions to ensure real-time reliability and includes the IMM's assessment of ISO operations.

2.1 Real-Time Energy Market

This section describes the outcomes, structure, and competitiveness of the Real-Time Energy Market and includes recommendations to improve the incentives for market participants to follow the ISO's dispatch instructions. The IMM's review of market outcomes shows that the Real-Time Energy Market was competitive in 2012.

The Real-Time Energy Market is the physical market in which generators and load-serving entities (LSEs) sell and purchase electricity. The ISO coordinates the production of electricity to ensure that the amount produced moment to moment equals the amount consumed, while respecting transmission constraints. The ISO publishes locational marginal prices (LMPs) every five minutes for each location on the transmission system at which power is either withdrawn or injected.[18] The prices for each location reflect the cost of the resource needed to meet the next increment of load at that location.

The Real-Time Energy Market settles the difference between positions taken in the Day-Ahead Energy Market (discussed in Section 3.1) and actual production or consumption in the Real-Time Energy Market. Participants either pay or are paid the real-time LMP for the amount of load or generation (in megawatt-hours; MWh) that deviates from their day-ahead schedule.

2.1.1 Prices

Real-time price data for 2012 and comparisons of the real-time prices with day-ahead prices are presented below. (See Section 3.1.1 for a full discussion on day-ahead pricing.)

2.1.1.1 Real-Time Prices

In 2012, the average real-time Hub price was $36.09/MWh, down approximately 23% from $46.68/MWh in 2011.[19] This price is consistent with observed market conditions, including those for input fuel costs, loads, and other generating resources. Price differences between the load zones primarily were due to marginal losses.[20] There was little congestion between zones.

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[18] The Hub, load zones, and internal network nodes are points on the New England transmission system at which LMPs are calculated. *Internal nodes* are individual pricing points (*pnodes*) on the system. *Load zones* are aggregations of internal nodes within specific geographic areas. The *Hub* is a collection of internal nodes that represents an uncongested price. An *external interface node* is a proxy location used for establishing an LMP for energy received by market participants from, or delivered by market participants to, a neighboring balancing authority area.

[19] Throughout this report, average prices are calculated using a simple average method.

[20] The loss component of the LMP is the marginal cost of additional losses caused by supplying an increment of load at the location. New England is divided into the following eight load zones used for wholesale market billing: 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).

Most of the congestion was the result of smaller, subzonal transient load pockets caused by transmission or generation elements being out of service.[21]

The Maine load zone continues to have the lowest average prices in the region, while the Western Central Massachusetts (WCMA) load zone had the highest. The average LMPs in the Maine load zone were about $0.90/MWh lower than the Hub price, largely because the marginal loss components of the LMPs in Maine were lower than these components at the Hub. The higher WCMA prices are attributable to local planned transmission outages required to incorporate system improvements to the area. The average LMPs in the WCMA load zone were $0.86/MWh greater than the average Hub price, largely because the congestion components of the LMPs in WCMA were higher than those components at the Hub. See Table 2-1.

Table 2-1
Simple Average Real-Time Hub Prices and Load-Zone Differences for 2011 and 2012 ($/MWh)

Location/Load Zone	2011	2012
Hub	$46.68	$36.09
Maine (ME)	−$1.73	−$0.90
New Hampshire (NH)	−$0.61	−$0.14
Vermont (VT)	−$0.11	$0.08
Connecticut (CT)	$1.27	$0.82
Rhode Island (RI)	−$0.54	−$0.21
Southeast Massachusetts (SEMA)	−$0.09	$0.05
Western Central Massachusetts (WCMA)	$0.56	$0.86
Northeast Massachusetts (NEMA)	−$0.11	$0.07

2.1.1.2 Day-Ahead and Real-Time Price Comparison

In 2012, average day-ahead prices at the Hub ($36.08/MWh) and average real-time energy prices at the Hub ($36.09/MWh) were virtually identical. This is consistent with the recent trend of a decline in the average day-ahead-to-real-time price difference. In 2006, the annual average difference between day-ahead and real-time prices was 2.1% (day ahead greater than real time). In mid-2009, the relationship switched, and real-time prices averaged 1.1% more than day-ahead prices. This relationship continued in 2011, with real-time prices averaging 0.6% more than day-ahead prices. Changes in LMPs at the Hub are consistent with changes in input fuel prices and are within normal ranges. In 2012, the small difference between day-

[21] *Load pockets* are areas of the system that require local generation to meet demand because the transfer capability of the transmission system is insufficient to serve the load in the area.

ahead and real-time prices indicates that the day-ahead market reasonably reflects average real-time outcomes. See Table 2-2.

Table 2-2
2012 Annual and Quarterly
Day-Ahead and Real-Time Hub Prices ($/MWh)

	Annual	Q1	Q2	Q3	Q4
Day ahead	$36.08	$32.59	$28.80	$37.38	$45.41
Real time	$36.09	$30.90	$29.06	$39.51	$44.75

In 2012, hourly real-time and day-ahead prices correlated positively (0.71), as expected. Hourly real-time LMPs at the Hub for 2012 had a standard deviation of $22.57, while hourly day-ahead LMPs at the Hub for 2012 had a standard deviation of $16.58. The higher standard deviation of real-time prices is expected because *contingencies* (i.e., unplanned [forced] generation or transmission outages) and Minimum Generation Emergency conditions that create price volatility occur only in real time.[22] See Figure 2-1.

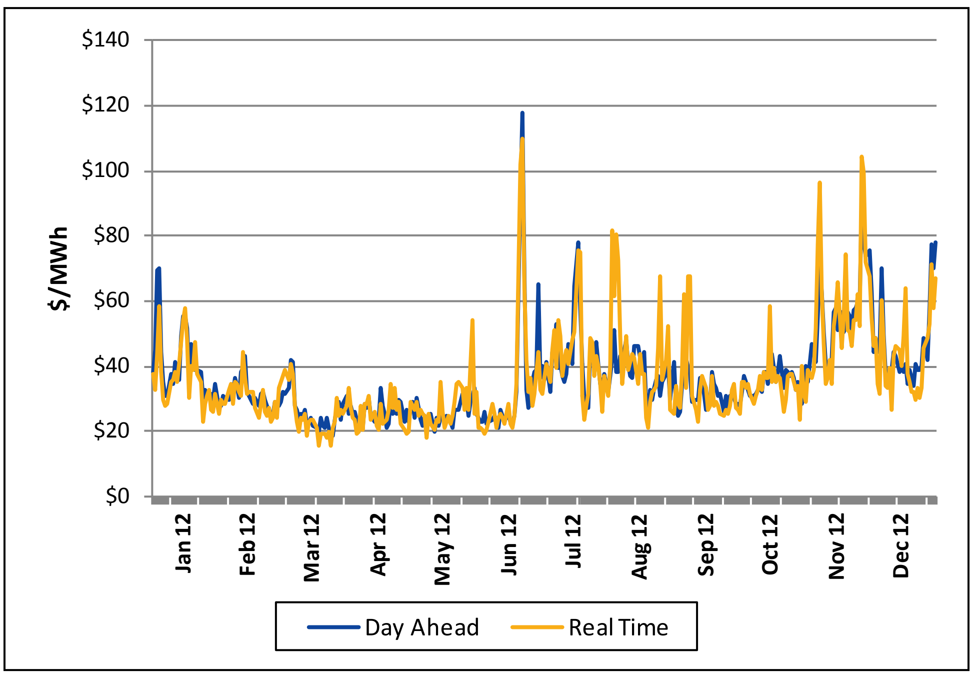

Figure 2-1: Average daily day-ahead and real-time Hub prices, 2012 ($/MWh).

[22]A *forced* outage is a type of unplanned outage that involves the unexpected removal from service of a generating unit, transmission facility, or other facility or portion of a facility because of an emergency failure or the discovery of a problem. A *planned* outage is the planned inoperability of a generator, generally to perform maintenance. The declaration of a *Minimum Generation (Min Gen) Emergency* is called when the on-line generation comes close to exceeding system load plus net imports and all generators are operating at *economic minimum* (ecomin) (i.e., the minimum amount of electric energy [in megawatts] available from a generating resource for economic dispatch. A Min Gen Emergency resets the economic minimums of resources down to their emergency minimums (if available) to gain additional dispatchable range and administratively sets LMPs to zero.

2.1.2 Market Structure

A core function of the IMM is to monitor market participant behavior and detect deviations from competitive behavior. The structure of the market (i.e., the number of competitors, the nature of the product, and the frequency with which suppliers are *pivotal*—or can set prices and are necessary to meet demand) affects the ability of a participant to raise its price above its marginal cost. Market structure affects a participant's ability to set price and sustain profits above the competitive level. As expected, the fewer competitors in the market, the easier it is for a participant to exercise market power.

This section presents the results of the IMM's analysis of market structure (Section 2.1.5 examines conduct and performance). The IMM assesses several statistics:

- The percentage of generation produced in the peak load hour for the year from the four-largest suppliers
- The amount of energy purchased in the peak load hour for the year by the four-largest load-serving entities
- Market concentration, as measured by the Herfindahl-Hirschman Index (HHI) (see Section 2.1.2.2)
- The number of hours in which participant portfolios were pivotal, as measured by the Residual Supplier Index (RSI) (see Section 2.1.2.3)

2.1.2.1 Market Share of Supply and Demand for the 2012 Peak Hour

A commonly used measure of market share is the percentage of the market controlled by the four-largest competitors (termed C4). The four-largest generating companies and the four-largest LSEs control slightly less than half the supply and load in the region, with two of the largest suppliers also serving a large percentage of the load.

For the 2012 peak load hour—July 17, 2012, hour ending (HE) 5:00 p.m.—generators produced 27,090 megawatts (MW) of electricity.[23] The four-largest generation suppliers provided 41% of the total electricity produced in New England in that hour, while all other market participants provided 59% of the electricity generated in that hour. The participant that supplied the most generation to the system during the peak hour was Dominion Energy Marketing, which supplied 3,994 MW (15%) of the total electricity generated. Constellation provided 3,195 MW (12%); H.Q. Energy Services, 2,072 MW (8%); and Entergy Nuclear Power Marketing provided 1,717 MW (6%) of total supply during the peak load hour of 2012. See Figure 2-2.

[23] *Hour ending* denotes the preceding hourly period. For example, 12:01 a.m. to 1:00 a.m. is hour ending 1:00 a.m. Hour ending 6:00 p.m. is the period from 5:01 p.m. to 6:00 p.m.

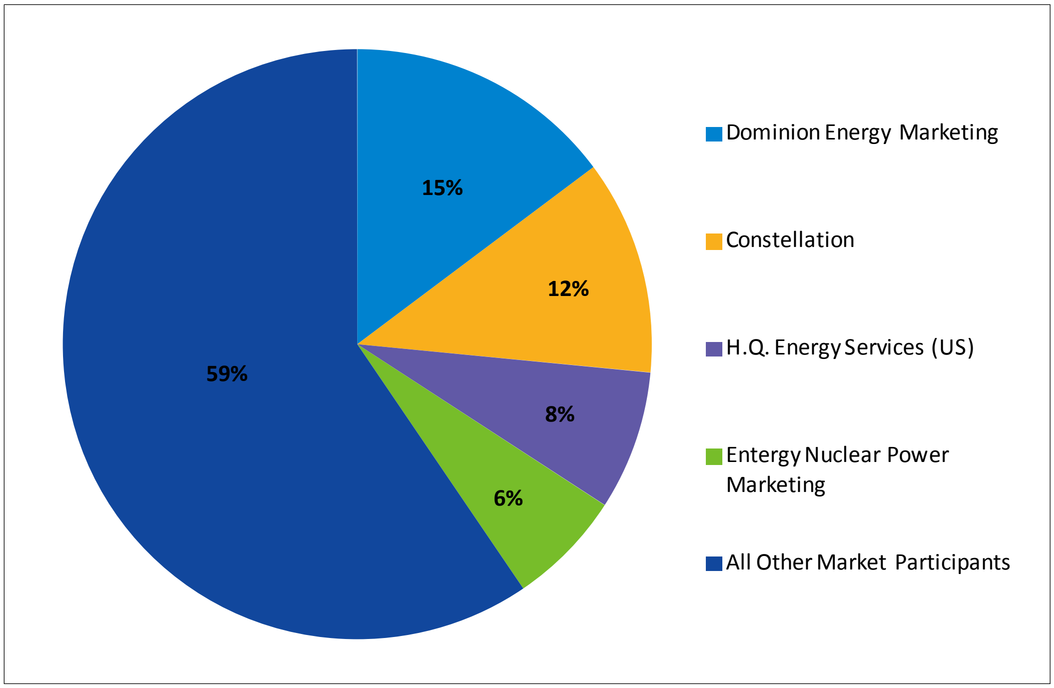

Figure 2-2: Market share of generation by participant, peak load hour 2012 (July 17, hour ending 5:00 p.m.).

For the 2012 peak load hour, the total amount of electricity purchased, or *real-time load obligation* (RTLO), was 26,903 MW.[24] Overall, the four-largest load-serving participants served 37% of the total system load for the 2012 peak load hour, while all other market participants served 63% of the total system load in that hour. Constellation had the largest real-time load obligation, serving 4,309 MW (16%) of total system peak load. TransCanada Power Marketing served 2,753 MW (10%); NextEra Energy Power Marketing, 1,550 MW (6%); and Hess Corporation, 1,355 MW (5%) of total system peak load in that hour. See Figure 2-3.

[24] Losses account for the difference between the 27,090 MW of sold generation and the 26,903 MW of bought generation.

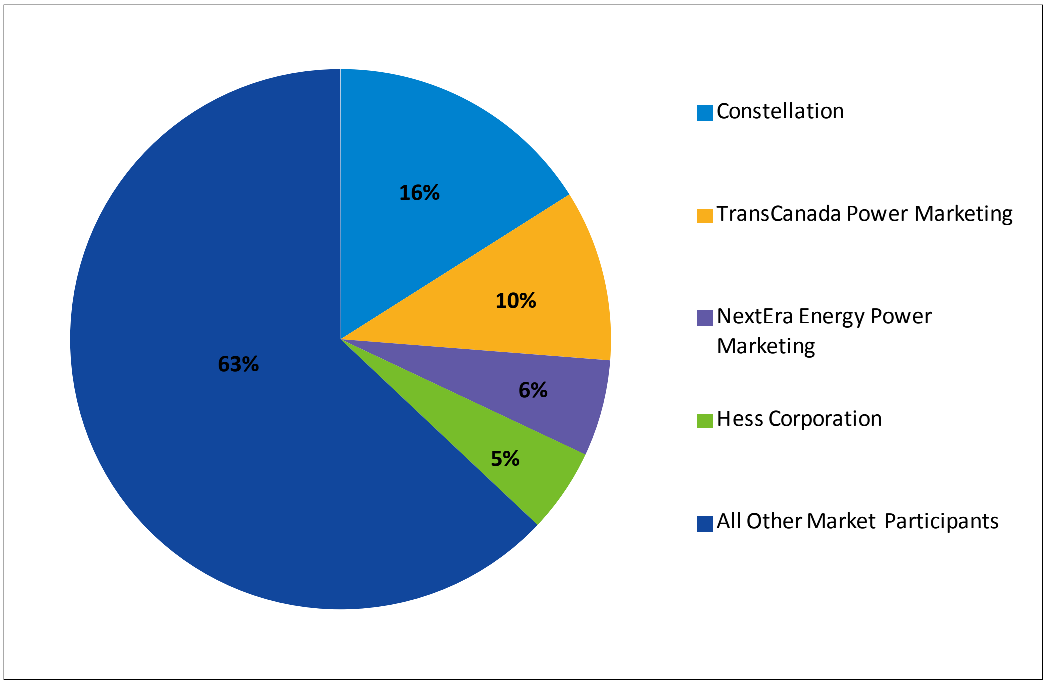

Figure 2-3: Real-time load obligation by participant, peak load hour 2012 (July 17, hour ending 5:00 p.m.).

Figure 2-2 and Figure 2-3 show that Constellation is in the top-four participant list for both load served and generation provided in the peak load hour of 2012. Participants with both load and generation generally have less incentive to exercise market power. Actions that would tend to raise prices for generation would come at a cost to load, and any actions that would suppress prices would come at a cost to generation. Consequently, the IMM is most concerned with a participant's net position and the conditions under which unilateral action might become profitable.

2.1.2.2 Structural Measure of the Real-Time Energy Market

The *Herfindahl-Hirschman Index* is a measure of market concentration that gives larger weights to larger firms. The HHI is calculated as the sum of the squared market shares of the firms in the market.[25] The IMM presents C4, HHI, and market share in this report because they each offer a different view of the market's structure, as illustrated by the following example. Consider five firms that make up the entire market in two situations: first, when market shares are 30%, 20%, 20%, 20%, and 10%, and second, when market shares are 57%, 11%, 11%, 11%, and 10%. In both cases, the four-firm concentration ratio, C4, is 90%, but the HHI is 2,200 in the first case and 3,712 in the second case. Because C4 is a simple sum of the shares of the four-largest firms, it is insensitive to how the sum is distributed among the top four firms, whereas the HHI is highly sensitive to the larger market shares. In addition, the United States (US) Department of Justice (DOJ) sets predetermined thresholds to separate unconcentrated markets from

[25] The HHI is calculated as follows:

$$H = \sum_{i=1}^{N} s_i^2$$

where s_i is the market share of firm *i* in the market, and *N* is the number of firms. The Herfindahl Index (*H*) ranges from 1/*N* to one, where *N* is the number of firms in the market. Equivalently, if percentages are used as whole numbers, as in 75 instead of 0.75, the index can range up to 100^2, or 10,000.

concentrated ones, and no such commonly used thresholds exist for C4.[26] The market share of the largest firms is important because the larger a firm is, the more likely it will be needed to meet the demand and, in those instances, able to unilaterally set price.

The IMM calculated market shares of each market participant and HHIs in the Real-Time Energy Market using cleared megawatts for each real-time pricing interval. The IMM did not calculate market shares or HHIs for load zones or other subregional areas because of the lack of transmission constraints on the system, as illustrated by the lack of congestion in real-time prices.

The HHI calculation is conservative because it uses the gross generation of each participant rather than its *net generation* (i.e., a participant's generation minus its load obligation). HHIs based on estimates of market share that accounted for each participant's net generation and load position would be lower than or equal to those calculated and presented herein.

Table 2-3 summarizes the results of the IMM's HHI analysis. The interquartile range (i.e., the range between the 25th and 75th percentiles of observation) for peak-hour HHIs in 2012 was 695 to 804, while the median and maximum peak-hour HHIs were 745 and 1,087, respectively. The HHI results have not changed significantly over the past three years. Using the DOJ's *Horizontal Merger Guidelines*, the IMM concluded that the Real-Time Energy Market in New England is not concentrated.

Table 2-3
Interquartile, Median and Maximum HHI, Median Hourly Load, Number of Participants, and Share of Top Participants (by Market Share) for Each Day's Peak-Load and Lowest-Load Hours in 2012

	Median HHI	Max HHI	Interquartile Ranges	Median Share of Top *N* Participants				Median Number of Participants	Median Load (MW)
				N = 1	***N = 4***	***N = 8***	***N = 16***		
Peak hour	745	1,087	695 to 804	15.6%	45.9%	68.0%	86.3%	118	17,817
Lowest-load hour	924	1,206	873 to 979	18.8%	52.0%	75.3%	89.3%	111	11,710

In general, the HHI is higher in low-load hours than peak hours. During low-load hours, large baseload units meet much of the demand. During peak load hours, more resources owned by other participants enter the market, lowering the market share of the participants that control the majority of baseload resources, as well as the overall market concentration. This was evident in 2012, when the top four participants (by market share) comprised 52% of the market in the hours with the lowest load, compared with 46% for the peak hours.

[26] The Department of Justice defines markets with an HHI below 1,500 points to be unconcentrated, an HHI between 1,500 and 2,500 points to be moderately concentrated, and an HHI above 2,500 points to be highly concentrated. US Department of Justice and the Federal Trade Commission, *Horizontal Merger Guidelines* (Washington, DC: US Department of Justice and Federal Trade Commission, August 19, 2010), http://www.justice.gov/atr/public/guidelines/hmg-2010.html.

2.1.2.3 Residual Supply Index

The systemwide Residual Supply Index (RSI) measures the percentage of demand in a given hour that can be met without any capacity from the largest supplier. The RSI also measures the number of hours in which at least one supplier is pivotal. A pivotal supplier can price above the competitive level, subject only to offer caps, mitigation measures, and the price elasticity of demand. When the RSI exceeds 100%, the system has sufficient capacity to meet demand without any capacity from the largest supplier. When the RSI is below 100%, a portion of the largest supplier's capacity is required to meet market demand, and the supplier is pivotal. As RSIs rise, the ability of market participants to set prices above competitive levels decreases. RSIs generally are lowest during periods of high demand.

Overall, the RSI analysis for 2012 suggests that suppliers at the system level and in the local reserve zones had limited ability to exercise market power.[27] The system-level analysis shows that pivotal suppliers existed during 66 hours in 2012, approximately 0.8% of all hours. This is a slight increase from 2011, when suppliers were pivotal in 47 hours, but the 2012 result is consistent with competitive outcomes. See Figure 2-4.

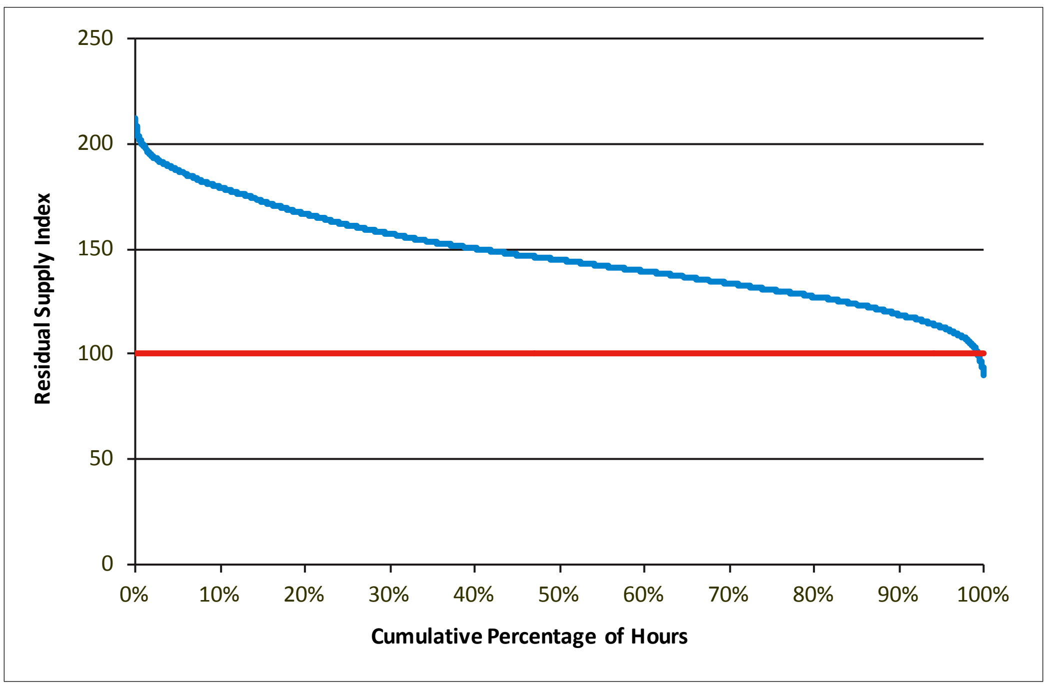

Figure 2-4: Systemwide Residual Supply Index duration curve, all hours, 2012.

To measure whether import constraints created local market power, the IMM analyzed RSIs for the Southwest Connecticut (SWCT), Connecticut (CT), and NEMA/Boston (Boston) reserve zones. These areas were chosen because they often are import constrained or have a more concentrated ownership than the overall system. In 2012, pivotal suppliers existed in SWCT and CT reserve zones at similar rates as the systemwide level. In the Boston zone, a supplier was pivotal for multiple hours during two days each in June and July and three days each in

[27] The region has four reserve zones—Connecticut (CT), Southwest Connecticut (SWCT), NEMA/Boston (Boston), and the rest of the system (Rest-of-System, ROS). The *Rest-of-System* zone is the area excluding the other local reserve zones.

September and October. These occurrences were associated with days where resources were out of service in the Boston zone. See Table 2-4.

Table 2-4
Local-Area RSIs for Selected System Interfaces, January to December 2012

Month	Boston		Southwest Connecticut		Connecticut	
	Average RSI	# of hours RSI <100	Average RSI	# of hours RSI <100	Average RSI	# of hours RSI <100
Jan	239	0	314	0	161	0
Feb	243	0	310	0	165	0
Mar	237	0	316	0	170	0
Apr	264	0	311	0	152	0
May	222	4	275	0	144	4
Jun	235	19	295	0	152	3
Jul	199	26	255	0	148	0
Aug	205	4	261	0	142	5
Sep	177	14	238	0	147	0
Oct	231	32	287	0	153	0
Nov	258	0	303	0	153	0
Dec	252	0	312	0	166	0

2.1.3 Relationship between Real-Time Energy Prices and Other Market Factors

This section describes the relationships between real-time electric energy prices, fuel prices, and other market factors. Short-lived price spikes typically are explained by unexpected sudden changes in weather, fuel prices, and unplanned generator or transmission outages.

2.1.3.1 Energy Prices and Marginal Units

The LMP is set by the cost of the megawatt dispatched to meet the next increment of load at the pricing location. The resource that sets price is called the marginal unit. Because the price of electricity changes as the price of the marginal unit changes, and the price of the marginal unit largely is determined by its fuel type, examining marginal units by fuel type largely explains changes in electricity prices. The system has at least one marginal unit associated with meeting the energy requirements on the system during each pricing interval. If transmission is not constrained, the marginal unit is classified as the *unconstrained* marginal unit. In intervals with binding transmission constraints, there is an additional marginal unit for each constraint.

In 2012, unconstrained pricing intervals accounted for approximately 90% of all pricing intervals. When considering both unconstrained and constrained intervals, natural gas was the marginal fuel during 81% of all pricing intervals, followed by pumped storage, which was marginal in 13% of all pricing intervals. See Figure 2-5.

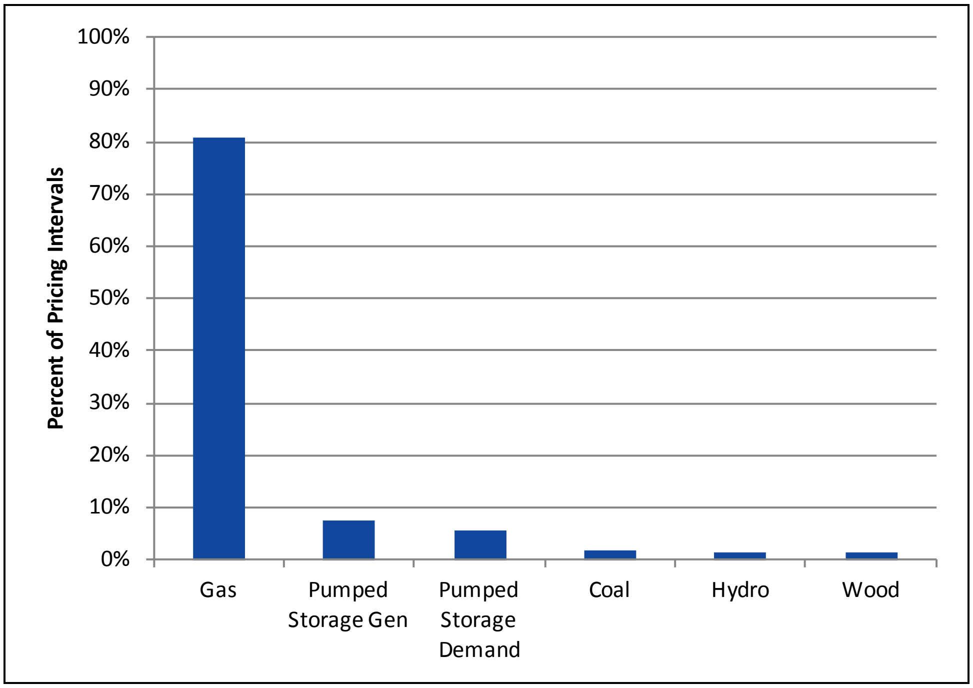

Figure 2-5: Marginal fuel-mix percentages of all pricing intervals, 2012.

2.1.3.2 Electricity Prices and Natural Gas Prices

The *spark spread* measures the relationship between real-time electricity prices and natural gas prices. Spark spread measures the gross margin (electricity revenues minus fuel costs) from converting natural gas to electricity for a typical natural-gas-fired power plant. The data used in calculating the spark spread include the wholesale price of electricity, the cost of natural gas as measured by a natural gas price index, and the efficiency of the generation technology in converting fuel input to electricity (i.e., the plant's *heat rate*). The IMM calculated the spark spread for a combined-cycle gas-turbine unit (CCGT) with a heat rate of 7,800 British thermal units/kilowatt-hour (Btu/kWh).[28] Figure 2-6 presents the quarterly estimated spark spreads for natural gas based on the following:

- The simple average of the quarterly real-time Hub price for on-peak hours from January 2010 through December 2012
- The fuel costs of a representative CCGT in New England, using the Algonquin gas price index[29]
- A 7,800 Btu/kWh heat rate
- 100% availability

[28] The heat rate (MMBtu/MWh) for a power plant is equal to its fuel consumption divided by its generation. A unit's heat rate depends on the individual plant design, its operating conditions, and its level of electrical power output. Plants with lower heat rates are more efficient than plants with higher rates.

[29] The Algonquin Gas Transmission is a regional interstate natural gas pipeline system that transports natural gas from pipeline interconnects in New Jersey and southeastern New England to major markets in New England.

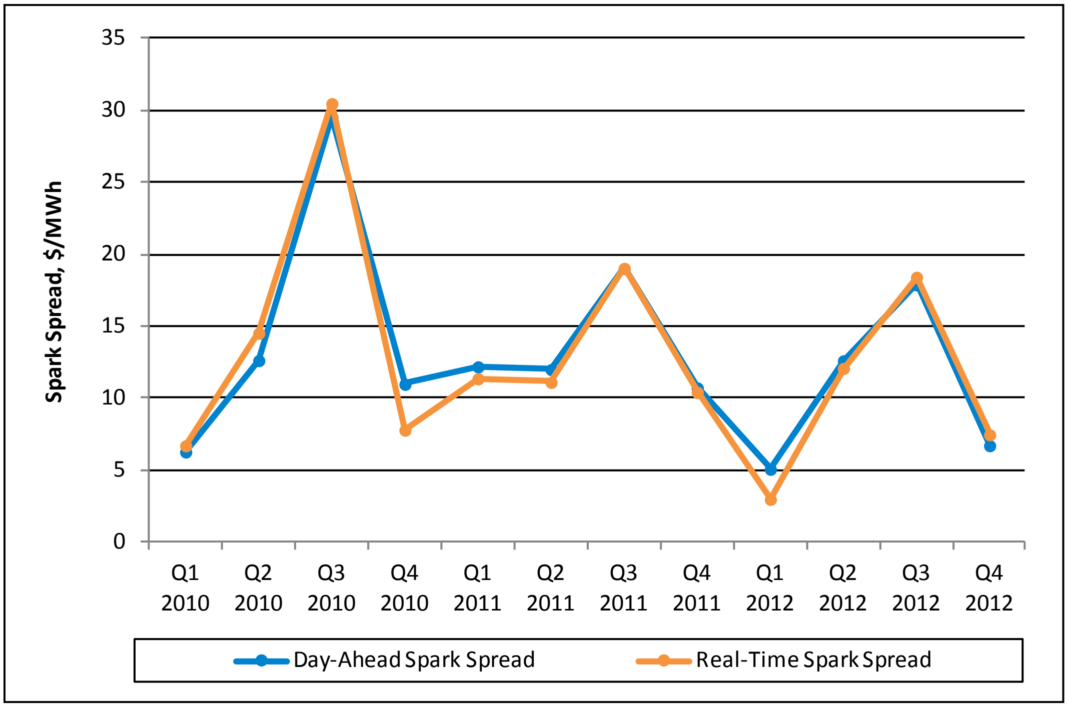

Figure 2-6: **Quarterly estimated spark spreads for on-peak hours, 2010 to 2012 ($/MWh).**

The results show that, on average, the representative gas unit earned a positive gross margin in 2012. The annual average spark spreads were approximately $10.53/MWh day ahead and $10.19/MWh in real time.[30] Spark spreads for natural gas increased in the summer months when high loads called for more expensive gas- and oil-fired units to operate and set price. The greater spark spread in 2010, relative to 2011, was the result of higher loads and the loss of a large flexible resource.

2.1.3.3 Availability of Natural-Gas-Fired Resources

New England's consumption of natural gas has grown over the past decade. Much of the growth has been driven by the declining price of natural gas and its lower environmental impacts, relative to other fuels. As a result, natural gas has become the preferred fuel for residential and commercial heating, many manufacturing processes and—most importantly—electricity generation.[31] In 2012, approximately 52% of the electricity generated in New England's wholesale market came from generators burning natural gas. By comparison, in 2000, less than 15% of New England's electricity was produced from natural gas, at the expense of oil and coal generation.

The increase in the use of natural gas for electricity generation has revealed two key issues that pose risks to the reliability of the electric power system. The first is the difference between the

30 This is an idealized representation of the gross margins to a combined-cycle unit. An evaluation of revenues earned by any particular resource should take into account all unit-specific operating characteristics (e.g., minimum run time, ramp rates, economic minimum, and heat rate).

31 ISO New England Inc., *Winter Operations Summary: January–February 2013*, draft white paper (February 27, 2013), http://iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/winter_operations_summary_2013_feb_%2027_draft_for_discussion.pdf.

scheduling days of the gas and electric power industries. The second is the adequacy of the infrastructure that supplies the region with natural gas. These problems and the risk they pose for electric power system reliability have been detailed in ISO reports.[32] This section summarizes each of the problems and provides evidence of their effects on system operations in recent years.

The gas industry's operating day runs from 10:00 a.m. to 10:00 a.m. The power system's operating day is the calendar day (i.e., midnight to midnight). Both industries create their schedules for an operating day the day before the operating day. The gas industry has two important deadlines for scheduling gas. The first is the 12:30 p.m. timely nomination deadline, and the second is 7:00 p.m. evening nomination deadline. Gas scheduled by the 12:30 p.m. cycle generally is firm. Gas procured at the 7:00 p.m. deadline is less firm, and procuring gas after 7:00 p.m. is more difficult and uncertain because gas scheduling generally is more liquid during weekdays and less liquid during nonbusiness hours. Because of these differences between the scheduling days of the two sectors, for each electric power operating day, gas-generating resources must secure fuel on two gas industry operating days (day 1 from 10:00 a.m. to midnight, and day 2 from midnight to 10:00 a.m.).

The infrastructure problems usually occur in the winter months when the demand for natural gas for heating occurs. The low price of natural gas, especially in relation to oil, its closest substitute, has caused the demand for natural gas to grow in all sectors—residential, commercial, industrial, as well as electric power—much more quickly than the pipeline capacity for buying it in New England.

Recent Performance of Natural-Gas-Fired Generation. The operational and adequacy issues with natural-gas-fired generation have been borne out in the last several years. A review of instances in which gas-fired generators have failed to follow dispatch instructions shows that the operational and adequacy concerns are real. Table 2-5 summarizes the instances, by time of day, when gas generators either reduced output or were unable to come on line.

[32] Most recently, see the ISO's white paper, *Addressing Gas Dependence* (July 2012), http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/natural-gas-white-paper-draft-july-2012.pdf.

Table 2-5
Natural Gas Generator Reduction Events (December 2009 to February 2013), by Time of Day

Time Period	Number of Events[(a)]	Percent
Midnight– 5:59 a.m.	32	16%
6:00 a.m.– 9:59 a.m.	37	19%
10:00 a.m. – 5:59 p.m.	57	29%
6:00 p.m.– 11:59 p.m.	73	37%
Total	199	100%

(a) For this analysis, the *number of events* refers to the number of instances the ISO logged concerning a gas unit's report that it needed to reduce output because of gas issues. Instances where output was reduced because of occurrences beyond the unit's control are excluded. All events were treated equally, and occurrences of a facility with multiple units needing to reduce output was counted as one event,

This table is consistent with the operational problems discussed above. Over 70% of the reductions occurred after the close of the evening nomination cycle. While a reduction event can occur for many reasons during any time of day, the IMM believes the data support the following observations:

- The ISO issues instructions for resources to come on line or remain on line after it conducts its daily Reserve Adequacy Assessment (RAA).[33] The ISO generally completes this analysis by 10:00 p.m. but may issue dispatch instructions earlier as well. The reduction events between 6:00 p.m. and 11:59 p.m. are likely because the ISO asks resources that have not nominated gas to come on line as part of the RAA. This includes resources that were not on line, as well as resources whose day-ahead market schedule was extended in the RAA.
- The events between midnight and 6:00 a.m. also may involve resources asked to come on line as part of the RAA in addition to resources called on as a result of a loss of generation or a transmission line unable to get gas at that hour. The IMM has observed gas-fired fast-start units, physically able to start in 30 minutes or less, often unable to do so during this time.
- The events between 6:00 a.m. and 10:00 a.m. generally involve resources called on line to meet the morning increase in load (the morning ramp). Again, these may be resources asked to come on line, including fast-start units, or units ordered to extend their runs past their day-ahead schedules. During this period, resources that operated above their day-ahead schedules earlier in the gas day may be forced to come off line or face large penalties from the pipeline for drawing more gas than nominated during the gas day.

This review and analysis leads to the conclusion that after the evening nomination cycle has passed, the probability that natural-gas-fired generators will not have access to the natural gas needed to follow dispatch instructions increases because of reduced liquidity in the gas markets overnight and failure by gas generators to arrange ahead of time for gas procurement during

[33] The ISO performs a Reserve Adequacy Assessment at the close of the reoffer period for the Real-Time Energy Market to ensure that adequate resources are committed to meet the ISO's forecasted load and operating reserve requirements.

those hours. These problems can occur both with resources that have nominated gas but are asked to generate more than expected and with resources not expecting to be dispatched at all. Additionally, the problems caused by the difference between the gas sector and electric power days shows up most acutely between midnight and 10:00 a.m. when the new electric day has begun but the next gas day has not yet started.[34]

Table 2-6 shows the same reduction data as above categorized by season. The table shows that most generator-reduction events have occurred during the winter. This is consistent with the earlier discussion about the ability of the region's natural gas pipeline to meet all the combined needs of the electric power, residential, commercial, and industrial sectors when the nonelectric power loads, driven primarily by space heating, are at their greatest. Specifically, most of the reduction events occurred on cold winter days. Figure 2-7 shows the cumulative number of reduction days by temperature. Reduction days were most likely when the average daily temperature was at or below 35 degrees Fahrenheit (°F). Only 5% of the reductions occurred at temperatures above 35°F. By month, December had 31 days during which a reduction event was recorded, January had 28 days, and February had 21 days.

Table 2-6
Natural Gas Generator Reduction Events by Season, December 2009 to February 2013

Season	No. of Reductions	% of Total
Winter (Dec, Jan, Feb)	130	65%
Spring (Mar, Apr, May)	10	5%
Summer (Jun, Jul, Aug)	21	11%
Fall (Sep, Oct, Nov)	38	19%

[34] The gas system has some flexibility when the overall demand for gas is not too high and the pipeline has adequate pressure. In these situations, generators may be able to use more than their nominations and purchase gas after the fact to ensure that, over the day, they do not draw more than they have purchased. However, as the demand for gas on each pipeline increases, gas system flexibility is less likely.

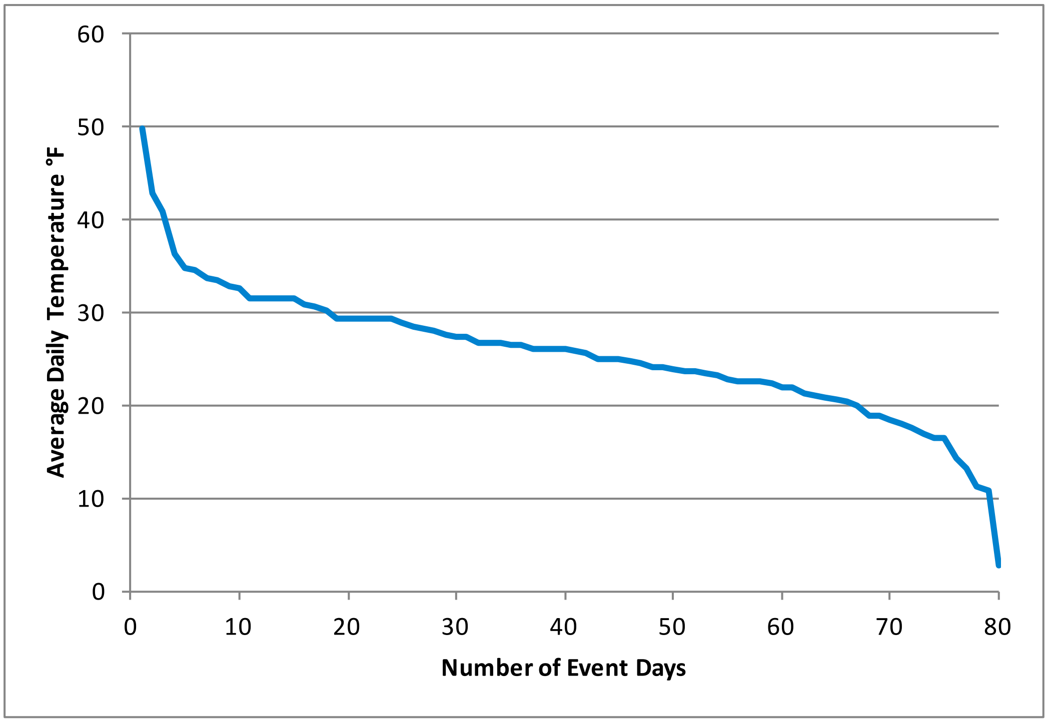

Figure 2-7: Cumulative number of reduction days by temperature (December, January, February), 2010 to 2012 (°F).

Figure 2-8 shows the monthly price of natural gas for December 2009 to February 2013. Prices are highest in the winter periods, providing evidence that pipeline capacity gets more difficult to obtain as temperatures drop and the demand for natural gas increases. The natural gas price increase shown in the figure for winter 2012/2013 also provides evidence that the gas infrastructure is almost completely utilized.

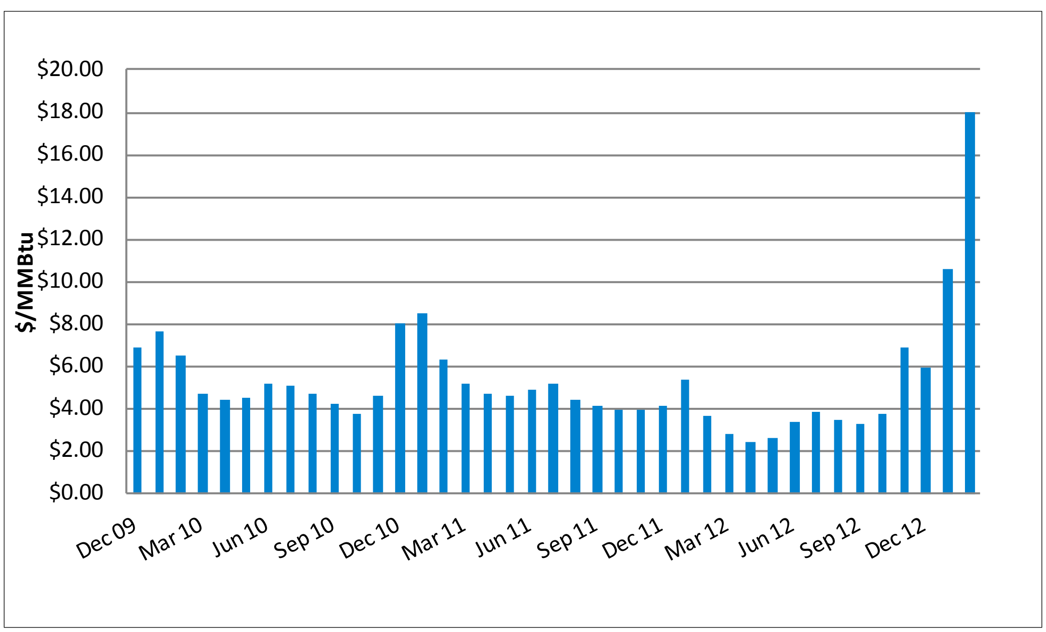

Figure 2-8: Monthly natural gas prices, December 2009 to February 2013.

ISO Actions to Address These Issues. The ISO has undertaken several actions, as follows, to enhance system reliability, generator performance, and the coordination between the electric energy and gas sectors:

- **Day-Ahead Market Timeline Adjustment (effective June 2013):** A recently filed proposal moves up the Day-Ahead Energy Market timeline to provide gas-fired generators more time to arrange fuel for the operating day and make fuel-switching decisions should they have dual-fuel capability. This change also would give ISO operators more flexibility to better accommodate resources, primarily nongas generators, that require a long time to start up. This should reduce the need to call on natural gas generators during the late evening and overnight hours when obtaining natural gas is diffucult.[35]
- **Intraday Reserves (effective October 2013):** Consistent with North American Electric Reliability Corporation (NERC) and Northeast Power Coordinating Council (NPCC) reliability standards, the ISO maintains, in real time, total 10-minute reserves (TMR) at least equal to 100% of New England's largest single-source contingency. It also maintains 30-minute operating reserves (TMOR) equal to 50% of the second-largest contingency.[36] Other than an adjustment to the TMR allocation to account for generator nonperformance, the ISO commits and dispatches the system only to meet the minimum TMR and TMOR requirements. While operating to these minimum requirements provides for adequate recovery from a single-source contingency under normal conditions, it does not provide a buffer for the instantaneous system load, which often exceeds the hourly integrated forecast peak by 300 MW. Moreover, the minimum level of reserves does not account for system uncertainties, such as load forecast deviations, forced generator outages and reductions, and fuel-procurement and scheduling difficulties.

  Beginning with winter 2013/2014, the ISO plans to operate the system to meet an incremental requirement for replacement reserve. The replacement reserve will be reflected as an increase in the system TMOR requirement in the FRM and consequently as an increase in the total system operating reserve requirement.[37] Resources will be redispatched to meet the replacement-reserve requirement using an additional Reserve Constraint Penalty Factor (RCPF) for replacement reserves, which is expected be in the range of $150 to $300/MWh. This will allow the pricing of replacement-reserves requirement to be in the markets.
- **Intraday Reoffers (effective the fourth quarter 2014):** The ISO is completing efforts with stakeholders to develop changes to allow supply offers in the Day-Ahead Energy Market to

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[35] *ISO New England Inc. and New England Power Pool, Filings of Market Rule Changes to Modify Day-Ahead Energy Market Schedule,* Docket No. ER13-895-000 (filed February 7, 2013), http://www.iso-ne.com/regulatory/ferc/filings/2013/feb/er13-895-000_%20mr_chges_mod_daem_2-7-2013.pdf.

[36] NERC is the electric reliability organization (ERO) certified by FERC to establish and enforce reliability standards for the bulk power system. For more information on NERC standards, see http://www.nerc.com/page.php?cid=2|20. NPCC is responsible for promoting and improving the reliability of the international, interconnected bulk power system in northeastern North America. For more information on NPCC standards, see https://www.npcc.org/Standards/default.aspx.

[37] ISO New England Inc., *TMOR RCPF and Replacement Reserve—Creating a Tiered Reserve Constraint Penalty Factor (RCPF) Structure for Total Operating Reserves*, NEPOOL Markets Committee presentation (March 22, 2013), http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/mar11122013/a13_iso_presentation_03_11_13.ppt.

> vary hourly and the offer information and pricing to be updated during the operating day. This will allow resource owners to more closely reflect their actual costs of fuel and operations in their energy market offers and thus to more likely secure the fuel needed to operate and perform without incuring losses due to changing conditions.[38]

IMM Analysis and Further Recommendations. The change in the day-ahead market timeline should reduce how often resources called on during the RAA will fail to follow dispatch instructions because most RAA-related instructions now will be given before the close of the evening gas-nomination cycle. This should address a large part of the gas-reduction events that have occurred. However, the change of the day-ahead market timeline will not address changes to the operating plan caused by load forecast errors or system events that occur after 6:00 p.m. The implementation of the intraday reserves should provide reserves ready to meet unexpected system events and decrease the number of gas-reduction events.

To the extent that the intraday reserves proposal relies on the design and incentives in the locational Forward Reserve Market (FRM), shortcomings in the FRM incentives structure design reduces the effectiveness of the intraday reserves proposal. The two major shortcomings of the incentive structure of the FRM are a penalty structure too weak to ensure that reserves are converted to electric energy when needed and the five-day-per-week, 16-hour-per day (5 x 16) period for the locational FRM. The problems with the FRM incentive structure and the IMM's recommendation to address them are described in detail in Section 3.3. The disconnect between the gas and electric power timelines means that natural gas resources are not likely to provide needed reserves after the close of the 6:00 p.m. nomination cycle unless these resources take action to provide them. If the FRM remains a 5 x 16 product, resources providing reserves will not increase their availability overnight and on weekends. The IMM recommends that when the intraday reserves are implemented, the FRM penalties are increased and that the FRM product be made available 24 hours per day, seven days per week (24 x 7).

The IMM strongly supports the implementation of the hourly and intraday offers proposal and will be developing the mitigation rules to support this implementation. This proposal will provide generators the ability to reprice their offers as fuel prices change, which is important for natural gas resources in the current environment.

Penalty for Failing to Follow Dispatch Instructions. As noted, the IMM continues to observe generator performance issues. The IMM is concerned that the market design does not provide proper incentives to follow real-time dispatch instructions.

When a resource fails to follow dispatch instructions, the ISO dispatches other units to balance the system, resulting in higher total production costs than otherwise would have been incurred.[39] At the five-minute dispatch level in the Real-Time Energy Market, demand does not respond to changes in price (i.e., the demand curve is vertical). Consequently, the cost imposed on the market by a resource that fails to follow dispatch instructions equals the difference between the production cost of the nonperforming resource and the production costs of the resource(s) selected to replace it. A resource that fails to follow dispatch instructions should

[38] ISO New England Inc., *Energy Market Offer Flexibility—Final Impact Analysis Report* and *Energy Market Offer Flexibility—Overview of Market Rule Revisions that Reflect Proposed Energy Market Change*, NEPOOL Markets Committee presentations (March 12, 2013), http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/mar11122013/index.html.

[39] *Undergeneration* is the focus of this section. The analysis is similar for *overgeneration*.

pay a penalty that compensates the market for the resulting incremental production costs incurred. To provide a strong incentive for resources to follow instructions, the penalty should have the following features:

- Reflect relative scarcity conditions in the market, imposing a much higher cost when no surplus exists and relatively smaller penalties when the surplus is substantial.

- Allow for an efficient breach; that is, the penalty should not be punitive. Rather, if a resource's cost to follow the dispatch instruction exceeds its incremental production-cost impact, the resource should be allowed make the economic choice and accept the penalty.

- Minimize incentives for economic withholding. A penalty for a nonperforming resource that equals the production-cost impact provides no incentive for the holders of small portfolios to withhold output. The approach also mitigates such incentives for all but very large portfolios (none of which are present in New England).

2.1.3.4 Use of the Limited-Energy Generator Provisions for Fossil Fuel Resources

The current market rules on limited-energy generators (LEGs) allow participants with resources that have limited fuel to specify the maximum amount of energy (MWh) the resource can produce in a day. The rules allow the participant to limit the resource's day-ahead commitment, as well as the resource's operation in real time. This effectively reduces the resource's availability and forces the ISO operators to adhere to this constraint when making commitment and dispatch decisions. Subsequent to receiving a day-ahead commitment, participants can inform operators that a resource has limited fuel and cannot operate beyond a stated value. Thus, the operators may not be able to use the fully stated capability of the unit to address system needs. While it is important for ISO operators to know whether a generator has limited fuel, the IMM is concerned with the use of LEG provisions by generators because this enables resources to withhold energy and capacity and potentially avoid meeting ISO tariff obligations as a capacity resource.[40]

In the Day-Ahead Energy Market, participants have the option of providing the ISO with the total maximum daily energy (MDE) available for any particular unit as part of the unit's supply offer.[41] Figure 2-9 shows the number of units that entered an MDE value for the day-ahead market between January 1, 2011, and December 31, 2012, where the participant offered less energy than needed to operate at maximum for 18 hours. Eighteen hours was used because it includes all on-peak hours in the operating day. The chart indicates an increase in the number

[40] *ISO New England Inc. Transmission, Markets, and Services Tariff* (ISO tariff), Section III, *Market Rule 1* (March 1, 2012), http://www.iso-ne.com/regulatory/tariff/sect_3/index.html.

[41] This is accomplished by a participant entering a nonzero positive daily MDE value as part of its supply offer. An MDE value ≥ eco max × 24 indicates a unit's output is not limited, and an MDE value < eco max × 24 indicates the unit's output is limited. *Economic maximum* (ecomax) is the highest unrestricted level of electric energy (in megawatts) a generating resource is able to produce, representing the highest megawatt output available from the resource for economic dispatch. Limited output units cannot run at ecomax for all hours of the day because of fuel restrictions, and the daily energy (i.e., MDE) available to the ISO will be optimized in the clearing of the day-ahead market.

of units entering MDE values that limited their total day-ahead energy in the last quarter of 2012.

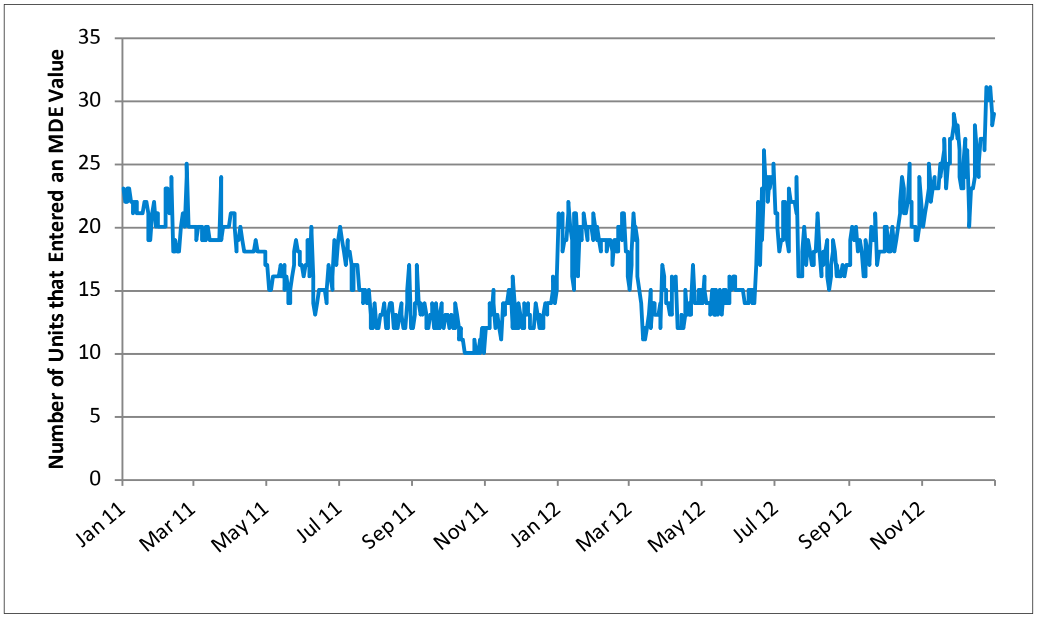

Figure 2-9: Number of units that entered an MDE value for the Day-Ahead Energy Market, January 1, 2012, to December 31, 2012.

Notes: The economic maximum (ecomax) value used is the bid-in ecomax for hour-ending 1 (i.e., 1:00 a.m.). Day-ahead data in the chart exclude hydro, nuclear, and wind units.

In real-time, a market participant can manage the use of electric energy from any portion of a limited-energy resource by using the limited-energy hourly maximum levels for the resource.[42] Figure 2-10 illustrates the number of units that elected to use the LEG flag in real time by day between January 1, 2011, and December 31, 2012. The number of these units was much lower than the number of units that entered an MDE value day ahead. The data indicate that the number of units that elect to use this feature in real time has not varied widely.

[42] *ISO New England Manual for Market Operations*, Manual M-11 (January 4, 2013), http://www.iso-ne.com/rules_proceds/isone_mnls/index.html.

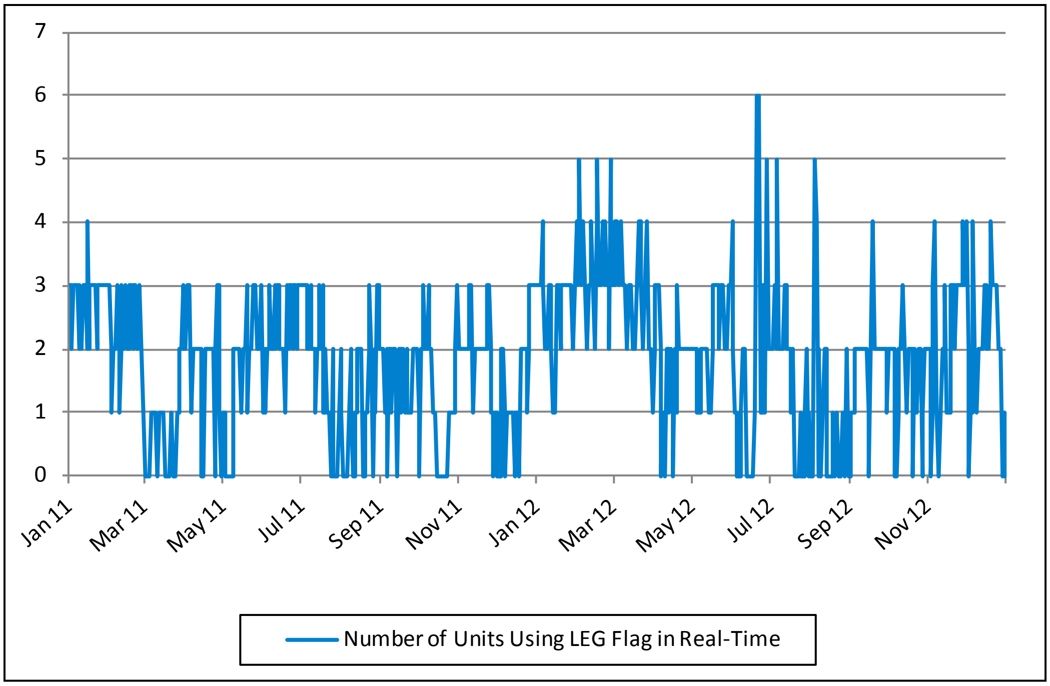

Figure 2-10: Number of units that elected to use the LEG flag in real time, January 1, 2012, to December 31, 2012.

Note: In the figure, real-time data exclude hydro, nuclear, and wind units.

The IMM believes that use of the LEG provisions does not excuse resources from meeting their obligations to have sufficient fuel to operate consistent with their supply offers. Resources must be able to operate at their maximum physical capability for the day if needed. The IMM recommends a review of the LEG rules to determine whether they need to be revised to prevent fossil fuel resources from using them to avoid meeting their obligations as capacity resources.

2.1.3.5 Energy Prices and Real-Time Demand

The demand for electricity in New England, defined as *net energy for load* (NEL), is weather sensitive and contributes to the seasonal variation in energy prices.[43] The NEL was highest in the third quarter of 2012, at 35,721 gigawatt-hours (GWh). The annual peak demand of 25,880 MW also occurred in the third quarter, on July 17. The first quarter had the second-highest demand for electricity in 2012, at 31,470 GWh of electricity consumption, which is consistent with historical observations and is driven by the higher electrical heating demand on the system during the peak winter months. As expected, the second and fourth quarters of 2012, with typically more mild temperatures, had the lowest demand for electricity. See Table 2-7.

[43] *Net energy for load* (NEL) is calculated as total generation (not including the generation used to support pumping at pumped-storage hydro generators) plus net imports.

Table 2-7
Energy Statistics, 2011 and 2012

	2011 Annual	2012 Annual	Q1 2012	Q2 2012	Q3 2012	Q4 2012
NEL (GWh)	129,162	128,007	31,470	30,040	35,721	30,776
Weather-normalized NEL (GWh)[(a)]	128,998	128,249	32,187	30,086	35,021	30,955
Recorded peak demand (MW)	27,707	25,880	19,926	25,678	25,880	19,119

(a) *Weather-normalized* results are those that would have been observed if the weather were the same as the long-term average.

Figure 2-11 shows real-time monthly LMPs and the cycle in seasonal demand over the past two years, illustrating the impact on price of higher demand in the winter and summer months and lower demand in the spring and autumn months. The correlation between the daily average hourly loads and real-time Hub prices was 0.57 for 2011 and 0.58 for 2012. The winter months (December to March) diverge from the pattern of lower loads and lower prices when cold weather drives up the demand and the price of natural gas, causing high electricity prices at lower load levels. This can be seen in January 2011 and in November and December of 2012.

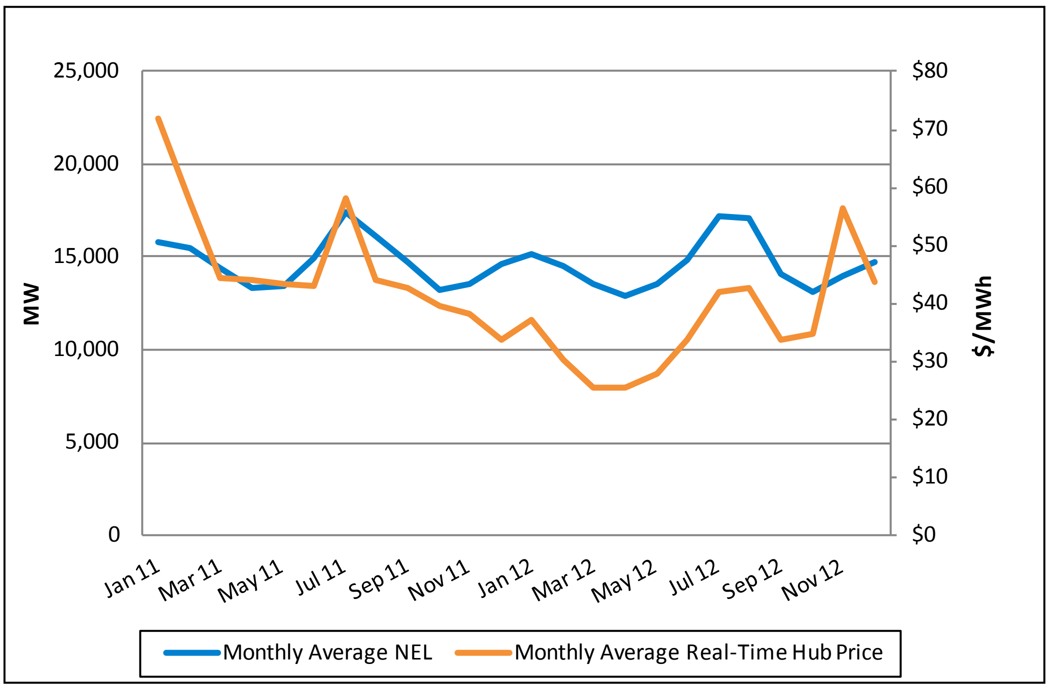

Figure 2-11: Monthly average net energy for load and real-time Hub prices, 2011 to 2012.

2.1.3.6 Automated Mitigation

Mitigation is the process that prevents noncompetitive offers from affecting the market price. The market rules governing the mitigation process use three tests; structure, conduct, and impact. The IMM conducts the following tasks:

- Evaluates the *structure* of the competition the generator faces (e.g., whether it is in a load pocket— or import-constrained area of the system—and faces less competition)

- Evaluates the generator's *offer* (i.e., its conduct) against a reference level prepared by the IMM[44]
- After the evaluations, estimates the *impact* the generator's offer will have on market outcomes

A generator's energy offer that is less than the applicable reference level plus the appropriate threshold is deemed competitive and not subject to possible mitigation, while an energy offer that exceeds the applicable reference level plus the appropriate threshold is subject to possible mitigation. This comparison of an energy offer against the reference level plus a threshold is performed for all resources across the system. For generators facing less competition (i.e., those within import-constrained areas of the system), the thresholds used in the comparison against an energy offer price are lower than the thresholds used for generators facing competition from all generators in New England. Generator energy offers are mitigated only when they exceed the applicable reference level plus the appropriate threshold and the offer price raises the market price (e.g., the LMP) by a specific impact threshold.

Another set of mitigation rules applies to commitment costs, primarily start-up and no-load costs that do not affect a market price. Commitment costs may instead result in out-of-market (OOM) "make-whole" payments, termed Net Commitment-Period Compensation (NCPC).[45] Mitigation rules that apply to generators committed for reliability have smaller thresholds than the general energy mitigation rules because units committed for reliability often face no competition and could offer significantly above their costs. Because the LMP calculation does not use commitment costs, the impact of commitment costs on market prices is not determined before mitigation.

In 2012, the IMM automated a number of mitigation processes and improved its calculation of the price-impact test. On April 17, 2012, the IMM implemented automated mitigation, which runs a separate dispatch of the electricity market in parallel with the actual dispatch.[46] This parallel dispatch uses all the same inputs as the actual dispatch, except that the generators' reference offers replace the offers that exceed the energy market conduct thresholds. After the parallel dispatch is run, the resulting prices are compared with the prices from the actual dispatch. If the difference between the prices exceeds the energy price impact threshold, the generator is mitigated. This comparison of the alternative dispatch with the original dispatch allows for a more accurate calculation of the price impact.

Table 2-8 shows all the mitigations for 2012 by mitigation type. Mitigations increased somewhat in April and May 2012 just after the implementation of automated mitigation because participants adjusted their offer behaviors and updated the reference level information

[44] A reference level generally reflects either the actual cost to the resource of generating electricity or, most frequently, in the case of hydroelectric units, the opportunity cost of producing electricity now compared with storing it and generating electricity later.

[45] NCPC payments are made to market participants with resources dispatched out of economic-merit order for reliability purposes when the costs of providing energy or reserves from the resources would otherwise exceed the revenue paid to the market participant. *Economic NCPC* arises when the total cost of committing and operating a generating resource exceeds the revenues it earns from the sale of energy at the LMP.

[46] *ISO New England Inc. and New England Power Pool, Market Rule 1 Revisions Relating to Real-Time Automated Mitigation of Supply Offers*, Docket No. ER11-4540-000 (filed September 15, 2011), http://www.iso-ne.com/regulatory/ferc/filings/2011/sep/er11_4540_000_9-15-11_rev_auto_mitigation.pdf.

held by the IMM. Some variations are consistent with changes in system conditions, such as high loads in July, leading to an increase in pivotal suppliers and pivotal-supplier mitigations.

Table 2-8
2012 Mitigations by Type

Month	Local Reliability Commitment Mitigation	General (Unconstrained) Commitment Mitigation	Constrained Area Commitment Mitigation	General (Unconstrained) Energy Mitigation	Constrained Area Energy Mitigation	Dual-Fuel Corrections
Jan	15	0	0	0	0	N/A
Feb	1	0	0	0	0	N/A
Mar	3	0	0	0	1	N/A
Apr	8	17	0	0	2	0
May	23	13	20	8	8	0
Jun	2	5	0	5	9	1
Jul	2	3	0	37	5	7
Aug	2	6	5	7	1	3
Sep	19	3	2	0	12	0
Oct	5	9	0	0	4	1
Nov	7	1	0	4	18	0
Dec	1	7	0	9	1	0
Total	**88**	**64**	**27**	**70**	**61**	**12**

(a) Section 4.1.3.1 explains each type of mitigation.

As noted, one factor that may have contributed to more mitigations is the change in consultation requirements. Before automated mitigation, resources were only subject to energy market mitigation if they were setting price. However, mitigation did not occur until after a resource consulted with the IMM. As a practical matter, by the time the consultation was complete, the generator often was no longer setting price; thus, no mitigation occurred. Under the new automated-mitigation rules, consultations must take place before the operating day because consulting with generators in real time is not practical. Some market participants failed to consult with the IMM about their reference levels before the implementation of auto mitigation, resulting in increases in the number of mitigations. After the implementation of automated mitigation, the IMM has observed a greater number of participants providing the information necessary to more accurately estimate reference levels, especially after the participants have been mitigated.

A second change that contributed to the increased number of mitigations was an improved ability to determine pivotal-supplier status in real time. Before automated mitigation, pivotal suppliers could be determined only during the peak hour for generators committed in the day-ahead market or RAA. Under automated mitigation, pivotal suppliers and their impact on prices are determined continuously in the real-time market.

Before automated mitigation, the manual mitigation process required the ISO to notify the IMM when a unit that exceeded its conduct threshold was setting price (i.e., the generator was marginal). Generators were mitigated only if they were setting price and violating their conduct test. Generators with offers above the clearing price were not evaluated, thus enabling them to withhold economically. Under automated mitigation, generators that attempt to withhold economically are evaluated and mitigated, which also contributed to the increase in mitigations.

2.1.3.7 Energy Prices and External Transactions

In 2012, New England was a net importer of power. Net imports from Canada exceeded net exports to New York (NY). The net interchange with neighboring balancing authority areas totaled 12,648 GWh for 2012, a 26% increase compared with the previous year. The increase in the net interchange is the result of both fewer exports and greater imports in 2012 compared with 2011. See Figure 2-12.

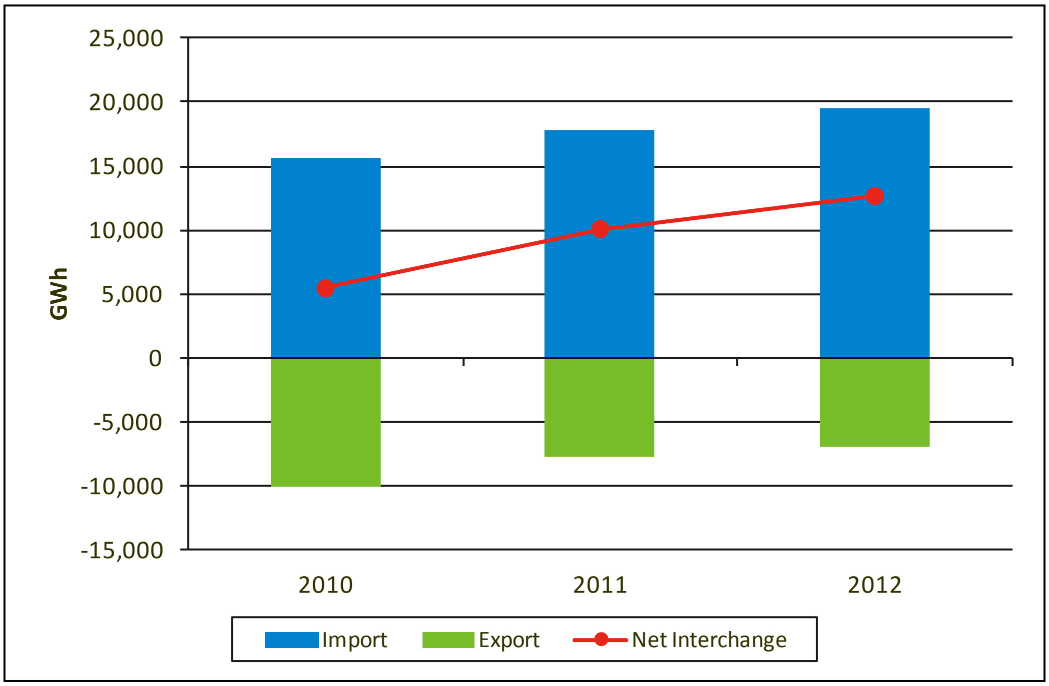

Figure 2-12: Scheduled imports and exports and net external energy flow, 2010 to 2012 (GWh).

The lower levels of New England exports are not directly attributable to a price differential between New England and New York. The current rules and systems that govern the interchange between New York and New England do not allow for the realization of all possible gains from trade between the regions. Ideally, power should flow from the region with lower costs to the region with higher costs. However, the current scheduling system does not allow market participants to modify their bids and offers during the day, nor does it allow the ISO to optimize tie flows with sufficient frequency to ensure the efficient scheduling of the ties under all conditions. As a result, on the northern alternating-current (AC) ties between the New York Independent System Operator (NYISO) and ISO New England, power only flows in the apparent "right" direction about half the time, that is, in the direction expected based on observable price differences between the Roseton and the Sandy Pond pricing locations.[47] See Table 2-9.

[47] *Roseton* and *Sandy Pond* are the "border," or proxy bus, pricing nodes for real-time, hourly integrated LMPs for NYISO and ISO New England.

Table 2-9
Percentage of Time Transactions Are Scheduled in the Direction of the Higher Price on the Roseton Interface, 2010 to 2012

Year	Real Time	Day Ahead
2010	48%	63%
2011	52%	57%
2012	52%	57%

In addition, production costs would be lower if the existing transmission interconnections were scheduled more efficiently, that is, scheduled in the prevailing direction of price up to the available total transfer capability (TTC). The data indicate that during many hours of the year, ample transmission capacity is available to move additional power from the lower-cost region to the higher-cost region. Potomac Economics, the ISO's External Market Monitor, estimates that if the transmission interface between New England and New York had been scheduled efficiently, the total production cost of meeting demand in the two regions (combined) would have been lower by a cumulative $77 million from 2006 through 2010.[48]

On January 20, 2012, stakeholders agreed to investigate coordinated transaction scheduling (CTS), which employs higher-frequency scheduling and eliminates charges and credits on external transactions that deter trade. FERC accepted CTS on April 19, 2012.[49] The IMM supports the efforts to adopt rules and systems to implement CTS.

2.1.3.8 Energy Prices and Transmission Outages

According to the US Department of Energy (DOE) *2009 National Electric Transmission Congestion Study,* which summarized the amounts of congestion throughout the Eastern Interconnection, the New England system currently experiences little system congestion.[50] As a result, DOE has removed New England as an "area of concern" for the identification of National Interest Electric Transmission Corridors.

Though congestion is no longer a major concern, short-term transmission issues, including planned or forced outages and transmission line trips, still affect market outcomes and prices. Through its daily surveillance of the energy market, the IMM has observed that transmission issues resulting from planned or forced outages and trips can create binding constraints, which can contribute to transient congestion or elevated price levels on the system.

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48 ISO New England Inc., *Interregional Interchange Scheduling (IRIS) Analysis and Options*, white paper (January 5, 2011), http://www.iso-ne.com/pubs/whtpprs/iris_white_paper.pdf.

49 FERC, *Order Accepting Tariff Revisions, Subject to a Compliance Filing*, Docket No. ER12-1155-000 (April 19, 2012), http://www.iso-ne.com/regulatory/ferc/orders/2012/apr/er12-1155-000_4-19-12_order_accept_cts.pdf.

50 DOE, *2009 National Electric Transmission Congestion Study* (December 2009), http://www.congestion09.anl.gov/documents/docs/Congestion_Study_2009.pdf. The *Eastern Interconnection* is one of North America's major AC grids that, during normal system conditions, interconnects transmission and distribution infrastructure synchronously operating (at 60-hertz average) east of the Rocky Mountains and south to Florida, excluding Québec and the portion of the system located in the Electric Reliability Corporation of Texas (ERCOT).

2.1.4 Demand Response

The following section reviews the participation and outcomes of demand resources in New England for 2012. The section also summarizes the IMM's analysis of the accuracy of the ISO's methodology for determining an asset's baseline and load reductions. This analysis incorporates the recommendations made in the *2011 Annual Markets Report* (AMR11) for calculating these baselines.[51]

2.1.4.1 Year in Review

Demand resources have been part of New England's wholesale electricity market since the start of the markets in 2003 when the ISO implemented a series of demand-response programs. Over the years, the programs were enhanced to include three basic categories: demand response that reduced load to support system reliability, demand response that reduced load in response to wholesale energy prices, and demand resources that reduced load through energy efficiency and other nondispatchable measures.

In 2010, demand resources were integrated into the Forward Capacity Market (FCM) (refer to Section 3.4). Under the FCM, demand resources compete in the Forward Capacity Auction (FCA), take on capacity supply obligations (CSOs), and receive capacity payments comparable to other supply-side resources.[52] The two broad categories of demand resources in the FCM are active and passive demand resources. *Active demand resources* are dispatchable and reduce load in response to ISO dispatch instructions. *Passive demand resources* are not dispatchable and provide load reductions during predetermined periods.

Active demand resources include real-time demand-response (RTDR) resources, which reduce load within 30 minutes of receiving an ISO dispatch instruction, and real-time emergency generation (RTEG) resources, which reduce load by transferring load that otherwise would be served from the electricity grid to emergency generators. Passive demand resources include on-peak resources, such as energy-efficiency projects and distributed generation that reduce load during predefined periods, and seasonal-peak resources, such as energy-efficiency projects where the project's load reduction is weather sensitive.[53]

In 2012, from January 1 through May 31, the ISO administered two demand-response programs that provided financial incentives for customers to reduce load in response to day-ahead and real-time energy prices: the Real-Time Price-Response (RTPR) Program and the Day-Ahead Load-Response Program (DALRP). A new, optional program, the Transitional Price-Responsive Demand (TPRD) Program, designed to comply with FERC Order 745, replaced both the RTPR program and the DALRP.[54] Similar to the DALRP, the TPRD program allows market participants with assets registered as RTDRs to offer load reductions in response to day-ahead LMPs. Market

[51] ISO New England Inc., *2011 Annual Markets Report* (AMR11) (May 15, 2012), http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/index.html.

[52] A CSO is a requirement for a resource to provide capacity, or a portion of capacity, to satisfy a portion of the ISO's total capacity requirement for a given year. Refer to Section 3.4 for more details.

[53] Distributed generators are a subset of demand-side resources and consist of relatively small-scale sources of power (i.e., several kilowatts to tens of megawatts in capacity) connected to the grid at the distribution or substation level. DG technologies include both renewable resources (e.g., solar photovoltaics, wind turbines, fuel cells, biomass, and small hydro) and conventional resources (e.g., diesel reciprocating engines and gas turbines).

[54] ISO New England Inc., *Order No. 745 Compliance Filing*, FERC Docket No. ER11-4336-001 (August 19, 2011), http://www.iso-ne.com/regulatory/ferc/filings/2011/aug/er11_4336-001_prd_filing.pdf.

participants are paid the day-ahead LMP for their cleared offers and are obligated to reduce load by the amount cleared day ahead. The participant is then charged or credited at the real-time LMP for any deviations in curtailment in real time compared with the amount cleared day ahead. The TPRD program is anticipated to remain in effect until June 1, 2017, at which time new market rules will become effective that will fully integrate dispatchable demand resources into the Day-Ahead and Real-Time Energy Markets.[55]

2.1.4.2 Demand Resources in the Forward Capacity Market

As shown in Table 2-10, the total capacity supply obligation for all demand resources participating in the FCM decreased by 11% in 2012 compared with 2011, a loss of 219 MW. The CSOs of active demand resources accounted for a reduction of 326 MW (30%). A probable reason for some of the decrease in CSOs for active demand resources was a change in the market rule, effective June 1, 2012, that eliminated the reserve-margin gross-up previously added to demand resources' CSOs.[56] In contrast, the CSOs of passive demand resources increased by 107 MW (12%)—even with the elimination of the reserve-margin gross-up—primarily because of the growth of the investor-owned utilities' energy-efficiency programs.

Table 2-10
Capacity Supply Obligations by Demand Resource Type, 2011 and 2012 (MW)

	Active Demand Resources[a]			Passive Demand Resources[a]			Total All Demand Resources
	Real-Time Demand Response Resource	Real-Time Emergency Generation Resource	Total Active Demand Resources	On-Peak Demand Resource	Seasonal-Peak Demand Resource	Total Passive Demand Resources	
2011 year end	632	439	1,071	613	259	872	**1,943**
2012 year end	446	299	745	723	256	979	**1,724**
% change, 2011 to 2012	−29%	−32%	−30%	18%	−1%	12%	**−11%**

(a) Values are based on the resources' CSOs as of December 31, 2011, and December 31, 2012.

Two participants accounted for approximately 70% of the RTDR and RTEG resources. Figure 2-13 shows the market participants with active demand resources in FCA #3 , as well as the percentage of cleared capacity (in MW) represented by these participants.[57]

[55] In April 2012, the ISO requested that the transitional rules remain in effect until June 1, 2017, when FCM rules address how capacity resources will be integrated into the energy markets. *ISO New England Inc., Market Rule 1 Price-Responsive Demand FCM Conforming Changes for Full Integration*, Docket No. ER12-1627-000 (filed April 26, 2012), http://www.iso-ne.com/regulatory/ferc/filings/2012/apr/er12-1627-000_4-26-2012_prd.pdf. RTEG resources will be prohibited from participating in the day-ahead and real-time markets because of air permit restrictions.

[56] ISO New England Inc. and New England Power Pool, *Tariff Revisions Regarding Elimination of the Reserve Margin Gross-Up for Demand Resources; Docket No. ER09-209-000* (October 31, 2008), http://www.iso-ne.com/regulatory/ferc/filings/2008/oct/er09-209-000_10-31-08_dr_gross-up_filing.pdf.

[57] FCA #3 has a *capacity commitment period* (CCP) from June 1, 2012, to May 31, 2013.

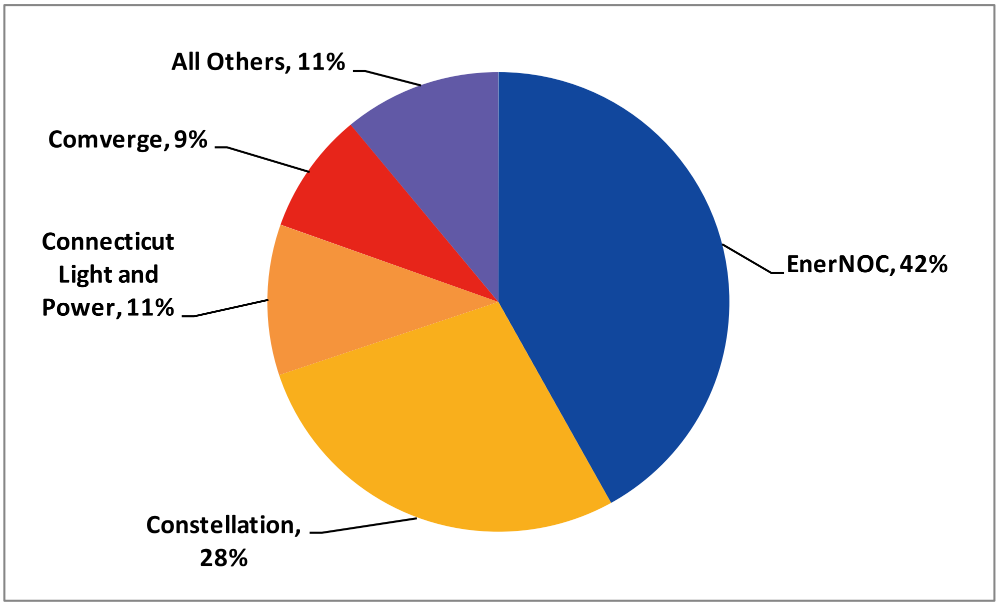

Figure 2-13: Distribution of active-demand-resource megawatts cleared by lead participants in FCA #3.

Figure 2-14 shows the market participants with passive demand resources in FCA #3, as well as the percentage of cleared capacity (in MW) represented by these participants. The top two participants control approximately 41% of the total.

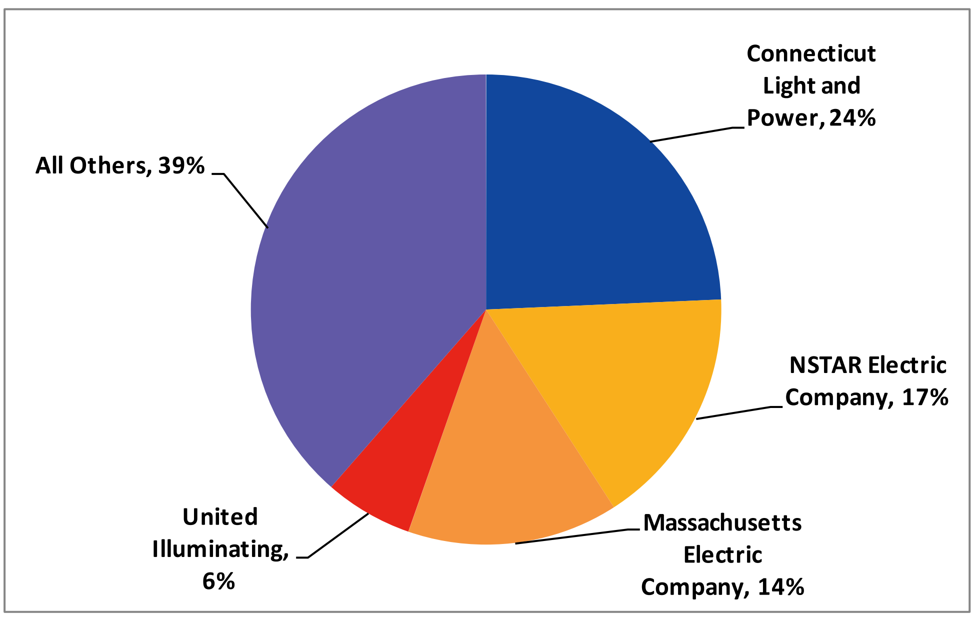

Figure 2-14: Percentage distribution of passive-demand-resource megawatts cleared by lead participants in FCA #3.

Market participants that provide either demand-response services exclusively or demand-response services and competitive electricity supply offer most of the active demand resources. In contrast, market participants that are investor-owned utilities and, for the most part, a part of state-sponsored energy-efficiency programs, offer most of the passive demand resources.

2.1.4.3 Demand-Resource Payments

As shown in Table 2-11, demand-resource payments totaled $91.4 million in 2012 compared with $104.3 million in 2011. Capacity payments are based on the FCM capacity clearing price and capacity values determined pursuant to the rules of the FCM. Total demand-resource capacity payments were lower in 2012 compared with 2011 because of a reduced capacity payment rate ($/kW-month) coupled with the elimination of the reserve-margin gross-up.

Table 2-11
Total Payments to Demand-Response Resources, 2011 and 2012

Period	Capacity Payments	DALRP Payments[(a)]	RTPR Payments[(a)]	Transitional PRD Payments[(a)]	Total Payments
2011	$97,591,568	$6,201,137	$485,105	$0	$104,277,810
2012	$89,181,607	$527,046	$51,767	$1,637,868	$91,398,288
Change	−$8,409,961				−$12,879,522
% Change 2011 to 2012	−8.6%				−12.4%

(a) The DALRP and the RTPR program ran until May 31, 2012, and were replaced with the TPRD program, which began on June 1, 2012.

The remainder of the payments to demand resources in 2012, approximately 2%, was for load reductions in the two price-response programs that ended on May 31, 2012 (RTPR and the DALRP) and the current Price-Responsive Demand Program.

2.1.4.4 Accuracy in Estimating Baseline Load Reductions

A baseline is used to forecast an asset's typical hourly loads during periods when it is not reducing load in response to an ISO dispatch instruction or a price signal. During an event, an asset's actual load is compared with its baseline load to estimate the asset's load reduction.[58]

In the *2011 Annual Markets Report*, the IMM made several recommendations regarding revising the calculations for determining an asset's baseline. In 2012, the ISO made several changes to the methodology for determining the baseline loads for active demand resources to improve the accuracy of the baselines and load-reduction calculations. The following recommendations went into effect on June 1, 2012:

- **Initial baseline calculation**—Initial baselines now require a minimum of 10 consecutive days of meter data. A larger sample size of 10 days, relative to the old requirement of 5 days, will improve the estimate of the initial baseline.

- **Symmetric adjustment of baseline**—On the day of a load-reduction event, an asset's baseline (used to calculate the asset's load reduction) will be adjusted either upward or

[58] An event can be in response to the ISO's dispatch instruction (i.e., during ISO Operating Procedure No. 4 [OP 4] or an audit) or times when the asset is responding to price. Operating Procedure No. 4, *Action during a Capacity Deficiency,* guidelines contain 16 actions that can be implemented individually or in groups depending on the severity of the situation. OP 4 is available at http://www.iso-ne.com/rules_proceds/operating/isone/op4/ (December 9, 2011).

downward (an adjustment factor) dependent on the asset's energy use 2.5 hours before the start of the event. Before the change, an asset's baseline could be adjusted upward but not downward.

- **Refresh baselines**—Before June 1, 2012, an asset's baseline could become "stale" if it was dispatched frequently or responded to price. After June 1, the methodology began to refresh the baseline more frequently with contemporary load data. The ISO determines whether or not to include metered data on an event day when refreshing the baseline by observing the past 10 days of the same type of day (for example, weekdays) and counting how many of these 10 days are nonevent days. A *nonevent day* is a day when an asset is not reducing load in response to an ISO dispatch instruction or price. A minimum of three nonevent days is required for "refreshing" the baseline. If an asset does not meet the minimum criterion, its metered data for event days will be included when refreshing its baseline.

Market Rule 1, Section 8, contains additional details on the calculation of baselines.[59]

The accuracy of an asset's baseline is paramount in determining a reliable estimate of its load reductions and ensuring proper compensation for its reductions. Also, accurate baselines and load reductions provide ISO system operators with a reliable estimate of the total megawatt reductions achieved during ISO Operating Procedure No. 4 (OP 4) events. Because the new baseline methodology took effect on June 1, 2012, the IMM assessed how well the new baselines forecasted the assets' loads over a specified period.

The following sections provide an overview of the methodology used to analyze the accuracy of the ISO's baseline calculation, a summary of the results, and an additional recommendation regarding the submission of meter data.

Methodology. The approach the IMM used to estimate baseline accuracy was similar to the methodology KEMA used in a baseline study conducted for the ISO in August 2011.[60] First, for any given day, the IMM calculated an asset's baseline using a method similar to the ISO's methodology previously described. The asset's baseline was then compared with the asset's actual metered load.[61] A difference between an asset's baseline and its actual load, in any period, represents the error in the baseline calculation. A "perfect" baseline would exactly predict an asset's load on a day it did not change its consumption in response to price or an ISO dispatch instruction. A positive value indicates the baseline is overforecasting the actual load, while a negative value indicates the baseline is underforecasting the actual load. The difference is calculated for each hour of the period of interest.

The IMM investigated two areas in determining the accuracy of baselines:

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[59] *Market Rule 1*, Section 8, http://www.iso-ne.com/regulatory/tariff/sect_3/index.html.

[60] KEMA, *Analysis and Assessment of Baseline Accuracy* (August 4, 2011). The objective of KEMA's study was to evaluate the accuracy and bias of the ISO's current baseline methodology, as well as several proposed baseline design changes.

[61] The baseline used in the IMM's calculation is the adjusted baseline for that particular asset for that particular day. The adjustment value is derived from the electric energy consumed in the two hours before the first hour of an event, as opposed to the ISO's method of using data from 2.5 hours before the event because of data limitations. Using two hours is a reasonable approximation and should not change the results.

1) **Baseline Bias:** The *baseline-bias* metric answers the question: Does the baseline methodology consistently overforecast or underforecast an asset's actual energy consumption over a predefined period in the day? For any given asset, the daily baseline forecast may be either too high or too low relative to the asset's actual load. Across all assets, a desired result would be slightly overforecasting the energy consumption of half the assets and slightly underforecasting the energy consumption of the other half. The over- and underforecast errors would cancel out, resulting in a zero bias.

2) **Magnitude of Error:** The *magnitude of the error* metric answers the question: How large is the asset's forecast (baseline) error? If the baseline error for an asset is significantly large, any load reduction for that asset, which is calculated relative to the baseline, would be unreliable. Significantly large errors can be ascertained by observing all the forecast errors for all assets and ranking the errors to construct an error distribution. To understand the magnitude-of-forecast error, the IMM calculates the mean absolute percent error (MAPE), described below.

To calculate an asset's baseline bias and MAPE, the IMM used load data from noon through 6:00 p.m. These hours were selected because they represent an on-peak period of typically higher loads and LMPs. Table 2-12 provides an example for the two calculations performed as part of the analysis for an asset. As shown, the average error across these hours equals 0.052 MW. Relative to the average load for these same hours, the asset's relative error is +3.0%, which is equivalent to the asset's baseline bias for the day. This baseline bias value is calculated for all assets for the day. The median of all bias values for a day indicates whether an overall bias exists in the baseline methodology. An optimal median value near zero for an asset indicates that half the asset's loads were underforecasted and half were overforecasted. The MAPE is calculated in the same manner as the baseline bias except the absolute value of the error is used. In the example below, the MAPE and baseline bias values are equal because the hourly baseline bias is positive in all hours.

Table 2-12
Baseline Bias and Mean Absolute Percent Error (MAPE) Calculation Example

Hour	Load (MW)	Baseline (MW)	Error (MW)
10 a.m.	1.777	1.799	
11 a.m.	1.862	1.841	
12:00 noon	1.860	1.869	0.008
1:00 p.m.	1.836	1.873	0.037
2:00 p.m.	1.834	1.906	0.071
3:00 p.m.	1.800	1.852	0.052
4:00 p.m.	1.710	1.759	0.049
5:00 p.m.	1.680	1.739	0.059
6:00 p.m.	1.610	1.701	0.090
Average	1.761		0.052
Asset relative error = average error / average load			**3.0%**

The data used for the IMM analysis includes daily data from June 1, 2012, through December 31, 2012. Weekends, holidays, and any days when an event occurred (e.g., OP 4 or audits.) were excluded from the analysis. Also, only demand-resource assets categorized as "load only" were evaluated, which excludes assets with behind-the-meter generation.[62] As of December 2012, the system had approximately 1,350 load-only assets.

Results. Figure 2-15 illustrates the daily baseline-bias percentage from June 1, 2012, through December 31, 2012. Each point represents the median value of all the calculated bias values for each asset by day for the predefined hours of noon to 6:00 p.m. A value of zero indicates, for that day, that the energy forecast was too high for half the assets and too low for the other half. While most months have an average bias near zero, September and October had a slight positive bias. This may be attributed to a change in cooling requirements (i.e., less need for air conditioning) from summer to autumn. Seasonal bias, if it exists, will be better understood as more data become available. From the months analyzed thus far, the data indicate that the current methodology for determining baselines introduces little or no bias.

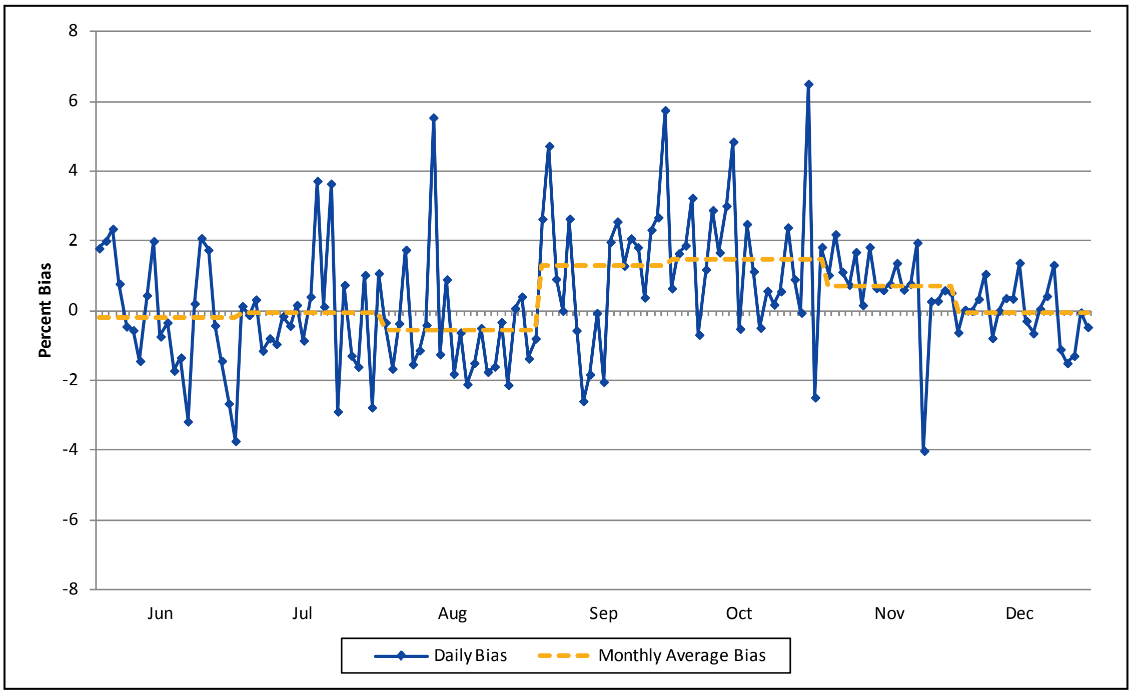

Figure 2-15: Daily baseline forecast bias, June through December 2012 (%).

By month, for each asset for each nonevent day, a mean absolute percentage error was calculated over the hours from noon through 6:00 p.m., and a monthly distribution was developed. Table 2-13 illustrates several percentiles of these monthly distributions. For example, in June, for half the assets, the current baseline methodology forecasts the actual hourly energy for noon through 6:00 p.m. with an error of 9.7% or less. For the other half of the assets, the forecast error is above 9.7%. These median MAPE values range from 7.8% to 11.5% for the months analyzed. At the other end of the spectrum, the 90th percentile, forecast errors range from 33% to 61%.

[62] "Load-only assets" can only consume electricity.

Table 2-13
Mean Absolute Percentage Error by Month and Percentile, June through December, 2012

Month	10th Percentile	25th Percentile	Median	75th Percentile	90th Percentile
Jun	3.9	6.0	9.7	17.5	37.5
Jul	3.3	4.8	8.4	17.9	41.2
Aug	3.1	4.3	7.8	16.1	35.3
Sep	3.6	5.1	8.7	16.1	33.0
Oct	3.6	5.9	11.5	21.5	45.5
Nov	2.6	4.3	9.0	20.2	50.9
Dec	2.0	4.2	9.9	22.7	61.4

The IMM's preliminary findings suggest that the ISO's new baseline methodology performs well for most load-only assets. Assets in the 10th and 25th percentile typically have consistent daily load shapes, and their loads can be forecast using the ISO's baseline methodology with greater precision. For example, for 10% of the assets (10th percentile) in December 2012, the forecast (baseline) was within 2.0% of the actual values. However, for assets in the 90th percentile and beyond, the ISO's baseline methodology produces a forecast (baseline) that does not accurately predict the asset's actual load. Assets in this category typically have highly variable, unpredictable loads, or in some cases, the market participant may have submitted erroneous meter data. Regardless of the root cause, given that the baselines for these assets are not highly accurate, there is equally little confidence in the accuracy of the assets' load-reduction calculations.

The IMM will continue to monitor and report on baseline bias and accuracy over the course of 2013. Having a full calendar year of data will aid in the understanding of seasonal influence, if any, on baseline bias and accuracy. The IMM's ongoing analysis will assess whether the ISO's methodology for determining baselines is unable to accurately estimate load reductions for a class of assets because of the nature of their load shapes. Depending on the results of the analysis, the IMM may recommend that the ISO revise the methodology to remedy any inaccuracies resulting from the current methodology.

Submission of Meter Data Issue and Recommendation: The IMM has observed instances of market participants submitting inaccurate meter data to the ISO for demand resources, which contribute to baseline and load-reduction inaccuracies. While the current market rules require an annual independent audit of the procedures to verify and submit meter data, and the *Measurement and Verification of Demand Reduction (MVDR) Manual* includes a number of requirements for verifying meter data, the IMM believes that a significant factor contributing to inaccurate meter data is that market participants report all meter data to the ISO without any third-party verification.[63]

[63] *ISO New England Manual for Measurement and Verification of Demand-Reduction Value from Demand Resources*, (Manual M-MVDR) (June 1, 2012), http://www.iso-ne.com/rules_proceds/isone_mnls/index.html.

Inaccurate meter data used in the calculation of baselines and load reductions can lead to consequences for ISO settlements, system operations, and system planning. Some, or all, of the following can occur if meter data are overstated:

- The compensation that some market participants with demand resources can receive for capacity and energy is based on overstated performance.
- Other market participants could pay for "phantom" load reductions.
- ISO system operators may rely on a demand resource that has overstated capability.
- The ISO can procure too little capacity in an FCA because some demand resources have overstated their capability.

Inaccuracies resulting from the submittal of erroneous data can be remedied by process changes. The IMM recommends, as in the *2011 Annual Markets Report*, tariff changes that would require a party independent from the market participant with registered RTDR assets, such as the local distribution utility, to provide meter data to the ISO. The IMM also recommends that market participants notify the ISO as soon as the participant determines that inaccurate information had been submitted for any demand resource or demand-resource asset. The changes should include minimum requirements for validating meter data and describing assets.

Including data-validation requirements in the ISO's tariff will enhance the ISO's and IMM's enforcement of such requirements when referrals to FERC are required. Finally, requiring market participants to self-report data-quality issues to the ISO in a timely manner and to refund payments based on inaccurately stated performance will further clarify expectations for proper market-participant behavior and responsibilities.

2.1.5 Performance and Conduct Measures

In this section, the IMM presents the results of two metrics that quantify the extent participants can sustain profits, above the competitive level, by raising electric energy prices above marginal costs. The *gross margin* measure is important because the level of profits available in the market is a driver of capital-allocation decisions. The *competitiveness measure* is important because price is the principle means of coordinating short-run production and consumption decisions. To the extent that either profits or prices are distorted as a result of the exercise of anticompetitive behavior (i.e., bids above cost), short- and long-term resource-allocation decisions can be distorted and increase overall costs.

2.1.5.1 Gross Margin

The gross margin measures the extent to which market participants are able to realize gross profits in the energy market above competitive levels as a percentage of their energy market revenues. This metric takes the difference between two simulations of market outcomes: (1) a *benchmark case* that assumes all market participants bid at marginal cost and (2) a *test case* that uses the actual bids market participants submitted during the year. The measure indicates the percentage of aggregate market profits explained by bids above cost. If all participants bid in a strictly competitive way, that is, offer all output at cost, the measure has a value of zero. Given the prevailing surplus supply conditions, the IMM expects the value to be relatively small but not zero. Overall, the results of the analysis show that the additional gross margin earned by market participants is consistent with competitive outcomes.

To calculate the gross margin as a percentage of all energy market revenues, the IMM first calculated the difference between the energy market revenues for all resources for the year and their total bid production costs for the year. This difference was then divided by the total energy market revenues for all resources.[64]

The IMM used a unit-commitment-and-dispatch simulation model to estimate the gross margin and to measure the effect of offers that differ from their marginal cost on the gross margins earned in the market.[65] The gross margin earned by the market, if all bids reflected their costs, was 29.4% in 2012. In other words, in total, resources earned 29% more than their fuel costs in 2012. The additional gross margin above marginal costs was 2.2% in 2012, for a total gross margin of 31.6%. The percentage above gross margin at cost was approximately 8.9% in 2010 and 4.7% in 2011. See Table 2-14.

Table 2-14
Median Gross Margin, 2010 to 2012 (%)

Year	Offer Based	Cost Based	Difference
2010	39.99	31.13	8.87
2011	36.37	31.67	4.69
2012	31.62	29.43	2.18

The outcomes are consistent with recent observations in the Real-Time Energy Market over the past three years. In 2010, real-time LMPs were higher than in 2011 and 2012. Higher natural gas prices increased all prices in 2010, relative to the following two years. Several factors, namely, less hydroelectric energy, higher loads, and the loss of a large flexible resource, caused the market to require resources higher up on the supply curve. The results in Table 2-14 show that the gross margin was roughly 4% higher in 2010 than in 2011, and 2.5% higher in 2011 than 2012. This result is expected because resources higher up on the supply curve, where it is steeper, offer less competitively than resources further down on the supply curve. One possible explanation for this behavior is that as demand increases, fewer resources remain to meet that demand, and those resources can offer above their costs without losing market share.

2.1.5.2 The Competitiveness Measure

This section analyzes market competitiveness and shows that the market was more competitive in 2012 than in 2011.

For this analysis, the IMM calculates a competitiveness measure that estimates the percentage of the price that is a consequence of the offers above cost. In a perfectly competitive market, all participant offers would equal marginal cost. Whereas the gross margin is an average measure that indicates the impact of offers above cost on the aggregate gross margins available in the market, the competitiveness measure assesses the impact of these same offers by examining

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[64] The resources' bid production costs were calculated by dividing the IMM's estimates of resources' costs by the total revenues.

[65] The IMM used the PROBE, or "Portfolio Ownership and Bid Evaluation," simulation model for this analysis. The software simulates the day-ahead and real-time LMP-based market clearing. See http://www.power-gem.com/PROBE.htm.

their impact on price. The analysis shows that competition among suppliers limits their ability to offer substantially above marginal cost.

For this analysis, the IMM calculated the LMPs for the benchmark case and test case. The competitiveness measure (L_t) is the percentage of the offer-based LMP resulting from marginal offers above cost and is calculated as follows:

$$L_t = \frac{LMP_t^o - LMP_t^c}{LMP_t^o}$$

Where LMP_t^o is the offer-based LMP at time t, and LMP_t^c is the cost-based LMP at time t.

A larger L_t means that a larger percentage of the price is the result of marginal offers above cost. Unlike the gross margin, a change in an inframarginal resource's marginal cost or market share does not change the competitiveness measure; only the offers of marginal units have an impact on this measure.[66]

For most of the days in 2012, offers above marginal cost added no more than 13% to the real-time price. Table 2-15 shows the summary results of the competitiveness measure.[67]

Table 2-15
Competitiveness Measure Results, 2010 to 2012 (%, $/MWh)

Year	Competitiveness Measure Median %	Median ($LMP^o - LMP^c$) ($/MWh)
2010	13.67%	5.62
2011	10.16%	3.92
2012	12.58%	4.66

To put these results in context, the IMM's offer-mitigation rules allow participants to submit offers $25/MWh above reference levels in constrained areas and $100/MWh above reference levels in unconstrained areas without review. If the market were not competitive, the profit-maximizing strategy, at least some of the time, would be to submit offers $25/MWh to $100/MWh above marginal cost, depending on system conditions. If this strategy were viable, instead of the marginal resource adding 12.58% on average to its offer, the market would observe a much larger adder above cost on the typical offer.[68] Clearly, this is not the case.

The IMM has reviewed the bidding behavior of all market participants as part of its monitoring and mitigation functions. While the IMM mitigated the offers of some resources, in 2012, the IMM did not

[66] As discussed in Section 2.1.2.3, the RSI is the other measure of competitiveness calculated by the IMM for units on the margin. The RSI shows the possibility of noncompetitive behavior, while the competitiveness measure shows the extent of the impact on price of additional revenues earned in the market from offers at the margin.

[67] The median percentage of additional revenues earned from offers at the margin is subject to measurement error.

[68] These calculations for these numbers are based on the average LMP of $36.09/MWh in 2012.

identify behavior that suggested a more systematic attempt to using pricing power to manipulate market outcomes, either via economic or physical withholding.

2.1.6 Reliability and Operations Assessment

This section discusses ISO actions to ensure real-time reliability and an assessment of ISO operations. It includes a review of Net Commitment-Period Compensation "make-whole" payments to resource owners that have not recovered their full as-bid cost from the energy markets.

2.1.6.1 Daily Reliability

The ISO is required to operate New England's wholesale power system to the reliability standards developed by NERC, the NPCC, and the ISO through open stakeholder processes.[69] To meet these requirements and maintain daily system reliability, the ISO may commit resources, in addition to those cleared in the Day-Ahead Energy Market, to ensure capacity balance in real time. Resources that operate at the ISO's instruction but do not recover their as-bid costs through energy market revenues are paid one of the following types of compensation, depending on the reason for the commitment:[70]

- Economic/first-contingency Net Commitment-Period Compensation
- Local second-contingency Net Commitment-Period Compensation
- Voltage reliability payments
- Distribution reliability payments

Daily Reliability Payments for 2012. As shown in Table 2-16, daily reliability payments totaled $87.1 million in 2012, or approximately 1.4% of the total wholesale cost of electricity.

Table 2-16
Total Daily Reliability Payments by Quarter, 2012 ($)

	2012	Q1	Q2	Q3	Q4
Total Daily Reliability Payments	$87,079,580	$10,229,465	$21,927,383	$23,232,383	$31,690,349

Daily reliability payments increased by $12.9 million (17%) from 2011, and first-contingency NCPC payments increased by $0.8 million in 2012. Voltage payments increased by $9.0 million in 2012 (154%) compared with 2011. This increase resulted from the frequent commitment of a unit needed to provide voltage support in a specific region. Second-contingency payments

[69] These requirements are codified in the NERC standards, NPCC criteria, and the ISO's operating procedures. For more information on NERC standards, see http://www.nerc.com/page.php?cid=2|20 (2012). For more information on NPCC standards, see https://www.npcc.org/Standards/default.aspx (2012). The ISO's system operating procedures are available at http://www.iso-ne.com/rules_proceds/operating/isone/index.html.

[70] A system's *first contingency* (N-1) is when the power element (facility) with the largest impact on system reliability is lost. A *second contingency* (N-1-1) takes place after a first contingency has occurred and is the loss of the facility that at that time has the largest impact on the system.

increased 45% compared with 2011. This increase occurred because a number of units were committed throughout the year to protect against local contingencies. See Table 2-17.

Table 2-17
Total Daily Reliability Payments, 2011 and 2012 ($)

Payment Type	2011	2012	Difference	% Change
Economic and first-contingency payments	58,980,945	59,785,038	804,093	1%
Second-contingency reliability payments	6,031,357	8,750,609	2,719,252	45%
Distribution	3,358,238	3,680,671	322,433	10%
Voltage	5,847,264	14,863,262	9,015,998	154%
Total	74,217,804	87,079,580	12,861,776	17%

Supplemental Commitments. Each day after the clearing of the Day-Ahead Energy Market, the ISO performs a Reserve Adequacy Assessment and, if necessary, commits additional generators to meet capacity and reserve requirements. The ISO commits generators in the RAA whenever insufficient capacity clears in the day-ahead market to meet the ISO load forecast plus operating reserve requirement. The amount of capacity on line affects LMPs and NCPC costs. When too much capacity is on line and units are operating at their economic minimum levels, LMPs are likely to be lower and NCPC costs higher than what they otherwise would be. Too little capacity on line may compromise reliable operation and lead to artificially high prices.

The IMM reviews supplemental commitments each day to assess the extent to which supplemental commitments result in surplus supply. Surplus on-line capacity can arise from generation that clears in the Day-Ahead Energy Market (e.g., if the load clearing in the day-ahead market exceeds the real-time load), self-schedules, or the supplemental commitment performed as a result of the RAA. Thus, the market and supplemental commitments made by the ISO for reliability both contribute to the surplus.

Table 2-18 illustrates the minimum, maximum, and quarterly percentiles of the daily supplemental commitments for each month of 2012. On most days in 2012, no generators were committed supplementally. On six days in 2012, supplemental commitments exceeded 1,000 MW. For those days that occurred in June and July, the additional commitment can be attributed to higher electrical demands on the system. For these high demand periods, capacity margins may become tight, and operators may commitment more generation to be able to cover for unplanned outages on the system. The day with the highest level of supplemental commitments in 2012 was November 1, when 2,230 MW of supplemental capacity was committed. Uncertainty regarding generator availability in the aftermath of Superstorm Sandy was the primary driver for these commitments in late October and early November. See Section 2.1.6.2.

Table 2-18
Monthly Minimum, Maximum, and Quarterly Percentiles of Daily Supplemental Commitments for the Peak Hour, January to December 2012 (MW)

Month	Daily Supplemental Commitment MW[(a)]				
	Minimum	25th Percentile	50th Percentile	75th Percentile	Maximum
Jan	0	0	0	108	783
Feb	0	0	0	0	57
Mar	0	0	0	54	430
Apr	0	0	122	145	303
May	0	0	48	150	765
Jun	0	0	0	235	1,030
Jul-	0	0	0	190	1,600
Aug	0	0	0	188	550
Sep	0	0	0	100	289
Oct	0	0	18	150	1,500
Nov	0	0	45	140	2,230
Dec	0	0	0	0	509

(a) Supplemental commitments are defined here as the aggregate capacity of non-fast-start generators the ISO committed outside the day-ahead market for the peak hour, dispatched at the generators' economic minimums.

2.1.6.2 IMM Market Operations Summary

This section discusses the ISO's operations for 2012. It includes an evaluation of ISO Operations during Superstorm Sandy and a review of the audits the ISO participated in during 2012.

Operations during Superstorm Sandy, October 28 to November 2, 2012. The IMM reviewed the events and operator actions before, during, and after Superstorm Sandy. The IMM concluded that the actions of ISO Operations generally resulted in prices that were consistent with system conditions and the resources supplying energy.

The ISO took several preparatory actions in anticipation of Superstorm Sandy, including communication with regulatory and transmission owner contacts, the National Oceanic and Atmospheric Administration (NOAA), all generator-designated entities, black-start generators, nuclear plants, gas pipelines, and NPCC reliability coordinators. Additional generation also was committed to provide support in the event of system shutdown or overloads, especially along the coastal regions.

As anticipated, Sandy had a significant impact on the region. Approximately 1.3 million customers lost power at the peak of the storm, and there were approximately 4,400 MW of generator outages. On the transmission system, 56 115 kV lines tripped, one 230 kV line tripped, and four 345 kV lines tripped. Most of these transmission outages occurred in Connecticut and Massachusetts, which were hit hardest by the storm. Throughout the event, the bulk power system was operated in accordance with all NPCC and NERC standards and criteria.

On Sunday, October 28, 2012, the ISO implemented Master/Local Control Center Procedure No. 2 (M/LCC 2), *Abnormal Conditions Alert.*[71]

Audits. In 2012, the following audits were conducted to ensure that the ISO followed the approved market rules and procedures and to provide transparency to New England stakeholders:

SOC 1 Type 2 examination—In November 2012, the ISO successfully completed a SOC 1 Type 2 examination, which resulted in an "unqualified opinion" about the description of the market operations and settlements systems. Developed by the American Institute of Certified Public Accountants, the SOC 1 examination covers aspects of a service organization's systems for processing transactions that may be relevant to a user entity's internal controls for financial reporting. Entities such as Regional Transmission Organizations complete SOC 1 examinations to assist them in evaluating their internal controls over financial reporting.

ISO's SOC 1 Type 2 examination is a rigorous examination that entails detailed testing of the business processes and information technology for bidding, accounting, settlement, and billing the market products of electric energy, regulation, transmission, capacity, load response, reserves, and associated market transactions. Conducted by the auditing firm KPMG LLP, the Type 2 examination covered the 12-month period from October 1, 2011, through September 30, 2012. The SOC 1 Type 2 examination reviews the following:

- The auditor's opinion on the fairness of the description of the market operations' and settlements systems' controls designed and implemented throughout the period
- Whether the controls were suitability designed to provide reasonable assurance that the control objectives would be achieved if the controls operated effectively throughout the period and users applied the complementary user-entity controls contemplated in the design
- The controls tested, which together with the complementary user-entity controls, were those necessary to provide reasonable assurance that the control objectives were achieved throughout the period

The ISO conducts a SOC 1 Type 2 examination annually. The 2012 SOC 1 Type 2 report is available to participants upon request through the ISO external website.[72]

Market-System Software Recertification—The ISO has committed to a practice of engaging an independent third party, PA Consulting, to review and certify that the market-system software complies with *Market Rule 1*, the manuals, and standard operating procedures.[73] This recertification takes place every two years or sooner, in the case of a major market-system enhancement or new market features. After conducting detailed tests and analyses of the applicable mathematical formulations, PA Consulting issues a compliance certificate for each

[71] Master/Local Control Center Procedure No. 2, *Abnormal Conditions Alert* (April 19, 2012), http://www.iso-ne.com/rules_proceds/operating/mast_satllte/mlcc2.pdf.

[72] KPMG. *Report on Management's Description of its System and the Suitability of the Design and Operating Effectiveness of Controls Pertaining to the Market Operations and Settlements System for the Period October 1, 2011, to September 30, 2012*, Prepared Pursuant to Statement on Standards for Attestation Engagements No.16. (2012). This report is available to participants by request through the ISO external website, http://www.iso-ne.com/aboutiso/audit_rpts/index.html and http://www.iso-ne.com/aboutiso/audit_rpts/SAS70Request.do.

[73] *Market Rule 1,* http://www.iso-ne.com/regulatory/tariff/sect_3/index.html.

market system module it audits. The certificates provide assurance that the software is operating as intended and is consistent with *Market Rule 1* and associated manuals and procedures.

In 2012, PA Consulting issued the following certifications:

- Auction Revenue Rights Market Software, November 5, 2012
- Financial Transmission Rights Market Software, November 5, 2012
- Locational Marginal Price Calculator Market Software, December 28, 2012
- Regulation Clearing Price Market Software, December 28, 2012
- Scheduling, Pricing, and Dispatch–Day Ahead Market Software, March 29, 2012
- Scheduling, Pricing, and Dispatch–Unit Dispatch and Scheduling Market Software, March 29, 2012
- Forward Capacity Auction Market Clearing Engine Software, December 28, 2012

Internal Audits—The ISO New England Internal Audit Department conducted a number of internal controls and compliance audits in the Forward Capacity Market (see Section 3.4) and demand-resource and information technology areas.

2.2 Real-Time Reserves

This section summarizes the performance of the real-time reserves markets. In real time, the dispatch of resources to meet the energy and reserve requirements is jointly optimized. In the presence of a binding reserve constraint, the real-time reserve price is equal to the opportunity cost of the resource not dispatched for energy to satisfy the reserve requirement, capped by the Reserve Constraint Penalty Factor (RCPF).[74]

2.2.1 Real-Time Reserve Types and Dispatch

The ISO's operating-reserve requirements are described in Operating Procedure No. 8 (OP 8), *Operating Reserve and Regulation*.[75] As specified in OP 8, the ISO must maintain a sufficient amount of reserves for the system as a whole and for identified transmission-import-constrained areas to be able to recover from the loss of the first-largest contingency within 10 minutes. The ISO has real-time reserve requirements (in MW) for the following reserve categories (or products):

- **Ten-minute spinning reserve (TMSR):** This is the highest-quality reserve product. TMSR is provided by on-line resources able to increase output within 10 minutes, allowing the system a high degree of certainty for being able to recover quickly from a significant system contingency.
- **Ten-minute nonspinning reserve (TMNSR):** This is the second-highest quality reserve product. TMNSR is provided by off-line units that require a successful start up

[74] RCPFs are administratively set limits on redispatch costs the system will incur to meet reserve constraints. Each type of reserve constraint has a corresponding RCPF.

[75] See Operating Procedure No. 8, *Operating Reserves and Regulation* (March 11, 2013), http://www.iso-ne.com/rules_proceds/operating/isone/op8/index.html.

(i.e., electrically synchronize to the system and increase output within 10 minutes) to ensure that needed reserves actually will be available in response to a contingency.[76]

- **Thirty-minute operating reserve (TMOR):** This is the lowest-quality reserve provided by less-flexible resources within the system (i.e., on-line or off-line resources that can either increase output within 30 minutes or electrically synchronize to the system and increase output within 30 minutes in response to a contingency).

TMNSR can be used to meet the TMOR requirements but not the other way around.

In the Real-Time Energy Market, the dispatch algorithm optimizes the use of generating resources to meet energy and reserve requirements while respecting transmission constraints. The dispatch uses each resource's real-time energy offer; there are no separate real-time reserve offers. Other features of the dispatch algorithm include the following:

- In the presence of a binding reserve constraint, the system dispatch may reduce the output of an otherwise economic unit in the energy market to create reserves on the system. When this occurs, the opportunity cost of altering the dispatch determines the market-clearing price for the reserve product.
- The market-clearing software will not redispatch resources to meet reserves at any price. When the redispatch costs exceed the RCPF, the price will be set equal to the penalty factor and the market software will not continue redispatching resources to meet reserves.[77]
- The market software optimizes the use of local transmission interfaces to minimize the cost of satisfying all reserve and energy requirements in the region.

To ensure that the incentives for providing the individual reserve products are correct, the market's reserve prices maintain an ordinal ranking consistent with the quality of the reserve provided, as follows:

$$\text{TMSR} \geq \text{TMNSR} \geq \text{TMOR}$$

The price of higher-quality reserve products must be at least as high as the price of lower-quality reserve products. For example, if the ISO alters the dispatch to provide TMOR at a cost of $40/MWh, the prices for TMSR and TMNSR both must equal or be greater than $40/MWh.[78]

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[76] *Ten-minute nonspinning reserve* also is called 10-minute nonsynchronized reserve.

[77] When an RCPF is reached and the Real-Time Energy Market's optimization software stops redispatching resources to satisfy the reserve requirement, the ISO will manually redispatch resources to obtain the needed reserve. The RCPFs are $50/MWh for systemwide TMSR, $850/MWh for systemwide total 10-minute reserve, $500/MWh for systemwide 30-minute reserve constraint, and $250/MWh for each local reserve constraint.

[78] This price "cascading" occurs when a binding reserve constraint exists and higher-quality reserve products obtain the same pricing as lower-quality reserve products. Because TMSR is the highest-quality reserve product, TMNSR is the second-highest quality reserve product, and TMOR is the lowest-quality reserve product, the TMSR price is always greater than or equal to the TMNSR and TMOR prices, and the TMNSR price is always greater than or equal to the TMOR price. Also, because TMSR megawatts can substitute for TMOR megawatts, TMSR megawatts always obtain at least TMOR prices and cannot have a price lower than the prices obtained for TMOR.

2.2.2 Real-Time Reserve Outcomes

Average nonzero annual reserve prices increased for all reserve products in 2012 compared with 2011. While the frequency of binding reserve constraints for TMSR decreased slightly, TMNSR and TMOR binding reserve constraints increased. While the frequency increases are significant as percentage changes, the absolute frequency values were still quite low in 2012. See Table 2-19.

Table 2-19
Average Reserve Prices and Frequencies for Intervals with Nonzero Prices, 2011 to 2012[(a)]

Product	Year	Average Annual Price ($/MW/ 5-Min. Interval)	Frequency (% of Total 5-Min. Intervals)
10-minute spinning reserve	2011	$24.70	4.00%
	2012	$41.79	3.95%
	% change	***69.2%***	***−1.3%***
10-minute nonspinning reserve	2011	$110.92	0.10%
	2012	$118.58	0.82%
	% change	***6.9%***	***720.0%***
30-minute operating reserve	2011	$73.74	0.30%
	2012	$120.70	0.80%
	% change	***63.7%***	***166.7%***

(a) Prices are presented for the Rest-of-System reserve zone.

Reserve pricing occurs when the system must redispatch (i.e., alter the dispatch) resources away from the lowest-cost solution for satisfying only demand, and incur additional costs to satisfy the reserve constraint. The reserve price is approximately the difference between the energy LMP and the short-run variable cost of the marginal resource needed to reduce energy output to provide reserves during redispatch. The cost incurred to redispatch on-line 10-minute reserve assets (by definition some of the most flexible resources in the system) is lower, on average, than the cost incurred to redispatch less flexible resources to provide the 30-minute reserves. This can be surmised by comparing average TMOR and TMSR prices while accounting for the frequency of reserve pricing for each product.

Table 2-19 shows that TMSR pricing intervals occurred four times as much as TMOR pricing intervals. This would mean that for the intervals when only the TMSR pricing occurred, and all other products were priced at $0/MWh, the interval price was low, reflecting the lower average cost after the dispatch. Note that because the 10-minute reserves (spinning and nonspinning) are fully fungible with TMOR, the higher-quality products receive the TMOR price, but the opposite is not true; TMOR products are not interchangeable with, and cannot receive the price of, the 10-minute reserves. The redispatch for TMOR tends to occur when the system is experiencing high loads relative to available supply, and hence, when energy LMPs also tend to be relatively high.

Table 2-20 compares the pricing frequency and average prices (during nonzero pricing intervals) across reserve zones for 2012. The frequency of binding constraints across zones was highly consistent in 2012. All three local reserve zones (NEMA/Boston, Connecticut, and

Southwest Connecticut) experienced TMOR prices that were slightly (less than 1%) higher than for the rest of system.

Table 2-20
Real-Time Reserve Clearing Prices for Nonzero Price Intervals, 2012

Product	Reserve Zone	Price ($/MW/ 5-Minute Intervals)	Frequency (% of 5-Minute Intervals)
TMSR	Connecticut	43.20	4.00%
	NEMA/Boston	42.64	3.98%
	Rest of System	41.79	3.95%
	Southwest Connecticut	43.57	4.02%
TMNSR	Connecticut	119.68	0.88%
	NEMA/Boston	119.63	0.85%
	Rest of System	118.58	0.82%
	Southwest Connecticut	119.80	0.90%
TMOR	Connecticut	121.67	0.86%
	NEMA/Boston	121.68	0.83%
	Rest of System	120.70	0.80%
	Southwest Connecticut	121.76	0.88%

Table 2-21 summarizes reserve payments for 2010 to 2012. The payments in 2012 are the highest in the three years. The largest increases were in TMNSR and TMOR payments that increased several-fold.

Table 2-21
Real-Time Reserve Payments, 2010 to 2012 ($)

Year	Systemwide TMSR	Systemwide TMNSR	Systemwide TMOR	SWCT TMOR	CT TMOR	NEMA/Boston TMOR	Total
2010	9,998,572	6,896,142	639,148	762,404	342,996	105,834	18,745,096
2011	5,931,579	2,373,491	220,488	535,377	354,332	56,249	9,471,516
2012	11,382,634	12,179,149	1,352,544	3,235,228	1,207,897	428,223	29,785,673

In 2012, the total real-time reserve payments were $29.8 million. In 2011, real-time reserve payments totaled $9.5 million, a significant reduction from $18.7 million in 2010. As discussed in the *2011 Annual Markets Report*, this decrease in payments was due to increases in supply throughout the year, as well as an overall reduction in electrical demand. Large year-to-year variation is not unusual for reserve payments.[79]

[79] Significant levels of reserve payments are incurred during system contingency periods (such as the loss of a large generator), extreme weather fluctuations, and other events that require the conversion of available reserves into electric energy or that otherwise limit the reserves available to the system. These events do not occur with the same frequency or magnitude each calendar year.

The IMM examined the several-fold increase in payments for 2012 in detail. Quarterly data show that payments were highest in the third and fourth quarters, with payments in the third quarter being particularly large. See Table 2-22.

Table 2-22
Quarterly Reserve Payments, 2012 ($)

Quarter	TMSR ($)	TMNSR ($)	TMOR ($)	Total ($)
Q1	787,385	88,196	40,691	916,272
Q2	932,939	160,171	105,426	1,198,536
Q3	6,631,999	8,386,002	4,211,659	19,229,660
Q4	3,030,311	3,544,780	1,866,116	8,441,207

Several factors explain the large increase in reserve payments during the third and fourth quarters, including changes to the market rules and reserve requirements in 2012:[80]

- The amount of total 10-minute reserve requirement increased by 25% in the summer of 2012.
- A market rule change increased the Reserve Constraint Penalty Factor for system TMOR from $100/MWh to $500/MWh.[81]
- Several days of tight system conditions, including capacity deficiencies, in August and November 2012, resulted in relatively high frequencies of TMOR binding constraints.

Approximately 25% to 30% of the total settlement values for the third and fourth quarters of 2012 resulted from an increase in the TMOR RCPF.[82] Two additional factors explain another 40% of the total settlement value: an increase in the reserve requirement for total 10-minute reserves (i.e., TMSR and TMNSR) and tight system conditions in August and November 2012 that led to a high frequency of TMOR reserve pricing.

The 25% increase of the total 10-minute reserve requirement in July 2012 increased the amount of capacity designated as providing 10-minute operating reserves. During the TMOR pricing intervals, it appears that 10-minute reserve designations had increased about 10% above the levels observed in the second quarter, and all the designated 10-minute reserve (as a

[80] The IMM reviewed several reserve market elements for the above explanation. These elements included average pricing levels for each of the products, the average megawatt designations available for each reserve product during the pricing periods, and the frequency of nonzero prices for each product. Because reserve prices cascade from the lowest- to highest-quality reserve products, each of these variables was isolated for each product, irrespective of the pricing for the other products (i.e., the influence of price cascading was removed). Examining the "noncascaded" results indicated that neither TMSR nor TMNSR products had much influence on the variation in settlement values—the TMOR product explains the variation in the quarterly results for all products.

[81] *Letter Order accepting RCPF Value Changes*, ER12-1314-000 (May 21, 2012), http://www.iso-ne.com/regulatory/ferc/orders/2012/may/er12-1314-000_5-21-12_ltr_ord_accept_rpcf_value_change.pdf.

[82] Beginning in the third quarter of 2012, the RCPF cap for system TMOR was increased from $100/MWh to $500/MWh. Because the $100/MWh RCPF could reduce incentives to provide TMOR whenever the opportunity cost of doing so exceeded $100/MWh, the increase in the RCPF represents an improvement in the ISO's ability to maintain adequate operating reserves and reliability during real time.

higher-quality reserve product), obtained the TMOR price. This increase in designations would be expected to result in a proportional increase in reserve payments (all other things being equal or held constant).

Finally, tight system conditions led to higher frequencies of TMOR pricing than usual during August and November 2012. For August 2 to August 5, August 25, and August 27 to August 28, various system conditions resulted in a high frequency of TMOR pricing intervals. Capacity deficiencies were experienced on August 5, August 25, August 27, and August 28, along with load levels that exceeded the forecast. Moreover, concern about system conditions causing TMOR reserve quantities to fall below adequate reliability levels led to temporary increases in the TMOR requirement, on most of these days, through the implementation of the reserve bias.[83] The tight system conditions, combined with the increased TMOR requirement, resulted in the observed, elevated pricing frequencies for TMOR. These few days in August explain about 36% of the observed reserve settlement values for the third quarter of 2012. Likewise, tight capacity conditions on November 6 to 7 resulted in more frequent TMOR pricing. These two days in November explain approximately 30% of total reserve settlement values for the fourth quarter.[84]

2.3 Regulation Market

This section presents data about the participation, outcomes, and competitiveness of the Regulation Market in 2012. The IMM concludes that the Regulation Market was competitive in 2012.

The Regulation Market is the mechanism for selecting and paying resources needed to balance supply levels with the second-to-second variations in electric power demand and to assist in maintaining the frequency of the entire Eastern Interconnection. The objective of the Regulation Market is to acquire adequate resources such that the ISO meets NERC's *Real Power Balancing Control Performance Standard* (BAL-001-0).[85] NERC establishes technical standards, known as Control Performance Standards, for evaluating area control error (unscheduled power flows) between balancing authority areas (e.g., between New England and New York). For New England, NERC has set the Control Performance Standard 2 (CPS 2) at 90%.[86]

The regulation clearing price (RCP) is calculated in real time and is based on the regulation offer of the highest-priced generator providing the service. Compensation to generators that provide

83 When system conditions threaten to reduce actual 10- or 30-minute reserve quantities below the current prescribed levels (based on the system's largest- and second-largest contingencies), system operators may increase each of the actual reserve requirements to a value greater than 100% of the current requirement to maintain system reliability. When conditions allow, the reserve bias is returned to the base value of 100%.

84 These results exclude the influence of the increased TMOR RCPF. See associated *ISO New England's Weekly Market Performance Reports*, http://www.iso-ne.com/markets/mkt_anlys_rpts/wkly_mktops_rpts/2012/index.html.

85 This NERC standard (effective May 13, 2009) can be accessed at http://www.nerc.com/page.php?cid=2|20. Additional information on NERC requirements is available at http://www.nerc.com (2012).

86 The primary measure for evaluating control performance, (CPS 2), is as follows:

> *Each balancing authority shall operate such that its average area control error (ACE) for at least 90% of clock-10-minute periods (six nonoverlapping periods per hour) during a calendar month is within a specified limit, referred to as L_{10}.*

More information on NERC's Control Performance Standard 2 is available at http://www.nerc.com/files/Reliability_Standards_Complete_Set.pdf (Resource and Demand Balancing; BAL).

regulation includes a regulation capacity payment, a service payment, and a unit-specific opportunity cost payment.[87] Unit-specific opportunity cost payments are not included as a component of the regulation clearing price.

2.3.1 Regulation Pricing

In 2012, the average regulation price of $6.74/MWh was 6% lower than the 2011 price of $7.17/MWh. See Table 2-23.

Table 2-23
Regulation Prices, 2010 to 2012 ($/MWh)

Year	Minimum	Average	Maximum
2010	$0.00	$7.07	$82.24
2011	$0.00	$7.17	$95.00
2012	$0.00	$6.74	$70.33

Payments to resources providing regulation service totaled $11.6 million in 2012, a decrease of $1.7 million from 2011. Regulation payments correlate with gas prices. In the reporting period, regulation opportunity costs made up approximately 35.4% of total regulation payments compared with 35.5% in 2011. The monthly opportunity cost in 2012 was more volatile than in 2011 and is attributable to volatility in the LMP and input fuel prices, in particular, the natural gas price.

2.3.2 Requirements and Performance

New England's hourly regulation requirement has been decreasing steadily from an average requirement of 181 MW in 2002, to below 60 MW in the past two years. The average hourly regulation requirement was virtually unchanged from 59.62 MW in 2011 to 59.54 MW in the reporting period. The regulation requirement in New England varies throughout the day and typically is highest in the early morning and the late evening. The higher regulation requirement during these hours is the result of load variability.

The ISO seeks to maintain Control Performance Standard 2 within the range of 92% to 97%. The ISO has continually met its more stringent, self-imposed CPS 2 targets. For 2012, the ISO achieved a minimum value of 94.1% and a maximum value of 96.3%. The higher performance of the Regulation Market has been achieved, while decreasing the regulation requirement and lowering costs.

The ISO has been able to reduce the regulation requirement because of the excellent performance of the resources providing regulation. One of the contributing factors to the high performance is the incentive structure that compensates faster-responding units for their higher contribution to regulation service.

[87] A *regulation opportunity cost payment* is compensation to a pool-scheduled generator for providing regulation service for a full hour or a portion of an hour.

2.3.3 Competitiveness of the Regulation Market

The IMM reviewed the competitiveness of the Regulation Market using demand and supply curves and the results of the hourly average residual supply index for the Regulation Market (see Section 2.3). Both these measures examine the market structure and resource abundance. The abundance of regulation resources implies that market participants have little opportunity to engage in economic or physical withholding. The IMM concludes that the Regulation Market was competitive in 2012.

Figure 2-16 shows the average and maximum regulation requirement (demand) and the average regulation supply for 2012 with and without the largest supplier. Because both the average and maximum regulation requirement lie to the far left end of the regulation supply curve, regulation prices do not change significantly with changes in regulation supply. If the largest supplier were removed from the Regulation Market, the impact on regulation prices would be very small. Consequently, no Regulation Market supplier can profitably withhold its resource(s) from the market.

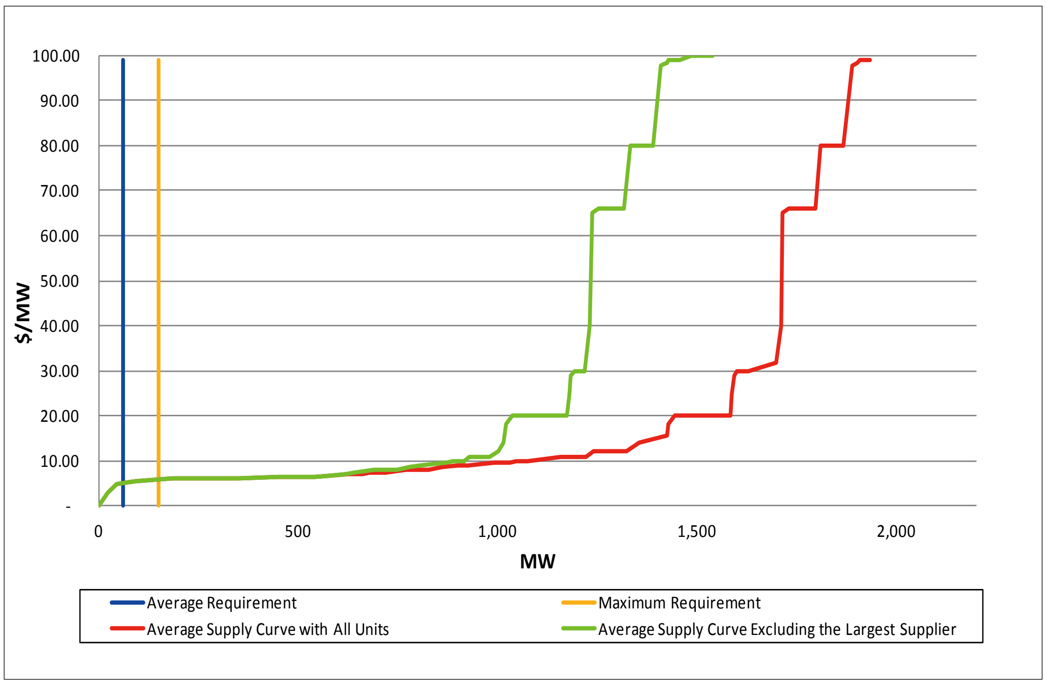

Figure 2-16: Regulation Market demand average and maximum requirements and supply curves with and without the largest supplier, 2012 (MW and $/MW).

Competitive conditions, along with changes in the regulation requirement, can vary during the day because of load variability and supply uncertainty. As shown in Figure 2-17, the regulation requirement and RSI are inversely correlated. In 2012, the lowest hourly average RSI did not fall below 1,000%, implying that, on average, the system has the capability to serve 10 times the regulation requirement without the largest regulation supplier, even in the hours with the greatest regulation requirement.

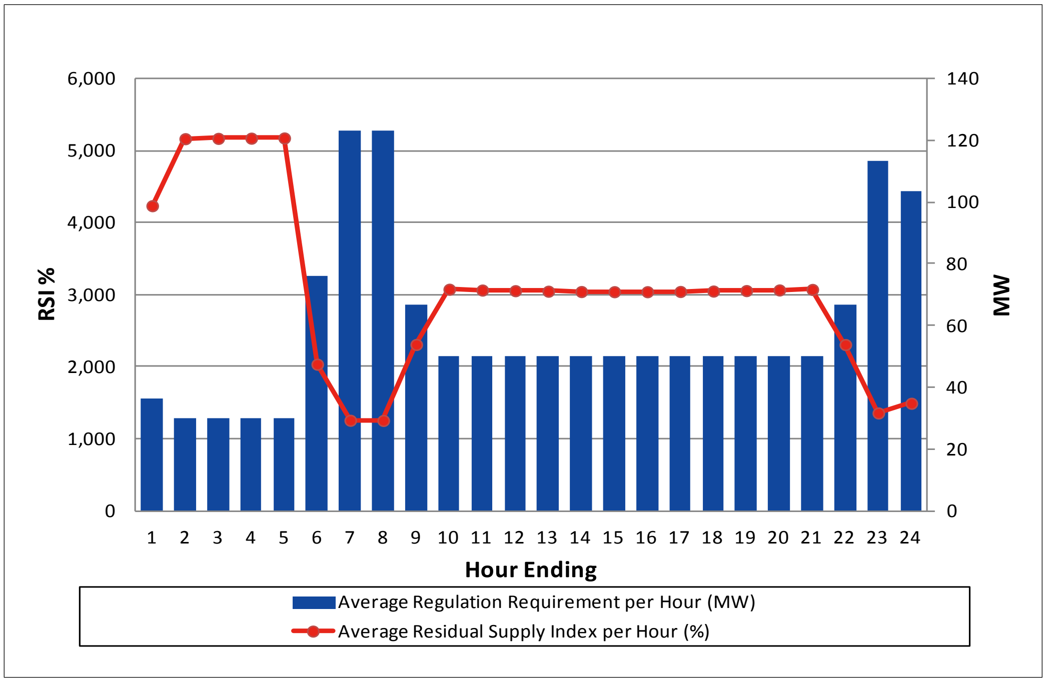

Figure 2-17: Average regulation requirement and residual supply index per hour, 2012.

Section 3
Forward Markets

This section describes the 2012 outcomes and recommendations regarding the ISO's forward markets, including the Day-Ahead Energy Market, the Forward Reserve Market, and the Forward Capacity Market. The outcomes and recommendations for Financial Transmission Rights also are discussed.

3.1 Day-Ahead Energy Market

This section describes the outcomes of the ISO's Day-Ahead Energy Market for 2012. In the day-ahead market, load-serving entities may submit energy demand schedules, which express the LSEs' willingness to pay for electric energy in this market. Each generator with a capacity supply obligation (see Section 3.4) must offer into the day-ahead market a quantity at least equal to its CSO. In addition, any market participant may submit virtual demand bids or supply offers (see Section 3.1.2.5) into the day-ahead market. Generator offers and virtual bids and offers are submitted at a nodal level (see Section 2.1) and indicate the willingness to buy or sell a quantity of electric energy in the day-ahead market. The day-ahead market accepts (clears) bids and offers to maximize economic efficiency by equating supply and demand, subject to transmission constraints. The day-ahead market results are posted at 4:00 p.m. the day before the operating day. Resources that clear in the Day-Ahead Energy Market but do not recover their as-bid costs from this market receive day-ahead Net Commitment-Period Compensation.

3.1.1 Day-Ahead Pricing

The average day-ahead Hub price in 2012 was $36.08/MWh. As in real-time, this price is consistent with observed market conditions, including natural gas prices, loads, hydroelectric production, and other available supply. Price differences among the load zones primarily stemmed from marginal losses, with little congestion at the zonal level. Congestion primarily was restricted to smaller, more transient load pockets that formed when transmission or generation elements were out of service.

The Maine load zone continues to have the lowest average price in the region. The average LMPs in the Maine load zone were about $0.18/MWh lower than the Hub price, largely because the marginal loss component of the LMPs in Maine were lower than those components at the Hub. The average LMPs in the Connecticut and western Massachusetts (WCMA) load zones were $0.69 and $0.90/MWh greater, respectively, than the average Hub price, largely because the congestion components of the LMP in these zones were higher than those components at the Hub. See Table 3-1.

Table 3-1
Simple Average Day-Ahead Hub Prices
and Load-Zone Differences for 2010, 2011, and 2012 ($/MWh)

Location/ Load Zone	2010	2011	2012
Hub	$48.89	$46.38	$36.08
Maine	−$2.19	−$0.80	−$0.18
New Hampshire	−$0.87	−$0.45	−$0.16
Vermont	$0.68	$0.28	$0.17
Connecticut	$1.87	$1.09	$0.69
Rhode Island	−$0.79	−$0.61	$0.16
SEMA	−$0.56	−$0.20	$0.01
WCMA	$0.63	$0.53	$0.90
NEMA	−$0.67	−$0.24	$0.08

3.1.2 Relationship between Day-Ahead Energy Prices and Other Market Factors

This section provides data on price setting in the day-ahead market, day-ahead demand and this demand compared with real-time demand, day-ahead supply and self-scheduling, and various aspects of virtual transactions.

3.1.2.1 Price Setting in the Day-Ahead Market

In the day-ahead market, generators set price approximately 43% of the time in 2012, and virtual transactions set price approximately 30% of the time. These percentages are similar to 2011, when generators set price 42% of the time, and virtual transactions set price 27% of the time. See Figure 3-1.

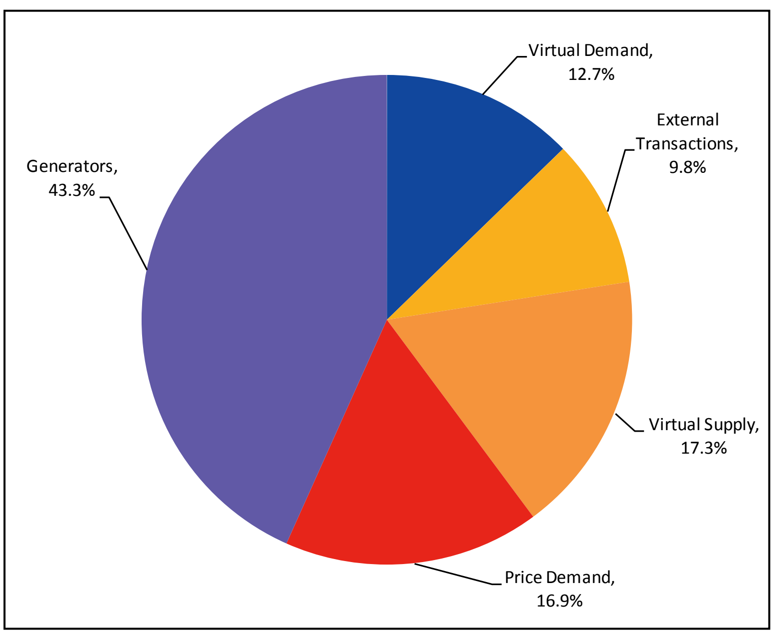

Figure 3-1: Percentage of price setting in the day-ahead market, 2012.

3.1.2.2 Day-Ahead Demand for Electric Energy

Although *fixed demand* (i.e., load that LSEs want to clear irrespective of price) decreased by 2,458 GWh from 2011, the percentage of fixed demand relative to total cleared demand remained stable at 65%. Fixed demand as a percentage of cleared demand was 63% in 2010 and 65% in 2011. Virtual demand and exports have decreased in both volume and as a percentage of total cleared demand over the three-year period. Price-sensitive demand is contributing a greater share of the total in 2012, comprising 29% of cleared demand. See Figure 3-2, which shows the total volume of day-ahead cleared demand for 2010 through 2012.

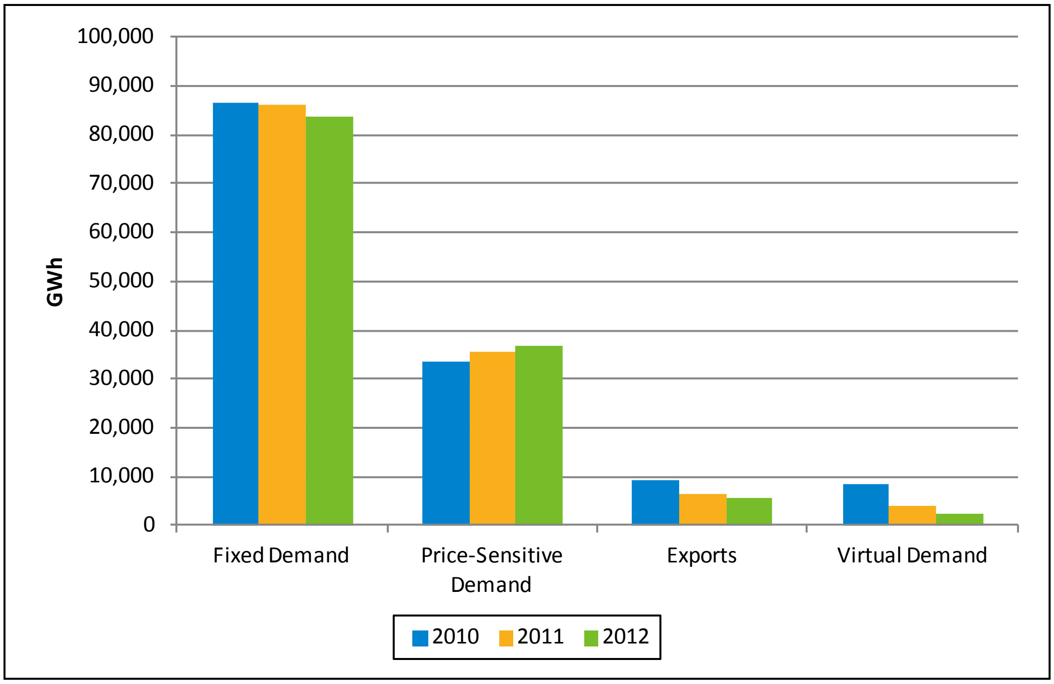

Figure 3-2: Total volume of day-ahead demand cleared, 2010 to 2012 (GWh).

3.1.2.3 Day-Ahead Demand Compared to Real-Time Demand

The quantity of demand clearing in the day-ahead market is one of the factors that can have an impact on the amount of supplemental (balancing) commitments made in the Reserve Adequacy Assessment. Although the percentage of demand purchased in the day-ahead market varies slightly from month to month, the annual percentage has remained at approximately 93% from 2010 through 2012.[88]

3.1.2.4 Day-Ahead Supply and Self-Scheduling of Electric Energy

Market participants have the option to self-schedule their generation resources in the day-ahead market. By self-scheduling, the market participant becomes a price taker, essentially offering to sell a specified quantity at the prevailing day-ahead price. Self-scheduling behavior

[88] The energy purchased in the day-ahead market is a percentage of actual energy consumption in New England and is calculated as follows:

> Day-Ahead Demand Cleared as a Percentage of Real-Time Load = (Cleared Fixed Demand Bids + Cleared Price-Sensitive Demand Bids + Cleared Virtual Demand Bids – Cleared Virtual Supply Offers)/(Net Energy for Load).

has been consistent over the past several years, and the IMM has not found any evidence of an attempt to manipulate market outcomes via self-schedules.

Day-ahead self-schedule volumes increased by 1,750 GWh from 2011 to 2012. Day-ahead self-schedule volumes accounted for 57% of total volumes, up from 54% in 2011. In 2010, self-schedule volumes were 60% of total volumes. In 2012, gas-fired units self-scheduled approximately 30% of the time, up from 25% of the time in 2010. Economic supply offers decreased to 27% of the total, similar to levels in 2010. Virtual supply decreased in both volume and as a percentage of total cleared supply. Import volumes increased in both volume and as a percentage over the past two years and now comprise 14% of total cleared supply. See Figure 3-3.

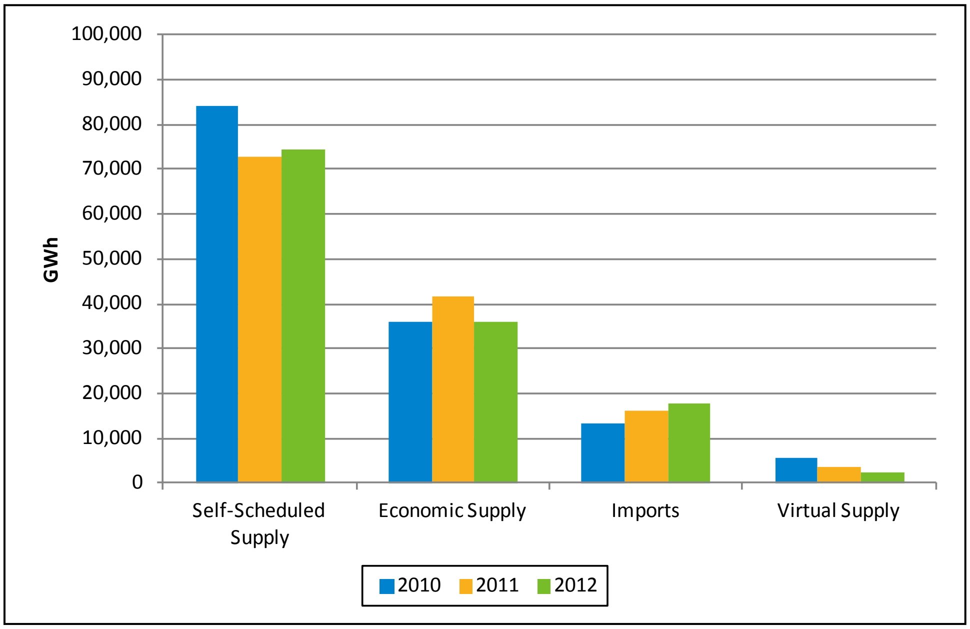

Figure 3-3: Total volume of day-ahead supply cleared, 2010 to 2012 (GWh).

3.1.2.5 Virtual Transactions

Virtual transactions allow participants to buy or sell power in the Day-Ahead Energy Market without physical supply or actual load. Through arbitrage, virtual transactions help ensure that day-ahead and real-time prices are reasonably consistent.

Cleared virtual supply offers (increments) in the day-ahead market and at a particular location in a certain hour, create a financial obligation for the participant to buy back the bid quantity at the real-time market price at that location in that hour. Cleared virtual demand bids (decrements) in the day-ahead market, create a similar financial obligation to sell the bid quantity at the real-time market price. The difference between the hourly day-ahead and real-time LMPs at the location at which the offer or bid clears determines the financial outcome for a particular participant.

Submitted and Cleared Virtual Transactions. In 2012, submitted and cleared virtual transactions continued to decline, as reported in the *2010* and *2011 Annual Markets Reports*, and in Figure 3-2 and Figure 3-3. Together, the volume of submitted virtual demand bids and virtual supply offers totaled approximately 27,519 GWh in 2012, a decline of 14% compared with 2011 and a decline of 35% compared with 2010. Cleared virtual transactions totaled approximately 4,500 GWh in 2012, a 40% year-to-year decline compared with 2011, and a 68% decline compared with 2010. See Figure 3-4.

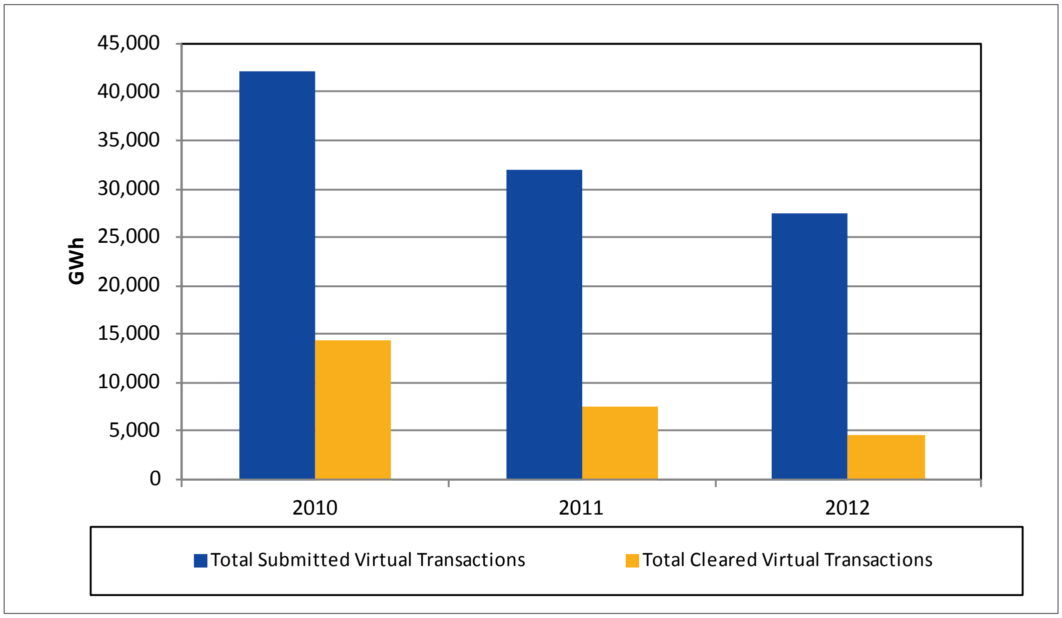

Figure 3-4: Total submitted and cleared virtual transactions, 2010 to 2012 (GWh).

The IMM analyzed trends in virtual trading at the Hub, load zones, internal network nodes, and the external interface nodes (the "node categories") for 2010 through 2012. In 2012, each of the node categories registered double-digit percentage declines in cleared volumes compared with 2011. The decline in virtual trading, particularly at the network nodes, is a cause of concern because the liquidity generally is the lowest at the network nodes compared with other node types. The virtual transactions bring additional liquidity to the network nodes, which is important for efficient market clearing. Other trends are as follows (see Figure 3-5):

- Cleared volumes at the Hub declined by 26% from 2011 to 2012.
- Cleared volumes at the load zones declined by approximately 27% from 2011 to 2012.
- Cleared volumes at the internal network nodes have declined by approximately 87% and 47% compared with 2010 and 2011, respectively. In 2010, the internal network nodes cleared 54% of total cleared virtual transactions, more than any other node category; however, in 2012, the internal network nodes only accounted for 22% of all trades.
- Cleared volumes at external interface nodes declined by 89% between 2011 and 2012.

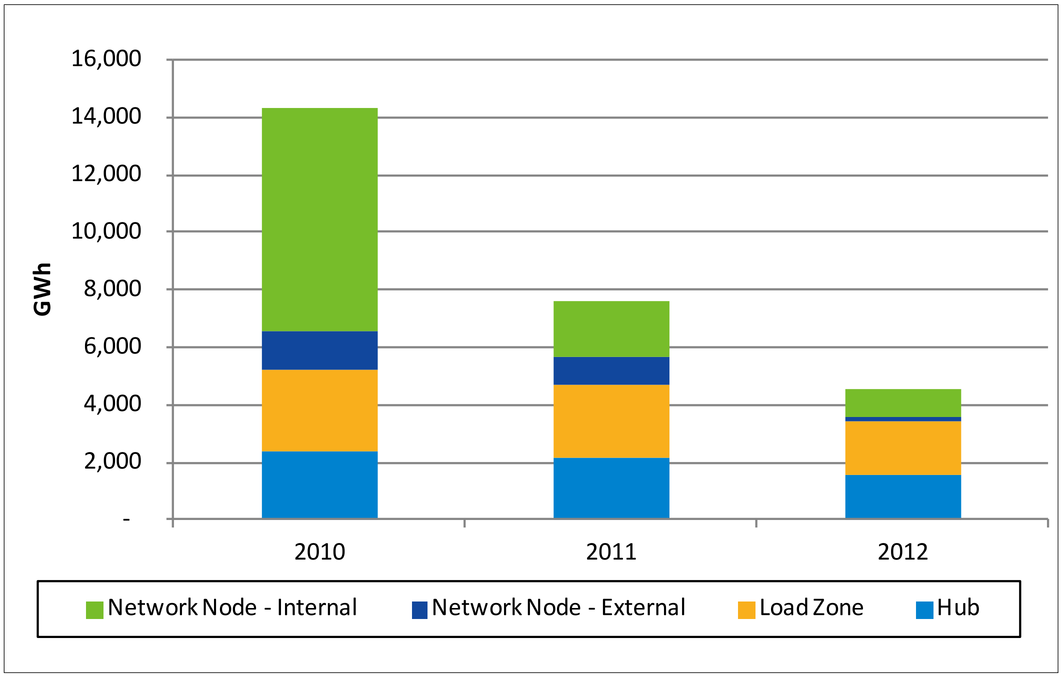

Figure 3-5: Total cleared virtual trade volumes by node category, 2010 to 2012 (GWh).

Virtual Transactions as Hedges—Types, Sizes, and Amounts. The IMM analyzed how participants are using virtual transactions to hedge their positions in conjunction with their real-time physical transactions, such as amount of generation, load, and external transactions.

A participant who clears its expected real-time physical obligation in the day-ahead market faces a risk that its actual real-time obligation may be different from the day-ahead cleared obligation. This deviation is settled at the appropriate real-time price, exposing the participant to differences between real-time and day-ahead prices. A virtual supply offer allows the participant with a load obligation to lock the price paid for the unanticipated load deviation in real time, protecting against real-time price changes. For instance, a participant with a real-time load obligation may make a virtual supply offer to protect against the day-ahead/real-time price divergence and unanticipated load deviation.[89] Similarly, a virtual demand bid lets the participant with a generation obligation lock the price received for a positive deviation in real-time generation relative to day ahead. Given that a generation asset owner must offer all its generation in the day ahead, the asset owner may want to make a virtual demand bid to take advantage of higher prices in real time.

To illustrate, consider a participant with a higher load obligation in real time than its day-ahead load obligation. This participant would incur a higher cost to meet its load if the real-time price were higher than the day-ahead price. Conversely, if the real-time price turned out to be lower than the day-ahead price but the participant's entire real-time obligation cleared day ahead, the participant would not be able to take advantage of that lower real-time price. Therefore, a

[89] A participant's portfolio may have both load and multiple generation assets in one or more neighboring RTOs. Therefore, the strategy space for hedging against the entire portfolio may be complex for an individual participant. In this analysis, the IMM focused only on an individual transaction at a specific location. The hedging behavior for an entire portfolio across multiple locations and markets is outside the scope of this analysis.

participant may want to create a hedge through virtual transactions, which would stabilize the cost of its physical obligation.

A virtual transaction is considered a "locational hedge" if a participant has a virtual position opposite a physical position in real time.[90] The IMM uses the following method to classify a transaction as a "locational hedge:"

- "Load hedge"—those transactions where a participant has an incremental offer position (virtual supply) and real-time load at the same location
- "Generation hedge"—those transactions where a participant has a decremental bid position (virtual demand) and positive real-time metered generation at the same location
- "External hedge"—those transactions where a participant has any virtual position (incremental offer or decremental bid) and a real-time external transaction ("import" or "export") at the same location

In 2012, the total number of hedged transactions declined to 12,022 transactions compared with 23,824 transactions in 2011. Much of the decline was due to the decrease in hedged transactions at the external nodes. The external hedged transactions declined by more than 90% in 2012 compared with the previous year. The total number of load hedges also declined to 7,223 from 10,088 in 2011. Similarly, the number of generation-hedged transactions registered a 45% decline in 2012 compared with 2011. In general, the total number of hedged transactions displayed a small increase in 2011 compared with 2010. See Table 3-2.

Table 3-2
Total Number of Hedged Transactions by Transaction Type, 2010 to 2012

Year	Total Number of Hedged Transactions	Number of Load Hedges	Number of Generation Hedges	Number of External Transaction Hedges
2010	23,160	8,244	9,651	5,265
2011	23,824	10,088	7,681	6,055
2012	12,022	7,223	4,211	588

The trend in the number of hedged transactions appears to hold for the total amount of physical positions (in GWh) for all transaction types. The trend also is consistent with the overall cleared virtual transactions shown in Figure 3-4 (above). The total amount of generation hedges continued to decline in 2011 and 2012 compared with 2010. Load-hedged and external-hedged transaction amounts increased in 2011 relative to 2010 and declined in 2012 relative to 2011. The overall amount of hedged transactions has shown a declining trend between 2010 and 2012 mostly because of the reduced amount of hedged generation transactions. See Figure 3-6.

[90] Participants engaging in external transactions may use the virtual transactions in a variety of ways depending on the specific node inside the ISO from (to) which they want to export (import) electricity. Also, they may have positions outside the ISO's markets, which adds to the complexity in hedging these transactions. Therefore, both incremental and decremental positions are considered a hedge for simplicity.

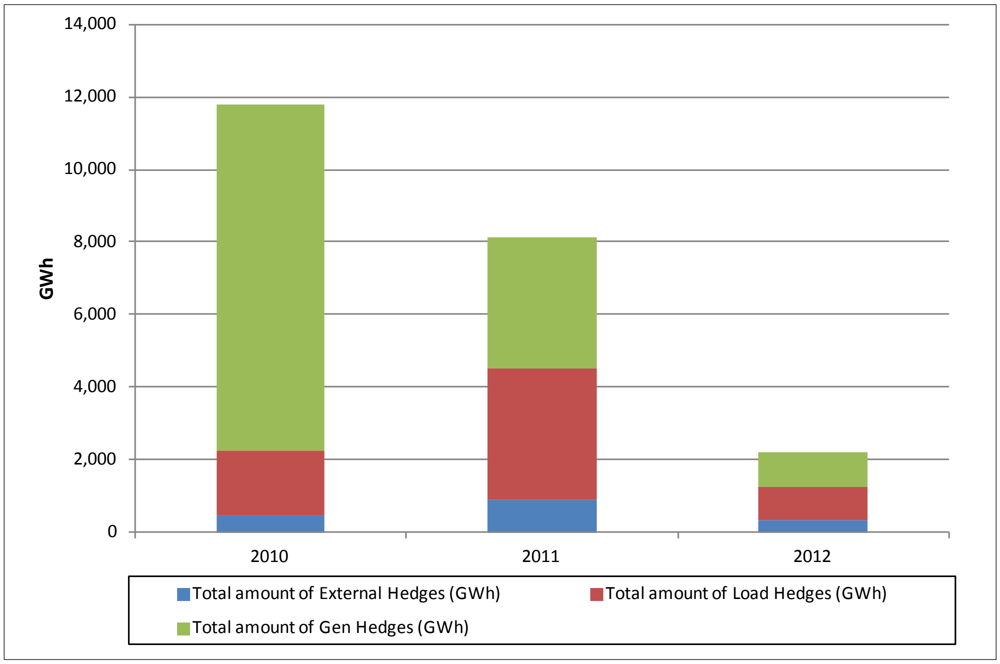

Figure 3-6: Total amount of hedged transactions by hedge type, 2010 to 2012 (GWh).

The IMM reviewed the size of the hedges relative to the associated physical transaction. The hedge size is defined as the ratio of cleared virtual transactions relative to the real-time physical obligation. For instance, in case of a participant with a real-time generation obligation at a location, the hedge size is the ratio of the amount of cleared decremental bids to the total real-time generation obligation at that location. The hedge size reflects the tolerance to risk due to uncertainty about deviation in prices and quantities between day ahead and real time. A risk-averse participant may choose to hedge a higher level of its physical obligation than a risk-neutral participant while responding to the same level of uncertainty about real-time outcomes.

The median load-hedge size showed a rising trend between 2010 and 2012. The median hedge size for load obligations went up from 27% of the real-time load obligation to 34% in 2012. A similar rising trend was observed for generation-hedge size, which increased significantly from 2% in 2010 to 35% in 2012 relative to the real-time generation obligation. Conversely, the median external-hedge size dropped significantly from 200% in 2010 to 19% in 2012 relative to the real-time external transactions. See Table 3-3.

Table 3-3
Size of Hedge Relative to Real-Time Obligations by Transaction Type, 2010 to 2012 (%)

Year	Median Load Hedge %	Median Generation Hedge %	Median External Transaction Hedge %
2010	27%	2%	200%
2011	31%	24%	236%
2012	34%	35%	19%

The IMM analyzed the absolute price deviations between day ahead and real time at the locations where locational hedges were placed and compared these deviations with the absolute deviations at the Hub. Table 3-4 shows the comparison between absolute price deviations for the locations where a hedge was placed and the Hub. The table shows a generally higher level of diversion relative to the Hub between day-ahead and real-time LMPs at the locations where locational hedging took place. The only exception was the absolute deviation at the locations where load hedges were placed in 2012. One of the possible reasons for the hedging despite the lower deviation may be the quantity uncertainty that the load participants faced.

Table 3-4
Average Absolute Day-Ahead to Real-Time LMP Deviations at the Hub and at the Hedged Locations, 2010 to 2012 ($/MWh)

Year	Hub	All Nodes with Locational Hedges	Nodes with Load Hedges	Nodes with Generation Hedges	Nodes with External Hedges
2010	8.58	9.54	9.28	9.24	10.49
2011	8.24	10.34	10.03	9.42	12.02
2012	7.33	9.11	6.95	12.53	11.04

Summary of Virtual Transactions. Overall, the volume of trading for virtual transactions continued to decline in 2012. The trend in the decline of cleared virtual transactions implies that the effects of high and uncertain transaction costs observed continues to persist, as documented in the *2011 Annual Markets Report*. The total amount of physical transactions for which participants use hedging also has displayed a declining trend. The decline in locational hedging may be attributed to the reduced deviation between day-ahead and real-time market outcomes, as well as the reduced deviation in the prices at locations relative to the Hub. The average absolute price deviation across each node type—load zones, generation nodes, and external nodes—has been declining. The absolute deviation has gone down from over $8.6/MWh in 2010 to less than $7.7/MWh for each node type. See Table 3-5. Similarly, the average difference between the real-time LMPs at the node and the node categories shows a declining trend. See Table 3-6.

Table 3-5
Average Absolute Day-Ahead to Real-Time LMP Deviations at Each Node Type, 2010 to 2012 ($/MWh)

Year	Load Zones	Generation Nodes	External Nodes
2010	8.64	8.78	8.68
2011	8.30	8.42	8.37
2012	7.54	7.66	7.49

Table 3-6
Difference between Average Real-Time Hub LMP and Average Real-Time LMP at Each Node Type, 2010 to 2012 ($/MWh)

Year	Load Zones	Generation Nodes	External Nodes
2010	0.32	0.28	0.61
2011	0.17	0.16	0.56
2012	−0.08	−0.12	0.38

The IMM continues to analyze the hedging behavior of the participants to understand how they respond to risks and the impact of their hedging behavior on the overall virtual trading volume.

The IMM recommended in the *2010 Annual Markets Report* that the ISO revise the market rules so that real-time Net Commitment-Period Compensation charges are not allocated to virtual transactions. The IMM reiterated this recommendation in the *2011 Annual Markets Report* and continues to support this recommendation.

3.2 Financial Transmission Rights

This section summarizes the 2012 activities and results associated with Financial Transmission Rights (FTRs).

Financial Transmission Rights allow participants to hedge transmission congestion costs by providing a financial instrument to arbitrage differences between expected and actual day-ahead congestion. The FTR instrument entitles the holder to receive, over a monthly or annual period, a stream of revenues (or obligates it to pay a stream of charges) that arise when the transmission grid is congested in the Day-Ahead Energy Market. The FTR payoff is based on the difference between the day-ahead congestion components of the hourly LMPs at each of the two pricing locations (nodes) that define the FTR and its megawatt quantity acquired in the FTR auctions.[91] Participants can acquire FTRs for any path on the system defined by two pricing locations. The origin location of an FTR is called the *source* point, and the FTR delivery location is called the *sink* point. The price of a particular FTR is determined by the difference between the prices at the sink location and the source location in the FTR auction.

Annual FTRs are offered in a single auction, and additional monthly FTRs are offered before each month during the year. The annual FTR auction makes available up to 50% of the transmission system capability expected to be in service during the year. In the monthly auctions, up to 95% of the expected transmission capability for the month is available.[92] The total volume of FTRs transacted in each auction is a function of the offers and bids submitted subject to the transmission limits modeled.

Participants buy or sell FTRs for different reasons. Participants with physical generation or load may choose to use FTRs as a tool for managing congestion risk associated with delivery obligations. A load-serving entity may choose to purchase FTRs to protect against transmission costs associated with congestion on particular paths or in particular zones where its load is served. Congestion-paying LSEs receive *Auction Revenue Rights* (ARRs), which are rights to receive a portion of FTR auction revenues. Revenues collected from the auctions are distributed back to congestion-paying LSEs.[93]

Financial players who have no physical obligations in the ISO markets also may buy and sell FTRs. These participants attempt to profit by arbitraging the difference between the prevailing FTR price and the FTR's true value as reflected in its payoff. These activities add liquidity to the FTR auctions. Participation by financial players can increase or decrease the total auction

[91] The minimum quantity for an FTR is 0.1 MW.

[92] The remaining 5% is reserved to account for unplanned outages.

[93] *ISO New England Inc. Transmission, Markets, and Services Tariff*, Section III.5.2, *Market Rule 1* "Transmission Congestion Credit Calculation" (March 8, 2012), http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_sec_1-12.pdf.

revenues. FTR paths that clear with a positive price result in increased auction revenues, while paths with negative clearing prices result in decreased auction revenues. Efficient auction outcomes are those that result in average path prices that have a risk-adjusted profit of zero.

3.2.1 FTR Auction Results

A total of 47 participants took part in at least one of the 13 FTR auctions in 2012. This number is up from 2011, in which 42 participants took part in at least one of the FTR auctions.

The total megawatts bought and sold in the 2012 FTR auctions, regardless of directional flow, was 428,384 MW.[94] Of this total, the percentage of megawatts associated with counterflow positions was 24%, up from 18% in 2011. Counterflow FTR positions free up transmission capacity that otherwise would have been constrained. Figure 3-7 shows the volume of megawatts bought and sold in each monthly FTR auction in 2012.

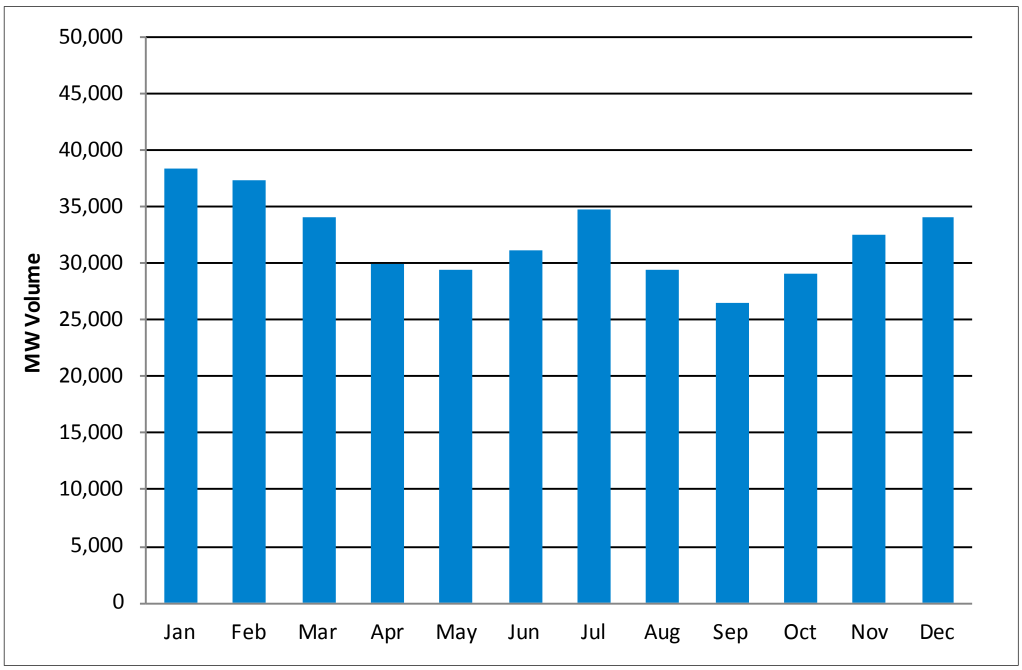

Figure 3-7: FTR monthly volumes, 2012 (MW).

Note: All megawatts, whether prevailing flow or counterflow, are treated as positive megawatts in this figure.

The total net revenue from the 12 monthly auctions and the single annual auction was $16.1 million, a 32% drop from 2011.[95] Of the $16.1 million in net revenue, $6.0 million was from the 12 monthly auctions. See Figure 3-8.

[94] The totals were 386,590 MW in the 12 monthly auctions and 41,794 MW in the annual auction.

[95] Net revenue for the monthly auctions = net revenue (bought FTRs) – net revenue (sold FTRs).

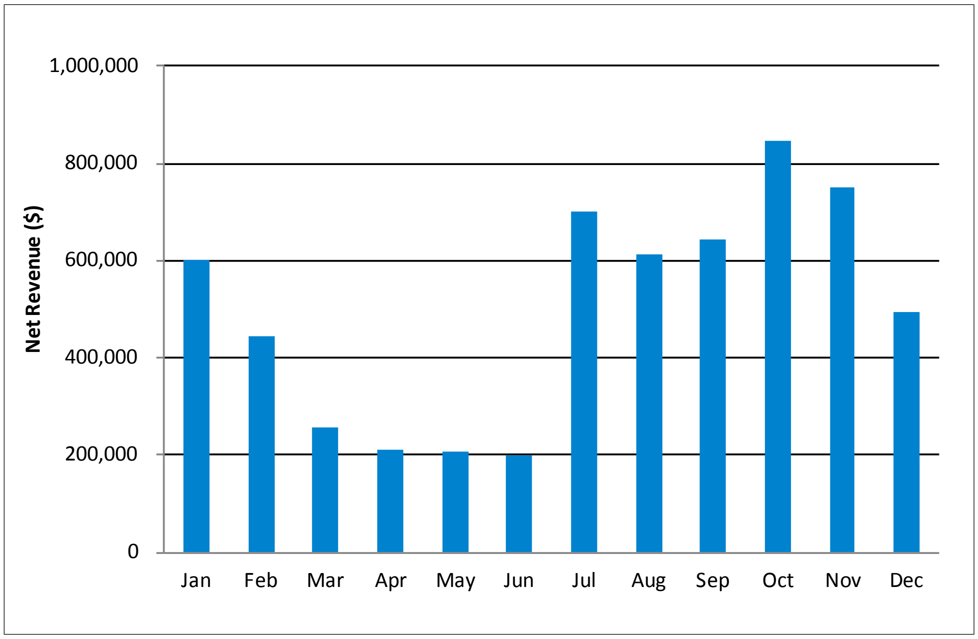

Figure 3-8: FTR monthly net revenues, 2012 ($).

If FTR participants had perfect foresight, the total auction revenue would equal the day-ahead congestion revenue; however, various factors contribute to differences between the two revenue streams. A primary factor is the large time gap between the FTR auction and when the actual congestion is realized. This gap keeps the basis of the FTRs bought and sold in the auction on market information available at the time of the auction and prevents them from accounting for any post-auction changes that may affect congestion on the transmission system. These changes could include unforeseen generator and transmission outages, which can result in some expected deviation between the day-ahead congestion revenue and the total auction revenue.

In 2012, the day-ahead congestion revenue was $29.3 million, an increase from the $18.0 million of day-ahead congestion revenue in 2011. Transmission facility outages, required as part of the construction process for a number of system upgrade projects within New England, contributed to the total day-ahead congestion revenues in the region. Additionally, 24% of the day-ahead congestion revenue for 2012 was from just 10 days in 2012. Although the day-ahead congestion revenue increased in 2012, the total auction revenue decreased from $23.5 million in 2011 to $16.1 million in 2012. This indicates that participants did not accurately predict the increase in day-ahead congestion revenue in 2012. See Table 3-7.

Table 3-7
Comparison of Day-Ahead Congestion Revenue with Auction Revenue, 2010 to 2012

	Day-Ahead Congestion Revenue (Millions $)	Total Auction Revenue (Millions $)	Auction Revenue as % of Day-Ahead Congestion Revenue
2010	37.3	30.2	81%
2011	18.0	23.5	131%
2012	29.3	16.1	55%

The IMM reviewed the most active FTR participants in 2012. Activity is defined as the sum of all megawatts transacted by a participant, regardless of whether the FTRs were prevailing flow, counterflow, bought, or sold. The two participants that were most active with FTRs in 2012, who accounted for approximately 40% of total transacted megawatts, were financial players. Financial players are more likely to buy and sell FTR positions many times as new information becomes available. See Figure 3-9.

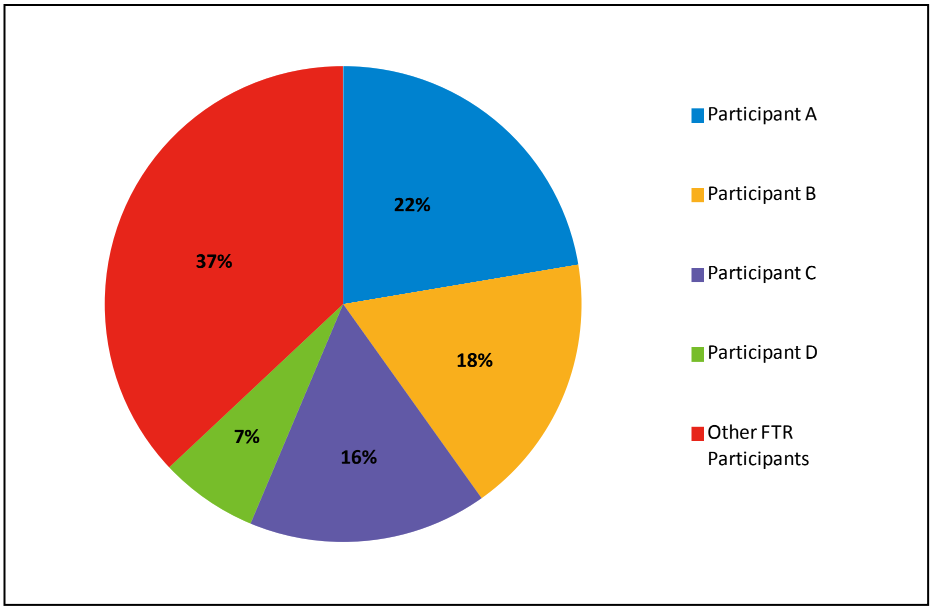

Figure 3-9: FTR participant activity, 2012 (%).

3.2.2 Publication of FTR Awards

The ISO noted in a FERC filing that the publication of strategic information at the end of an auction may create an opportunity for signaling and collusion among bidders.[96] This occurs when the auction is repeated and the results of one auction or auction round can be used by competitor "A" to signal appropriate behavior to competitor "B" for a mutually beneficial outcome. This is a general property of repeated auctions.[97] The case in point referred to multiple rounds of an FTR auction. The proposed, and FERC-accepted, resolution was to restrict the information publishing between rounds to include only the auction clearing prices and awarded FTRs (paths and quantities) without ownership information.[98]

This docket only addressed the introduction of multiround auctions for FTRs and did not extend the principle to all FTR auctions. However, 12 monthly auctions follow the annual auction conducted for the same paths. Thus, the same possibilities of signaling and collusion exist, albeit with a lag of a month rather than days or hours. As noted, the signaling problem is a general problem of repeated auctions.

96 "Testimony of Jonathan B. Lowell," ISO New England Inc., *NEPOOL Participants Committee, and Participating Transmission Owners Administrative Committee; Filing of FTR Enhancements, Docket No. ER11-___-000* (May 13, 2011), 14, http://www.iso-ne.com/regulatory/ferc/filings/2011/may/er11-3568-000_5-13-11_ftr_enhancements.pdf.

97 Paul Klemperer, "What Really Matters in Auction Design," *Journal of Economic Perspectives* 16, no. 1 (Winter 2002).

98 Lowell testimony (2011), 15.

The IMM recommends that the ISO adopt the same publication criteria for all FTR auctions as it proposed for the publication of rounds between auctions, specifically, that it cease identifying the winning bidders when announcing the results of the any FTR auction and publish only clearing prices and awarded FTRs (paths and quantities) without ownership information.

3.3 Forward Reserve Market

This section presents data about the participation, outcomes, and competitiveness of the two forward-reserve auctions conducted in 2012. The IMM concludes that the auction design is susceptible to price distortions and inefficiencies as a consequence of resources' offering into the market with effective zero-price offers.

To maintain system reliability, all bulk power systems maintain reserve capacity to respond to contingencies, such as unexpected outages (refer to Section 2.2). The locational Forward Reserve Market (FRM) procures operating reserves from participants with resources that can provide reserves, including 10-minute nonspinning reserve (TMNSR) and 30-minute operating reserve (TMOR) and locational TMOR. Auctions are held twice a year, for a summer delivery period and a winter delivery period. Participants submit offers to sell a quantity of a reserve type in a particular location and at a specific price. During the delivery period, a participant with an obligation must assign resources daily to meet the obligation or incur nonperformance penalties.

3.3.1 Auction Results

The clearing price in the FRM auctions in summer 2012 and winter 2012/2013 were $3,450/MW-month and $3,301/MW-month. These are the lowest prices in the FRM since its inception in 2004. See Table 3-8.

Table 3-8
Auction Clearing Price, Four-Most-Recent FRM Auctions ($/MW-month)

Location	Product	Summer 2011	Winter 2011/2012	Summer 2012	Winter 2012/2013
CT	TMOR	4,500	4,350	3,450	3,301
NEMA/Boston	TMOR	4,500	4,350	3,450	3,301
SWCT	TMOR	4,500	4,350	3,450	3,301
Systemwide	TMNSR	4,500	4,350	3,450	3,301
Systemwide	TMOR	4,500	4,350	3,450	3,301

The net payments to FRM resources equal the FRM auction clearing price minus the Forward Capacity Market clearing price. The FCM clearing price for the 2012/2013 capacity commitment period (see Section 3.4) was $2,950/MW-month; the net payment received by reserve providers was $500/MW-month for the summer 2012 auction and $351/MW-month for the winter 2012/2013 auction.

The 2012 auctions had no price separation, mostly because new resources were built in Connecticut and Southwest Connecticut, and the *external reserve support* (ERS)—the ability to import power into these regions—has improved, as described in Section 3.3.3.

3.3.2 Market Requirements

The ISO defines locational requirements, as well as a systemwide requirement, for each reserve product procured in the auction.[99] The systemwide requirement for TMNSR in summer 2012 and winter 2012/2013, were 815 MW and 820 MW, respectively. The combined requirement for TMNSR and TMOR in summer 2012 was 1,565 MW, and the combined requirement for winter 2012/2013 was 1,595 MW. The combined local reserve requirement for NEMA/Boston was zero because the external reserve support exceeded the local second contingencies in this location in the auctions held in 2012. For SWCT, the local reserve requirement was zero for the summer auction but was 50 MW for the winter 2012/2013 auction. See Table 3-9.

Table 3-9
Local Reserve Requirements
Summer 2012 and Winter 2012/2013 Forward Reserve Auctions (MW)

Location Name	Product	Summer 2012	Winter 2012/2013
CT	TMOR[(a)]	765	837
NEMA/Boston	TMOR[(a)]	0	0
SWCT	TMOR[(a)]	0	50
Systemwide	TMNSR	815	820
Systemwide	TMOR[(a)]	1,565	1,595

(a) TMNSR also can be used to satisfy this requirement.

3.3.3 External Reserve Support

Through external reserve support, resources within a local region as well as reserves available in other locations, if needed, can satisfy second contingencies. As a result of transmission upgrades, the ERS to several import-constrained regions has increased. The most notable enhancements in ERS have taken place in Connecticut and Southwest Connecticut, where improvements in ERS reduced the minimum amount of reserve capacity needed from local resources in 2011. See Table 3-10.

Table 3-10
External Reserve Support in the Past Four FRM Auctions (MW)

Location Name	Summer 2011	Winter 2011/2012	Summer 2012	Winter 2012/2013
CT	490	457	447	399
NEMA/Boston	1,394	958	822	1,080
SWCT	560	720	1107	214

99 The TMNSR and TMOR requirements are based on first- and second-contingency losses (refer to Sections 2.1.6.1 and 2.2). The methodology to calculate these requirements are described in OP 8 (see Section 2.2.1) and *the ISO New England Manual for Forward Reserve* (Manual M-36) (April 5, 2013), http://www.iso-ne.com/rules_proceds/isone_mnls/index.html.

3.3.4 Observations and Concerns

Similar to what the IMM reported in earlier Quarterly and Annual Market Reports, the FRM auction for summer 2012 and winter of 2012/2013 potentially is suffering from inefficiently low offers that seem to be below the resources' incremental costs of providing reserves. These offers would be profitable only if the participants who submit such offers receive out-of-market payments. Such offers also could depress the price and thus send incorrect price signals to the market, especially in Connecticut and Southwest Connecticut. In addition, because the penalties of nonperformance are linked to the clearing prices, these low clearing prices create weak incentives to activate reserve in response to ISO instructions.

3.3.5 Review of Forward Reserve Market Penalty Structure

This section reviews the FRM penalty structure and discusses an IMM recommendation to change the failure-to-reserve penalty.

3.3.5.1 Overview of FRM Penalty Structure

The Forward Reserve Market has two penalties: a failure-to-reserve penalty for resources that have not satisfied the requirements for availability and ability to provide reserve, and a failure-to-activate penalty for FRM resources that do not provide energy when called.

The failure-to-reserve penalty is set at 1.5 times the hourly payment rate derived from the semiannual FRM auction. The failure-to-activate penalty is set at the greater of 2.25 times the same hourly payment rate, or the LMP. Thus, both penalties decline as the auction price declines. Because expected penalties are a primary component of the clearing price, the effect compounds.

In 2011 and 2012, both penalties and clearing price revenues declined, as is illustrated in Table 3-11. The 2012, total net forward credit paid to FRM suppliers was 8.19% of the 2010 total. The 2012 failure-to-reserve penalty total was 16.79% of the 2010 total.

Table 3-11
Forward and Real-Time Reserve Payments and Penalties, 2010 to 2012

Year	Fail-To-Activate Penalties	Fail-To-Reserve Penalties	Forward Credit	Net Forward Credit
2010	−$87,510	−$5,057,742	$118,545,939	$113,400,687
2011	−$2,671	−$1,082,569	$18,950,856	$17,865,615
2012	$0	−$848,972	$10,138,757	$9,289,785

The following sections explore the hypothesis that the lower levels of FRM penalties indicate that the penalty structure may be flawed.

3.3.5.2 The Failure-to-Reserve Penalty

Because the failure-to-reserve penalty declines when the auction clearing price declines, a low clearing price yields a low penalty. This creates an incentive to default when the auction price it is based on is low and the reserve and electric energy prices are high. In these cases, the supplier has an incentive to self-schedule to follow the energy price. The returns from capturing a spike in the energy price can be much greater than the penalty for failing to reserve.

The problem arises when a resource designated to provide reserve then is backed down and incurs an energy opportunity cost. Typically, such resources are kept indifferent through the payment of real-time reserve. However, forward-reserve resources are understood to have already sold the reserve, and thus their real-time reserve is deducted from their payment.

Using the winter 2012/2013 FRM delivery period as an example, where the hourly payment rate was $1.09/MWh and the hourly penalty was $1.64/MWh, assume that for a given day, the LMP was $200/MWh, the real-time reserve price was $99/MWh, and the generator's offer was $101/MWh. If the generator is paid the reserve price for the unloaded megawatts, it would have made just as much net revenue as if it generated at $200/MWh. However, if the generator is designated as an FRM resource, it would have been paid only $1.09/MWh instead of the $99/MWh. Thus, if the generator had followed dispatch instructions and remained on reserve, it would have earned a net revenue of $1.09/MWh. Not following dispatch, but chasing the price with a self-schedule, would have yielded a higher net revenue of $97.36/MWh (= $200 – $101– $1.64).

Two predictions can be made given this incentive. First, the higher the forward-reserve clearing price and hence penalty, the fewer failures to reserve (i.e., defaults) there should be. Second, higher energy prices should correlate with higher default occurrences. These are both borne out in the following two illustrations.

In Figure 3-10, as the failure-to-reserve penalty falls, the failures to reserve rise as a percentage of the forward-reserve obligation. Figure 3-11 demonstrates that, since winter 2006, the average price during hours with failures to reserve has been higher than the average of all delivery hours.

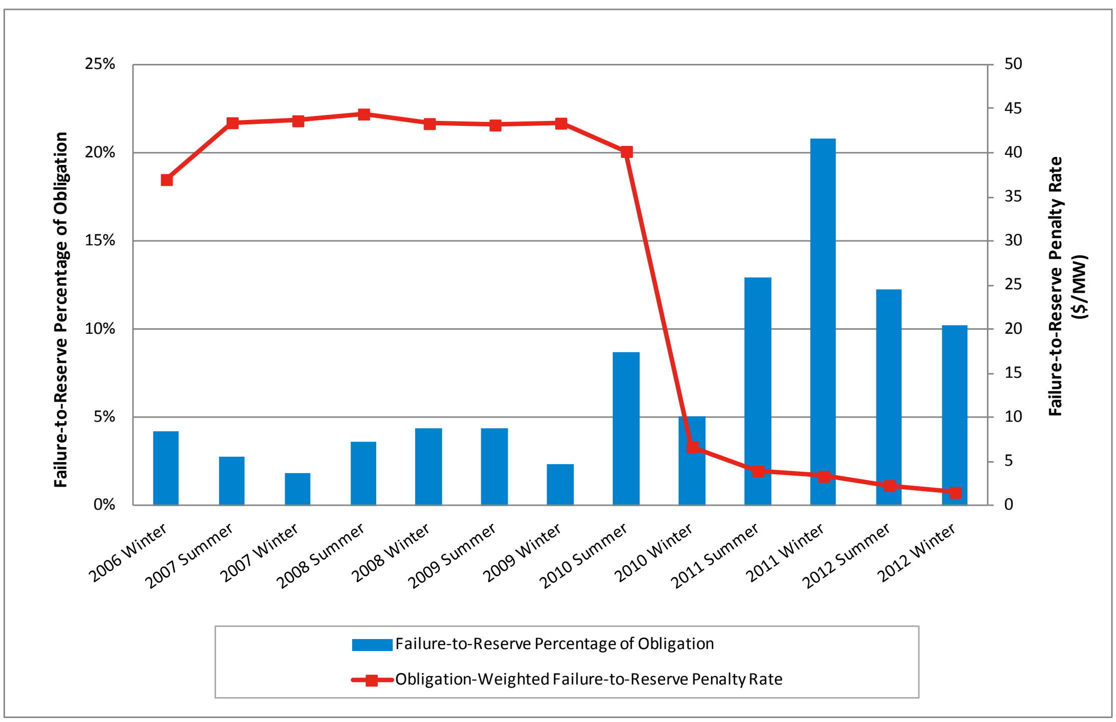

Figure 3-10: Thirty-minute operating reserve failures to reserve, as a percentage of obligations, and the penalty rate, 2006 to 2012.

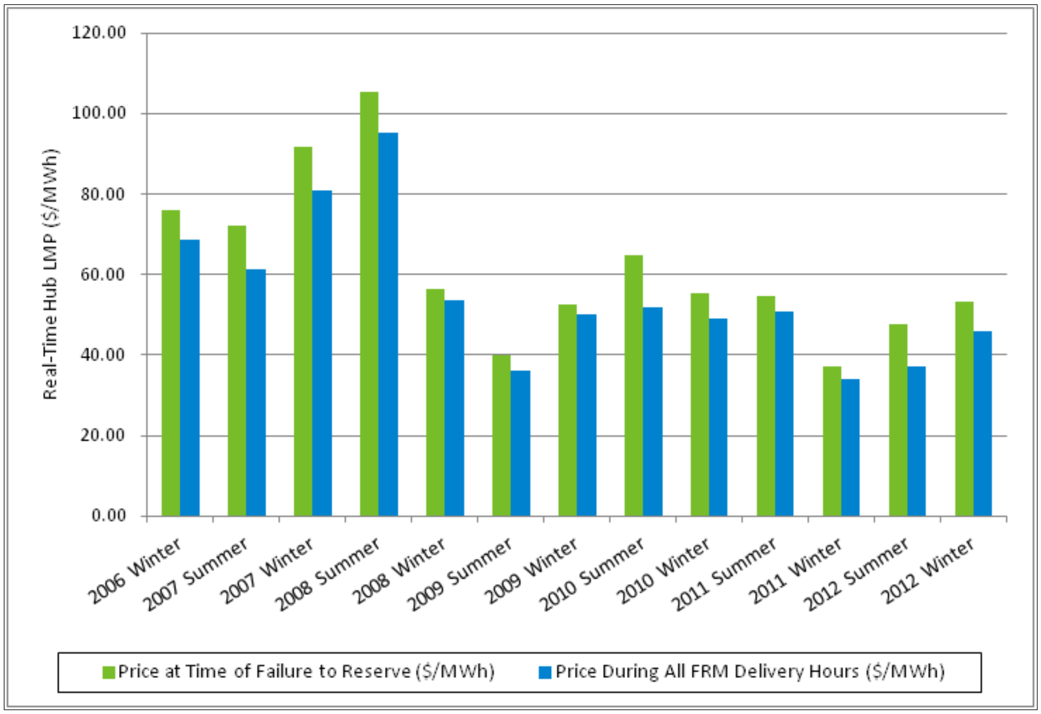

Figure 3-11: Prices at times of failures to reserve compared with prices during all FRM delivery hours, 2006 to 2012 ($/MWh).

Failure-to-Reserve Penalty Discussion. The current FRM design creates an incentive for the resource owner to default on the obligation when the real-time LMP is high because of a reserve shortage. In these circumstances, the resource owner captures the LMP by self-scheduling the energy and failing to reserve the forward reserve. The owner chooses to default on the FRM obligation and pays only the FRM failure-to-reserve penalty. A typical resource would be indifferent because the owner would receive the reserve price. To avoid this incentive problem, the failure-to-reserve penalty should have a minimum level equal to the reserve price.

A second, related shortfall in the penalty structure is the linking of the failure-to-reserve penalty to the clearing price of the FRM auction. Because of the link, when the expected auction price falls, the expected penalties fall, thus leading to lower bids. This in turn leads to lower actual auction prices and lower actual penalties. As noted in previous Quarterly Market Reports, one reason that prices, and hence penalties, have fallen is that suppliers with state contracts bidding below their costs have depressed the recent auction prices.[100] The lower penalties lead to the increasing likelihood that defaulting on the FRM obligation during periods of high energy price will be profitable for the participant.

Failure-to-Reserve Penalty Recommendations. A failure-to-reserve penalty should recognize the true cost of creating reserves. Of the resources available to system operators to provide reserves—either off-line fast-start resources or slower resources committed on line—it often is costly for the slower resources to provide reserves because doing so is not economic for them. While the costs to assure adequate reserves are substantial, and NCPC payments reflect the

[100] See the Q2 and Q3 2011 Quarterly Market Reports at http://www.iso-ne.com/markets/mkt_anlys_rpts/qtrly_mktops_rpts/2011/index.html. The *2011 Annual Markets Report* also discusses the issue.

additional costs, the real-time reserve prices do not. A failure-to-reserve penalty commensurate with the size of these commitment costs would be appropriate because these costs serve as the alternative cost to acquire reserve, or the replacement cost.

One estimate of the replacement cost of reserve is the cost of committing incremental resources to acquire reserves. The annual commitment costs for reserves have been significant, as reflected in the NCPC costs for the generators ordered on for first- and second-contingency coverage as a result of the RAA. In 2011 and 2012, these costs were $65 million and $68.5 million, respectively. Out-of-merit commitments add additional costs to the market by depressing the energy clearing price and investment incentives. Thus, from a broader perspective, the actual out-of-merit commitment cost would be a lower bound on the replacement cost.

While the failure-to-reserve penalty should reflect these commitment costs, a penalty based on the real-time reserve price would ignore these costs. The real-time reserve price can be high during periods of reserve scarcity and thus provide an adequate penalty, but commitments are made precisely to avoid such periods of reserve scarcity. Thus, a low real-time reserve price may coincide with a high incurred commitment cost of reserve.

The true replacement cost differs day to day as the out-of-merit commitment costs and the real-time reserve price vary with supply and demand conditions. One option for reflecting the true replacement cost is to set the penalty as the greater of a fixed estimate of the out-of-merit commitment cost and the real-time reserve price. The market design provides for the use of hourly bilateral contracts and portfolio assignment to satisfy shortfalls so that the fixed estimate would only be an incentive to engage in the bilateral market. It never would be paid in equilibrium and would only amount to a cap on the provider's risk. The bilateral market should find the most time-varying replacement cost of reserve.

3.3.5.3 Failure-To-Activate Penalty

As noted in Table 3-11, the total dollar amount of failure-to-activate penalties in 2012 was $0. This suggests either that performance was outstanding or that the penalty structure has an underlying design flaw. The later appears to be the case.

The failure-to-activate penalty is triggered only when the ISO uses an emergency version of the dispatch software ("Contingency SPD"). Under current system procedures, this tool is used when a supply resource (generation or imports) exceeding 500 MW is lost suddenly.[101] These are NPCC reportable events. It also may be used when a neighboring balancing authority area requests assistance under a previously agreed on shared activation of reserve.

Another limitation of Contingency SPD is that it does not start generators with a combined start-up and notification time of greater than 15 minutes. This is because the narrow objective of Contingency SPD is to replace the electric energy lost in time to satisfy NPCC requirements to recover within 15 minutes. Thus, generators with 30-minute operating-reserve obligations in the FRM rarely are tested for activation and rarely receive a failure-to-activate penalty.

[101] ISO New England Inc., *Implement Disturbance Remedial Action*, ISO System Operating Procedure RTMKTS.0120.0040, Attachment B-EOP-1, "Implement Disturbance Remedial Action," flow chart (April 22, 2013), http://www.iso-ne.com/rules_proceds/operating/sysop/rt_mkts/index.html.

System operators have two other tools they use to activate off-line reserve units. First, they have a fast-start resource tool that activates only off-line fast-start resources that can provide electric energy within 30 minutes. Second, they can adjust the short-term load forecast, which may in turn cause the normal dispatch software ("SPD") to commit fast-start units as well as dispatch on-line units.

Given the use of alternative tools and the narrow use of the Contingency SPD, in practice, the ISO uses Contingency SPD infrequently. Thus, the fast-start and on-line resources that fail to provide the electric energy reserved by the Forward Reserve Market are unlikely to be penalized. Three observations during 2012 corroborate this:

- No actual FRM failure-to-activate penalties were collected during 2012; the total was $0.
- In all of 2012, Contingency SPD was run only 13 times during FRM delivery hours. In addition, Contingency SPD dispatch may call only a subset of FRM-designated generators. At times, Contingency SPD primarily dispatches on-line resources, in which case, FRM units are not tested. For example, on January 10, 2013, the ISO ran Contingency SPD to dispatch an additional 696 MW, and no FRM-designated generators were dispatched.
- The infrequent use of Contingency SPD contrasts with the 467 hours the LMP exceeded the FRM threshold price during FRM delivery hours. This order-of-magnitude difference illustrates how conservative the failure-to-activate trigger is. Using Contingency SPD as the trigger results in observing fewer instances when the FRM reserved energy is in merit and is called but is not delivered.

The IMM recommends having more options available for triggering the failure-to-activate penalty than only the Contingency SPD. One alternative would be to require the penalty to be triggered any time the ISO dispatches an FRM resource into the expensive energy reserved by the FRM but the generator does not provide the energy. In addition, it should be noted that participants face additional future costs of designating alternative resources or covering their obligations bilaterally when a failure-to-activate penalty coincides with reduced future reserve capability.[102]

3.4 Forward Capacity Market

The Forward Capacity Market is a long-term market designed to procure the resources needed to meet the region's local and systemwide resource adequacy requirements. It does this by compensating generation and demand resources for fixed capacity costs not covered through the other markets.[103] The FCM is designed to send price signals to attract new capacity resources (e.g., generation, imports, and demand resources) and maintain existing resources to meet the region's resource adequacy standard. To allow enough time to construct new capacity resources, Forward Capacity Auctions (FCAs) are held each year 40 months in advance of when

102 On November 6, 2012, the ISO filed with FERC revisions to the auditing provisions, *ISO New England Inc. and New England Power Pool, Docket No. ER13-___-000, Market Rule 1 Revisions Relating to Auditing of Generation Resources*; Docket No. ER13-323-000, http://www.iso-ne.com/regulatory/ferc/filings/2012/nov/index.html. The new audit requirements are more stringent and result in a more conservative calculation of a generator's reserve capability.

103 One reason why the energy markets do not cover all fixed costs is that a price cap in the energy markets limits energy offers to $1,000/MWh.

the capacity resources must provide service, called the *capacity commitment period* (CCP). Both new and existing capacity resources that qualify for an FCA can participate in the auction.

Each Forward Capacity Auction is conducted in two stages: a descending-clock auction followed by an auction-clearing process. The descending-clock auction consists of multiple rounds. During one of the rounds in each auction, the amount of capacity willing to remain in the auction at a given price level will equal or fall below the *Installed Capacity Requirement* (ICR).[104] FCM resources that remain in the auction receive the FCA clearing price as determined in the auction-clearing stage of the FCA.

Reconfiguration auctions take place before and during the capacity commitment period to allow participants with capacity supply obligations to trade out of their positions to other resources that do not have CSOs. Annual reconfiguration auctions (ARAs) to acquire one-year commitments are held approximately two years, one year, and just before the FCA commitment period begins. Monthly reconfiguration auctions, held beginning the first month of a commitment period, adjust the annual commitments during the commitment period.

Two key provisions of the capacity payment structure are the peak energy rent (PER) adjustment and the penalties incurred for resource unavailability during shortage events.[105] The *peak energy rent* adjustment reduces capacity market payments for all generation and import capacity resources, even those not producing energy, when the LMP rises above the PER threshold (i.e., *strike*) price, which is an estimate of the cost of the most expensive resource on the system. Demand resources are excluded from the PER adjustment. The PER value is based on revenues that would be earned in the energy market by a hypothetical peaking unit with heat rate of 22,000 British thermal units/kilowatt-hour (Btu/kWh) that uses the more expensive of either natural gas and No. 2 fuel oil. The PER adjustment also is a hedge for load against energy prices above the strike price; it discourages physical and economic withholding because a resource that withholds to raise price for other resources in its portfolio reduces the capacity payments to all its resources, negating the benefit of the higher energy price to the portfolio.[106]

3.4.1 Capacity Market Auction Outcomes

This section reviews the outcomes and performance for the second through sixth FCAs and represents the auctions conducted through the reporting periods. Information on past capacity commitment periods is included in prior Annual Markets Reports.

3.4.1.1 Forward Capacity Market Results

Table 3-12 shows, for FCA #2 through FCA #6, (1) the total amount of capacity cleared in each auction, (2) the amount of capacity needed (i.e., the ICR), (3) the amount of surplus capacity, (4) the net capacity additions for that period, and (5) the capacity price.

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104 The ICR is the minimum amount of resources (level of capacity) a balancing authority area needs in a particular year to meet its resource adequacy planning criterion, according to the NPCC criterion, A-2, *Basic Criteria for Design and Operation of Interconnected Power Systems*. This criterion states that the probability of disconnecting any firm load because of resource deficiencies must be, on average, less than once in 10 years.

105 A *shortage event* is when the system is short of 10-minute reserves for at least 30 minutes.

106 The lower volatility of total payments might not affect the entire amount that load participants pay in the long run because the resources' capacity bids reflect the lower PER-adjustment amounts.

Table 3-12
FCM Capacity Commitment Period Results, 2011/2012 to 2015/2016
(MW and $kW-month)

Factor	FCM Capacity Commitment Period (a)				
	2011/ 2012	2012/ 2013	2013/ 2014	2014/ 2015	2015/ 2016
Cleared capacity resources (MW)	37,283	36,996	37,500	36,918	36,309
Net ICR (MW)	32,528	31,965	32,127	33,200	33,456
Surplus (MW)	4,755	5,031	5,373	3,718	2,853
Net capacity additions (MW)[(b)]	2,760	1,329	1,490	1,176	2,041
Capacity price ($/kW-month)	3.60	2.95	2.95	3.21	3.13

(a) The FCM period began June 1, 2010; the capacity commitment period 2011/2012 is for the second FCA.

(b) Net capacity additions reflect cleared new capacity, excluding repowering projects and including imports.

3.4.1.2 Reconfiguration and Bilateral Auction Results

The annual and monthly reconfiguration auctions provide participants the opportunity to exchange the CSOs they have for an annual commitment period or for a particular month. Each reconfiguration auction clears at a different price and quantity depending on the amount of CSOs participants are willing to acquire and transfer. Table 3-13 shows that the clearing prices in the annual reconfiguration auctions have declined steadily and are significantly lower than the prices in the corresponding FCAs (shown in Table 3-12).

Table 3-13
Annual Reconfiguration Auction Clearing Prices and Quantities,
2011/2012 to 2013/2014 (MW and $kW-month)

Commitment Period	Auction	Cleared CSOs (MW)	Clearing Price ($/kW-month)
2011/2012	ARA #2	188	1.00
	ARA #3	362	0.93
2012/2013	ARA #2	636	0.94
	ARA #3	623	0.55
2013/2014	ARA #2	920	0.50

Table 3-14 shows the clearing prices and quantities in the monthly reconfiguration auctions; prices in the monthly auctions also have declined over time and are significantly lower than the prices in the corresponding FCAs.

Table 3-14
Clearing Prices and Quantities in the Monthly Reconfiguration Auctions,
2011/2012 to 2012/2013 (MW and $kW-month)

Commitment Period	Average of Monthly Cleared CSOs (MW)	Weighted Average of Monthly Clearing Price ($/kW-month)
2011/2012	408	0.35
2012/2013	545	0.27

(a) All monthly reconfiguration auctions have not been completed for all months in the 2012/2013 capacity commitment period.

For the 2011/2012 commitment period, the monthly prices ranged from $0.15/kW-month to $1.01/kW-month, and cleared volumes ranged from 227 MW (for August 2011) to 576 MW (for January 2012). The 2012/2013 commitment period, to date, has obtained prices ranging from $0.10/kW-month to $0.43/kW-month, whereas cleared volumes have ranged from 273 MW (for August 2012) to 754 MW (for July 2012).

The clearing price and cleared CSO megawatts appear to have a negative relationship, which is consistent with expectations. The participant who has a cleared CSO in an FCA has an incentive to transfer the CSO if the difference between the FCA clearing price and the reconfiguration price is positive. At lower reconfiguration auction clearing prices, the potential payoff of transferring a CSO increases, resulting in the transfer of more CSOs.

3.4.2 Trends in Cleared Capacity in FCA #1 to FCA #6

Table 3-15 presents data for generation, demand response, and import capacity cleared for each capacity commitment period.

Table 3-15
Cleared Capacity Resources for Each FCM Capacity Commitment Period, 2010/2011 to 2015/2016 (MW)

Factor	FCM Capacity Commitment Period					
	2010/ 2011	2011/ 2012	2012/ 2013	2013/ 2014	2014/ 2015	2015/ 2016
Installed generation[(a)]	30,865	32,207	32,228	32,247	31,439	30,757
Demand resources (capacity obligation)[(b)]	2,279	2,778	2,868	3,261	3,468	3,628
External capacity contracts[(a)]	934	2,298	1,900	1,992	2,011	1,924
Surplus above the ICR	1,173	4,755	5,031	5,373	3,718	2,853
Total capacity resources	34,078	37,283	36,996	37,500	36,918	36,309

(a) Data for FCM periods are based on cleared megawatts.

(b) Data for FCM commitment periods are based on cleared megawatts, including those for energy efficiency and demand-response resources, which reflect the 600 MW RTEG cap.

Two trends have continued through the first six FCAs. One trend is the clearing of far more capacity than is needed to meet the Installed Capacity Requirement. The second is the addition of large amounts of demand resources and imports that started in the FCM transition period.[107] The surplus capacity cleared after FCA #1 was 1,773 MW, which rose to 5,373 MW after FCA #4 and dropped to 2,853 MW for FCA #6.

However, demand resources also have chosen to shed a portion of their CSOs for the capacity commitment periods. This shedding activity has increased over time, as indicated in Table 3-16.[108] Except for the 2011/2012 period, demand resources so far have transferred

[107] The FCM transition period ran from December 2006 to May 2010,

[108] These estimates are net of transfers between demand resources and transfers from other resources to demand resources and thus represent the net transfers of CSOs from demand resources to other resource types. Except for the 2013/2014 commitment period, estimates represent the summed values for "annual" reconfiguration net transfers and the average of "monthly" reconfiguration net transfers. Because monthly reconfiguration activities have not occurred for the 2013/2014 commitment period, these estimates represent only the summed annual net transfers.

approximately 25% of their CSOs to nondemand resources through reconfiguration auctions and bilateral contracts. Given the low clearing prices for reconfiguration CSO transfers (illustrated by the reconfiguration auction prices presented above) and the much higher floor prices in the primary FCAs, demand resources have been able to retain a significant portion of the capacity revenue from the obligations transferred to other resource types, while not having to deliver that capacity to the market.

Table 3-16
Impact of FCM Reconfiguration Activity on Demand Resource CSOs, by Capacity Commitment Period (MW)

Factor	FCM Capacity Commitment Period					
	2010/ 2011	2011/ 2012	2012/ 2013	2013/ 2014	2014/ 2015	2015/ 2016
Demand resources (capacity obligation)[(a)]	2,279	2,778	2,868	3,261	3,468	3,628
Net demand-resource CSO transfers[(b)]	540	523	683	825	n/a	n/a
CSO net of transfers	1,739	2,255	2,185	2,436	3,468	3,628
Percent CSO Transferred	24%	19%	24%	25%	n/a	n/a

(a) Data for FCM commitment periods are based on cleared megawatts, including those for energy efficiency and demand-response resources, which reflect the 600 MW RTEG cap.

(b) These estimates represent the net transfers of CSOs from demand resources to other resource types. Partial data available for 2013/2014; data not available for the 2014/2015 and 2015/2016 capacity commitment periods.

3.4.3 Forward Capacity Market Performance

This section reviews how well the FCM has met its objectives in attracting sufficient capacity and appropriately pricing that capacity.

3.4.3.1 Reliability Needs and Performance

Since the start of FCM transition-period payments and continuing through each FCA, more than enough capacity has been available to meet New England's Installed Capacity Requirement. Thus, the FCM has met its primary purpose of sending price signals that attract new resources and maintain existing resources to meet the region's resource adequacy standard. Additionally, the rules to facilitate the participation of demand resources in the capacity market have successfully attracted these resources.

The FCM has helped meet the region's reliability needs at prices noticeably lower than the cost of new generation; each FCA has cleared at the floor price for the auction. The significant surplus since the start of the transition period at capacity prices lower than the estimated cost of new entry can be attributed to several factors:

- **First, the amount of capacity paid during the transition period was not limited.** Transition payments attracted a significant amount of demand resources and capacity imports into the market, much of which has remained.
- **Second, the need for capacity since the transition period has grown only modestly.** The ICR has increased at an average annual rate of 1.28% from the 2006/2007 commitment period to the 2015/2016 commitment period, for a total increase of 3,630 MW. This ICR growth is about 700 MW less than the surplus of

4,337 MW available in June 2007, the first summer after the start of transition payments.

- **Third, demand-response resources and imports have shown they can enter the market quickly and at prices lower than the estimated cost of new entry for new generators.**
- **Fourth, a significant amount of resources whose estimated cost of new entry exceeded the auction clearing price entered the market.** This out-of-market entry is the result of state concerns over the risk of high capacity prices and state policy objectives that have encouraged the development of demand-side and renewable resources.

Table 3-17 shows the new generation and demand resources and the megawatts and percentages provided by OOM resources for the current and future capacity commitment periods.

Table 3-17
New In- and Out-of-Market Generation and Demand Resources and OOM Resources as a Percentage of these New Resources (MW, %)[(a)]

Type of Resource	FCA #2	FCA #3	FCA #4	FCA #5	FCA #6	Total
New generation and demand resources	1,231	512	659	305	393	3,100
In-market resources	337	239	111	124	257	1,068
Out-of-market resources	894	273	548	181	136	2,032
% OOM	73%	53%	83%	59%	35%	66%

(a) Net of repowerings and excluding imports.

Table 3-17 shows that 66% of new generation and demand resources added have been out of market and that the percentage has been as high as 83% of all new generation and demand resources in a single year. Generation and demand resources both have been out-of-market, but as Table 3-18 shows, a higher percentage of generation has been out of market. Two new generation projects, the Kleen project and the Connecticut request for proposals (RFP) for peaking resources, sponsored by the State of Connecticut, represent most of the out-of-market generation.

Table 3-18
Percentage of Out-of-Market New Capacity, by Resource Type, FCA #2 to FCA #6 (MW, %)[(a)]

Type of Resource	Total New Capacity Added (MW)	Total OOM Added (MW)	% OOM
Generation	1,251	1,098	88%
Demand	1,849	934	51%

(a) Net of repowerings and excluding imports.

While the amount of OOM entry has been substantial, it has not yet affected the auction clearing price because the capacity surplus at the start of each auction has been sufficient to cause the auction to clear at the floor price.

3.4.3.2 Peak Energy Rent

On December 1, 2010, the fuel used to calculate the PER adjustment was changed from the lower price of natural gas and No. 2 fuel oil to the higher price of the two.[109] As a result, the strike price increased from approximately $116/MWh on November 30, 2010, to $425/MWh on December 1, 2010. Because the amount of the PER adjustment is calculated from a moving 12-month average, the gas-based strike price and adjustment affected the PER adjustment through November 2011.

The PER adjustments decreased through 2011 because of the increase in the strike price. From the implementation of the FERC order in December 2010 through the end of 2012 (and in particular, for all 2012) no hours had a positive hourly PER.[110] As a result, the PER adjustment fell to zero in December 2011, when all effects from a gas-based, calculated strike price ended.[111] See Table 3-19.

Table 3-19
Monthly PER Adjustments, 2010 to 2012 ($)

Month	2010	2011	2012
January		$17,623,452.89	$0
February		$17,181,011.72	$0
March		$16,790,838.86	$0
April		$16,336,232.44	$0
May		$16,325,239.04	$0
June	$8,354,906.47	$14,042,658.27	$0
July	$10,019,246.04	$12,131,439.22	$0
August	$14,125,532.62	$7,936,773.12	$0
September	$16,598,235.84	$2,866,969.67	$0
October	$19,017,941.15	$267,586.41	$0
November	$18,278,258.29	$208,254.68	$0
December	$18,020,748.10	$0	$0
Total	$104,414,868.51	$121,710,456.32	$0
Total 2010 to 2012	$226,125,324.83		

These results are expected because the higher strike price means that the PER adjustment is triggered less often. While the two main functions of PER (i.e., to reduce the incentive to exercise market power and provide a hedging mechanism) are weakened because of this change, the IMM believes PER still is an important protection against the exercise of market power.

109 See *Order Accepting Tariff Provisions in Part, and Rejecting Tariff Provisions in Part*, FERC Docket No. ER11-2427-000, (February 17, 2011), http://www.iso-ne.com/regulatory/ferc/orders/2011/feb/er11-2427-000_2-17-11_partial_accept-reject_tariff_rev.pdf. At the beginning of the FCM transition period (December 2006), and during most of the transition period, the prices of natural gas and oil were close to each other. Thus, the difference between adopting one or the other fuel as the standard was not substantial. This changed, however, when gas and oil prices diverged in January 2009.

110 FERC order, February 17, 2011; see above note.

111 See AMR11, Section 3.5.3.2, http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/index.html.

3.4.3.3 FCM Performance Incentives

To ensure that the capacity payment from the FCM is paid only to resources that perform when needed, the FCM includes design features intended to ensure that resources perform when system reliability is at risk. However, these features are not effective.

One performance feature of the FCM is reducing the capacity payments to resources that fail to perform during shortage events. The peak energy rent deduction reduces capacity payments by any energy revenues above the PER threshold or strike price to reduce the incentives for generators to exercise market power and protect the market from high energy prices. The final performance feature of the FCM prevents poorly performing units from remaining in the market. However, the poor-performance clause requires resources to be unavailable 60% of the time and for 10 shortage events, and no units are likely to be poor performers under the current rules. The weakness of this clause can be seen in the fact that during two recent events, units that have been unavailable for several months or more continue(d) to receive full capacity payments. Finally, a resource that holds a capacity supply obligation faces no risk of losing money by participating in the capacity market because the deductions for failing to perform during a shortage event or when prices exceed the PER threshold are limited to the capacity payment.

The ISO's experience with the FCM over the first three commitment periods (2010/2011 to 2012/2013) has shown that these performance incentives are too weak to provide any incentives for resources with capacity supply obligations to invest or take actions to improve performance. Table 3-20 shows the performance-related deductions in the FCM from 2010/2011 to February 2013.

Table 3-20
Performance Deductions to Date in the Forward Capacity Market,
June 2010 to February 2013 ($ and %)

Performance Factor	Amount	% of Revenues
Shortage events	0	0%
Peak energy rent deductions	$226,527,840	6%
Poorly performing units	0	0%
Total	$226,527,840	6%

This table demonstrates that, as a practical matter, the capacity payment has become an entitlement. There have been no shortage events or poorly performing units since the start of the FCM, and the total amount deducted through the PER deduction has been only $227 million, which is just 6% of FCM payments to date.

ISO Actions to Address these Issues. The ISO has undertaken several actions to strengthen the FCM incentive structure.

- **FCM Shortage-Event Trigger Definition (Effective October 2013):** In 2013, market rules will be proposed for initiating the shortage-event trigger earlier—during periods when the grid has a deficiency in total operating reserves rather than a deficiency only in 10-minute reserves. By triggering shortage events sooner, resources will have an increased incentive to be ready to perform during at-risk periods, which in turn should increase their ability to perform in all hours.

- **<u>FCM Performance Incentives (Effective June 2018)</u>**: FCM enhancements that provide stronger financial incentives for all resources to perform during stressed system conditions are being developed. As the region's reliance on natural gas grows (see Section 2.1.3.3), increased private investment in hardware, fuel arrangements, and other supplier-selected solutions to ensure resource performance and fuel availability are essential. Changes to the FCM will significantly improve suppliers' incentives to undertake these investments. This is scheduled for implementation in 2014 with the ninth Forward Capacity Auction—effective for the 2018/2019 commitment period.[112]

IMM Analysis and Recommendations. The IMM supports both the short-term proposal to change the definition of shortage events and the longer-term approach of creating strong performance incentives for the FCM. The short-term change is necessary because, per the current definition of a shortage event (i.e., when the system is short of 10-minute reserves for at least 30 minutes), such an event has never happened in the region, and the use of a 30-minute shortage of 30-minute reserves is a much more effective measure of system reliability for this purpose. Under the long-term proposal, resources will receive the proper price signals to be able to make the proper investments for being available as much as possible. The IMM will be developing a mitigation proposal to support this effort that enables generators to price the risks of these performance incentives appropriately in their FCM offers.

To address the weakness in the FCM performance incentives that will persist until the implementation of the revised FCM performance incentives in 2018, the IMM is increasing penalties for resources that fail to provide electric energy because of a lack of fuel.

During the FCM transition period, the ISO had rules in place that required resources to meet all the obligations of a capacity resource each month or lose its capacity payment for the month. The IMM believes that having sufficient fuel to operate when dispatched is an obligation of resources with a capacity supply obligation, and resources with a CSO that fail to follow dispatch instructions because of a lack of fuel should not receive full capacity payments in a given month.[113] The IMM recommends that the obligation to have sufficient fuel to operate be added to the tariff's list of explicit obligations and that the provisions that require a capacity resource to meet its obligations to receive full capacity payments be added back into the tariff.

3.4.4 Update on Forward Capacity Market Recommendations

In the *2011 Annual Markets Report*, the IMM made several recommendations:

- Eliminate the price floor in upcoming auctions and implement the Minimum Offer Price Rule (MOPR)

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[112] ISO New England Inc., *FCM performance Incentives,* white paper (October, 2012), http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/fcm_performance_white_paper.pdf, and *FCM Performance Incentives— A Strategic Planning Initiative,* ISO presentation to the NEPOOL Markets Committee (November 16, 2012), http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2012/nov162012/a02_iso_presentation_11_16_12.ppt.

[113] ISO New England Inc., *Market Participant Performance Obligations*, presentation to the NEPOOL Markets Committee (November 7, 2012), http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2012/nov782012/a09a_iso_memo_11_05_12.pdf.

- Align FCM and energy market incentives through several means:
    - Implement hourly offers and intraday offers
    - Provide stronger performance incentives, such as penalties for failing to deliver energy in real time
- Model all capacity zones within the Forward Capacity Auction
- Implement a demand curve, along with design features intended to add elasticity to the curve (to dampen capacity price volatility).

The status of MOPR recommendation is that, on December 3, 2012, the ISO filed a compliance filing that included changes to the FCM design in response to FERC's order of April 2011.[114] Among other things, this filing eliminated the floor price beginning in FCA #8 and included rule changes to implement a new buyer-side offer-floor mitigation mechanism for FCA #8 as well. Buyer-side mitigation is intended to discourage the restriction of resources from entering the capacity market at prices below their costs and unduly depressing capacity prices.

The MOPR proposal includes resource-specific benchmark prices, known as offer-review trigger prices (ORTPs) that approximate the net cost of entry of each resource. The IMM developed ORTPs for various resource types, which establish floor prices for new resources in the auction. A new resource must exit the auction when the auction price drops below its ORTP, absent a request submitted to the IMM, and approved, to offer at a lower price. For example, the proposed ORTP for a combustion turbine for FCA #8 is $10/kW-month. A new combustion turbine resource that wishes to remain in the FCA below this price must submit both cost data and the requested offer price to the IMM for review and approval. FERC accepted the ORTPs for various resource types in a February 12, 2013, letter order, which accepted in part and rejected in part the December 3, 2012, filing.[115]

To improve the effectiveness of the FCM performance incentives and to better align them with energy market incentives, the ISO has undertaken a major initiative to improve the performance incentives in the FCM. In the proposed pay-for-performance design, resource payments would depend on performance. If the ISO were short of operating reserve, capacity resources would be expected to supply either energy or reserves. Resources that do not perform during these periods would receive reduced capacity payments, while resources that perform above their expected level could earn more than their capacity payment. Resources with superior performance during scarcity conditions would receive transfer payments from resources with inferior performance during these conditions. The new design should meet the IMM's performance recommendations included in the 2011 AMR and encourage new and existing resources, such as efficient, flexible units, to be available when called. The new proposal currently is being reviewed under the normal stakeholder process and is targeted to be implemented for FCA #9, for the 2018/2019 capacity commitment period.

[114] ISO New England Inc., *Forward Capacity Market Redesign Compliance Filing and Request for Waiver of Compliance Obligation, or, in the Alternative, Limited Filing Pursuant to Section 205 of the Federal Power Act*, Docket Nos. ER10-787- , EL10-50- , EL10-57- , and ER 12-953, Docket No. ER12-953-001 (December 3, 2012), http://www.iso-ne.com/regulatory/ferc/filings/2012/dec/er12-953-001_12-3-12_fcm_redesign_compl.pdf.

[115] FERC, *Order Accepting in Part, and Rejecting in Part, FCM Compliance Filing,* Docket No. ER12-953-001 (February 12, 2013), http://www.iso-ne.com/regulatory/ferc/orders/2013/feb/er12-953-001_2-12-13_order_fcm_compliance.pdf.

Although no additional analysis regarding the implementation of a demand curve has been conducted for the *2012 Annual Markets Report*, the IMM continues to strongly support the recommendation made in the *2011 Annual Markets Report* to implement a demand curve as quickly as possible.

Finally, the recommendation to model capacity zones in the FCA has been incorporated into the FCM market rules and is being addressed further in FERC Docket No. ER12-953.[116]

[116] ISO compliance filing, December 3, 2912; see above note.

Section 4
Data Appendix

This appendix contains details on the energy, forward capacity, locational forward reserve, and regulation markets. It also contains information about actions taken to ensure reliability and the tariff charges that fund ISO operations and provide compensation for the products and services provided by participants through the tariff.

4.1 Real-Time Energy Markets

This section includes additional information about the Real-Time Energy Market.

4.1.1 Real-Time Market

4.1.1.1 Pricing

The annual average day-ahead premium for the Hub and eight load zones is shown in Table 4-1.

Table 4-1
Average Day-Ahead Premium, 2010 to 2012 ($/MWh)

Location	2010	2011	2012
Hub	−$0.67	−$0.29	−$0.01
CT	−$0.01	−$0.48	−$0.14
ME	−$0.37	$0.64	$0.71
NEMA	−$1.02	−$0.42	−$0.00
NH	−$0.68	−$0.13	−$0.03
RI	−$0.76	−$0.36	$0.36
SEMA	−$0.95	−$0.40	−$0.05
VT	−$0.33	$0.10	$0.08
WCMA	−$0.55	−$0.31	−$0.03

4.1.1.2 Market Structure

Table 4-2 presents additional statistics on the Herfindahl-Hirschman Indices.

Table 4-2
HHI Statistics for New England, 2010 to 2012

	HHI Statistics for the Peak Load Hour			HHI Statistics for the Lowest Load Hour		
Year	Median	Mean	Max	Median	Mean	Max
2010	732	745	1,091	991	987	1,408
2011	712	713	901	889	886	1,171
2012	745	748	1,087	924	930	1,206

4.1.1.3 Relationships to Pricing and Other Factors

Table 4-3 shows a three-year comparison of annual average fuel prices for the main fuel types.

Table 4-3
Average Annual Fuel Prices for Selected Input Fuels, 2010 to 2012 ($/MMbtu)

Fuel	2010	2011	2012	% Change 2011 to 2012[(a)]
Natural gas	5.21	4.98	4.01	-19.5%
Coal (high sulfur)	2.49	2.88	2.42	-16.0%
No. 6 oil (1%)	11.60	15.90	17.02	7.0%
No. 2 oil	15.31	21.22	21.79	2.7%

(a) The numbers and percentages are rounded and thus show slight variations.

The three-year monthly average fuel-price series is shown in Figure 4-1.

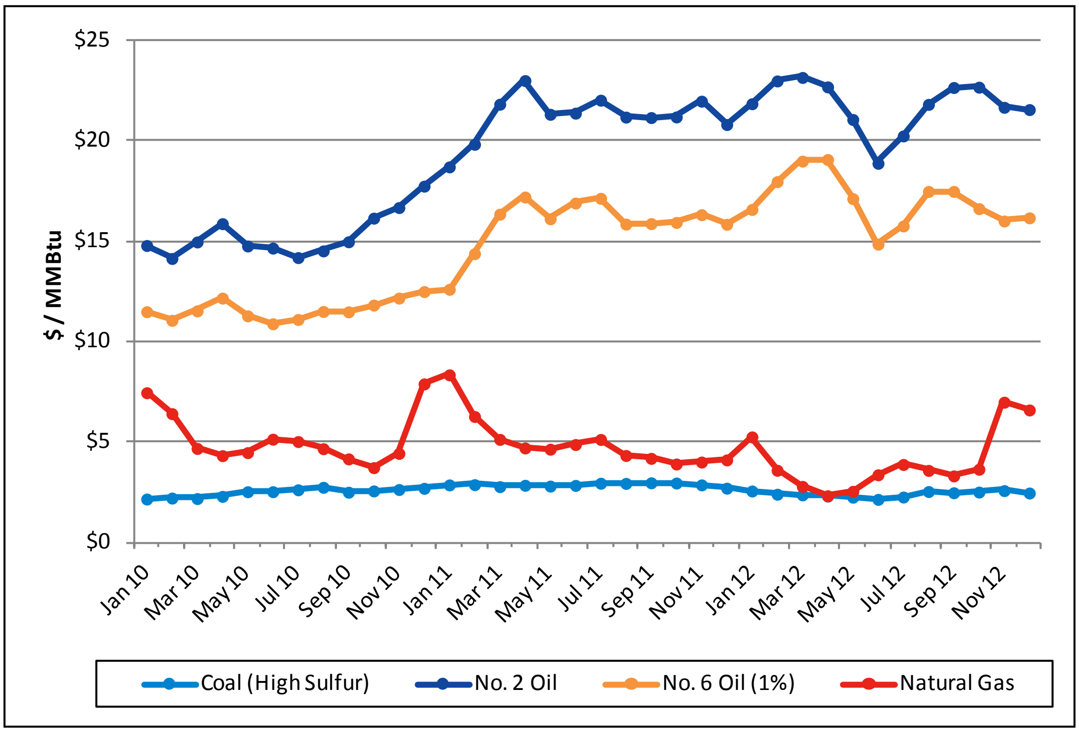

Figure 4-1: Average monthly fuel prices for selected input fuels, 2010 to 2012 ($/MMBtu).

Table 4-4 shows the average and minimum heat rates of generating resources in New England by technology and fuel type.

Table 4-4
Average and Minimum Heat Rates for New England Generators, 2012 (Btu/kWh)

Technology	Fuel Type	Average Heat Rate	Minimum Heat Rate
Combined cycle	Gas	7,900	6,900
	No. 6 oil (1%)	10,100	10,100
Combustion turbine	Diesel	12,100	11,400
	Gas	11,100	8,900
	Jet fuel	13,000	10,400
	No. 2 oil	16,100	15,500
Steam turbine	Coal	9,600	8,700
	Gas	10,400	10,200
	No. 6 oil (1%)	10,600	9,800
	No. 2 oil	10,500	10,500
	Wood	12,600	10,000

Table 4-5 shows a three-year comparison of annual generation by fuel type.

Table 4-5
Yearly Generation by Fuel Type, 2010 to 2012 (GWh)

Fuel	2010	2011	2012	Change 2012 to 2011	% Change
Gas	42,042	46,378	49,573	3,195	7%
Nuclear	38,364	34,283	36,116	1,833	5%
Oil/Gas	15,542	15,925	11,505	−4,420	−28%
Renewables	7,686	7,261	7,988	727	10%
Hydro run of river and pondage	7,227	8,252	6,692	−1,560	−19%
Coal	14,131	7,080	3,701	−3,379	−48%
Hydro: pumped storage	854	1,149	1,129	−20	−2%
Oil	570	282	232	−50	−18%
Total generation (GWh)	126,416	120,610	116,936	−3,674	−3%

Table 4-6 shows natural gas generation capability by the pipeline on which they are located for 2012.

Table 4-6
Natural Gas Generation Capability by Pipeline on Which They Are Located, 2012 (MW)

Pipeline	Seasonal Claimed Capability (SCC)	% of Total
Algonquin	9,981.1	50.6
Tennessee	4,480.0	22.7
Distrigas	1,693.6	8.6
Maritimes and Northeast (M&N)	1,662.2	8.4
Iroquois	1,471.6	7.5
Portland Natural Gas Transmission System (PNGTS)	436.3	2.2

Table 4-7 shows natural gas generation capability by load zone for 2012.

Table 4-7
Natural Gas Generation Capability by Load Zone, 2012 (MW)

Load Zone	Seasonal Claimed Capability (SCC)	% of Total
Connecticut	5,029.6	25.5
Southeast Massachusetts	4,542.5	23.0
Rhode Island	2,904.7	14.7
Northeast Massachusetts/Boston	2,610.2	13.2
New Hampshire	1,760.5	8.9
Western Central Massachusetts	1,740.0	8.8
Maine	1,137.3	5.8

Table 4-8 shows the difference between day-ahead and real-time self-scheduled generation.

Table 4-8
Day-Ahead, Real-Time, and
Real-Time Supplemental Self-Schedules, 2011 to 2012 (GWh)

Year	Month	Day-Ahead Self-Schedule (GWh)	Real-Time Self-Schedule (GWh)	Real-Time Supplemental Self-Schedule (GWh)	Percentage (Day Ahead/ Real Time)
2011	Jan	7,594	8,375	781	91%
	Feb	6,289	7,305	1,016	86%
	Mar	6,575	7,773	1,198	85%
	Apr	4,625	5,968	1,342	78%
	May	5,321	6,195	874	86%
	Jun	6,389	7,391	1,002	86%
	Jul	7,444	8,408	964	89%
	Aug	6,903	7,735	832	89%
	Sep	6,007	6,822	815	88%
	Oct	4,197	4,999	802	84%
	Nov	5,025	5,923	898	85%
	Dec	6,213	7,218	1,004	86%
2012	Jan	6,720	7,719	999	87%
	Feb	6,218	7,037	818	88%
	Mar	6,175	7,200	1,025	86%
	Apr	5,691	6,589	898	86%
	May	6,367	7,347	980	87%
	Jun	6,467	7,509	1,043	86%
	Jul	7,455	8,679	1,224	86%
	Aug	6,760	7,440	680	91%
	Sep	5,715	6,383	669	90%
	Oct	5,055	5,737	683	88%
	Nov	5,589	6,362	773	88%
	Dec	6,160	7,213	1,052	85%

Table 4-9 shows the net interchange by interface for 2010, 2011, and 2012.

Table 4-9
Net Interchange, by Year, by Interface, 2010 to 2012 (GWh)

External Interface	2010	2011	2012
Hydro Quebec Highgate	1,419	1,567	1,472
Hydro Quebec Phase I/II	7,794	9,923	11,606
NY-1385 (Northport)	−533	−962	−948
NY-AC (Roseton)	−1,558	888	2,081
NY-Cross-Sound Cable (CSC) (Shoreham)	−2,405	−2,205	−2,201
New Brunswick	722	865	639

Figure 4-2 shows a summary of 2012 net interchange by interface.

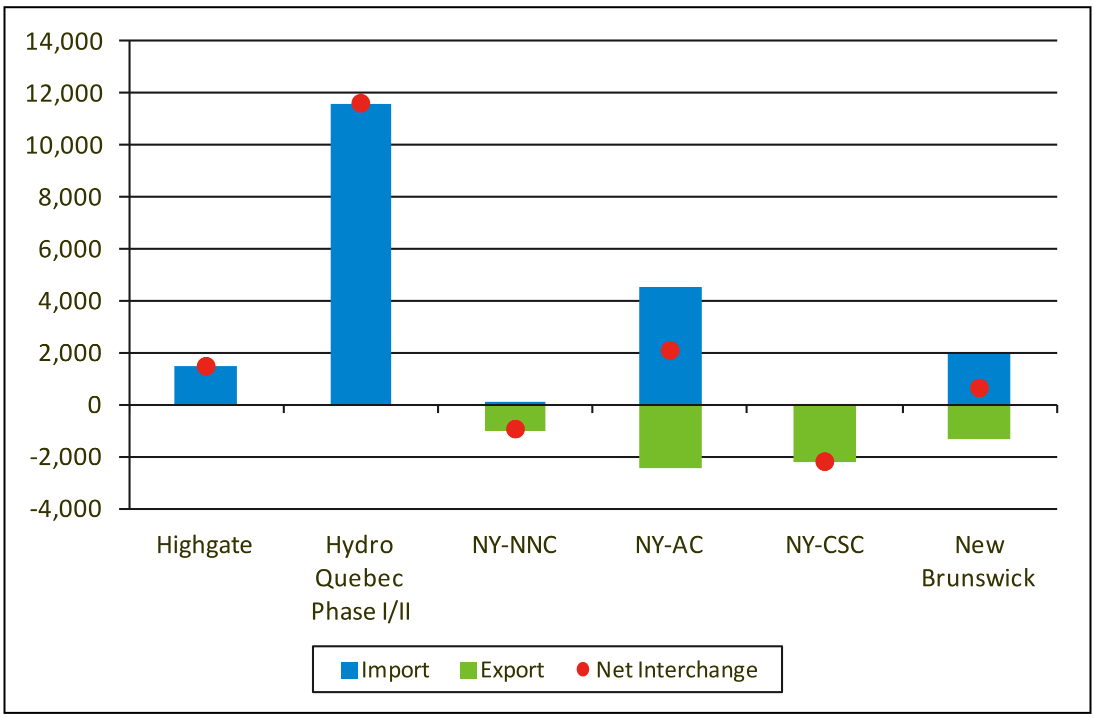

Figure 4-2: Scheduled imports and exports and net external energy flow, by interface, 2012 (GWh).

Table 4-10 is a summary of annual demand statistics for 2010 through 2012.

Table 4-10
Annual and Peak Electric Energy Statistics, 2010 to 2012

	2010	2011	2012	% Change 2011 to 2012
Annual NEL (GWh)	130,771	129,162	128,007	−0.9%
Normalized NEL (GWh)	129,910	128,998	128,249	−0.6%
Recorded peak demand (MW)	27,102	27,707	25,880	−6.6%
Normalized peak demand (MW)	27,075	27,240	27,430	0.7%

Figure 4-3 summarizes the NCPC payments made to generators for local second-contingency protection resource (LSCPR), distribution, and voltage and economic (first-contingency) NCPC.

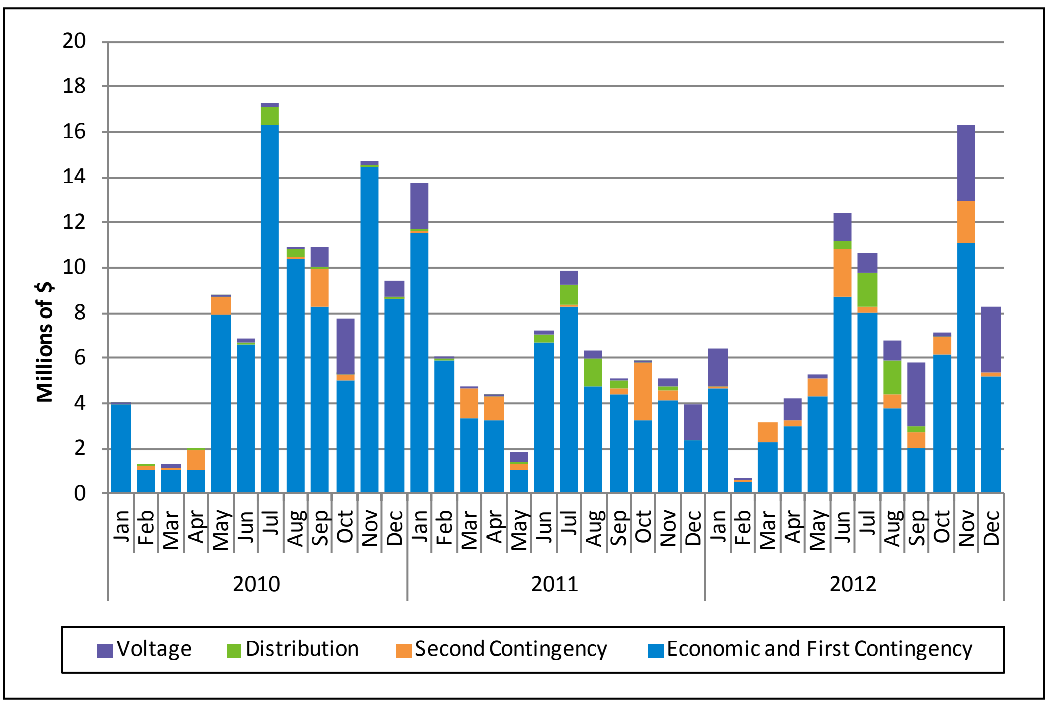

Figure 4-3: Daily reliability payments by month, January 2010 to December 2012 (millions of $).

Figure 4-4 shows the annual all-in wholesale electricity cost for 2012.

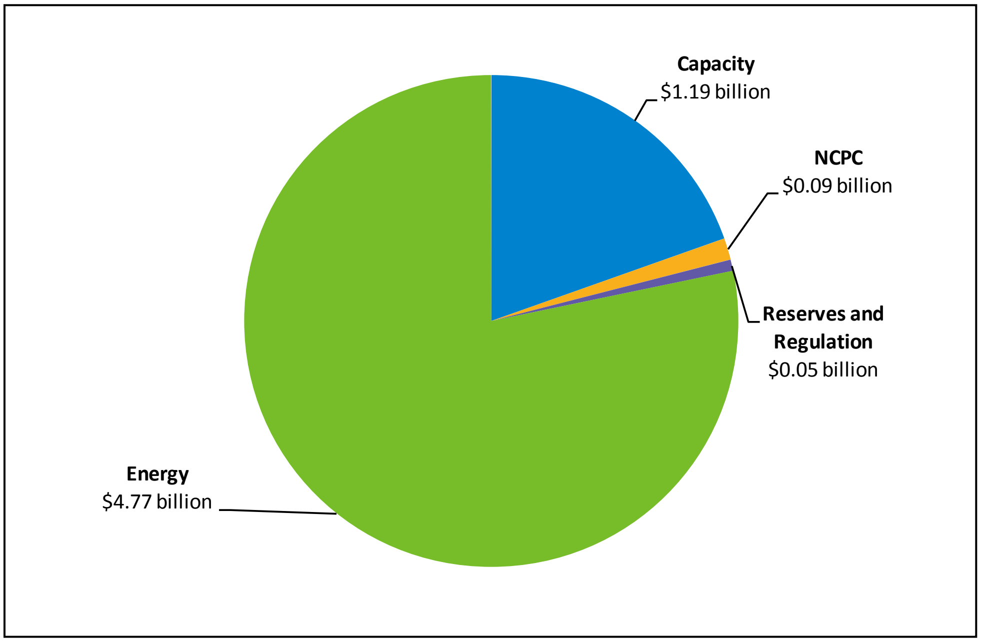

Figure 4-4: All-in cost, 2012 ($).

Figure 4-5 shows the average annual all-in wholesale electricity cost ($/MWh) and natural gas prices for 2010 through 2012.

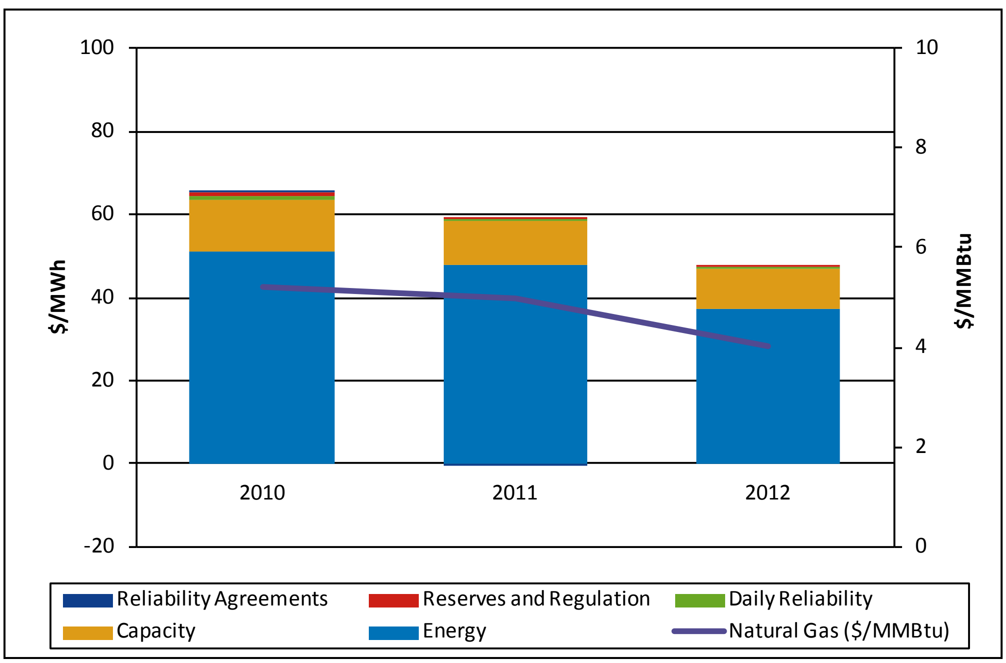

Figure 4-5: All-in cost, 2010 to 2012 ($/MWh).

Notes: The daily reliability and Reliability Agreement costs are allocated systemwide to enable a systemwide rate to be calculated. These costs actually are allocated to the load zone in which they occur. MMBtu stands for *millions of British thermal units*, a measure of the amount of heat energy in natural gas.

Source: Natural gas price information provided by the Intercontinental Exchange, Inc. (ICE), http://www.theice.com.

4.1.2 Regulation Appendix

Table 4-11 is a summary of 2012 regulation clearing prices by month.

Table 4-11
Monthly Regulation Clearing Price Statistics, 2012 ($)

Month	Minimum	Average	Maximum
Jan	1.49	7.23	22.02
Feb	5.01	6.32	17.82
Mar	0.00	6.21	11.63
Apr	4.46	6.61	70.33
May	4.75	6.07	20.08
Jun	0.93	6.78	45.00
Jul	3.93	6.87	36.97
Aug	4.45	6.82	25.99
Sep	4.33	6.45	61.71
Oct	4.50	6.54	15.63
Nov	1.00	7.68	70.00
Dec	3.00	7.42	70.00

Figure 4-6 shows the NERC CPS 2 compliance requirement and the monthly ISO performance for 2012.

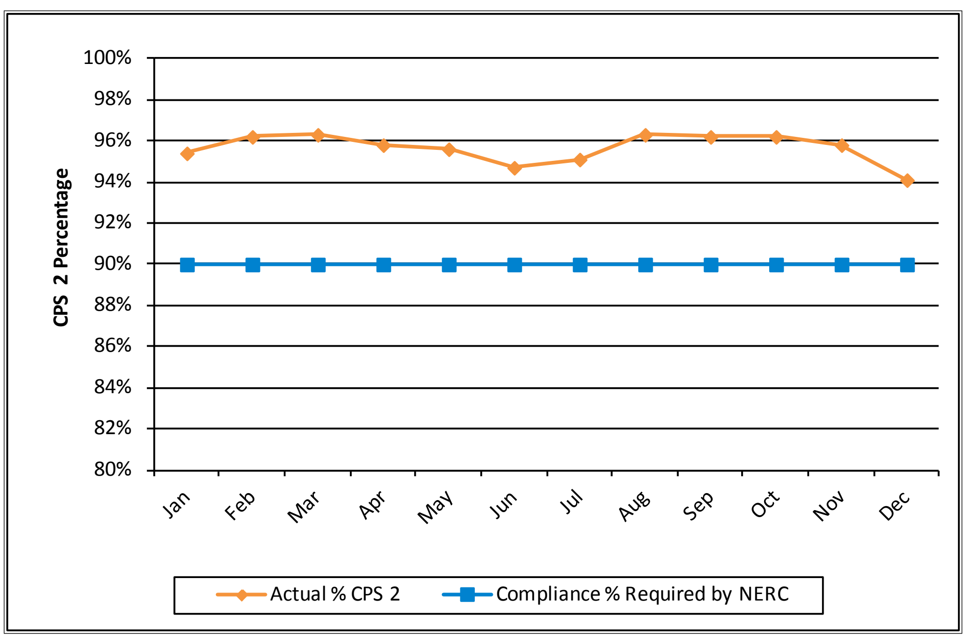

Figure 4-6: CPS 2 compliance, 2012 (%).

Figure 4-7 shows the 2011 and 2012 Regulation Market payments by component.

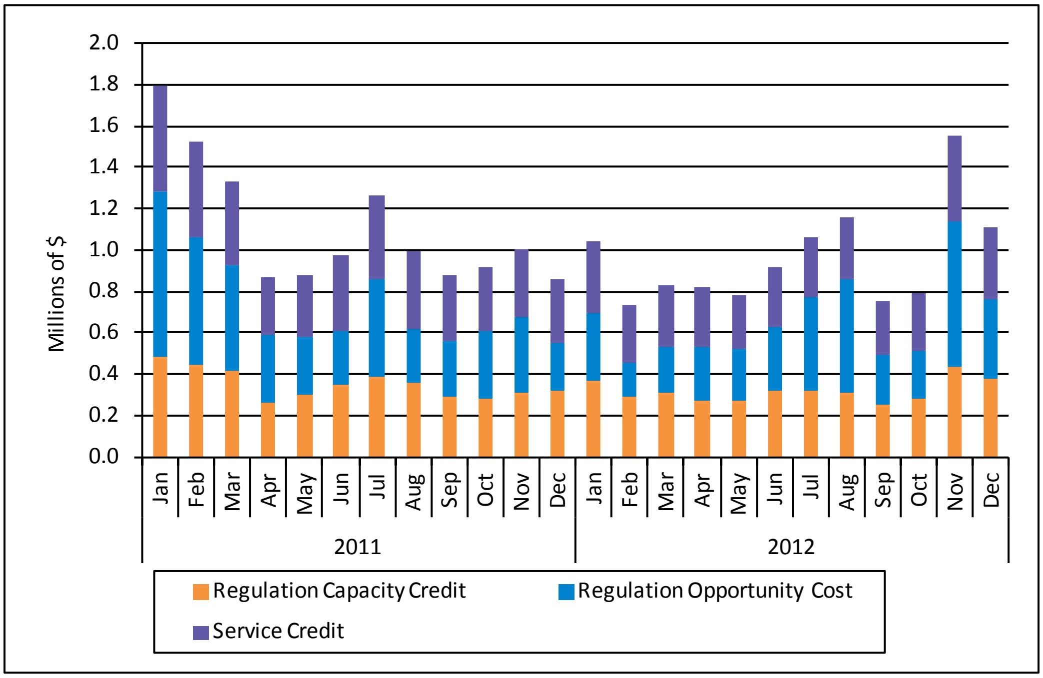

Figure 4-7: Total regulation payments by month, 2011 to 2012 (millions of $).

4.1.3 Reliability and Operations Assessment Appendix

This section includes information on net tariff charges, as well as a listing of hours the system was under Minimum Generation Emergency events or Master/Local Control Center Procedure No. 2 (M/LCC2), *Abnormal Conditions Alert*.

Total payments under each ISO schedule are shown in Table 4-12.

Table 4-12
ISO Self-Funding Tariff Charges ($)

Date	Schedule 1: Scheduling, System Control, and Dispatch Service	Schedule 2: Energy Administration Service	Schedule 3: Reliability Administration Service
2012 Total	$31,985,658	$62,231,117	$44,489,240

Total payments under each Open Access Transmission Tariff (OATT) schedule are shown in Table 4-13.[117]

Table 4-13
OATT Charges ($)

Date	Schedule 1	Schedule 2: Capacity Costs	Schedule 2: VAR[(a)]	Schedule 8: TOUT[(a)]	Schedule 9: RNS[(a)]	Schedule 16: Black Start	Schedule 19: SCR[(a)]
2012 Total	$35,905,374	$24,018,884	$14,861,724	$10,438,572	$1,432,647,002	$12,682,548	$3,680,671

(a) *VAR* refers to voltage ampere reactive (voltage control); *TOUT* refers to through or out service; *RNS* refers to regional network service; and *SCR* refers to special-constraint resource.

Table 4-14 lists the days when M/LCC2 was declared in 2012.

Table 4-14
M/LCC2 Events, 2012

Date	Event	Area Affected
Mar 2–3	M/LCC2	For all dates, all of New England was affected for capacity.
Apr 19	M/LCC2	
Apr 25	M/LCC2	
May 29	M/LCC2	
Jun 20–22	M/LCC2	
Jul 18	M/LCC2	
Jul 24	M/LCC2	
Oct 13	M/LCC2	
Oct 15	M/LCC2	
Oct 28–Nov 2	M/LCC2	

117 *ISO New England Open Access Transmission Tariff,* (January 1, 2013), http://www.iso-ne.com/regulatory/tariff/sect_2/oatt/sect_ii.pdf.

Table 4-15 shows the days and times when Minimum Generation Emergencies were declared.

Table 4-15
Minimum Generation Emergency Events, 2012

Date	Hours Declared
Jan 2	1:00 a.m.– 9:00 a.m.
Jan 3	2:00 a.m.– 6:00 a.m.
Apr 28	1:00 a.m.– 5:00 a.m.
Apr 28	3:30 a.m. – 5:00 a.m.
Jun 8	4:00 a.m. – 6:00 a.m.
Jun 17	6:00 a.m. – 8:00 a.m.
Jun 20	4:00 a.m. – 7:00 a.m.
Jun 30	6:00 a.m. – 8:00 a.m.
Jul 1	6:00 a.m. – 8:00 a.m.
Aug 31	1:00 a.m. – 6:00 a.m.
Sep 11	2:00 a.m. – 5:00 a.m.
Oct 29–30	8:30 p.m. – next day 6:30 a.m.
Dec 4–Dec 5	11:00 p.m. – next day 7:00 a.m.
Dec 11	5:00 a.m. – 7:00 a.m.
Dec 22	6:00 a.m. – 8:00 a.m.

4.1.3.1 IMM Mitigation and Investigation Activities

Mitigation. The types of mitigation are as follows:

- **Local reliability commitment mitigation—**occurs when a market participant submits a supply offer for a generator committed for reliability, and the generator's supply offer exceeds the reliability commitment offer thresholds. When the conditions are met, mitigation is applied *ex ante* at the time the decision to commit the generator is made.
- **General (unconstrained) commitment mitigation—**occurs when a market participant, determined to be a pivotal supplier, submits a supply offer, and the parameters of the generator's start-up or no-load offers exceed specified conduct-offer thresholds. When the conditions are met, mitigation is applied *ex ant*e at the time the decision to commit the generator is made.
- **Constrained area commitment mitigation—**occurs when a market participant submits a supply offer for a generator located and committed in a constrained area in the Real-Time Energy Market, and the parameters of the generator's start-up or no-load offers exceed specified conduct-offer thresholds. When the conditions are met, mitigation is applied *ex ant*e at the time the decision to commit the generator is made.
- **General (unconstrained) energy mitigation—**occurs when a market participant, determined to be a pivotal supplier, submits a supply offer that exceeds specified offer

and market-impact thresholds. When the conditions are met, mitigation is applied automatically *ex ante* in the energy market.

- **Constrained energy mitigation—**occurs when a market participant submits a supply offer for a generator located within a constrained area, and the generator's supply offer exceeds specified offer and market impact thresholds. When the conditions are met, mitigation is applied automatically *ex ante* in the energy market.
- **Dual-fuel corrections** are *ex post* corrections to dual-fuel override requests.

Table 4-16 shows the mitigations imposed by the IMM for 2012 and prior years. Automated mitigation was introduced in 2012 and led to an increase in the number of mitigations.

Table 4-16
Mitigations, 2010-2012

Year	Number of Occurrences
2010	61
2011	48
2012— before automated mitigation	20
2012— after automated mitigation	302
2012	322

FTR Capping. Two participants had their FTR revenues, associated with 10 paths, reduced by a total of $5,766.32, pursuant to the FTR revenue-capping provisions of *Market Rule 1*.[118]

Investigations and Referrals to FERC. Before 2012, the IMM had four open referrals before FERC. In 2012, the IMM made eight additional nonpublic referrals, and FERC closed four, bringing the year-end total of open referrals made by the IMM before FERC to eight. Of the four referrals FERC closed in 2012, it closed two with no action. It imposed penalties to the participant in two cases.

The ISO tariff requires resources to follow dispatch instructions and to be able to supply energy when dispatched according to the terms of their supply offers. This means that instances when generators fail to operate when dispatched because of a lack of fuel may be tariff violations, which the IMM must report to FERC.

[118] See *Market Rule 1*, Section III.A.8.4, Appendix A, "Cap on FTR Revenues" (March 13, 2012), http://www.iso-ne.com/regulatory/tariff/sect_3/index.html.

4.1.3.2 Administrative Price Corrections

Table 4-17 shows the ISO's administrative price corrections for 2012.

Table 4-17
Administrative Price Corrections, 2012

Location/Load Zone	Number of Occurrences
Data error	21
Hardware/software outage, scheduled	0
Hardware/software outage, unscheduled	0
Software limitation	4
Software error	0
Dead-bus logic	43

4.2 Forward Markets

4.2.1 Congestion, Congestion Revenues, and Auction Revenue Rights

Figure 4-8 is a summary of monthly day-ahead and real-time congestion revenues in 2012.

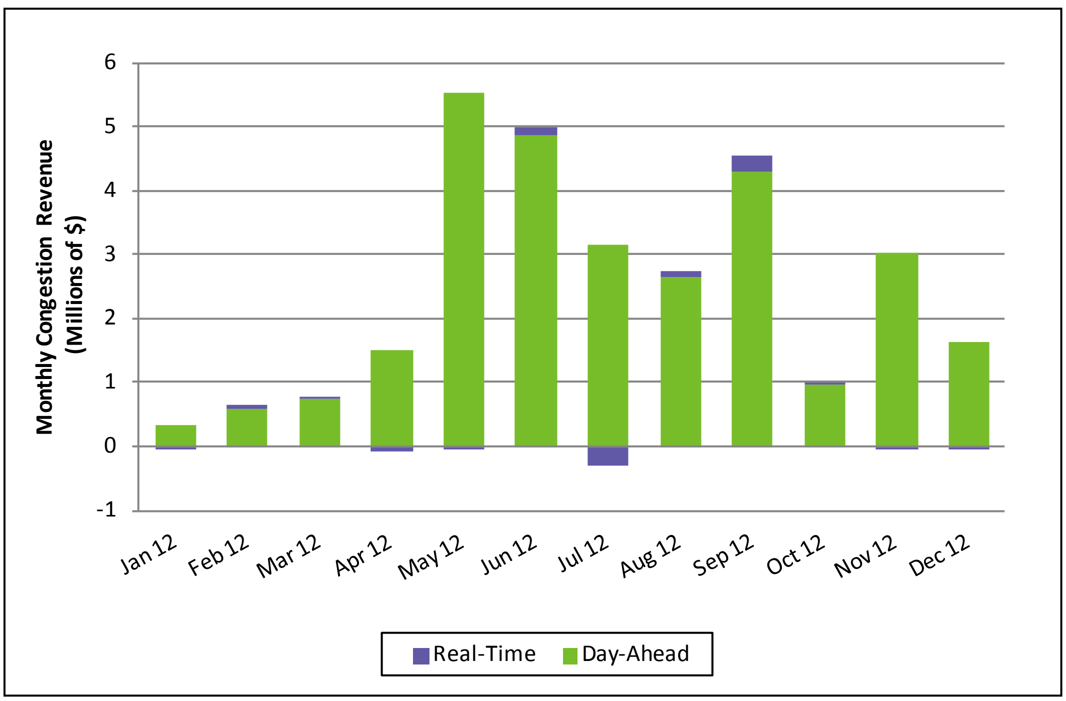

Figure 4-8: Day-ahead and real-time congestion revenue by month, 2012 (millions of $).

Table 4-18 and Table 4-19 show the annual average marginal congestion component and marginal loss component for the Hub and eight load zones in 2012.

Table 4-18
Average Day-Ahead Marginal Congestion Component, Marginal Loss Component, and Combined, 2012 ($/MWh)

Location/ Load Zone	Congestion Component	Marginal Loss Component	Congestion Component Plus Marginal Loss Component
Hub	−$0.34	$0.02	−$0.32
Maine	$0.21	−$0.71	−$0.50
New Hampshire	−$0.34	−$0.14	−$0.48
Vermont	−$0.30	$0.15	−$0.15
Connecticut	$0.08	$0.29	$0.37
Rhode Island	$0.11	−$0.27	−$0.16
SEMA	−$0.25	−$0.06	−$0.31
WCMA	$0.28	$0.30	$0.58
NEMA	−$0.18	−$0.06	−$0.25

Table 4-19
Average Real-Time Marginal Congestion Component, Marginal Loss Component, and Combined, 2012 ($/MWh)

Location/ Load Zone	Congestion Component	Marginal Loss Component	Congestion Component Plus Marginal Loss Component
Hub	−$0.24	$0.00	−$0.24
Maine	−$0.37	−$0.77	−$1.15
New Hampshire	−$0.23	−$0.15	−$0.38
Vermont	−$0.20	$0.03	−$0.16
Connecticut	$0.29	$0.29	$0.58
Rhode Island	−$0.20	−$0.25	−$0.46
SEMA	−$0.21	$0.02	−$0.19
WCMA	$0.41	$0.20	$0.62
NEMA	−$0.17	−$0.01	−$0.18

Table 4-20 is a summary of Auction Revenue Rights distributions for 2010 to 2012.

Table 4-20
Total Auction Revenue Distribution, 2010 to 2012 ($)

	2010	2011	2012
Qualified Upgrade Awards (2010–2011) Incremental Auction Revenue Rights (2012)	3,074,310	2,203,086	848,690
Excepted transactions[a]	2,160	929	55
NEMA contract holders	130,563	92,900	96,402
ARR holders	26,950,479	21,183,093	15,115,962
Total auction revenue	30,157,511	23,480,009	16,061,109

(a) Effective January 1, 2012, Qualified Upgrade Awards were replaced by Incremental Auction Revenue Rights.

(b) *Excepted transactions* are certain power transfers and other uses of the pool transmission facilities effected under transmission agreements in effect on November 1, 1996, as specified in the ISO's *Open Access Transmission Tariff*, Section II.40, and for the time periods described therein. These transactions are included in the OATT, Attachments G, G-1, and G-3; http://www.iso-ne.com/regulatory/tariff/index.html.

Figure 4-8 shows the ARR distributions by zone for 2012.

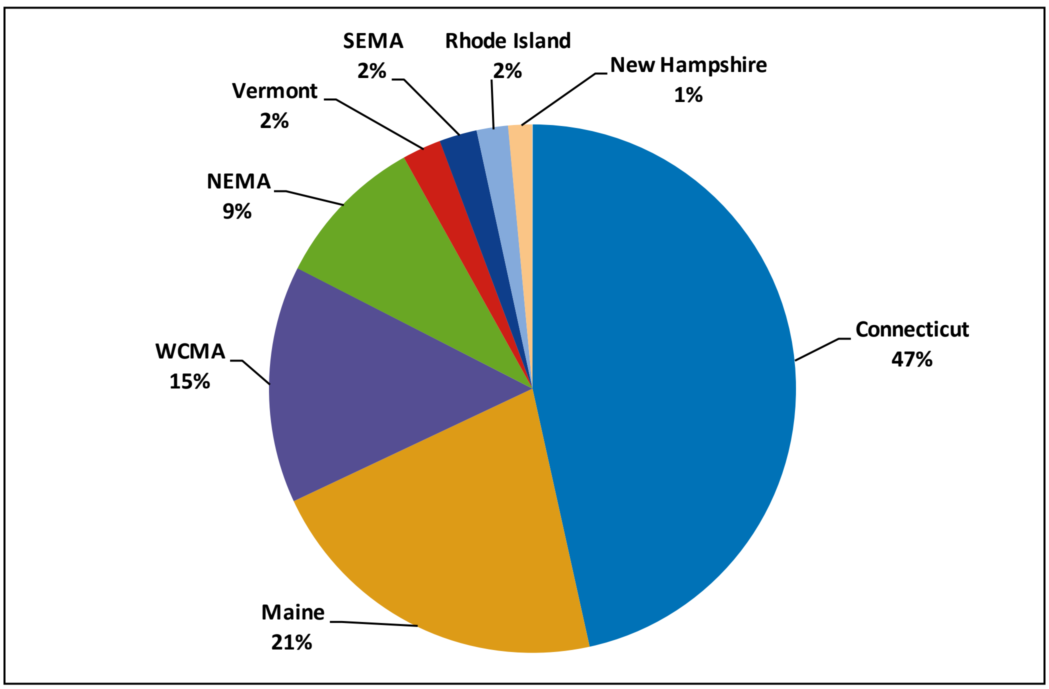

Figure 4-9: Load-share ARR distribution by load zone, 2012.

4.2.2 Forward Capacity Market

4.2.2.1 FCA Supply Curves

Figure 4-10 through Figure 4-13 show the FCA supply curves for auctions two through six.

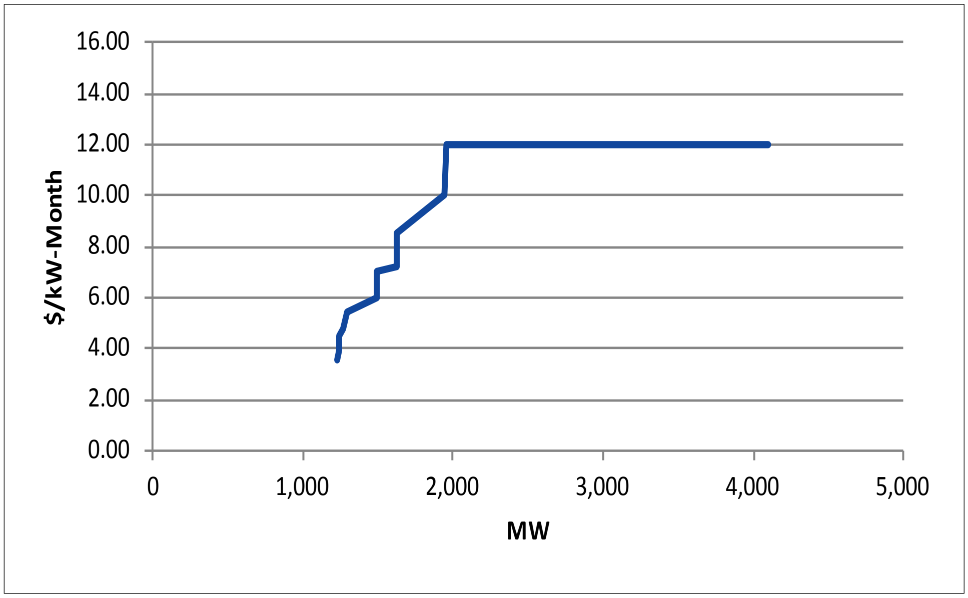

Figure 4-10: Supply curve, FCA #2.

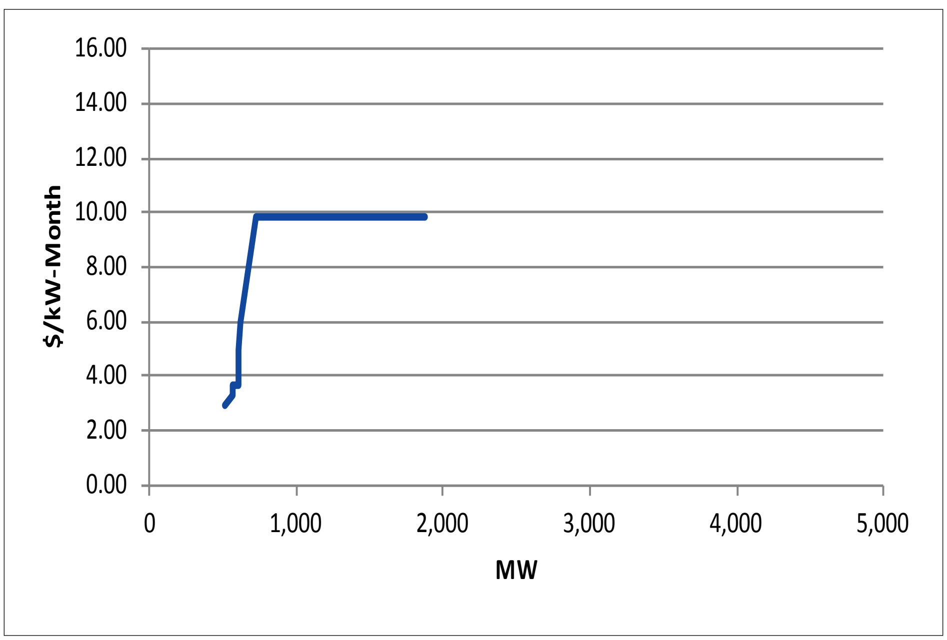

Figure 4-11: Supply curve, FCA #3.

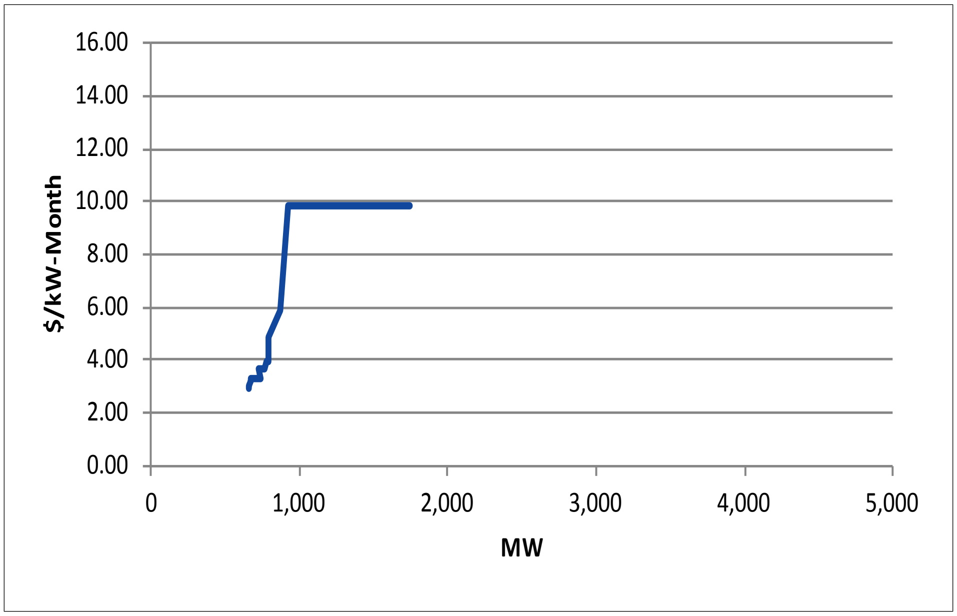

Figure 4-12: Supply curve, FCA #4.

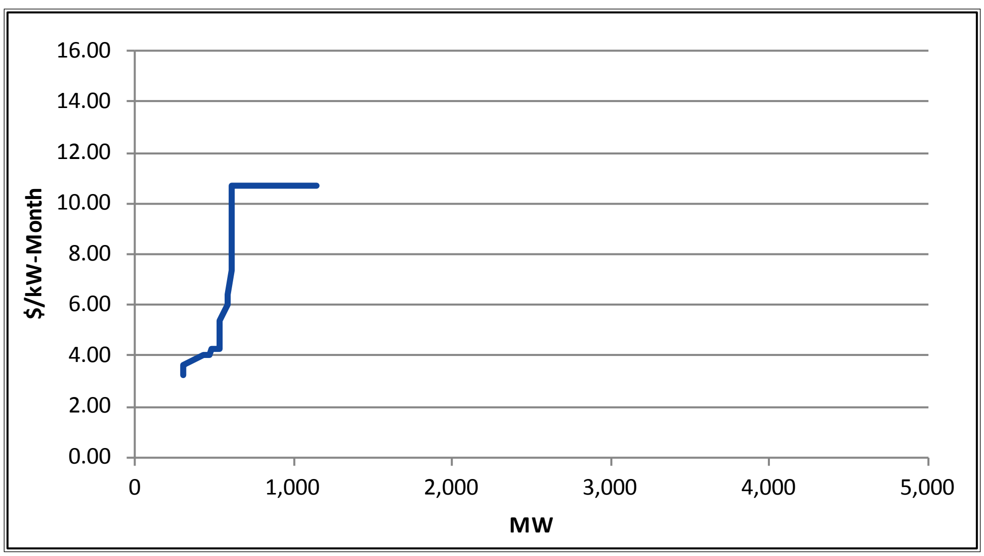

Figure 4-13: Supply curve, FCA #5.

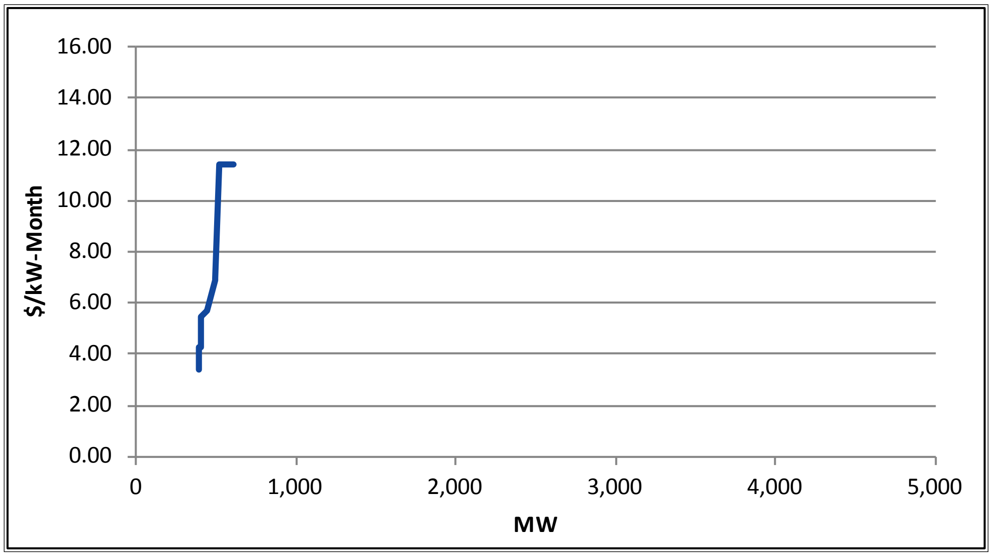

Figure 4-14: Supply curve, FCA #6.

4.2.2.2 Reconfiguration Auction Results and Bilateral Transactions

Table 4-21 shows annual bilateral transaction quantities.

Table 4-21
Annual Bilateral Transaction Quantities

Commitment Period	Auction	Total Traded CSOs (MW)
2011/2012	ARA #2 Bilateral Period 1	1,152
	ARA #2 Bilateral Period 2	3
	ARA #3 Bilateral Period 1	665
2012/2013	ARA #2 Bilateral Period 1	252
	ARA #2 Bilateral Period 2	253
	ARA #3 Bilateral Period 1	830
2013/2014	ARA #2 Bilateral Period 1	413
	ARA #2 Bilateral Period 2	211
	ARA #3 Bilateral Period 1	1,004

Table 4-22 shows monthly bilateral transactions for 2012.

Table 4-22
Monthly Bilateral Transactions: Traded Quantity

Commitment Period	Average of Monthly Cleared Quantity (MW)
2011/2012	525
2012/2013	420

4.2.2.3 Price Convergence across Auctions

Figure 4-15 shows the trend in CSO prices for the same commitment period from the FCA to the monthly reconfiguration auctions.

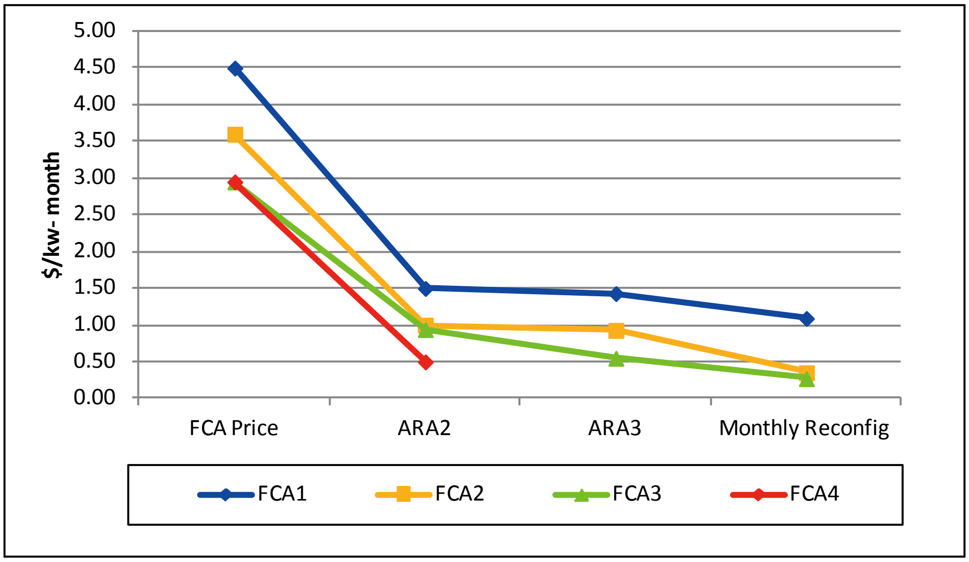

Figure 4-15: CSO prices from the FCA to the monthly reconfiguration auctions.

List of Acronyms and Abbreviations

Acronyms and Abbreviations	Description
°F	degrees Fahrenheit
5 x 16	5 days per week; 16 hours per day
24 x 7	24 hours per day; 7 days per week
AC	alternating current
ACE	area control error
AMR	Annual Markets Report
AMR11	*2011 Annual Markets Report*
ARA	annual reconfiguration auction
ARR	Auction Revenue Rights
BAL-001-0	NERC's *Real Power Balancing Control Performance Standard*
Boston	Northeast Massachusetts/Boston Reserve Zone
Btu	British thermal unit
C4	four-largest competitors
C8	eight-largest competitors
CCGT	combined-cycle gas turbine
CCP	capacity commitment period
CONE	cost of new entry
CPS 2	NERC *Control Performance Standard 2*
CSC	Cross-Sound Cable
CSO	capacity supply obligation
CT	State of Connecticut, Connecticut load zone, Connecticut reserve zone
CTS	Coordinated Transaction Scheduling
DALRP	Day-Ahead Load Response Program
DOE	US Department of Energy
DOJ	US Department of Justice
ecomax	economic minimum limit
ecomin	economic maximum limit
EMM	External Market Monitor

Acronyms and Abbreviations	Description
ERCOT	Electric Reliability Council of Texas
ERO	electric reliability organization
ERS	external reserve support
F	Fahrenheit
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
FRM	Forward Reserve Market
FTR	Financial Transmission Right
GT	gas turbine
GWh	gigawatt-hour
HE	hour ending
HHI (also H)	Herfindahl-Hirschman Index
Highgate	Vermont–Hydro Quebec Interconnection
HQ	Hydro-Québec
HQICC	Hydro-Québec Phase I/II Interface
ICE	Intercontinental Exchange, Inc.
ICR	Installed Capacity Requirement
IMM	Internal Market Monitor
IRIS	Interregional Interchange Scheduling
ISO	Independent System Operator, ISO New England
ISO tariff	*ISO New England Transmission, Markets, and Services Tariff*
kW	kilowatt
kWh	kilowatt-hour
kW-mo	kilowatt-month
L_{10}	The specified limit within which each balancing authority area’s average area control error must be for at least 90% of the clock 10-minute periods (six nonoverlapping periods per hour) during a calendar month, as the primary measure for evaluating the area’s control performance standard (CPS 2)
LEG	limited-energy generator
LMP	locational marginal price

Acronyms and Abbreviations	Description
LSCPR	local second-contingency protection resource
LSE	load-serving entity
LSR	local sourcing requirement
L_t	symbol for the competitiveness level of the LMP
M-36	*ISO New England Manual for Forward Reserve*
M&N	Maritimes and Northeast pipeline
MAPE	mean absolute percent error
MDE	maximum daily energy
ME	State of Maine and Maine load zone
M/LCC2	Master/Local Control Center Procedure No. 2, *Abnormal Conditions Alert*
MMBtu	million British thermal units
M-MVDR	*ISO New England Manual for Measurement and Verification of Demand-Reduction Value from Demand Resources*
MOPR	Minimum Offer Price Rule
MVDR	measurement and verification of demand reduction
MW	megawatt
MWh	megawatt-hour
N-1	first contingency
N-1-1	second contingency
NCPC	Net Commitment-Period Compensation
NEL	net energy for load
NEMA	Northeast Massachusetts, Boston load zone
NEMA/Boston	Northeast Massachusetts/Boston local reserve zone
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Corporation
NH	State of New Hampshire, New Hampshire load zone
NNC	Norwalk Harbor–Northport, NY, Cable (formerly called the New York 1385 transmission line)
NOAA	National Oceanographic and Atmospheric Administration
NPCC	Northeast Power Coordinating Council
NY	State of New York

Acronyms and Abbreviations	Description
NYISO	New York Independent System Operator
NY-NNC (Old NY 1885)	Norwalk Harbor–Northport, NY, Cable (formerly called the New York 1385 transmission line)
NY-AC	New York Alternating-Current Interface
NY-CSC	New York Cross-Sound Cable
OATT	*Open Access Transmission Tariff*
OOM	out of market
OP 4	ISO Operating Procedure No. 4
OP 8	ISO Operating Procedure No. 8
ORTP	offer-review trigger price
PER	peak energy rent
PJM	PJM Interconnection, L.L.C.
PNGTS	Portland Natural Gas Transmission System
pnode	pricing node
PRD	price-responsive demand
Q	quarter
RAA	Reserve Adequacy Assessment
RCP	regulation clearing price
RCPF	Reserve Constraint Penalty Factor
RFP	request for proposals
RI	State of Rhode Island, Rhode Island load zone
RISEC	Rhode Island State Energy Center
RNS	Regional Network Service
ROS	Rest-of-System reserve zone
RSI	Residual Supply Index
RTDR	real-time demand response
RTEG	real-time emergency generation
RTLO	real-time load obligation
RTO	Regional Transmission Organization
RTPR	real-time price response
SCC	seasonal claimed capability

Acronyms and Abbreviations	Description
SCR	special-constraint resource
SEMA	Southeast Massachusetts load zone
SOC1	present audit of market operations and settlement systems
SWCT	Southwest Connecticut
TMNSR	10-minute nonspinning reserve
TMR	10-minute reserve
TMOR	30-minute operating reserve
TMSR	10-minute spinning reserve
TOUT	through-or-out service
TPRD	transitional price-responsive demand
TTC	total transfer capability
US	United States
VAR	voltage ampere reactive (voltage control)
VT	Vermont and Vermont load zone
WCMA	Western/Central Massachusetts