2013 Annual Markets Report

Internal Market Monitor
May 6, 2014

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 *2013 Annual Markets Report* covers the ISO's most recent operating year, January 1 to December 31, 2013. 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, Net Commitment-Period Compensation costs and the performance of the Forward Capacity Market and 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 US 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 a 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 2013. Section 1 summarizes the region's wholesale electricity market outcomes for 2013, 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 include more detailed discussions of each of the markets, market results, and

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[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" (January 24, 2014), 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).

the IMM's analysis and recommendations. A list of 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 subject to resettlement. Underlying natural gas data furnished by the Intercontinental Exchange (ICE):

ICE Global markets in clear view

[3] *Overview of New England's Wholesale Electricity Markets and Market Oversight* (May 6, 2014), http://www.iso-ne.com/pubs/spcl_rpts/index.html.

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Section 1
Executive Summary

The *2013 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. In addition to trading wholesale electric energy, day ahead and in real time, the participants in the ISO-administered forward and real-time markets buy and sell reserve products; regulation service; Financial Transmission Rights (FTRs); and capacity, including demand resources. These markets ensure the competitive and efficient supply of electricity to meet the energy needs of the New England region and secure adequate resources required for the reliable operation of the power system.

This section summarizes the region's wholesale electricity market outcomes for 2013, the important market issues and the Internal Market Monitor's (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, respectively. 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. 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.[4]

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 include reviewing the competitiveness of the wholesale electricity markets, reporting on the performance of the markets, and recommending improvements to the market design. The IMM reviewed market outcomes and associated information for 2013 and concluded that the wholesale electric markets operated competitively in 2013. Market concentration is low, and energy prices remain at levels consistent with the short-run marginal cost of production. Overall, market outcomes reflected the increase in natural gas prices compared with 2012, causing energy costs in 2013 to be higher than in 2012. See Table 1-1.

[4] *Overview of New England's Wholesale Electricity Markets and Market Oversight* (May 6, 2013), http://www.iso-ne.com/pubs/spcl_rpts/index.html.

Table 1-1
Key Statistics on Load, Locational Marginal Prices (LMPs), and Input Fuels

Statistic[a]	2012	2013	% Change 2012 to 2013
Real-time Load (GWh)	128,082	129,336	1%
Weather-normalized real-time load (GWh)	128,249	127,754	0%
Peak real-time load (MW)	25,880	27,379	6%
Average day-ahead Hub LMP ($/MWh)	36.08	56.42	56%
Average real-time Hub LMP ($/MWh)	36.09	56.06	55%
Average natural gas price ($/MMBtu)	3.95	6.97	76%

(a) GWh and MWh stand for *gigawatt-hours* and *megawatt-hours*, respectively; MW stands for *megawatts*; and MMBtu stands for *million British thermal units*. The *Hub* is a collection of energy pricing locations that has a price intended to represent an uncongested price for electric energy, facilitate energy trading, and enhance transparency and liquidity in the marketplace. *Weather-normalized* results are those that would have been observed if the weather were the same as the long-term average.

Table 1-2 shows wholesale electricity costs (in dollars and dollars per megawatt-hour; $/MWh) by market in 2013 compared with 2012. Total costs increased by about 45%, while energy costs increased by about 57%.[5] As discussed in the sections that follow, the increase in energy costs was the result of an increase in natural gas prices. Higher ancillary service costs resulted from the implementation of rule changes that increased both the amount of reserves purchased in the Forward Reserve Market (FRM) and the systemwide 30-minute reserve requirements, as well as the inclusion of opportunity costs in the calculation of the regulation clearing price.[6]

Table 1-2
Wholesale Market Cost Summary

Type	Annual Costs ($ Billions)			Average Costs ($/MWh)		
	2012	2013	% Change	2012	2013	% Change
Energy	4.77	7.49	57%	37.42	58.14	55%
Capacity	1.19	1.06	−11%	9.36	8.20	−12%
Ancillary Services	0.13	0.27	107%	1.04	2.12	105%
Total	6.10	8.82	45%	47.81	68.46	43%

[5] 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 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.

[6] Thirty-minute operating-reserve (TMOR) can be provided by an on-line or off-line resource that can increase output within 30 minutes or electrically synchronize to the system and increase output within 30 minutes in response to a contingency. The TMOR requirement is set to equal at least 50% of the second-largest contingency loss. 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.

In 2013, total Net Commitment-Period Compensation (NCPC) payments were $158.7 million.[7] Compared with 2012, economic, or first-contingency, NCPC payments increased by $38.3 million, and second-contingency NCPC payments increased by $29.3 million. Approximately 70% of all reliability payments in 2013 were made in January, February, July, and December—months that had unusual operating conditions resulting in tight or uncertain system conditions and causing the commitment of additional resources out of merit order.[8]

1.1.1 Dependence on Natural Gas

The reliability of New England's wholesale electricity market is dependent on the availability of natural gas and fuel oil. A number of market forces influence the codependency between New England's natural gas and electricity markets including the following:

- An influx of natural gas-fired generating capacity over the past 15 years
- An aging fleet of legacy oil- and coal-fired generators
- The lowering of natural gas prices with the increased production of domestic shale gas
- A relatively static gas pipeline capacity in New England that has had to accommodate a 37% increase in overall natural gas consumption since 1999

In fact, the increase in natural gas consumption by New England generators since 1999 accounts for more than 95% of the overall increase in natural gas consumption for the region. The confluence of these forces has resulted in a much higher proportion of electricity being generated by gas-fired generators in New England, while pushing gas pipeline capacity to its limits during periods of peak gas demand. As a consequence, the reliability of New England's wholesale electricity grid is dependent, in part, on the owners and operators of natural gas-fired generators effectively managing natural gas deliveries during contemporaneous periods of high gas and electric power demand. Reliability is also dependent on the region's oil fleet having sufficient oil on hand to operate when gas prices rise to levels that exceed the price of oil. When this occurs, oil units are dispatched more frequently because they are the least cost source of energy.

1.1.2 Capacity Resource Obligations

In 2012 and 2013, litigation at the Federal Energy Regulatory Commission (FERC) sought to clearly state the energy market performance obligations of resources with a capacity supply obligation (CSO).[9] The litigation resulted in a FERC order on rehearing.[10] In brief, FERC

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[7] *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.

[8] See Section 2.1.3.4 for a review of the unusual system operating conditions in 2013.

[9] A *capacity supply obligation* is a requirement for a resource to provide capacity, or a portion of capacity, to satisfy a portion of the ISO's annual Installed Capacity Requirement (ICR) acquired through an Forward Capacity Auction (FCA), a reconfiguration auction, or a CSO bilateral contract through which a market participant may transfer all or part of its CSO to another entity. 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 2009 *Northeast Power Coordinating Council (NPCC) Regional Reliability Reference Directory #1 Design and Operation of the Bulk Power System* (https://www.npcc.org/Standards/Directories/Forms/Public%20List.aspx). This criterion states

concluded that the ISO's market rules require resources with a CSO to procure fuel to meet the terms of the resource's energy market offer if fuel is physically available. While the litigation was prompted by concerns about fuel availability for natural-gas-fired units, the obligations apply to all resources.

As part of its ruling in this proceeding, FERC required the IMM to issue a list of factors it uses in evaluating whether or not resources have met their obligations. The IMM issued this list in September 2013.[11] With the experience it has gained in implementing this list, the IMM is supplementing these factors with the following principles it uses to determine whether resources with a CSO have met their tariff obligations with respect to fuel procurement (see Section 2.1.4):

- Generators are obligated to purchase fuel if it is physically available.
- Physical availability for gas units involves assessing the pipeline system conditions and resource owner actions in the day-ahead and real-time nomination cycles.
- A review of whether an oil or coal generator had fuel physically available includes reviewing the resource's inventory and replenishment plans. Under the FERC order, and under the lower Good Utility Practice standard advocated by generators, resources are obligated to have sufficient oil in their tanks to meet their obligations to offer into the day-ahead market and operate in accordance with their offers.[12] An oil generator with insufficient oil in its tank that failed to operate when dispatched would not be excused from meeting its obligation because oil was physically unavailable on the day when the dispatch order was given.
- If replenishment becomes difficult because of physical constraints (e.g., ice or river constraints preventing barges from reaching the generator), a resource's use of the limited-energy generator (LEG) option to manage its remaining fuel inventory would be appropriate.[13]

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that the probability of disconnecting any firm load because of resource deficiencies shall be, on average, not more than 0.1 day per year.

[10] FERC, *Order on Complaint, New England Power Generators Association v. ISO New England*, Docket No. EL13-66-000 (August 27, 2013), http://www.iso-ne.com/regulatory/ferc/orders/2013/aug/el13-66_8-27-13_order_nepga_complaint.pdf.

[11] ISO New England, "Factors the Internal Market Monitor Considers in Evaluating Physical Availability of Fuel for Generating Resources" (September 27, 2013), http://www.iso-ne.com/markets/mktmonmit/rpts/other/factors_imm_considers_in_eval_physical_avail_of_fuel_for_gen_res.pdf.

[12] The tariff, Section I, defines *good utility practice* as any of the practices, methods, and acts that a significant portion of the electric utility industry engage in or approve during the relevant time period, or any of the practices, methods, and acts that reasonably can be judged to accomplish the desired result at a reasonable cost, consistent with good business practices, reliability, safety, and expedition. Good utility practice is not intended to be limited to the optimum practice or method, or to exclude all others, but rather it includes all acceptable practices, methods, or acts generally accepted in the region, including those practices required by the *Federal Power Act*, Section 215(a)(4). See http://www.iso-ne.com/regulatory/tariff/sect_1/sect_i.pdf.

[13] The tariff, Section I, defines a *limited-energy resource* as a generating resource that, because of design considerations; environmental restriction on operations; cyclical requirements, such as the need to recharge or refill or manage water flow; or fuel limitations, is unable to operate continuously at full output on a daily basis (see above link).

There were 20 fewer instances of resources failing to have sufficient fuel in 2013 than in 2012, which is attributable to several factors:

- FERC's clarification of generator obligations (see Section 2.1.4)[14]
- Generators' extensive use of fuel-price adjustments to ensure that their offers will cover the cost of procuring fuel (see Section 2.1.4.3)
- The change in the day-ahead market timeline resulting in earlier notification of day-ahead market results and reserve adequacy analysis (RAA) commitments (see Section 2.1.4.5)
- Improvement in the tools and processes used by system operations in assessing the availability of natural gas for generators, reducing the likelihood of committing resources that do not have fuel

1.1.3 Forward Capacity Market

The seventh Forward Capacity Auction (FCA #7) was held on February 4–5, 2013. The rest-of-pool capacity zone cleared at the floor price of $3.15/kilowatt (kW)-month because more resources were in the rest-of-pool capacity zone than needed to meet the Installed Capacity Requirement (ICR) at the floor price.[15] However, the Northeast Massachusetts (NEMA)/Boston zone cleared at $14.999/kW-month for new resources, and $6.661/kW-month for existing resources. The price paid to new resources and existing resources was different because the competition among new resources was insufficient to set a competitive price in the zone, resulting in the application of administrative pricing rules. Under the rules effective at the time of the FCA, existing resources are to be paid the lower of either the capacity clearing price (CCP) or 1.1 times the cost of new entry (CONE). For FCA #7, resources will be paid $6.661/kW-month, which is 1.1 X CONE.[16] Capacity payments made to all resources in 2013 totaled $1.06 billion, an 11% drop from 2012.

1.1.4 Ancillary Service Markets

In 2013, the number of hours with positive prices for 30-minute operating reserves (TMORs) increased by 40%, or an additional 28 hours compared with 2012. Two factors explain most of this increase in positive pricing:

- The addition of "replacement reserves" to the TMOR requirement, beginning in October 2013, which increased this requirement by 20 to 25%.[17]

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[14] See above footnote; FERC, *Order on Complaint* (August 27, 2013).

[15] The *Rest-of-Pool* capacity zone comprises the Western/Central Massachusetts, Southeastern Massachusetts, Vermont, New Hampshire, and Rhode Island load zones. *Load zones* are aggregations of internal nodes within specific geographic areas of New England.

[16] ISO New England Inc., *Forward Capacity Auction Results*, FERC filing, Docket No. ER13-___-000 (February 26, 2013), http://www.iso-ne.com/regulatory/ferc/filings/2013/feb/er13-992-000_2-26-13_7th_fca_results_filing.pdf.

[17] Operating Procedure No. 8, *Operating Reserve and Regulation* (OP 8) states that in addition to the operating-reserve requirements, the ISO must maintain sufficient *replacement reserves* in the form of additional TMOR for meeting the NPCC requirement to restore its 10-minute reserve within 105 minutes if it becomes deficient as a result of a reportable contingency, and within 90 minutes if it becomes deficient for reasons other than a reportable contingency, as described in NPCC Directory #5, *Reserve* (October 11, 2013), https://www.npcc.org/Standards/Directories/Forms/Public%20List.aspx.

- Several days of tight system conditions in July, September, October, and December 2013.

Payments to resources providing regulation service totaled $20.4 million in 2013, an increase of $8.8 million from 2012. An interim Regulation Market solution that included regulation opportunity costs in the regulation clearing price was implemented on July 1, 2013, to address the major elements of FERC Order 755.[18]

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 2013 and the analysis presented herein:

1. The limited-energy generator feature permits generators to manage fuel limitations under the current single-pricing system (i.e., one offer is in effect for the entire market day). The IMM recommends modifying the market rules as necessary when hourly markets are introduced and resources can change their offers on an hourly basis to ensure that the use of the LEG provisions in both the day-ahead and real-time markets are restricted to instances when the availability of fuel is physically limited. This view of the use of the LEG provisions is consistent with the recent FERC order clarifying generator obligations. The order states that generators may only limit availability when the supply has a physical restriction; reductions in availability for economic considerations, such as simply choosing not to purchase sufficient fuel to follow dispatch signals, are incompatible with the requirements of the tariff (see Section 2.1.4).
2. The IMM recommends that the ISO discontinue or replace the locational marginal price calculator for calculating real-time prices. The LMP calculator, an automated optimization program, runs every five minutes and generates the ex-post prices used in settlements. However, the LMP calculator produces LMPs that do not reflect scarcity when resources are operating at less than their desired dispatch point and reserves are insufficient to meet operating-reserve requirements (see Section 2.1.1.3).
3. The IMM continues to support the recommendation made in the *2010, 2011, and 2012 Annual Markets Reports* 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. Currently, the ISO is sponsoring market rule changes that will exclude decrement bids from receiving real-time NCPC charges.[19] The IMM will be reviewing the results of these changes and may make additional recommendations for improvements in the future (see Section 3.1.4).

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[18] ISO New England Inc. and New England Power Pool, *Regulation Market Opportunity Cost Change*, Docket No. ER13-1259-000, FERC filing (filed April 11, 2013), http://www.iso-ne.com/regulatory/ferc/filings/2013/apr/er13-1259-000_4-11-2013_reg_mkt_opp_cost_chg.pdf. FERC, letter order accepting the opportunity cost changes (June 27, 2013), http://www.iso-ne.com/regulatory/ferc/orders/2013/jun/er13-1259-000_6-17-13_ltr_order_accept_reg_mrkt_rev.pdf.

[19] A decrement bid is a bid to purchase energy at a specified location in the Day-Ahead Energy Market that is not associated with a physical load. An accepted decrement bid results in scheduled load at the specified location in the Day-Ahead Energy Market.

4. The IMM recommends that as part of the market development plan, the ISO study, develop, and implement a market-based reliability commitment method to improve incentives for meeting reliability objectives and the efficiency of the Day-Ahead Energy Market and Real-Time Energy Market. A careful study of similar experiences at other domestic and international organized markets should be included as part of this project. The IMM recognizes that this is a long-term project requiring significant design work and software changes (see Section 3.1.6.2).

1.3 Market Design Changes

The major revisions to the market design implemented in 2013 and new market design changes proposed in 2013 for implementation in future years are summarized below.

1.3.1 Major Design Changes Implemented in 2013

Seven major design changes to the market design were implemented in 2013.

1.3.1.1 Day-Ahead Energy Market Timeline Shift

The ISO implemented a change in the Day-Ahead Energy Market timeline to provide the ISO and market participants additional time to prepare for the operating day and allow for earlier clearing of the market and earlier completion of the reserve adequacy analysis process. The earlier completion of the day-ahead market processes allow the ISO to commit long-lead-time resources earlier and allow participants with gas-fired resources to learn their next-day commitments earlier so that they have more time to make fuel arrangements reflecting these commitments. In April 2013, FERC accepted the New England Power Pool's (NEPOOL's) proposal to move the closing of the day-ahead market to 10:00 a.m., effective on May 23, 2013.[20] The timeline change was implemented without incident and may have contributed to a reduction in the number of times resources were unable to follow dispatch instructions because of a lack of natural gas. The IMM found no evidence that the change in the timeline had an effect on the timing of natural gas trading in the region.

1.3.1.2 Implementation of Replacement Reserves

To better reflect in market prices the cost of ISO actions to maintain system reliability, the ISO has (1) implemented a replacement-reserve requirement as allowed under Operating Procedure No. 8 (OP 8) to procure additional reserves, and (2) implemented market rule changes that set a Reserve Constraint Penalty Factor (RCPF) (i.e., a maximum cost of redispatch) of $250/MWh for the replacement-reserve requirement. The proposed market rule changes were filed on June 20, 2013, and became effective on October 1, 2013.[21] This change increased the number of positive reserve prices in the region.

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[20] FERC, *Order on Proposed Tariff Revisions*, Docket Nos. ER13-895-000 and ER13-895-001 (April 24, 2013), http://www.iso-ne.com/regulatory/ferc/orders/2013/apr/er13-895-000_4-24-13_order_accept_dam_timing.pdf. The region's private and municipal utilities formed NEPOOL to foster cooperation and coordination among the utilities in the six-state region and ensure a dependable supply of electricity. Today, NEPOOL members serve as ISO stakeholders and market participants. The NEPOOL stakeholder process provides advisory input on market, reliability, and *Open Access Transmission Tariff* (OATT) matters. More information is available at http://www.iso-ne.com/committees/nepool_part/index.html.

[21] ISO New England Inc. and New England Power Pool, *Revisions to Market Rule 1 to Establish a Reserve Constraint Penalty Factor for Replacement Reserve Requirement*, Docket No. ER13-1736, FERC filing (June 20, 2013, effective on

1.3.1.3 *Increased 10-Minute Nonspinning Reserve Product Procured in the Forward Reserve Market*

On February 8, 2013, FERC accepted a market rule change to increase the amount of 10-minute nonspinning reserve (TMNSR) procured in advance through the Forward Reserve Market.[22] Permitting an additional amount of reserve to be procured in the Forward Reserve Market helps support the availability of reserves to meet the increased real-time reserve requirements. This change, which became effective on March 1, 2013, increased the number of positive reserve prices in the region.

1.3.1.4 *Forward Capacity Market Shortage-Event Definition*

On November 1, 2013, FERC issued an order that accepted expanding the definition of "shortage event" in the Forward Capacity Market.[23] Effective November 3, 2013, a shortage event can be triggered when the Reserve Constraint Penalty factor for 30-minute operating reserves is activated for 30 or more contiguous minutes and Action 2 under OP 4 is implemented for the same 30 contiguous minutes.[24] Under the prior rule, a shortage-event was triggered only when an RCPF was activated for 10-minute nonspinning reserves for 30 or more contiguous minutes.

1.3.1.5 *Interim Regulation Market Changes*

An interim Regulation Market solution was implemented on July 1, 2013, to address the major elements of FERC Order 755. The interim solution has no impact on the way that units are selected for regulation. The interim solution incorporates unit-specific regulation opportunity costs into the uniform regulation clearing price, which is applicable to all customers providing regulation services. This change increased regulation prices.

1.3.1.6 *Modifying Generator Resource Auditing Requirements and Procedures*

In January 2013, FERC accepted modifications intended to provide the ISO with a more accurate assessment of the 10- and 30-minute reserve capability of reserve resources.[25] These modifications should work in conjunction with the modifications made to the real-time reserve requirements and the proposal to modify the forward-reserve requirements to ensure sufficient reserve resources. These changes became effective on June 1, 2013. An additional series of changes filed in the same docket to address the auditing of the claimed capability of generator assets went into effect on September 1, 2013.

October 1, 2013), http://www.iso-ne.com/regulatory/ferc/filings/2013/jun/er13-1736-000_6-20-2013_est_res_con_pen_fac.pdf.

[22] FERC, *Revisions to Forward Reserve Market Rules to Permit the Procurement of Additional 10-Minute Nonspinning Reserve*, Docket No. ER13-465-000 (February 8, 2013), http://www.iso-ne.com/regulatory/ferc/orders/2013/feb/er13-465-000_2-8-13_tmnsr_order.pdf.

[23] FERC, *Order On Proposed Tariff Revisions*, Docket No. ER13-2313-000 (November 1, 2013), http://www.iso-ne.com/regulatory/ferc/orders/2013/nov/er13-2313-000_11-1-13_order_shortage_events.pdf.

[24] OP 4, Action 2, is the ISO dispatch of real-time demand resources (RTDRs) to the extent and location required to manage the operating-reserve requirements. Operating Procedure No. 4, *Action during a Capacity Deficiency* (October 5, 2013), http://www.iso-ne.com/rules_proceds/operating/isone/op4/index.html.

[25] FERC, *Order On Proposed Tariff Revisions*, Docket No. ER13-323-000 (January 9, 2013), http://www.iso-ne.com/regulatory/ferc/orders/2013/jan/er13-323-000_1-9-13_order_auditing_revisions.pdf.

1.3.1.7 Performance Incentives Associated with the Forward Reserve Market

To improve the performance incentives associated with the Forward Reserve Market, the ISO implemented several market rule changes:

- Modifications to the forward-reserve "failure-to-reserve" penalty so that it better incents performance by reserve resources
- Adjustments to the "trigger" used to determine whether a resource should be assessed a forward-reserve failure-to-activate penalty.

These changes were filed on June 20, 2013, and become effective on October 1, 2013.[26]

1.3.2 Major Design Changes Proposed in 2013

Two major design changes to the market design were proposed in 2013.

1.3.2.1 FCM Pay-for-Performance Market Design

On January 17, 2014, the ISO filed a proposal to modify the FCM design to more strongly link capacity payments to resource performance during scarcity conditions.[27] The pay-for-performance design is based on the two-settlement logic generally used in forward markets, which entails two key elements. The first element is a forward position in which a quantity of capacity is obligated, or sold in the capacity auction. Each megawatt is paid at the auction clearing price, and the sale creates a resource-specific physical obligation and forward financial position in the capacity market. A resource's forward financial position is a share of the system's energy and reserve requirements during reserve deficiencies.

The second element includes a settlement for deviations. A resource that delivers more than its share of the system's requirements during a reserve deficiency (i.e., an overperformer) will be paid for that incremental production. If it delivers less than its share (i.e., it underperforms), it will "buy out" of its position by paying other resources that did deliver. Positive and negative deviations are paid or charged at the same rate prespecified in the tariff.

The two-settlement approach is standard in forward contracts, both for electricity and commodities, ranging from oil to pork bellies to iron ore. In fact, the two-settlement design underlies the design of New England's day-ahead and real-time electricity markets and is well understood by stakeholders.

Under PFP, consumers will pay the auction clearing price to all resources that clear in the auction. Because the overperformers will be paid by the underperformers, consumers will not bear the short-run risk of covering any unexpectedly high performance payments. This will continue to provide consumers with a predictable capacity price three years after the close of each Forward Capacity Auction. Having underperformers pay overperformers will also provide strong incentives for each resource to perform as needed and for overperformers to benefit by

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[26] ISO New England Inc. and NEPOOL, *Market Rule 1 Revisions Concerning Forward Reserve Market Incentives,* in Docket No. ER13-1733, FERC filing (June 20, 2013), http://www.iso-ne.com/regulatory/ferc/filings/2013/jun/er13_1733_000_6-20-2013_rev_frm_incentives.pdf.

[27] ISO New England Inc. and NEPOOL, *Filings of Performance Incentives Market Rule Changes*, Docket No. ER14- -000, FERC filings, parts 1 and 2 (January 17, 2013), http://www.iso-ne.com/regulatory/ferc/filings/2014/jan/index.html.

helping meet the system's needs. These incentives will place performance risk on all FCM resources, and each resource will need to price this risk in its future capacity auction bids.

1.3.2.2 Revisions to the Rules on Offer Flexibility

Under the current market structure, no offer changes are permitted during the operating day. The revisions to the rules regarding offer flexibility, filed on July 1, 2013, and accepted by FERC on October 3, 2013, would allow market participants to change their offers during the operating day, which will improve their ability to reflect in their energy market offers the cost of obtaining fuel in real time.[28] Offers that are more reflective of actual fuel prices will improve energy market price signals and permit a better match between these prices and the cost of procuring fuel in real time. The revisions to offer-flexibility rules are targeted to be implemented by the end of 2014.

1.4 Status of IMM Recommendations from the *2012 Annual Markets Report*

The status of the IMM recommendations from the *2012 Annual Markets Report* are shown in Table 1-3.

[28] ISO New England Inc. and NEPOOL, *Energy Market Offer Flexibility Changes*, Docket No. ER13-___-000, FERC filing, (July 1, 2013), http://www.iso-ne.com/regulatory/ferc/filings/2013/jul/er13-1877-000_mkt_offer_flex_7-1-2013.pdf. FERC, *Order Conditionally Accepting Tariff Revisions*, Docket No. ER13-1877-000 (October 3, 2013), http://www.iso-ne.com/regulatory/ferc/orders/2013/oct/er13-1877-000_10-3-13_order_condition_accept_flex_rev.pdf.

Table 1-3
Status of Key IMM Recommendations from the *2012 Annual Markets Report*

2012 Recommendations	Status as of the AMR13 Publication Date
Continue to support the recommendation made in the *2011 Annual Markets Report* 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.	Complete, to be effective Q4 2014
Develop additional forward markets so that resources committed by the ISO for reliability reasons have a financial obligation to provide energy.	Replaced by recommendation in 2013 AMR
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 arrange for fuel in the overnight hours.	Open, pending assessment by the ISO
Increase the locational FRM penalties to assure the effectiveness of the intraday reserves.	Closed, modifications filed and approved in 2013[a]
Have 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.	Addressed with pay-for-performance in the long term[b]
Have the ISO develop a sloped demand curve for use in the Forward Capacity Auction.	Closed, filed with FERC April 1, 2014
Review the rules defining limited-energy generator resources to determine whether they need to be revised.	Recommendation updated in this AMR
Continue to support the recommendation made in the 2010 and 2011 Annual Markets Reports 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.	Open, in stakeholder review process
Modify the locational FRM's failure-to-activate penalty so that it is not triggered solely by the emergency version of the dispatch software.	Closed, modifications filed and approved in 2013[c]
Cease identifying the bidders when announcing the results of any Financial Transmission Rights auction.	Open, pending assessment by the ISO
Continue 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.	Open, pending assessment by the ISO
Continue 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.	Complete, to be effective June 1, 2014

(a) FERC, *Revisions Concerning Forward Reserve Market Incentives*, Docket ER13-1733-000, http://www.iso-ne.com/regulatory/ferc/orders/2013/aug/er13-1733-000_8-15-13_ltr_ord_accept_frm_incentives.pdf.

(b) The pay-for-performance market design is discussed in Section 3.4.3.4.

(c) ISO New England Inc. and NEPOOL, *Market Rule 1 Revisions Concerning Forward Reserve Market Incentives* (Docket No. ER13-1733), FERC filing (June 20, 2013), http://www.iso-ne.com/regulatory/ferc/filings/2013/jun/er13_1733_000_6-20-2013_rev_frm_incentives.pdf.

Section 2
Real-Time Markets

The ISO New England's (ISO's) real-time markets include the Real-Time Energy Market, the Regulation Market, and real-time reserves. This section describes the 2013 outcomes of the real-time markets and the Internal Market Monitor's (IMM's) 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 made by the IMM. The IMM's review of market outcomes shows that the Real-Time Energy Market was competitive in 2013.

The Real-Time Energy Market is the physical market in which generators sell, and load-serving entities (LSEs) 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.[29] 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 that consume more or provide less than their day-ahead schedule pay the real-time LMP, and participants that consume less or provide more than their day-ahead schedule get paid the real-time LMP. Because of the dependencies between the Rea-Time Energy Market, the Day-Ahead Energy Market, and other forward markets, this section contains information on forward markets where relevant.

2.1.1 Prices

Real-time price data for 2013 and comparisons of real-time prices and day-ahead prices are presented below (see Section 3.1.1 for a full discussion of day-ahead pricing).

2.1.1.1 Real-Time Prices

In 2013, the average real-time Hub price was $56.06/MWh, up approximately 55% from $36.09/MWh in 2012.[30] This price is consistent with observed market conditions, including those for input fuel costs, loads, and generating resource operations. Price differences between the load zones primarily were due to marginal losses.[31] There was little congestion between

[29] 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 not typically congested. An *external interface node* is a proxy location used for establishing an LMP for electric energy received by market participants from, or delivered by market participants to, a neighboring balancing authority area.

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

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

zones. Most of the congestion was the result of subzonal transient load pockets caused by transmission or generation elements being out of service.[32]

The Maine load zone continues to have the lowest average prices in the region, while the Southeastern Massachusetts (SEMA) load zone had the highest. The average LMPs in the Maine load zone were $2.83/MWh lower than the Hub price, largely because the marginal loss components of the LMPs in Maine were lower than at the Hub. The higher SEMA prices are attributable to local area constraints within the zone. The average LMPs in the SEMA load zone were $0.37/megawatt-hours (MWh) greater than the average Hub price, largely because of the congestion caused by these local area constraints. See Table 2-1.

Table 2-1
Simple Average Real-Time Hub Prices and Load-Zone Differences for 2012 and 2013 ($/MWh)

Location/Load Zone	2012	2013
Hub	36.09	56.06
Maine (ME)	−0.90	−2.83
New Hampshire (NH)	−0.14	−0.91
Vermont (VT)	0.08	−0.98
Connecticut (CT)	0.82	−0.16
Rhode Island (RI)	−0.21	0.04
Southeast Massachusetts (SEMA)	0.05	0.37
Western Central Massachusetts (WCMA)	0.86	0.06
Northeast Massachusetts (NEMA)	0.07	0.26

2.1.1.2 Day-Ahead and Real-Time Price Comparison

In 2013, average day-ahead prices at the Hub ($56.42/MWh) were 0.7% more than average real-time energy prices at the Hub ($56.06/MWh). This is consistent with the recent trend of a decline in the average price difference between day-ahead and real-time prices. In 2006, the annual average day-ahead prices were 2.1% more than the average real-time prices. In mid-2009, the relationship switched, and real-time prices averaged 1.1% more than day-ahead prices. The small difference between day-ahead and real-time prices, as shown for 2013, continues to indicate that average day-ahead market prices are consistent with real-time prices. See Table 2-2.

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).

[32] *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.

Table 2-2
2013 Annual and Quarterly
Day-Ahead and Real-Time Hub Prices ($/MWh)

	Annual	Q1	Q2	Q3	Q4
Day-ahead	56.42	86.16	40.09	42.42	57.50
Real-time	56.06	81.28	40.19	42.89	60.24

In 2013, hourly real-time and day-ahead prices correlated positively (0.78). Hourly real-time LMPs at the Hub for 2013 had a standard deviation of $54.25/MWh, while hourly day-ahead LMPs at the Hub for 2013 had a standard deviation of $44.41. 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 create price volatility that occurs only in real time.[33] See Figure 2-1.

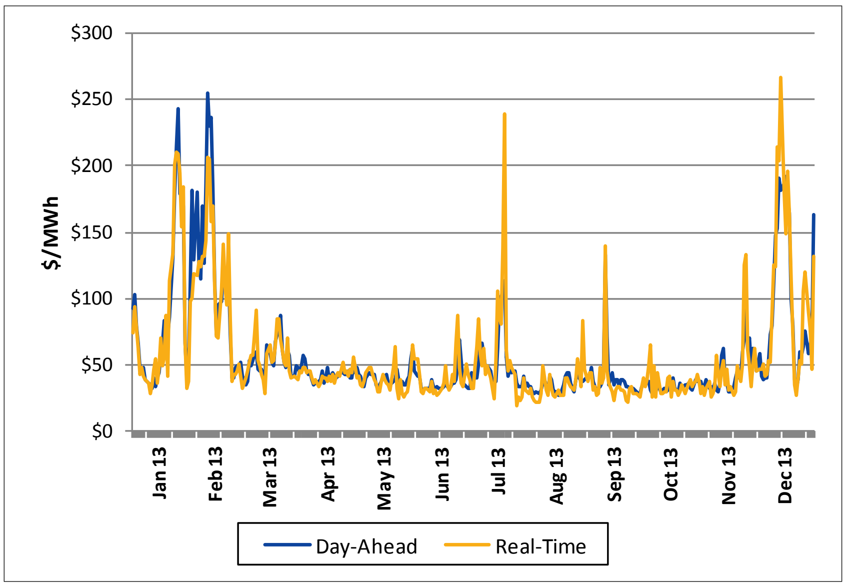

Figure 2-1: Average daily day-ahead and real-time Hub prices, 2013 ($/MWh).

2.1.1.3 Ex-Post Prices

The LMP calculator (LMPc) is an automated optimization program that runs every five minutes and generates the ex-post prices used in settlements based on the most recent telemetry and unit-dispatch and scheduling (UDS) solutions.[34] The LMP calculator was intended to distinguish

[33]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 or transmission facility, generally to perform maintenance. The declaration of a *Minimum Generation (Min Gen) Emergency* is called when the on-line generation plus net imports comes close to exceeding system load 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.

[34] A second-case identification, called contingency UDS or CD UDS, provides new desired dispatch points. The distinction is not important for the explanation.

the prices set by generators operating close to their desired dispatch points from those operating further away.

As fully described in the *2010 Annual Markets Report*, the LMP calculator produced inappropriately low energy and reserve prices on September 2, 2010, during a reliability event.[35] The ISO was unable to meet North American Electric Reliability Corporation (NERC) requirements for recovery from a contingency due to lagging generator responses. Under these conditions, the LMP calculator prices did not reflect actual reserve scarcity conditions. More accurate, higher prices may have helped avert the NERC violation.

Separately, the External Market Monitor has also identified several inconsistencies between ex ante and ex post prices produced by the LMP calculator.[36]

While the LMP calculator may understate the value of reserves, it provides little, if any, change in prices from the UDS solutions, even under normal operating conditions. This is illustrated in Table 2-3, which compares the LMP calculator and UDS prices for all pricing nodes in 2013 and shows that the LMP calculator and UDS prices are often very close. The table shows the percentage of time the LMP calculator price was within a given percentage of the UDS price. For example, in 96.9% of all observations, the difference between the LMP calculator price and the UDS price was less than 1%. Differences greater than 5% only occurred in 0.3% of all observations. The percentage difference between the two prices was calculated as follows:

$$LMP\ Difference\ \% = \frac{LMPc - UDS}{UDS} \times 100$$

Table 2-3
Comparison of LMP Calculator and UDS Pricing at Generator and External Nodes, 2013

Percentage Difference from UDS	Percentage of Total Sample
< 1	96.9
< 5	99.7
< 10	99.9

Large differences between the two prices typically occur when a reserve constraint is binding, creating inaccurate LMP calculator prices during difficult operating conditions when accurate prices are essential to maintaining reliability. UDS prices have become reliable enough that the LMP calculator is no longer needed.

Recommendation. The IMM recommends that the ISO discontinue or replace the LMP calculator for calculating real-time prices. The LMP calculator, an automated optimization program, runs every five minutes and generates the ex-post prices used in settlements. However, the LMP calculator produces LMPs that do not reflect scarcity when resources are operating at less than

[35] The report is available at http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/2010/amr10_final_060311.pdf.

[36] David B. Patton, et al., *External Market Monitor 2012 ISO-NE Market Assessment* (Potomac Economics, May 2013), http://www.iso-ne.com/markets/mktmonmit/rpts/ind_mkt_advsr/isone_2012_emm_rprt_final.pdf.

their desired dispatch point and reserves are insufficient to meet operating-reserve requirements.

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 is determined by the number of competitors and the frequency with which suppliers are pivotal. A *pivotal* supplier has the ability to exercise market power because it is needed for meeting demand and can therefore offer energy and set prices above competitive levels, subject only to offer caps and mitigation measures. Thus, market structure affects the ability of a participant to raise its price above its marginal cost and sustain profits above the competitive level. 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 presents two measures of market concentration in this section. C4 is the simpler measure of whether or not concentration exists. C4 is the percentage of the market controlled by the four largest competitors, or the simple sum of the market shares of the top-four firms. A C4 value of 100% means that the top-four firms supply all the market demand. However, this measure does not distinguish between a virtual monopoly condition where one firm supplies 97% of the market with the other three supplying 1% each and a more competitive situation where each firm supplies 25% of the market.

The second measure of market concentration, the Herfindahl-Hirschman Index (HHI), provides more detail on market structures than C4.[37] The HHI would identify the example of a firm with 97% of the market share as virtually indistinguishable from a monopoly and the example of four equal market shares of 25% as more competitive. The HHI is calculated as the sum of the squared market shares of the firms in the market. The example of a firm with 97% market share would yield a value of 9,412 out of a maximum value of 10,000 for a pure monopoly. The more competitive example of four equal market shares of 25% would yield a value of 2,500. This value of 2,500 is close to the threshold used by the United States (US) Department of Justice (DOJ) to separate unconcentrated markets from concentrated markets—no such commonly used thresholds exist for C4.[38]

The IMM also calculated the number of hours in which a given participant's portfolio was pivotal, as measured by the Residual Supplier Index (RSI), described in Section 2.1.2.3.

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[37] 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.

[38] 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.

2.1.2.1 Market Share Controlled by the Four Largest Competitors for the 2013 Peak Hour

In 2013, the four largest generating companies and the four largest LSEs controlled more than 30% of the supply and load in the region, with two of the largest suppliers also serving a large percentage of the load.

For the 2013 peak load hour—July 19, 2013, hour ending (HE) 5:00 p.m.—generators produced 28,161 megawatts (MW) of electricity.[39] The four largest generation suppliers provided 33.3% of the total electricity produced in New England in that hour, while all other market participants provided 66.7% of the electricity generated in that hour. The participant that supplied the most generation to the system during the peak hour was Exelon Generation Company, which supplied 3,115 MW (11.1%) of the total electricity generated. Dominion Energy Marketing provided 2,442 MW (8.7%); GDF Suez Energy Marketing NA, 1,917 MW (6.8%); and NextEra Energy Power Marketing provided 1,913 MW (6.8%) of total supply during the peak load hour of 2013. See Figure 2-2.

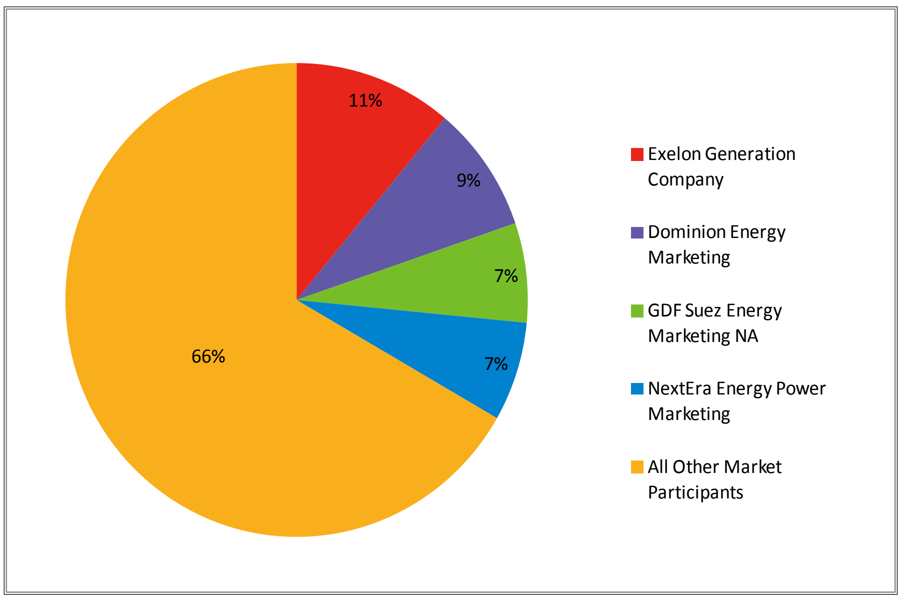

Figure 2-2: Market share of generation by participant, peak load hour, 2013 (July 19, hour ending 5:00 p.m.).

For the 2013 peak load hour, the total amount of electricity purchased, or *real-time load obligation* (RTLO), was 27,837 MW.[40] Overall, as shown in Figure 2-3, the four largest load-serving participants served 35% of the total system load for the 2013 peak load hour, while all other market participants served 65% of the total system load in that hour. Exelon had the largest real-time load obligation, serving 4,170 MW (15%) of total system peak load. Hess Corporation served 2,331 MW of total system peak load in that hour (8%); TransCanada Power Marketing, 1,707 MW (6%); and Next Era Energy Marketing, 1,522 MW (6%).

[39] *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.

[40] Losses account for the difference between the 28,161 MW of sold generation and the 27,837 MW of bought generation.

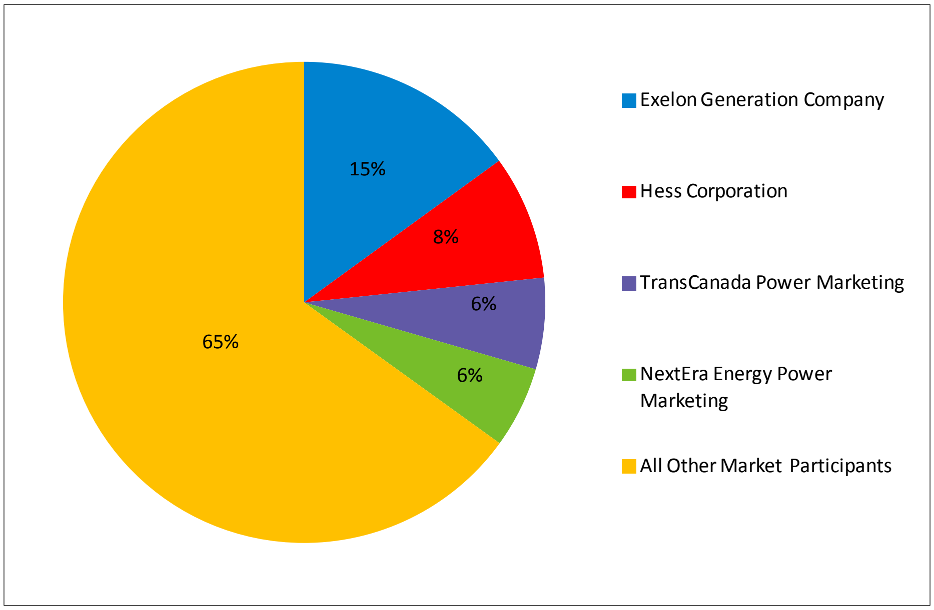

Figure 2-3: Real-time load obligation by participant, peak load hour, 2013 (July 19, hour ending 5:00 p.m.).

Figure 2-2 and Figure 2-3 show that Exelon is in the top-four participant list for both load served and generation provided in the peak load hour of 2013. 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. The amount of generation and load held by the four largest suppliers or providers is not large enough to raise concerns about the exercise of market power.

2.1.2.2 Herfindahl-Hirschman Index

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 2-4 summarizes the results of the IMM's HHI analysis. The median HHI calculated using the value corresponding to each day's peak hour is 742 and the median HHI calculated using the value corresponding to each day's lowest load hour is 878. 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 2-4
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 2013

	Median HHI	Max HHI	Median Share of Top *N* Participants				Median Number of Participants	Median Load (MW)
			N = 1	*N = 4*	*N = 8*	*N = 16*		
Peak hour	742	964	*14.7%*	*45.1%*	*69.0%*	*86.4%*	121	17,656
Lowest-load hour	878	1,154	*17.3%*	*51.0%*	*73.0%*	*87.3%*	117	12,015

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 2013, when the top-four participants (by market share) comprised 51.0% of the market in the hours with the lowest load, compared with 45.1% for the peak hours.

2.1.2.3 Residual Supply Index

The systemwide Residual Supply Index measures the percentage of real-time demand in a given hour that can be met without any capacity from the largest supplier.[41] The RSI also measures the number of hours in which at least one supplier is pivotal and able to exercise market power. 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 2013 suggests that suppliers at the system level had limited ability to exercise market power.[42] The system-level analysis shows that pivotal suppliers existed during 123 hours in 2013, approximately 1.4% of all hours. This is an increase from 2012, when suppliers were pivotal in 85 hours, but overall, the 2013 result is consistent with competitive outcomes. See Figure 2-4.

[41] The calculation recognizes that participants submit a single supply offer that covers the 24-hour period of the market day and they have limited ability to alter that offer during the course of the day. As a result, the RSI calculation uses the total quantity offered from generating resources during the reoffer period.

[42] The IMM has revised the RSI estimation methodology in this report to better reflect the known availability of generators, generators' economic maximums (ecomax), and the system reserve requirement. A generator's ecomax is the highest unrestricted level of electric energy (in megawatts) it can produce, representing its highest megawatt output available for economic dispatch.

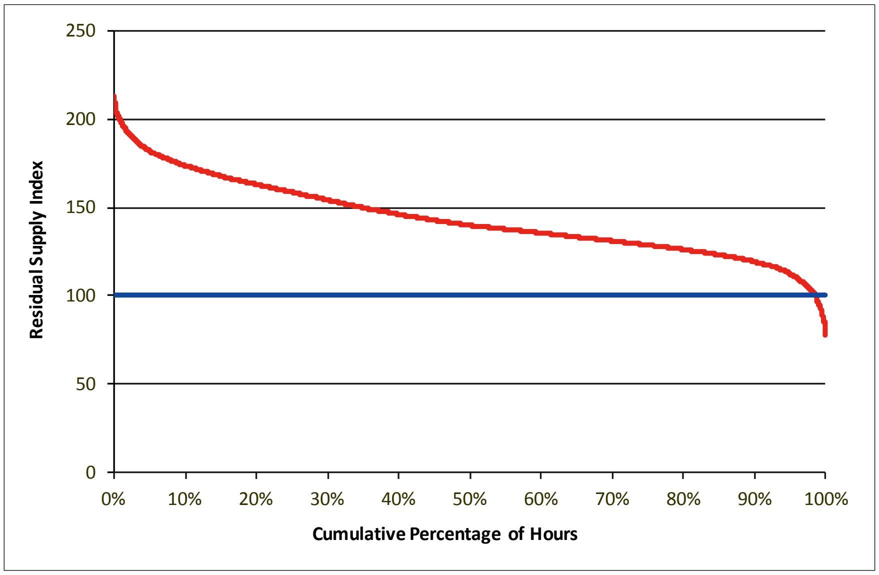

Figure 2-4: Systemwide Residual Supply Index duration curve, all hours, 2013.

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

This section examines the relationships between real-time electric energy prices, fuel prices, and other market factors. Day-ahead market outcomes are also referenced where appropriate. 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 is largely determined by its fuel type, examining marginal units by fuel type helps explain 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, an additional marginal unit exists for each constraint.

In 2013, unconstrained pricing intervals accounted for approximately 93% of all pricing intervals. When considering both unconstrained and constrained intervals, natural gas was the marginal fuel during 69% of all pricing intervals, followed by pumped-storage generation and coal, which were marginal in 8% and 7% of all pricing intervals, respectively. See Figure 2-5.

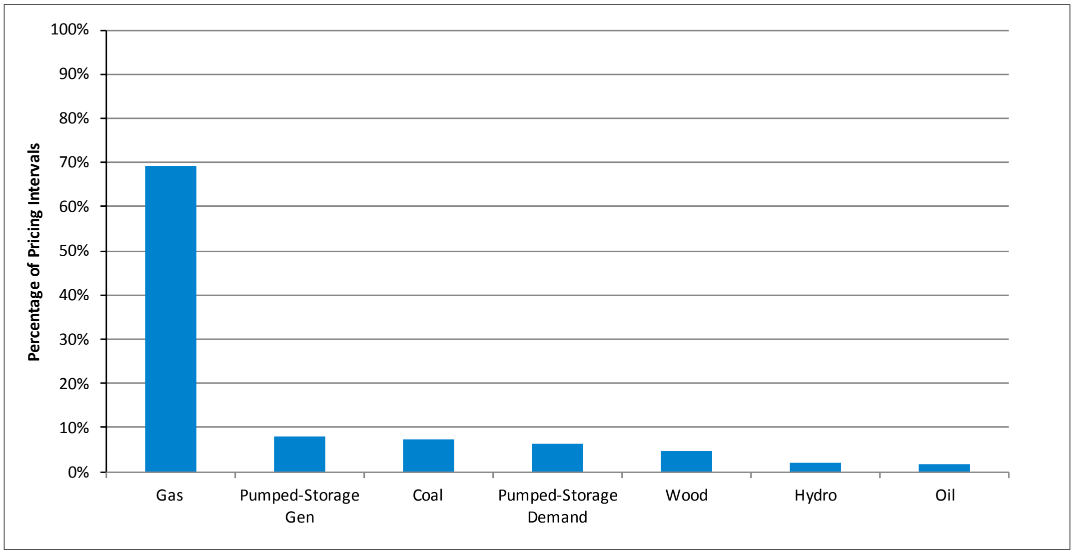

Figure 2-5: Marginal fuel-mix percentages of all pricing intervals, 2013.

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 required to calculate the spark spread includes the wholesale price of electricity, the cost of natural gas (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).[43] 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 2011 through December 2013
- The fuel costs of a representative CCGT in New England, using the Algonquin gas price index[44]
- A 7,800 Btu/kWh heat rate
- 100% availability

[43] The heat rate (Btu/kWh) 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.

[44] 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.

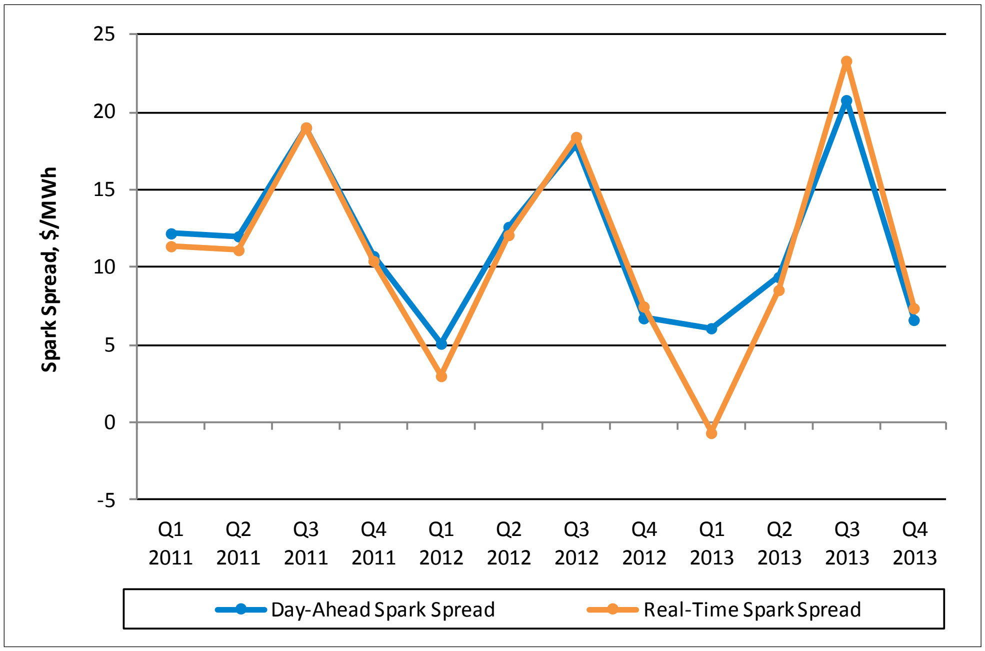

Figure 2-6: **Quarterly estimated spark spreads for on-peak hours, 2011 to 2013 ($/MWh).**

The results show that, on average, the representative gas unit earned a positive gross margin in 2013. The annual average spark spreads were approximately $10.81/MWh day-ahead and $9.76/MWh in real-time.[45] Spark spreads for natural gas increased in the summer months when high loads called for more expensive gas-fired and oil-fired units to operate and set price. Real-time spark spreads are lower in the winter month because constraints on the natural gas pipelines raise the cost of natural gas, sometimes to levels that exceed the price of oil. The spark spread has declined since the winter of 2011/2012 because the number of days where gas prices have exceeded the cost of oil have increased. When gas prices are higher than oil prices, gas is either the marginal unit or off line, resulting in a very low or zero spark spreads for a gas unit.

2.1.3.3 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.[46] As shown in Table 2-5, the NEL was highest in the third quarter of 2013, at 35,331 gigawatt-hours (GWh). The annual peak demand of 27,379 MW also occurred in the third quarter, on July 19. The first quarter had the second-highest demand for electricity in 2013, at 32,311 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 2013, with more mild temperatures, had the lowest demand for electricity.

[45] 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).

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

Table 2-5
Energy Statistics, 2012 and 2013

	2012 Annual	2013 Annual	Q1 2013	Q2 2013	Q3 2013	Q4 2013
NEL (GWh)	128,082	129,336	32,311	30,211	35,331	31,483
Weather-normalized NEL (GWh)[(a)]	128,249	127,754	32,474	29,805	34,239	31,236
Recorded peak demand (MW)	25,880	27,379	20,887	25,129	27,379	21,448

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

Figure 2-7 illustrates real-time monthly LMPs and shows that the recent increase in natural gas prices have caused energy prices in the winter months to be higher than they are in the summer months. This occurs even though the summer electrical demand exceeds the winter electrical demands (see Table 2-5). This can be seen in January and December of 2013, when average prices exceeded $100/MWH, while the average prices in July of 2013 were slightly below $60/MWH.

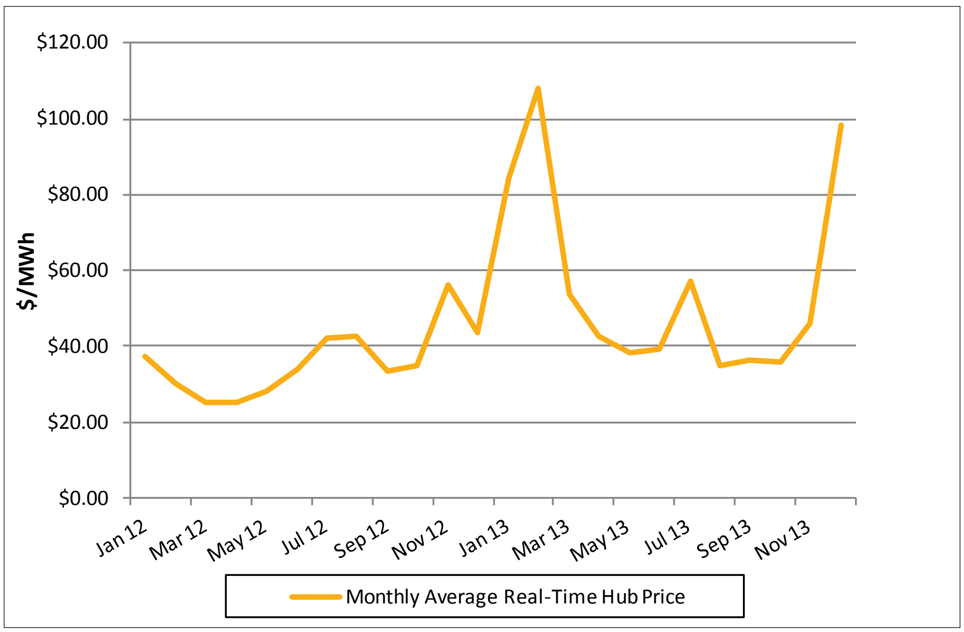

Figure 2-7: Monthly average real-time Hub prices, 2012 to 2013 ($/MWh).

2.1.3.4 Energy Prices, Weather, and System Conditions

Weather and other system conditions affected prices on a number of days in 2013:

- A combination of cold temperatures, severe weather, and high natural gas prices in January and February created unusual operating conditions. The IMM concluded that the system operated as expected and the markets were competitive during these extreme weather events, but as noted in the *2012 Annual Markets Report*, issues regarding fuel procurement and availability, especially during the February 2013 weekend blizzard ("Winter Storm Nemo"), continued to be of concern.

- New England experienced hot weather and high loads from July 15–20, which resulted in a Master/Local Control Center 2 (M/LCC2), Abnormal Conditions Alert, and an Operating Procedure No. 4 (OP 4), *Action during a Capacity Deficiency*, event.[47]
- Unusual day-ahead price separation occurred at the New England Hub on September 11, 2013.
- On Saturday, December 14, 2013, New England experienced unseasonably cold temperatures and snow, resulting in a capacity deficiency. In addition to declaring OP 4, a shortage event was triggered under the Forward Capacity Market (FCM) (see Section 3.4.3.4).[48] This was the first shortage event triggered since the start of the FCM in 2010.

This section provides an overview of these events.

Winter 2012/2013. New England experienced two extreme weather events in the winter of 2013. The first event, from January 21 through January 28, was New England's coldest multiple-day stretch since 2009. The second event, occurring two weeks later in February, was a weekend blizzard that left record snowfall across the region.[49]

During the first event, no major power outages were reported; however, OP 4 emergency actions were required on Monday, January 28, to manage unplanned generator outages and loads higher than forecast following the stretch of cold weather. During the second event, a blizzard began on Friday, February 8, and continued into Sunday, February 10, knocking out power to more than 645,000 retail electricity customers. Despite the number of power outages affecting retail customers, wholesale power system conditions did not require the ISO to implement any emergency procedures.

January 21–28, 2013. During January 21–28, low temperatures throughout New England contributed to an increased demand for natural gas, specifically for commercial and residential heating, which contributed to increased natural gas prices. Natural gas prices in New England during this period reached a high of $35/million British thermal units (MMBtu). In contrast, natural gas prices across the rest of the country were in the range of $4/MMBtu. On January 23–25, the price of natural gas in New England surpassed the approximately $18/MMBtu price of 0.3% sulfur no. 6 oil. These higher fuel prices were directly reflected in the wholesale day-ahead and real-time electricity prices.

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[47] An *Abnormal Conditions Alert* is a notice from the ISO to applicable power system operations, maintenance, construction, and test personnel, as well as each applicable market participant, to alert them about an existing abnormal condition affecting the reliability of the power system or about an anticipated abnormal condition. Master/Local Control Center Procedure No. 2 (M/LCC2), *Abnormal Conditions Alert* (February 21, 2014), http://www.iso-ne.com/rules_proceds/operating/mast_satllte/mlcc2.pdf. OP 4 guidelines contain 11 actions that can be implemented individually or in groups depending on the severity of the situation. These actions include allowing the depletion of the 30-minute and partial depletion of the 10-minute reserves, scheduling market participants' submitted emergency transactions and arranging emergency purchases between balancing authority areas, and implementing 5% voltage reductions. Operating Procedure No. 4, *Action during a Capacity Deficiency* (October 5, 2013), http://www.iso-ne.com/rules_proceds/operating/isone/op4/index.html.

[48] A *shortage event* is when the system is short of 10-minute reserves for at least 30 minutes. Refer to *Market Rule 1*, Section III.13.7.1.1.1, for a complete explanation of shortage events.

[49] ISO New England, *Winter Operations Summary: January–February 2013* (February 27, 2013), http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/winter_operations_summary_2013_feb_%2027_draft_for_discussion.pdf.

The system performed well during the period, reliably serving all electrical loads and maintaining required reserves. Electric generation from oil-fired resources was higher than in prior periods, primarily due to the price of oil relative to natural gas. Specifically, during the period, energy from oil-fired resources made up 10% of the total energy produced, while energy from gas-fired resources made up 35%. For the rest of the month, less than 1% of the total energy produced was served from oil-fired resources, while energy from gas-fired resources made up 40%.

Because of the increase in natural gas prices, dual-fuel generators operated on oil, which reduced already-low oil inventories. Some natural-gas-fired resources were needed earlier in the day than planned and became unavailable for extended operation later in the day because they had not made arrangements to procure all the natural gas that would have been needed for the entire operating day. As a result of these events, the ISO committed additional generation. Refer to Section 2.1.6.3.

The IMM further analyzed market conditions and performance on January 28, 2013, when the ISO implemented Actions 1 and 2 of OP 4. Overall, participants acted competitively, and no suppliers were pivotal. Lower-than-forecasted afternoon temperatures resulted in higher-than-expected loads. Capacity and reserve shortages, along with generator performance issues, resulted from actual loads being greater than forecast loads. The ISO dispatched 373 MW of real-time demand-response resources and obtained nearly 95% of the requested load reduction.

February Snowstorm. New England experienced a record snowstorm during a three-day period from Friday, February 8, to Sunday, February 10. The snowfall across much of the region ranged from 30 to 40 inches. During this event, natural gas prices in New England increased to a high of $31/MMBtu. In comparison, natural gas prices during this time were slightly above $3/MMBtu across the rest of the country. The higher natural gas prices in New England directly affected New England's wholesale electricity prices. From February 8–12, the price of gas on the Algonquin pipeline surpassed the 0.3% sulfur no. 6 fuel oil price, which remained relatively constant throughout the period at approximately $20/MMBtu.

The day-ahead and real-time LMPs remained above $100/MWh for most of the hours during the blizzard except for a few hours on February 8 and February 9. During most of this period, the real-time LMPs were consistent with day-ahead LMPs. However, on February 9, a Minimum Generation Emergency was declared. During this period, the real-time LMP was administratively set to $0/MWh systemwide for one hour. The Minimum Generation Emergency event was caused by the actual peak load being 1,200 MW less than forecast and the return to service of approximately 800 MW of previously unavailable generation.

The blizzard conditions created a range of operational challenges for ISO system operators. Transmission outages started around 7 p.m., Friday, February 8, and peaked after midnight, mostly from high winds and snow-packed substation equipment, affecting 115 kilovolt (kV) and 345 kV lines. A loss of more than 2,000 MW of generation in the Southeast Massachusetts/Rhode Island (SEMA/RI) area made it difficult to manage system security in Rhode Island as well as New England west-to-east power-system transfers. Early Saturday morning, February 9, six natural-gas-fired generators informed ISO system operators that they could not get fuel. The inability of gas generators to obtain fuel during this period increased concerns about the reliability of the fuel supply to natural-gas-fired generating facilities.

July 15–20, 2013. In mid-July 2013, New England experienced higher than normal temperatures (≥89°F) for six consecutive days beginning on Monday, July 15, and ending on Saturday, July 20. On Monday, July 15, at 10:45 a.m., the ISO entered M/LCC 2 (Abnormal Conditions Alert) in anticipation of hot weather and high loads during the remainder of the week. Peak daily loads ranged from 26,111 MW on Monday, July 15, to a high of 27,379 MW on Friday, July 19, which was the fourth-highest demand day on record.[50] The peak load of 24,668 MW on Saturday, July 20, was the highest weekend demand day ever recorded.

During this period, more-expensive units were required to be on line to serve the higher electricity demands. Many of these more-expensive units were the marginal (price-setting) units, causing day-ahead and real-time wholesale electricity prices to rise. High loads, tight capacity, and binding reserve constraints resulted in real-time LMPs in excess of $200/MWh for three hours on Monday, July 15, and six hours on Thursday, July 18. On July 19, real-time LMPs exceeded $400/MWh for seven hours due to a capacity deficiency, which resulted in the ISO declaring OP 4.

The IMM further analyzed market conditions and performance on July 19, 2013, when the ISO implemented Actions of 1, 2, 3, and 5 OP 4.[51] The high loads resulted in one or more pivotal suppliers in 15 hours. Loads exceeding 27,000 MW, coupled with generator outages and reductions, resulted in capacity and reserve shortages.

On July 19, 2013, the ISO had 318 MW of real-time demand-response resources (RTDRs) available to reduce load within 30 minutes of dispatch (see Section 3.5).[52] At 1:00 p.m., the ISO dispatched 193 MW of RTDRs in all zones except Maine. The ISO obtained nearly 95% (184 MW) of the requested load reduction, which helped mitigate the capacity deficiency on the system.

The IMM compared the results of the July 19 demand-response event with the demand-response event on July 22, 2011.[53] The results were comparable. The July 22, 2011, event resulted in a 90% response (101% when including Maine's demand-response resources) of the requested load reduction.[54] The IMM observed, however, that, similar to the July 22, 2011, event, some demand-response resources overperformed on July 19, and some resources underperformed.[55]

September 11, 2013. On September 11, 2013, high temperatures resulted in higher real-time demand for electricity. The actual peak load was 1,992 MW higher than the forecasted peak

[50] ISO New England, "Top 10 Demand Days," webpage (2014), http://www.iso-ne.com/nwsiss/grid_mkts/demnd_days/index.html.

[51] Actions 2, 3, and 5 of OP4 excluded Maine.

[52] The RTDRs' net capacity supply obligation (CSO) on this day was 318 MW. 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.

[53] July 22, 2011, was a similar day to July 19, 2013, with high loads (27,707 MW for the peak hour). On the 2011 day, the ISO implemented Actions 1, 2, 3, and 5 of OP 4.

[54] See the ISO's *2011 Third Quarter Quarterly Markets Report*, Demand-Response Working Group presentation (July 31, 2013), http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/dr_wkgrp/mtrls/2013/jul312013/index.html.

[55] ISO New England, *July 19, 2013, OP 4 Action 2 Initial Real-Time Demand-Resource Performance*, Demand-Resources Working Group presentation (July 31, 2013), http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/dr_wkgrp/mtrls/2013/jul312013/index.html.

load, which resulted in real-time LMPs being considerably higher than day-ahead LMPs at the New England Hub, load zones, and nodes over the peak hours. Real-time Hub LMPs exceeded day-ahead Hub LMPs by an average of $6.19/MWh over the day. The highest Hub price deviation was observed during HE 2:00 p.m., when the real-time LMP exceeded the day-ahead LMP by $226.73/MWh.

On September 1, in addition to the large deviations between the day-ahead and real-time LMPs at the Hub, unusual day-ahead price separation occurred at the Hub. Day-ahead LMPs at the Hub were higher than the load zone LMPs from HE 12:00 noon to 9:00 p.m. In these hours, the day-ahead LMPs averaged around $252/MWh, compared with the load zone LMP average of $112/MWh.

The price separation observed on September 11 between the Hub and the load zones is not typical. The Hub is comprised of nodes that are chosen in such a way that the congestion component of the LMPs at these nodes, compared with other nodes on the system, is minimal. Figure 2-8 shows the Hub and load zone LMPs observed on September 11. The figure shows that the day-ahead Hub LMPs were higher than any of the load-zone LMPs during HE 12:00 noon to 9:00 p.m.

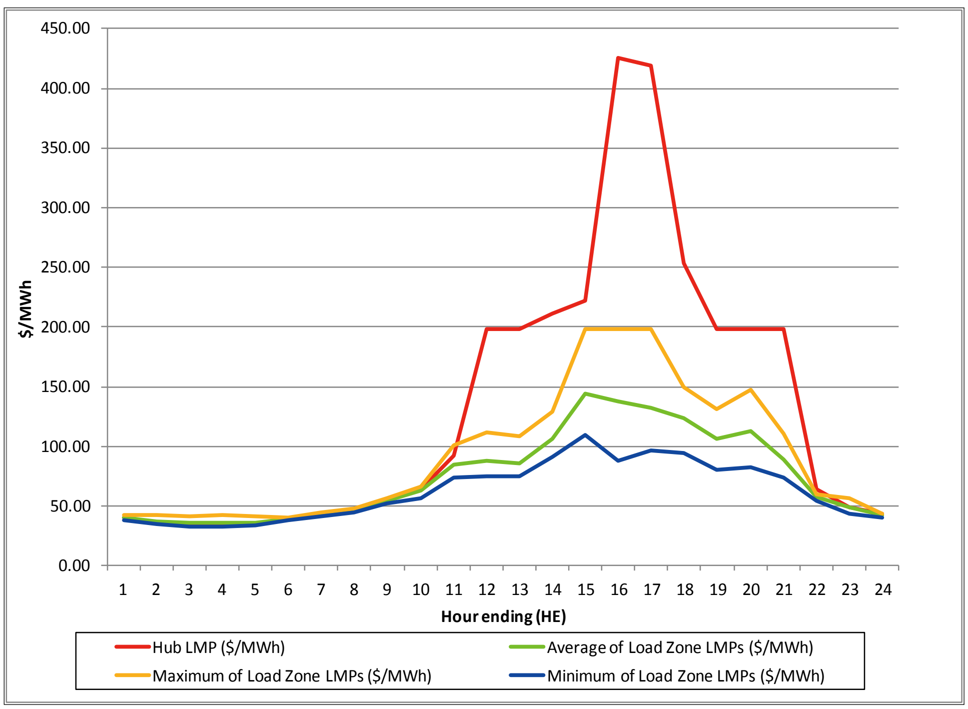

Figure 2-8: September 11, 2013, day-ahead hourly Hub LMPs, and average, maximum, and minimum load-zone LMPs ($/MWh).

The IMM reviewed the system and market conditions on September 11 and found that the market outcomes, while atypical, were consistent with the ISO's market rules, and were not the result of participant behavior intended to distort market outcomes.

A key component to understanding the price separation on September 11 is understanding how the Hub and load-zone price is derived. The Hub LMP is calculated as a simple average of the LMPs at the 32 nodes that make up the Hub, while load-zone LMPs are calculated as a weighted average of all the nodes within the load zone.[56] Because of this, a node that resides in both the Hub and a particular load zone can have different impacts on the Hub or zonal LMP.

In addition to understanding price derivation, it is important to understand the difference between how day-ahead demand bids within the Hub are allocated to the individual nodes in the Hub, compared with how the day-ahead bids at a load zone are allocated to the nodes within the zone. A demand bid at the Hub is similar to 32 separate demand bids at the 32 individual nodes that make up the Hub. The quantity included in the demand bid at the Hub is evenly divided by 32, and this simple average then becomes the quantity demanded at the individual nodes. In the load-zone LMP calculation, a demand bid at the load zone is distributed across the individual nodes on the basis of a load-weighted average. Collectively, as long as the cost of serving the quantity demanded at the nodes in a load zone or Hub does not exceed the cost of the demand bid at the load zone or Hub, the market-clearing engine will clear all, or the maximum possible quantity, of the demand bid at the Hub or load zones.[57]

On September 11, two transmission lines on planned outage affected four nodes within the Hub and the WCMA load zone. If the four constrained nodes did not have any demand or load, they would not have affected the LMP; however, price-sensitive demand cleared at the Hub and WCMA load zone. As a result, both the line outages and price-sensitive demand clearing at the Hub and WCMA load zone contributed to increased congestion at the Hub, WCMA load zone, and the four Hub nodes during HE 12:00 noon to 9:00 p.m.

Given that the Hub LMP is a simple average of all 32 nodal LMPs, these congested nodes had a sizeable impact on the Hub LMP (4/32 or 12.5%). The price impact of the four nodes was also observed in the WCMA load zone LMP; however, because the WCMA zone contains over 150 nodes and its LMPs are based on the weighted average nodal LMP, the impact was less severe (less than 3%).

December 14, 2013. On December 14, 2013, New England experienced unseasonably cold temperatures and snow, resulting in a capacity deficiency that led to binding reserve constraints. The curtailment of imports from Hydro-Québec into New England, coupled with the higher-than-forecast loads in the late afternoon and evening, resulted in the declaration of OP 4, Actions 1, 2, and 5, at 5:00 p.m. and an FCM shortage (see Section 3.4.3.4) event between 4:50 p.m. and 6:15 pm.

The penalties assessed from the shortage event totaled $6.6 million. The IMM further analyzed market conditions and performance on December 14, 2013, for the ISO's implementation of OP 4. Overall, the markets performed as expected, and most participants acted competitively. Several participants with off-line resources submitted supply offers that the IMM determined were noncompetitive, and, therefore, subject to the shortage-event penalties.

As part of the event, the ISO dispatched systemwide all RTDR resources with a positive net capacity supply obligation (CSO). The net CSO of the RTDR resources totaled approximately

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[56] *ISO New England Manual for Market Operations*, Manual M–11 (October 6, 2013), http://www.iso-ne.com/rules_proceds/isone_mnls/m_11_market_operations_revision_47_10_06_13.doc.

[57] The cost of the demand bid in at the load zone or Hub equals the price multiplied by the quantity demanded at the load zone or Hub.

248 MW.[58] On average, demand resources delivered approximately 77% of the total load reduction the ISO dispatched on December 14, helping mitigate the capacity deficiency on the system. By comparison, the performance of a December 19, 2011, winter OP 4 event also measured 77% of dispatch.[59] Overall, the demand-response performance discrepancies do not appear to be an attempt by market participants to manipulate market outcomes, but rather the consequence of the market rule that allows overperforming demand-response resources to receive an allocation of the penalties paid by underperforming resources.

The ISO filed, and FERC has accepted, market rule changes that conform the FCM rules addressing the participation and performance of demand-response resources in the capacity market to the new rules that fully integrate demand-response resources into the energy market.[60] A component of the FCM market rule changes will measure the performance of, and assess penalties for, demand-response resources using shortage-event availability in a manner comparable to generating and import capacity resources. This will eliminate the current market rule provision allowing overperforming demand-response resources to receive an allocation of the penalties paid by underperforming resources.

2.1.3.5 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 does the following:

- 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[61]
- 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 is not evaluated further for potential mitigation, while an energy offer that exceeds the applicable reference level plus the appropriate threshold is evaluated for 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

[58] The net CSO excludes the transmission and distribution factor added to demand-response resource capacity for FCM settlement purposes.

[59] See the ISO's *2011 Fourth Quarter Quarterly Markets Report* (February 21, 2012), http://www.iso-ne.com/markets/mkt_anlys_rpts/qtrly_mktops_rpts/2011/imm_q4_2011_qmr.pdf.

[60] ISO New England Inc., *Market Rule 1 Price-Responsive Demand FCM Conforming Changes for Full Integr*ation, Docket No. ER12-1627-000, FERC filing (April 26, 2012; effective date of June 1, 2017). FERC, Errata Notice (for Order on Proposed Tariff Revisions of January 14, 2013), Docket No, ER12-1627-000 (January 15, 2013), http://www.iso-ne.com/regulatory/ferc/orders/2013/jan/er12-167-000_1-15-13_errata_order_on_prd.pdf.

[61] 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.

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, or Net Commitment-Period Compensation (NCPC).[62] 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 calculation of LMPs does not use commitment costs, mitigation of commitment costs does not include a review of their impact on LMPs.

Table 2-6 shows all the mitigations for 2013. Some variations in the types of mitigations over time are consistent with changes in system conditions, such as high loads in June and July, leading to an increase in commitment mitigations. In December 2013, transmission line outages created import-constrained areas within the system. These import-constrained areas, coupled with higher natural gas prices, resulted in more units failing the tighter (50% or $25) constrained-area energy-mitigation conduct test and therefore, a larger amount of energy mitigations.

Table 2-6
2013 Day-Ahead and Real-Time Mitigations

Month	Commitment Mitigations	Energy Mitigations	Total
Jan	22	14	36
Feb	22	18	40
Mar	14	13	27
Apr	11	3	14
May	12	0	12
Jun	30	11	41
Jul	46	5	51
Aug	9	1	10
Sep	16	2	18
Oct	16	4	20
Nov	6	0	6
Dec	9	58	67
Total	213	129	342

[62] 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*, also referred to as *first-contingency 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.

2.1.3.6 Energy Prices and External Transactions

In 2013, 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 19,037 GWh for 2013, a 51% increase compared with the previous year. The increase in the net interchange is the result of both fewer exports and greater imports in 2013 compared with 2012. See Figure 2-9.

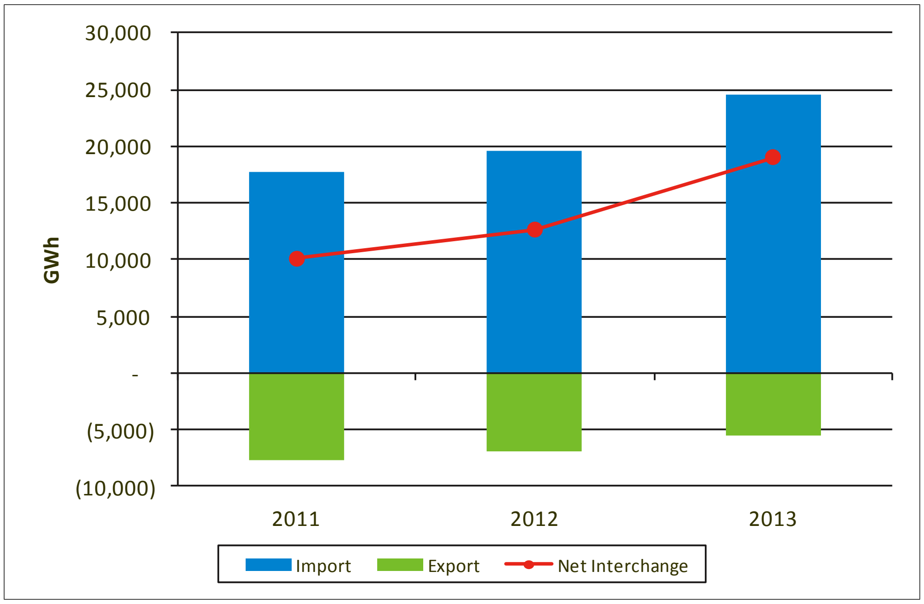

Figure 2-9: Scheduled imports and exports and net external energy flow, 2011 to 2013 (GWh).

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.[63] See Table 2-7.

[63] *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 2-7
Percentage of Time Transactions Are Scheduled in the Direction of the Higher Price on the Roseton Interface, 2011 to 2013

Year	Real-Time (%)	Day-Ahead (%)
2011	52	57
2012	52	57
2013	52	55

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.

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.[64] The IMM supports the ongoing efforts to implement CTS.

2.1.4 Availability, Commitment, Dispatch, and Performance of Natural-Gas-Fired Resources

New England's wholesale electricity market has become dependent on the availability of natural gas. Consequently, understanding the factors that influence natural gas and natural gas-fired power plant availability, commitment, dispatch, and performance was a major focus of the Internal Market Monitor's market surveillance and analysis activities in 2013. A number of forces influence the codependency between New England's natural gas and electricity markets:

- An influx of natural gas-fired generating capacity over the past 15 years
- An aging fleet of legacy oil- and coal-fired generators in the electricity market
- The decrease in natural gas prices with the increased production of domestic shale gas
- Relatively static gas pipeline capacity in New England that has had to accommodate a 37% increase in overall natural gas consumption since 1999; 95% of this 37% was for gas generation.[65]

The confluence of these forces has resulted in gas-fired generators generating a much higher proportion of electricity in New England, while pushing gas pipeline capacity to its limits during peak gas demand periods. As a consequence, ensuring the reliability of New England's wholesale electricity grid relies in part on the owners and operators of natural gas-fired

[64] 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.

[65] Approximately 12,000 of 14,000 MW of new capacity have come from gas-fired, combined-cycle generators. *ISO New England 2013 Regional Electricity Outlook*, p. 15 (2014), http://www.iso-ne.com/aboutiso/fin/annl_reports/2000/2014_reo.pdf. US Energy Information Administration (EIA), "Natural Gas Consumption by End Use," webpage (data for state-level and end-user natural gas consumption, 1999–2012) (March 31, 2014), http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_SCT_a.htm. Note that these data have not been weather normalized.

generators effectively managing their natural gas deliveries during contemporaneous periods of high gas and electric power demand.

This subsection discusses the general trends that have emerged from the IMM's review of natural gas infrastructure, constraints, and pricing, as well as natural gas generator risks, electricity supply obligations, commitment, dispatch, availability, and performance.

2.1.4.1 Gas Infrastructure, Constraints, and Pricing

New England has five interstate pipelines that transport natural gas into the region. The Tennessee and Algonquin pipelines enter New England through the state of New York, and extend through southern New England. The other interstate gas pipelines link Canadian gas supplies to the northeastern US gas markets:

- Iroquois brings gas from Ontario to New York and New England
- The Maritimes and Northeast pipeline extends along the eastern Canadian coast into Maine
- The Portland Natural Gas pipeline enters New Hampshire from Québec

See Table 2-8, which shows New England natural gas pipeline capacity.

Table 2-8
New England Interstate Natural Gas Pipeline Capacity (MMcf/d)

New England Interstate Gas Pipelines[(a)]	Capacity[(b)]
Tennessee Gas Pipeline	1,261
Algonquin Gas Transmission	1,087
Maritimes and Northeast Pipeline	833
Iroquois Gas Transmission	220
Portland Natural Gas Transmission[(c)]	168
Total	3,569

(a) Excludes the Granite State Gas pipeline, which does not extend outside of New England.

(b) Contract capacity, winter 2011/2012, in million cubic feet per day.

(c) FERC-certified capacity.

Source: ICF International, LLC, *Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Power Generation Needs*, PAC presentation public version (June 21, 2012), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2012/gas_study_public_slides.pdf.

The interstate pipelines have a combined capacity of approximately 3,500 MMcf/d to serve New England's residential, commercial, municipal, and industrial customers, as well as the demands of the region's natural-gas-fired power plants. During the peak winter period for natural gas demand, natural gas consumption can easily reach the capacity limits of the pipelines. For example, daily consumption during January 2012 averaged 92% of the capacity limit within the region.[66] High gas demand relative to pipeline capacity in New England has led to elevated natural gas pricing, compared with nearby regions.

Figure 2-10 shows the daily average basis for trading points in New York City and New England, relative to the Marcellus natural gas trading point over three winter periods. Like New England, the New York City area experiences gas pipeline delivery constraints and elevated natural gas pricing.

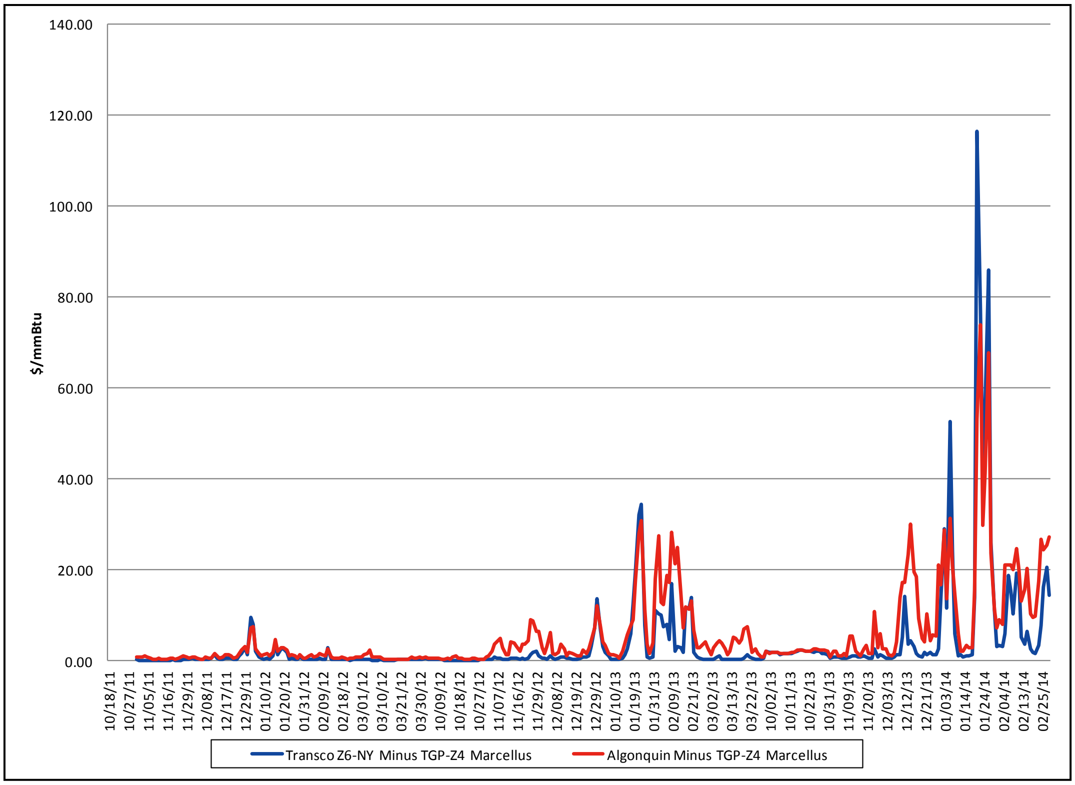

Figure 2-10: New York City and New England natural gas basis relative to the Marcellus Shale hub (daily, $/MMBtu).

Note: Summer periods are excluded in the graph because prices during these periods are less volatile due to a decrease in the demand for natural gas from residential and commercial heating customers. *Basis* refers to the difference between prices, for example: Algonquin Citygates price minus the TGP-Z4 Marcellus price.

The Algonquin trading point is reflective of natural gas prices within New England. The Transco Z6 NY trading point provides pricing for the New York City area, while the Marcellus trading point reflects natural gas prices in the Marcellus Shale region (a significant nearby gas basin that frequently has lower pricing than Henry hub). As Figure 2-10 indicates, during the current and just prior winter, areas in the northeastern US with gas pipeline constraints have been subject to very high natural gas prices and have experienced considerable price volatility. The significant separation in prices between the constrained areas and other nearby regions begins in November 2013 and extends through March 2014.

[66] EIA natural gas monthly consumption data (see above footnote) compared with pipeline capacity (ICF Gas Study, citation in Table 2-8). EIA data for winter 2012/2013 are not yet available.

Table 2-9 details this trend, showing the average day-ahead natural gas basis by month relative to the average prices for the Marcellus Shale region. New England wholesale gas customers often pay a significant premium for gas compared with nearby regions; this premium has been as great as 637% in a month. Moreover, the basis differential for New England has exceeded the basis for New York City in every month but one and has been about 50% higher over the entire period than New York City's basis.

Table 2-9
Monthly Average Gas Prices and Basis in Northeastern US Region, Given Gas Pipeline Constraints ($/MMBtu, %)[(a)]

Year	Month	Price	Basis			
		TGP Z4 Marcellus ($/MMBtu)	Transco Z6 NY ($/MMBtu)	Transco Premium %	Algonquin Citygates ($/MMBtu)	Algonquin Premium %
2011	Nov	3.32	0.21	6%	0.66	20%
	Dec	3.01	0.74	25%	1.15	38%
2012	Jan	2.59	1.97	76%	2.40	93%
	Feb	2.54	0.46	18%	0.99	39%
	Mar	2.09	0.27	13%	0.73	35%
	Oct	3.21	0.27	8%	0.55	17%
	Nov	3.34	0.73	22%	3.95	118%
	Dec	3.14	1.15	37%	2.60	83%
2013	Jan	3.14	7.04	225%	7.64	244%
	Feb	3.27	6.35	194%	13.72	420%
	Mar	3.72	0.51	14%	3.56	96%
	Oct	1.78	1.90	107%	2.11	119%
	Nov	2.78	0.94	34%	2.89	104%
	Dec	3.10	2.41	78%	10.43	337%
2014	Jan	3.51	27.46	782%	22.37	637%
	Feb	3.15	9.46	300%	18.21	578%

(a) Data were obtained from the Intercontinental Exchange: https://www.theice.com/marketdata/reports/ReportCenter.shtml?reportId=77#report/76.

2.1.4.2 Natural Gas Generator Risks and Electricity Supply Obligations

Currently, generators have two opportunities to submit supply offers in the wholesale electricity market: the day-ahead market and the real-time market. Generators are required to honor the terms of their supply offer (i.e., price and quantity) for the entire operating day. Because generators are required to submit supply offers before they know how much, if any, of their electricity will be purchased by the market, the operators of natural-gas-fired generators face price and quantity risk when procuring natural gas.[67] The price risk occurs because the generator could face higher day-ahead or spot natural gas costs than expected when

[67] Generators submit day-ahead energy market offers at 10:00 a.m., and the energy supply commitments for that market become available no later than 1:30 p.m. Generators that procure natural gas before 10:00 a.m. face quantity risk; their supply offers can reflect the price of natural gas, but the amount of gas they will need to meet their day-ahead schedule is unknown at the time of gas procurement. Generators that procure gas between 10:00 a.m. and 1:30 p.m. face both price and quantity risk because their offers cannot reflect the gas price they will pay, and the quantity of natural gas needed to satisfy a day-ahead commitment also is unknown. Generators that purchase gas after 1:30 p.m. have quantity certainty, but their Day-Ahead Energy Market offers (submitted by 10:00 a.m.) will subject them to price risk because they did not have gas price information when submitting the day-ahead offer.

formulating its supply offer for the Day-Ahead Energy Market, creating the possibility of receiving a day-ahead obligation to operate at a loss. When natural gas prices are volatile, predicting the natural gas price to include in the supply offer is more difficult and increases this risk. Generators that procure gas in the day-ahead natural gas market before receiving a commitment in the Day-Ahead Energy Market are at risk of over- or underprocuring the amount of natural gas they will need during the operating day. High and volatile natural gas prices also exacerbate this risk.

Generators must manage these supply risks, while meeting their supply-offer obligations in the ISO New England energy market. These obligations include restrictions against the economic and physical withholding of capacity, the need to follow the ISO's dispatch instructions, and the "must-offer" requirement for generators with capacity supply obligations.[68] These requirements focus on ensuring the efficient and reliable operation of the electricity market. To these ends, the ISO's tariff requires that generators follow the ISO's dispatch instructions with respect to starting, shutting down, or changing output levels, and maintain offer information concurrent with on-line operating information.[69] Likewise, generators that obtain CSOs through the Forward Capacity Market have agreed to offer capacity into the day-ahead and real-time markets, consistent with this obligation:

> "A Generating Capacity Resource having a Capacity Supply Obligation shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market at a MW amount equal to or greater than its Capacity Supply Obligation whenever the resource is physically available. If the resource is physically available at a level less than its Capacity Supply Obligation, however, the resource shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market at that level."[70]

A FERC order on capacity resource performance obligations issued in August 2013 has further clarified generator supply obligations:

> "[A] resource with a Capacity Supply Obligation must offer a MW amount equal to or greater than its Capacity Supply Obligation into the day-ahead and real-time energy markets when that resource is physically available, and those offers must remain open through the operating day for which the supply offer is submitted. Given that the exceptions to performance for physical unavailability, Forced Outage or Force Majeure are not applicable when a resource owner declines to purchase fuel due to price considerations, the Commission finds that a capacity resource that fails to comply with dispatch instructions when it is physically available but has determined not to procure fuel or transportation due to economic considerations is in violation of the Tariff."[71]

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68 See Appendix A, *Market Rule 1*. For the latter two obligations, the ISO offered guidance to generators explaining tariff obligations. See the ISO's "Memo to the NEPOOL Markets Committee," Subject: Market Participant Performance Obligations, Markets Committee meeting materials, second set (November 5, 2012), http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2012/nov782012/index.html.

69 *Market Rule 1*, Section III.1.7.20(b).

70 *Market Rule 1*, Section III.13.6.1.1.1.

71 FERC, *Order on Complaint*, *New England Power Generators Association*, Docket EL13-66-000 (August 27, 2013), p. 23, paragraph 58, http://www.iso-ne.com/regulatory/ferc/orders/2013/aug/el13-66_8-27-13_order_nepga_complaint.pdf.

This order also states that an inability to physically obtain fuel is tantamount to being physically unavailable, and constitutes an exception to the must-offer requirement of tariff.[72] While the litigation was prompted by concerns about natural gas-fired units, the obligations apply to all resources. As required by FERC as part of this order, the IMM has issued a list of factors it will use in evaluating whether or not resources have met their obligations.[73] Based on its experience in applying the list of factors since they were developed in fall 2013, the IMM is supplementing these factors with the following principles it will use in determining whether resources with a CSO have met their tariff obligations with respect to fuel procurements:

- Generators are obligated to purchase fuel if it is physically available.
- Physical availability for gas units involves assessing the pipeline system conditions and resource owner actions in the day-ahead and real-time nomination cycles.
- A review of whether an oil or coal generator had fuel physically available includes reviewing the resource's inventory and replenishment plans. Under the FERC orders on generator obligations and under the lower Good Utility Practice standard advocated by generators, resources are obligated to have sufficient oil in their tanks to meet their obligations to offer into the day-ahead market and operate in accordance with their offers. An oil generator with insufficient oil in its tank that failed to operate when dispatched would not be excused from meeting its obligation because oil was physically unavailable on the day when the dispatch order was given.
- If replenishment becomes difficult because of physical constraints (e.g., ice or river constraints preventing barges from reaching the generator), a resource's use of the limited-energy generator (LEG) option to manage the remaining fuel inventory would be appropriate.[74]

2.1.4.3 Gas-Fired Generator Commitment and Dispatch

This section provides data that highlight the impact of high natural gas prices on gas-fired generator offers and the resulting commitment and dispatch of these generators. These are instances where gas-fired generators obtain a less advantageous position in the commitment and dispatch economic merit order because of increased fuel prices. This subsection addresses fuel switching, fuel-price adjustments (FPAs), and intermarket friction, which illustrate the seasonality, magnitude, and economic trade-offs from high natural gas prices.

Fuel Switching. Dual-fuel generators have the ability to switch between fuels on a day-to-day basis or, for some units, during the same operating day. The term *fuel switching* refers to the process of dual-fuel generators informing the IMM that they intend to operate on a particular

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[72] FERC, *Order on Complaint,* (August 27, 2013) p. 22, paragraph 56, states that if a capacity resource cannot procure fuel or transportation in real time to run at dispatch levels beyond its day-ahead commitment (or when not scheduled in the day-ahead market), the resource is not physically available to perform for a reason beyond the resource's control for either or both those additional hours or incremental megawatts; thus, the resource may be excused for nonperformance.

[73] ISO New England, "Factors the Internal Market Monitor Considers in Evaluating Physical Availability of Fuel for Generating Resources" (September 27, 2013), http://www.iso-ne.com/markets/mktmonmit/rpts/other/factors_imm_considers_in_eval_physical_avail_of_fuel_for_gen_res.pdf.

[74] The tariff, Section I, defines a *limited-energy resource* as a generating resource that, due to design considerations; environmental restriction on operations; cyclical requirements, such as the need to recharge or refill or manage water flow; or fuel limitations, is unable to operate continuously at full output on a daily basis. See http://www.iso-ne.com/regulatory/tariff/sect_1/sect_i.pdf.

fuel source and requesting the IMM to calculate their "reference" price used in supply-offer mitigations based on their chosen fuel for the operating day (i.e., basically to reflect the generator's use of a higher-cost fuel).[75] Such notifications indicating that the generator will not be using the least-cost fuel options when formulating its supply offer often occur when a generator has limited supply for natural gas when it is the lower-cost fuel, or the generator has limited oil in its inventory and oil is the lower-cost fuel.

The IMM began tracking fuel-switching notifications in mid-2011.[76] Each unit may request a fuel switch for each day. The total number of fuel-switching requests has increased from 2,427 in 2012 to 2,566 in 2013. Nearly 93% of the requests to switch to a higher-cost fuel were made on days when oil prices exceeded gas prices.[77] The IMM has observed a high degree of seasonality in these notifications and a steady increase in the number of these notifications during the winter months. See Figure 2-11.

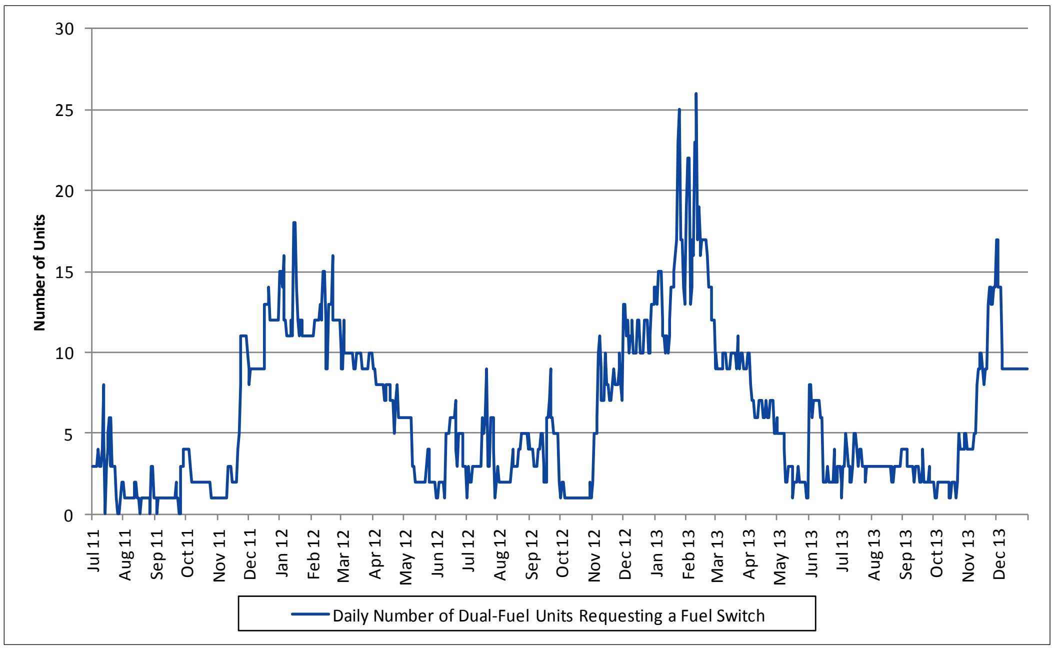

Figure 2-11: Daily number of dual-fuel units requesting a fuel switch, July 2011 to December 2013.

The IMM also analyzed the amount of generation by the assets providing fuel-switching notifications. Compared with all dual-fueled units, fuel-switching units are less likely to be economic because, by definition, their offers reflect the more expensive fuel. As indicated in Figure 2-12, which compares the performance of all dual-fuel generators to those that switched to higher-priced fuel, the fuel-switching generators provided considerably less generation to the market (about 1 GWh average daily generation) than their dual-fuel cohort (about 31.7 GWh average daily generation).

[75] The reference levels are used in the tests the IMM performs to determine whether a generator's supply offer should be mitigated to prevent the exercise of market power. The reference price typically assumes a generator will operate using the lower-cost fuel. The IMM calculates generator reference levels every day.

[76] The IMM observed 700 fuel-switching requests in 2011.

[77] A total of 4,621 of the fuel-switch notifications were requests to switch from gas to oil.

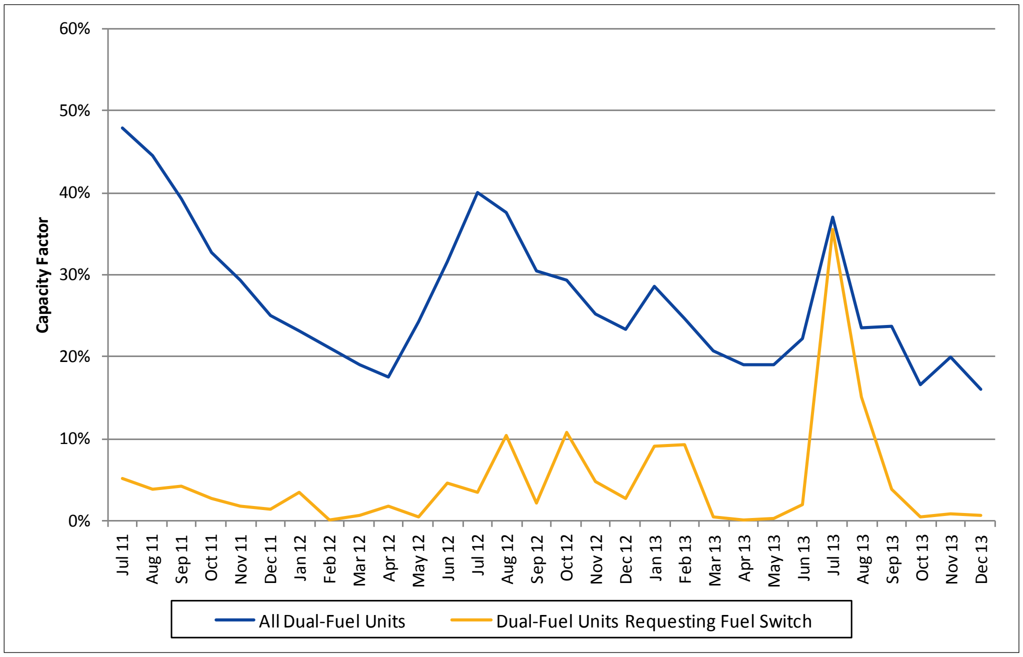

Figure 2-12: Monthly capacity factor of dual-fuel units, July 2011 to December 2013 (%).

The average monthly capacity factor for fuel-switching generators has been approximately 5%, significantly less than the average monthly capacity factor of 27% for all dual-fuel capable units. The capacity factor for fuel-switching units was highest during the summer months of 2013.

Fuel-Price Adjustments. If a generator's supply offer is mitigated to prevent the exercise of market power, the financial parameters of its reference level replace the financial parameters of its supply offer. The IMM calculates the daily generator reference levels using publically available fuel-price indices. For natural-gas-fired generators, the IMM uses the Intercontinental Exchange's (ICE) next-day gas index prices for New England trading hubs (e.g., Algonquin Citygates hub). However, given regional natural gas supply uncertainty and the resultant volatile and high gas prices, gas-fired generators may expect to purchase natural gas at price levels different from the published index prices. Gas generators can request an FPA so that the IMM's evaluation of their supply offers at a different gas price will be based on their individual expectations about gas costs. The most common reasons for assets to request fuel-price adjustments are as follows:

- Timing differences between the gas day and the electricity day[78]
- Illiquidity at some trading hubs
- Differences between next-day and same-day gas prices
- Price uncertainty associated with illiquidity for next-day and same-day gas trades

[78] The current gas day begins at 10:00 a.m. of the current calendar day and extends to 10:00 a.m. of the following calendar day. The electricity day is the same as a calendar day. Therefore, each electricity day bridges two gas days: the first 10 hours of the electricity day (from 12:00 a.m. to 9:59 a.m.) represent the last 10 hours of the preceding gas day; the last 14 hours of the electricity day (from 10:00 a.m. to 11:59 p.m.) are the first 14 hours of the current gas day.

The IMM analyzed requests for gas FPAs received between November 2012 and January 2014.[79] Figure 2-13 shows the number of requests by week for the study period. During this period, the IMM received 4,298 requests for FPAs. Overall, 71 assets, with a combined capability of 15,180 MW, requested at least one fuel-price adjustment during this period. On average, more than nine requests were made per day. More than half of the requests occurred during the winter months of December, January, and February, with January 2014 alone accounting for more than 1,000 requests.

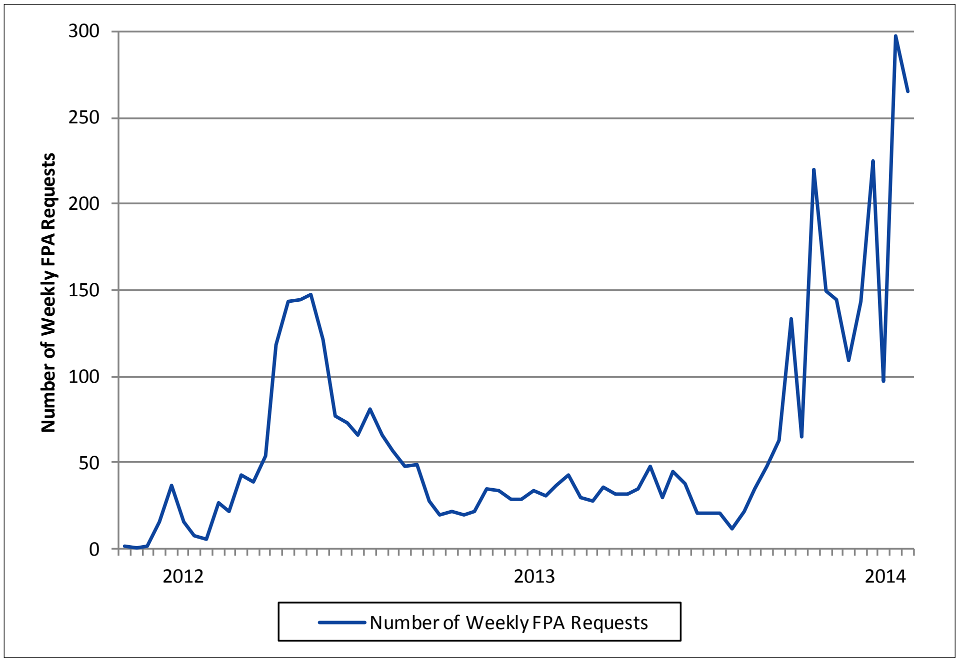

Figure 2-13: Number of assets requesting fuel-price adjustments by week, November 2012 to January 2014.

Figure 2-14 shows the daily energy generated by assets requesting fuel-price adjustments between November 2012 and January 2014 as a percentage of the daily energy generated by all assets. The assets requesting FPAs generated about 11 GWh of energy daily (about 3% of total daily energy) on average. The highest amount of electricity generation (96 GWh) by FPA-requesting assets was observed on December 10, 2013. On this day, the FPA-requesting assets accounted for about 25% of the total daily energy served. The winter months of December, January, and February accounted for more than 68% of the total energy produced by the FPA-requesting assets during the study period. Generally, the amount of generation by the FPA-requesting units tracked well with the number of FPA requests. There was a strong positive correlation (more than 80%) between the number of FPA requests and the energy generation by FPA-generating assets.

[79] Generator requests for FPAs began in November 2012.

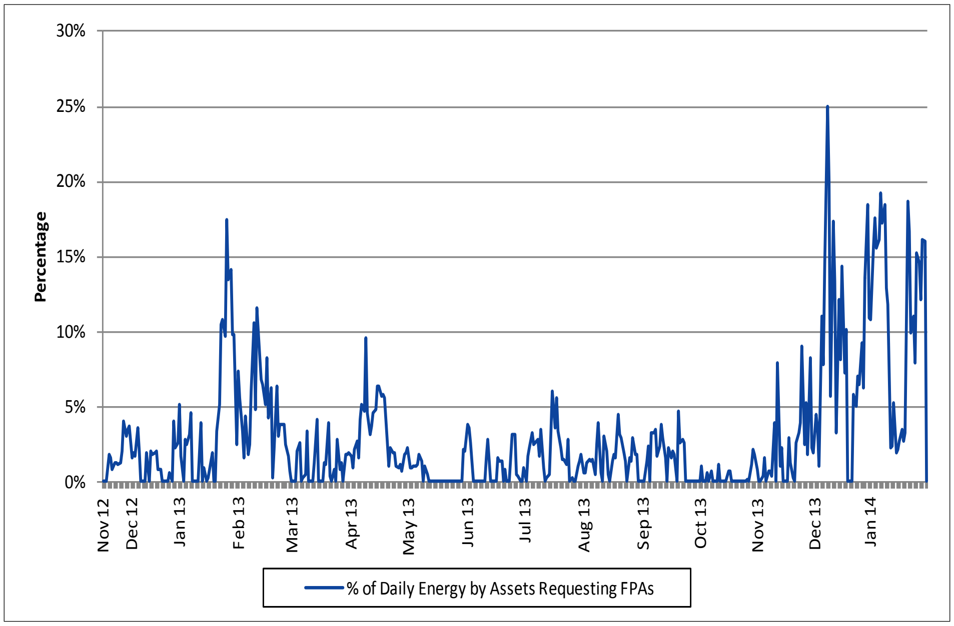

Figure 2-14: Percentage of daily energy by assets requesting FPAs, November 2012 to January 2014.

Intermarket Friction. Because of the different timelines for the gas and electric power markets, gas-fired generators can face considerable fuel volume and price risk at 10:00 a.m., when they need to submit their offers into the day-ahead market. The trading of next-day gas can be limited at this time, and consequently, price discovery can also be limited. Under current gas market trading, most of the gas trades occur after 9:30 a.m., while the day-ahead market offers are due by 10:00 a.m. By the time the day-ahead market schedules are published (typically at 1:00 p.m.), the deadline for submitting nominations in the gas sector's timely nomination cycle has passed. The gas-fired generators are consequently exposed to an intraday gas price risk.

Because limited gas trading has occurred before 9:30 a.m., the IMM allows gas-fired generators to reflect their expected fuel cost in the IMM's reference price for that generator; while FPAs help alleviate price-mitigation risk, a higher fuel cost generally means higher energy offers, which makes these generators less likely to run. Generation that may have been produced if not for the FPA can be considered a measure of the impact that the disconnection between the gas and electric market has on natural gas generation. For this analysis, the IMM refers to the decline in generation from resources that submit fuel-price adjustments as a measure of *intermarket friction*. The IMM evaluated the impact of FPAs on generator output and concluded that, as expected, FPA-requesting units typically produced less energy compared with similar units that did not request an FPA.

The study, which covered February 2013 to January 2014, was conducted on a subset of gas-fired generators within New England that have similar physical characteristics. The assumption was that, except for an FPA, these generators could be expected to have similar commitment and dispatch patterns.[80] The units without FPAs were treated as a control group. The pool of

[80] Units that were off line and unavailable for dispatch (i.e., units in Unit Control Mode 1) were excluded from this analysis.

selected generators was large enough to compensate for random impacts. Twenty-three gas units with similar characteristics were selected.[81] The total winter capability of these units was 8,102 MW, and the total summer capability was 7,248 MW. Figure 2-15 provides an overview of the FPA usage level for the group of study generators, which was higher in winter when gas price volatility was high.

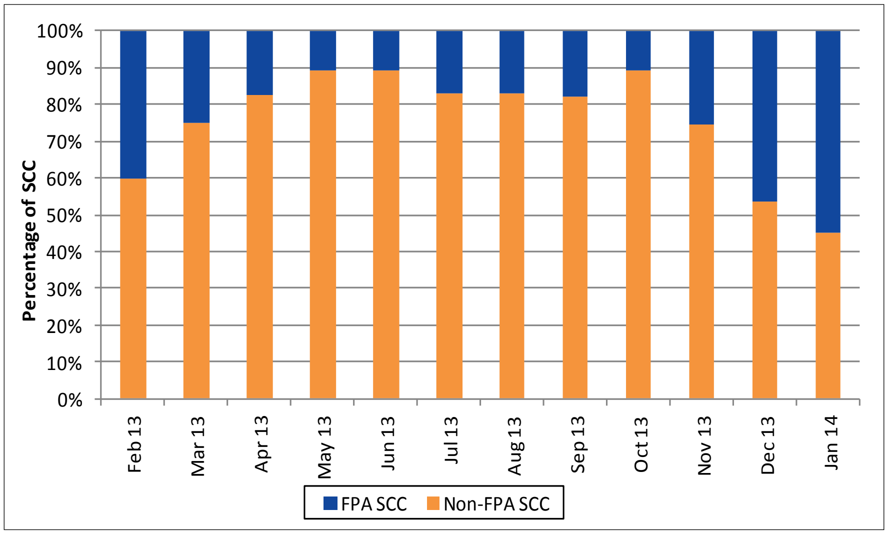

Figure 2-15: FPA participation from study generators, as measured by seasonal claimed capability (SCC), February 2013 to January 2014 (%).

Figure 2-16 compares the megawatt-weighted offer price of gas-fired generators with and without FPA requests. Generators requesting an FPA consistently had higher-offer pricing than the similar non-FPA generators.

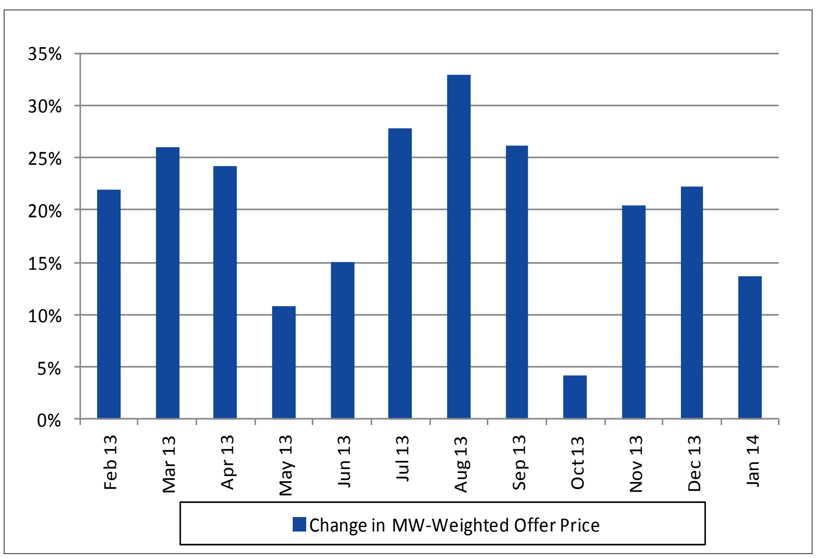

Figure 2-16: Offer-price change of FPA-requesting units compared with control units, February 2013 to January 2014 (%).

[81] The criteria for the generators were that they were built between 1999 and 2011, used combined-cycle technology and natural gas as the primary fuel, and had a heat rate between 7,000 and 8,000 Btu/kWh.

Figure 2-17 compares the capacity factors of the two cohorts of generators. Because of the higher offer prices of the FPA-requesting generators, their lower capacity factors compared with the control group generators was anticipated.

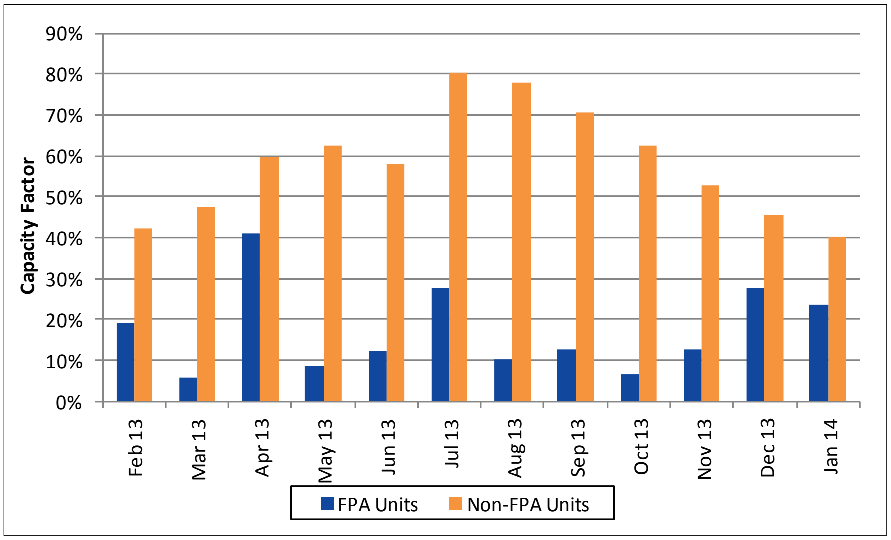

Figure 2-17: Capacity factor by FPA status, February 2013 to January 2014 (%).

On average over the study period, 25% of the capacity from the selected generators requested FPAs. This statistic reached a peak in January 2014, when 55% of the capacity from the selected generators used FPAs. On average, generators with FPA requests offer 20% higher than the counterpart generators without FPA requests. This higher-offer pricing led to a drop in these units' capacity factors. The average capacity factor for units with FPA requests was 19% over the study period, compared with 60% for non-FPA generators. The missing output due to intermarket friction has been calculated as the difference between the metered generation and the generation that would have been produced had the FPAs not been needed.[82] The daily average missing output due to intermarket friction was 13,339 MWh, or 16% of total generation.

These results indicate the market has had to purchase higher-cost generation because of the lack of coordination between the gas and electricity market. If the two markets were perfectly aligned, it would not be necessary to include a risk premium within the offer. The electricity market would benefit from better coordination by purchasing power from the more economic gas units.

2.1.4.4 Gas-Fired Generator Availability

This section reviews the times when gas-fired generators are not physically available. These periods may result from gas-fired generators' either lacking physical access to natural gas or

[82] The measure of missing output due to intermarket friction is calculated under the assumption that if those units did not submit FPA requests, they would have the same capacity factor as the control group. Therefore, the formula of missing output due to intermarket friction is as follows:

$$\text{Missing Output} = \text{Non-FPA Capacity Factor} \times \text{FPA SCC} - \text{FPA Metered MW};$$

where the capacity factor is calculated as:

$$\text{Non-FPA Capacity Factor} = \text{Non-FPA Metered MW/Non-FPA SCC}.$$

failing to procure natural gas when gas prices are high, which, as noted earlier, may increase both price and quantity risks for gas-fired generators. This part addresses the following topics:

- Gas-fired generators' use of the limited-energy generation feature
- Real-time limited-energy generation
- Generator reductions resulting from gas-availability issues

Gas-Fired Generators' Use of the Limited-Energy Generation Feature. The current market rules allow participants to submit supply offers in a way that limits the energy output of their resource in both the Day-Ahead Energy Market and Real-Time Energy Market. Participants with resources that have limited fuel can specify the maximum amount of energy (MWh) the resource can produce in a day through the provision in the rules addressing limited-energy resources. The LEGs market rule was intended primarily for hydroelectric generators, but the tariff wording allows any resource with limited fuel to offer in this way.

Because of the region's increased reliance on natural gas and the challenges that its dependence on natural gas has created, the IMM analyzed the use of the LEG feature by gas-fired and dual-fuel (gas-/oil-fired) capacity resources. By offering as a limited-energy resource, a participant can limit the resource's Day-Ahead Energy Market obligations, as well as how its gas-fired resource operates in the Real-Time Energy Market. The use of the LEG feature is one way in which generators with fuel limitations or other fuel-management restrictions can manage the risks that exist under the current energy market design that employs a single-pricing system (i.e., one offer in effect for the entire market day).

In the Day-Ahead Energy Market, a participant can offer a nonzero, positive "maximum daily energy" (MDE) value as part of a resource's supply offer. The MDE sets the total energy (MWh) available for an operating day from that capacity resource. The total available energy is optimized over the entire day to maximize social welfare. In this analysis, the MDE value is said to be "limiting" when it precludes the generator from satisfying a capacity supply obligation in all 24 hours of the day. Generators with CSOs are required to offer, for each hour of the operating day, an amount of generating capacity at least equal to the CSO. Thus, an offered MDE value that is less than the CSO × 24 indicates that the generator would be unable to supply its full CSO for all 24 hours of the day.

The example in Table 2-10 examines the availability of two gas-fired generators "A" and "B," each with a CSO of 100 MW. Generator A entered an MDE of 2,400 MWh, which is equal to the unit's CSO × 24 hours. This means that Generator A would be able to operate up to its CSO for the entire operating day. Generator B entered an MDE value of 1,400 MWh, preventing it from operating at its CSO for the entire operating day. Generator B has limited its available total daily energy to 58% of its CSO through the use of a limiting MDE. The 58% availability score does not indicate that only 58% of Generator B's CSO (or 58 MW) is available for any given hour of the day. Rather, Generator B's daily total available energy of 1,400 MWh will be optimized over 24 hours, meaning that the generator could run at its CSO for 14 hours of the day or operate at a lower output over more hours of the day if it were economic to do so.

Table 2-10
Example of Limiting Maximum Daily Energy

	MDE (MWh)	CSO X 24 (MWh)	Availability
Generator A	2,400	2,400	100%
Generator B	1,400	2,400	58%

Table 2-11 details the monthly availability of resources that offered a limiting MDE for June 1, 2010, to December 31, 2013, for the Day-Ahead Energy Market.[83] Specifically, this measure calculates the total monthly available energy from resources with limiting MDE values, as a percentage of these same resources' total obligation over the month.[84] This is the same calculation as used for Generator B in Table 2-10 for all generators with a limiting MDE over a month. As Table 2-11 shows, the amount of restricted energy from limited MDEs in the day-ahead market exhibited seasonality. Most of the restrictions occurred in the winter months when gas generators face more price and quantity risk in the gas market.

Table 2-11
Day-Ahead Availability of Units with Limited MDEs, June 2010 to December 2013 (%)

Month	2010	2011	2012	2013
January	-	63	68	66
February	-	64	72	58
March	-	66	74	63
April	-	73	71	73
May	-	75	72	70
June	81	74	70	73
July	79	72	80	82
August	80	76	84	82
September	80	74	80	80
October	79	78	84	76
November	66	77	75	71
December	63	64	68	69

To measure the amount of energy not offered into the day-ahead market because of limiting MDEs, Figure 2-18 illustrates the difference between the daily average energy available from gas-fired capacity resources with limiting MDEs and the daily average energy that would have been available from these resources had they not been limited. For example, in December 2013, the daily average offered MDE from resources with a limited MDE was 35,586 MWh. Had the energy been fully available from these resources, the expected average offered energy for the day would have been 51,588 MWh. The difference between these two numbers (16,002 MWh) represents the energy that was not available in the day-ahead market due to limiting LEGs. This is the energy equivalent of a 667 MW capacity resource not offering into the day-ahead market

[83] The analysis includes gas-fired and dual-fuel (gas-/oil-fired) units and excludes weekend days. June 2010 was selected as the start state because units did not have FCM obligations before that date.

[84] The IMM is unable to determine whether a generator offered a limiting MDE because of a restricted supply of natural gas or because the generator simply chose to offer in an MDE as a way to manage how much fuel it would need to purchase to support a day-ahead obligation. In both cases, the generator's total energy available to the energy market was limited.

for all hours of the day. Sixteen to 40 gas-fired capacity resources per month between June 2010 and December 2013 entered a limiting MDE in the New England day-ahead market, with an average of approximately 27 resources per month.

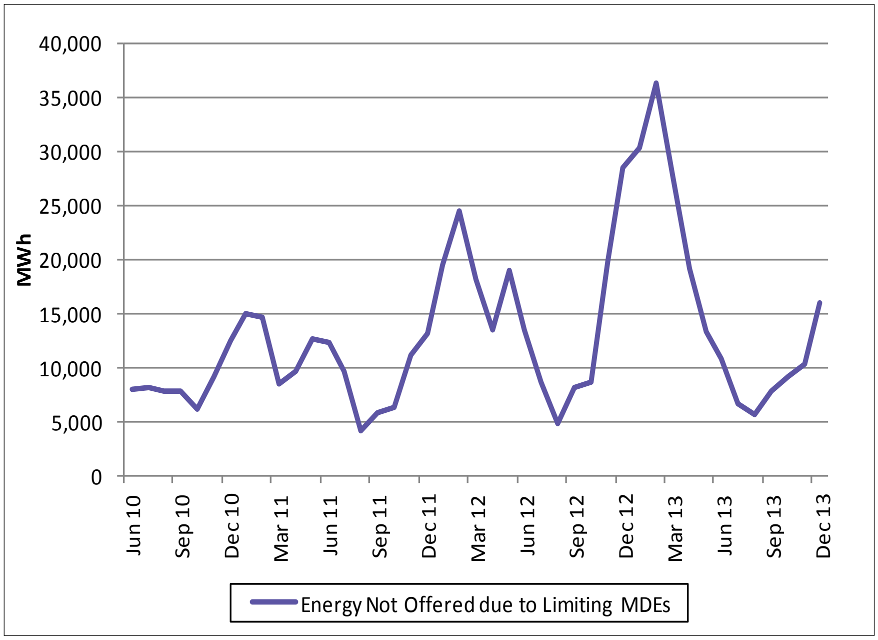

Figure 2-18: Energy not offered because of limiting MDEs, June 2010 to December 2013 (MWh).

To this point in the analysis, only the reduction in the amount of energy offered into the day-ahead market had been examined. The next step was to determine whether the reduced amount of energy offered resulted in the market purchasing less than it would have purchased had the resource not submitted a binding LEG offer. In many cases, generators with limiting MDEs do not clear 100% of their total energy because they are not part of the least-cost reliable solution for clearing in the day-ahead market, regardless of the energy constraint. Generators not clearing 100% of their limiting MDEs are less likely to have an impact on day-ahead market prices because the market would not have purchased any additional energy from these generators regardless of the MDE value. However, when a generator has a limiting MDE and then clears 100% of that limited energy, the LEG is said to be binding and has an impact on the day-ahead market.

Table 2-12 examines Generators "C" and "D," both of which have a CSO of 200 MW and MDEs of 3,000 MWh. Although both generators offered a limiting MDE of 3,000 MWh, each generator cleared different amounts of energy in the market. Generator C cleared 67% of its energy, meaning that the MDE did not affect the amount of energy cleared. However, Generator D entered a limiting MDE and cleared 100% of that MDE, meaning the market may have purchased more energy from that unit but was unable to do so because of the unit's energy constraint.

Table 2-12
Example of Binding MDE

	MDE (MWh)	CSO x 24 (MWh)	Cleared Energy (MWh)	% Cleared	Market Impact
Generator C	3,000	4,800	2,000	67%	No
Generator D	3,000	4,800	3,000	100%	Yes

In the New England day-ahead market, the energy cleared from binding MDEs between June 2010 and December 2013 was small, ranging from 1% to 11% of day-ahead cleared generation. On average, 4% of the energy cleared in the day-ahead market was energy from capacity resources with binding MDEs. See Figure 2-19.

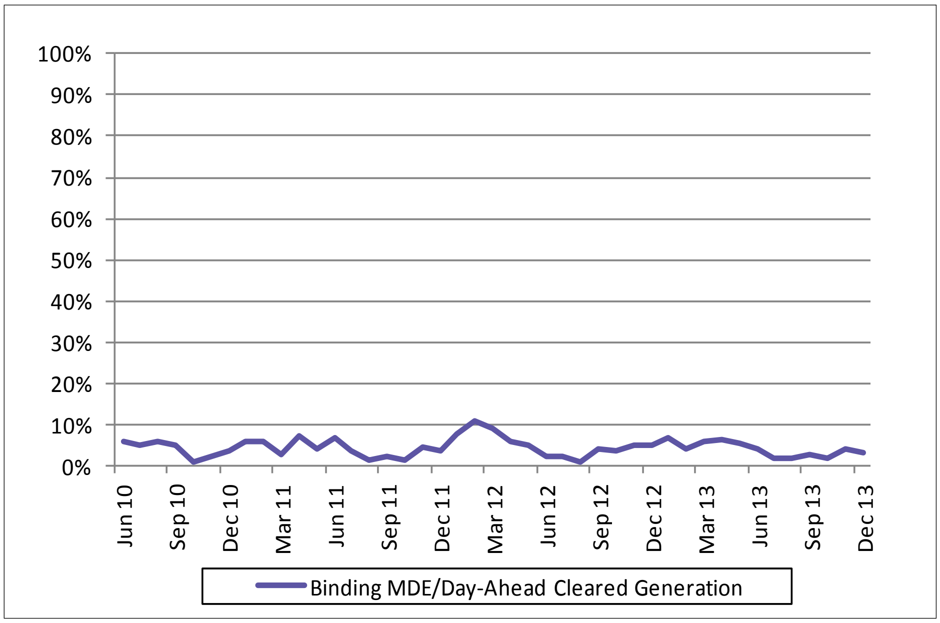

Figure 2-19: Binding MDEs as a percentage of day-ahead cleared generation, June 2010 to December 2013.

Real-Time Limited-Energy Generation. Only those resources that entered an MDE in the day-ahead market have the option to call the ISO and activate the LEG option in the real-time market. This option allows the resource to request to be operated at a specified hourly output level. Real-time LEG activity of gas-fired capacity resources has been a small percentage of real-time energy and small compared with the energy from limiting MDEs in the day-ahead market. Real-time LEG energy from gas-fired capacity resources as a percentage of net energy for load ranged from 0.04% to 1.94% per month with an average of 0.89% between June 2010 and December 2013. Similarly, the number of resources that chose to use the real-time LEG option was also small relative to the number of resources that offered a limiting MDE in the day-ahead market, ranging from two to 12 resources per month between June 2010 and December 2013.

Generator Reductions Resulting from Gas-Availability Issues. The ISO has observed operational and gas-availability issues stemming from gas-fired generators' notification to the ISO regarding gas supply limitations. Table 2-13 summarizes the instances by time of day, and the IMM's observations, when gas generators either reduced output or were unable to come on line.

Table 2-13
Gas Generator Reductions by Time of Day and IMM Observations

Time Period	2009–2012 Number of Events[(a)]	%	2013 Number of Events	%	IMM Observations
Midnight–5:59 a.m. (prior gas day)	26	15%	10	34%	These events may involve resources that were asked to come on line as part of the reserve adequacy analysis (RAA) in addition to those resources called on because of the loss of generation or a transmission line.[(b)]
6:00 a.m.–9:59 a.m. (prior gas day)	29	17%	12	41%	These events generally involve resources called on line to meet the morning increase in load. These may be resources asked to come on line or units ordered to extend their runs past their day-ahead schedules. During this period, resources may be forced to come off line or face large penalties from the pipeline for drawing more gas than nominated during the gas day.
10:00 a.m.– 5:59 p.m. (current gas day)	54	32%	4	14%	These events generally involve resources called on line or requested to extend their runs past their day-ahead schedules to meet unanticipated load or to address a contingency.
6:00 p.m.–11:59 p.m. (current gas day, but after the evening nomination cycle for gas)	62	36%	3	10%	These events are likely because the ISO asks resources that have not nominated gas in the day ahead to come on line as part of the RAA. This includes off-line resources, as well as resources whose day-ahead market schedule was extended in the RAA.
Total	**171**	**100%**	**29**	**100%**	

(a) For this analysis, the *number of events* refers to the number of instances the ISO logged a gas unit's report of needing 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 were counted as one event.

(b) Each day after the clearing of the Day-Ahead Energy Market, the ISO performs an RAA, and if necessary, commits additional resources above those committed day ahead to meet capacity and reserve requirements; refer to Section 2.1.6.3. This analysis is repeated throughout the operating day as necessary.

This table is consistent with the operational problems discussed above. Over 70% of the reductions that took place in 2009 through 2013 occurred after the close of the evening nomination cycle for gas, which is 6:00 p.m., and before the beginning of the next gas day, which is 10:00 a.m. After the evening nomination cycle, 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 the failure by gas generators to arrange for gas procurement overnight, before the gas will be needed. 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 appears most acutely between midnight and 10:00 a.m. when the new electric power day has begun but the next gas day has not yet started.[85] The table also shows that while fewer events occurred in 2013 overall, on average, more events occurred in 2013 during the midnight to 10:00 a.m. period when obtaining natural gas is difficult but when generators need to prepare for and meet the morning load.

Table 2-14 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.

Table 2-14
Natural Gas Generator Reduction Events by Season, December 2009 to December 2013

Year	Spring	Summer	Fall	Winter[(a)]
2010	2		2	10
2011	5	5	10	83
2012	0	17	25	7
2013	7	1	0	25
2014	n/a	n/a	n/a	1[(b)]
Total	**14**	**23**	**37**	**126**

(a) In this analysis, "winter" includes the previous year's December (e.g., winter 2012 includes December 2011, January 2012, and February 2012.)

(b) Includes December 2013 only.

As shown in Table 2-15, only 29 gas-reduction events were observed in 2013, down from a high of 89 events in 2011. The decline in reduction events in 2013 is coincident with the FERC orders clarifying the obligations of resources to procure fuel and with the change in the day-ahead market timeline. In fact, only two gas reduction events occurred in 2013 after the change in the market timeline. The decline in gas generator reductions may also be due to system operators' improved understanding of the region's gas pipeline and gas markets, which reduces the likelihood that resources unlikely to have fuel will be dispatched.

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[85] 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, the gas system tends to be less flexible. (Also refer to the fuel-price adjustment section above for more information on the differences between the "gas day" and "electricity day.")

Table 2-15
Natural Gas Generator Reductions by Year, December 2009 to December 2013

Year	Number of Reductions
2009	1
2010	32
2011	89
2012	49
2013	29
Total	200

Conclusions and Recommendations. The IMM has formed the following conclusions from its review of the impact of natural gas pricing and risk issues on the New England electricity markets:

- The use of the tariff's limited-energy resource (or LEG) provisions by gas-fired generators results in a reduction of the potential energy available to the ISO's energy markets, but only a small amount of this limited energy is binding when clearing the day-ahead market.
- Within a market that employs a single-pricing system, the use of the LEG provisions could be used to manage risks associated with fuel management in the day-ahead market.
- As expected, the high natural gas prices observed in New England can result in the less economic commitment and dispatch of gas-fired generators compared with generators using other fuels. In particular, when natural gas prices become higher than fuel oil prices, fuel oil generators will displace gas-fired generators in the commitment and dispatch order. This displacement places more demands on fuel oil generators to maintain adequate oil inventories throughout the winter months.
- To the extent that fuel oil generators have CSOs and have limited inventories of fuel oil, these generators may have difficulty meeting the FCM obligations and may be incented to limit output through binding LEGs or self-scheduling.

The limited-energy generator feature permits generators to manage fuel limitations under the current single-pricing system. To ensure that the use of the LEG provisions in both the day-ahead and real-time markets are restricted to instances when the availability of fuel is physically limited, the IMM recommends modifying the market rules as necessary when hourly markets are introduced and resources can change their offers on an hourly basis. This view of the use of the LEG provisions is consistent with FERC's August 27, 2013, order clarifying generator obligations: generators may only limit availability when the physical supply is restricted; reductions in availability for economic considerations, such as simply choosing not to purchase sufficient fuel to follow dispatch signals, are incompatible with the requirements of the tariff.[86]

2.1.4.5 Gas-Fired Generator Performance in the Real-Time Energy Market, Given a Day-Ahead Schedule

The gas-reduction events discussed above indicate that on several days within a year, gas-fired generators cannot meet the ISO's schedules and dispatch instructions. On these days, generators lacking gas and unable to follow ISO instructions may significantly affect reliability. This section reviews the average, aggregate ability of gas-fired generators to meet their day-ahead schedules in real time in light of gas pricing and availability issues. The section also discusses the IMM's analysis of the changes made to the energy market timeline.

Performance of Day-Ahead Committed Gas-Fired Units. On average, 96.4% of the real-time generation obtained from gas-fired units was committed in the day-ahead market. In the real-time market, the noncommitted gas-fired generators have provided a relatively small amount, 3.6%, of the total generation from gas-fired units. Figure 2-20 shows the performance of day-ahead committed gas-fired units. On average, these committed gas-fired units produced approximately 100% of their day-ahead scheduled generation.

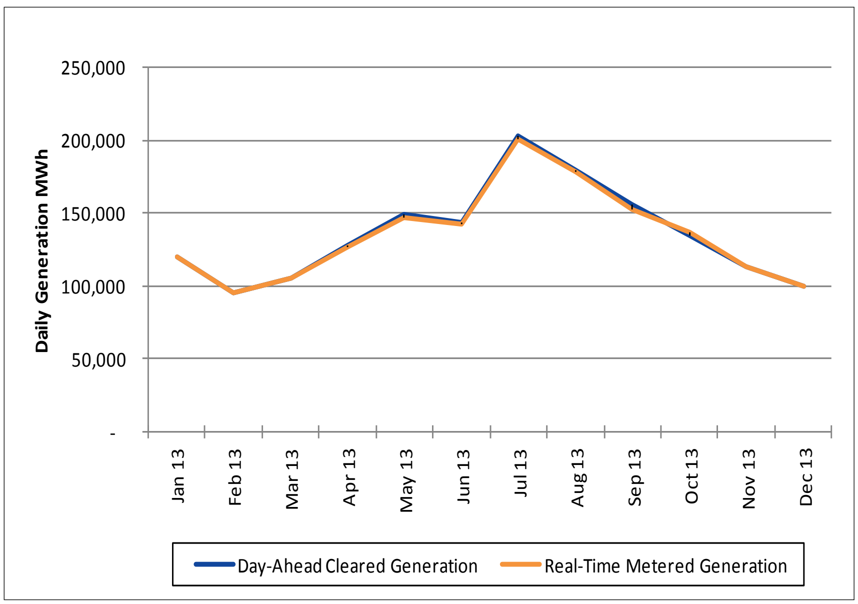

Figure 2-20: Daily generation of gas units with day-ahead schedule, January 2013 to December 2013.

Analysis of Energy Market Timeline Changes. The ISO has undertaken a number of initiatives to ensure the reliable operation of the electricity market in light of fuel supply issues and its various impacts on generator pricing and availability. One such initiative was adjusting energy market timelines to allow enhanced opportunities to schedule natural gas.

The ISO accelerated the deadlines for the day-ahead market and the reserve adequacy analysis. Previously, the deadlines for submitting generator offers were 12:00 p.m. and 6:00 p.m., respectively; results were posted for participants by 4:00 p.m. and 10 p.m., respectively. The

[86] FERC, *Order on Complaint, New England Power Generators Association*, Docket EL13-66-000 (August 27, 2013), http://www.iso-ne.com/regulatory/ferc/orders/2013/aug/el13-66_8-27-13_order_nepga_complaint.pdf.

current deadline for the day-ahead market is 10:00 a.m., and the deadline for the reoffer period that precedes the RAA is 2:00 p.m. Under the new timeline, the day-ahead market schedules are available by no later than 1:30 p.m., and the RAA results are provided at 5:00 p.m. This timeline change had a two-fold purpose: to provide more timely information for the ISO to commit long lead-time resources and to provide electricity schedules to gas units earlier in the day for facilitating opportunities for gas procurement.[87]

Regarding gas procurement risk, the changes in the timeline provide an enhanced opportunity to arrange for gas supplies to meet known day-ahead market and RAA schedules (provided to generators no later than 1:30 p.m. and 5:00 p.m., respectively), while gas trading desks are open and gas nomination cycles are still active for the following gas day.[88] (See Section 2.1.4.2 for a discussion of the price and quantity risks natural gas generators face.)

To examine the possible impact of changing the day-ahead market timeline on natural gas markets, the IMM reviewed natural gas trading activities for the New England region. This review included trading execution times and traded volumes, using data for consummated trades on the Intercontinental Exchange (ICE) for next-day gas contracts at the Algonquin hub.[89] The data suggest that the timing of natural gas trades and the mix of products traded has not changed because of the ISO's timeline change in May 2013:

- Starting in 2012, fixed-price natural gas contracts have been trending toward later trading times.[90]
- Trading times for price-indexed gas contracts have trended slightly later since late 2012.[91]
- The percentage of price-indexed gas contracts has increased, while fixed-price contract volumes have declined from 2011 to 2013. In total, contract volumes for the Algonquin Citygates hub decreased significantly in 2013, after increasing in preceding years.
- The ISO's timeline change did not change the timing of natural gas trades.

Since November 2012, fixed-price natural gas trading has occurred later in the morning, compared with year-earlier periods. Table 2-16 shows that the year-to-year median trade-execution times by month, from 2010 to 2013, do not exhibit a clear trend until November

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87 ISO New England, "Interdependencies of Market and Operational Changes to Address Resource Performance and Gas Dependency," paper (2013), http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/interdependency_of_iso_proposals_to_key_spi_risks.pdf.

88 Gas market liquidity significantly declines by the afternoon. Gas contracts are scheduled for delivery on the pipelines for the following day during the "timely nomination cycle" (closing at 12:30 p.m.) and the evening cycle (closing at 7:00 p.m.).

89 Trading data, for 2010 to 2013 were used for this review. These trades are for any end-use of natural gas, including (but not limited to) power plant gas consumption.

90 Fixed-price contracts provide price certainty to the purchasers of the contracts. While the contract can provide price certainty in the formulation of day-ahead supply offers (if purchased before the filing of day-ahead offers), generators still face quantity risk because a generator's day-ahead schedule (and hence the quantity of natural gas needed to satisfy the day-ahead schedule) is unknown at the time of the contract purchase.

91 Price-indexed gas contracts do not trade at a fixed price. The index price is calculated as the weighted average of all trades at a given location. For generators, the use of these contracts requires both an estimate of price and quantity, if purchased before the filing of a day-ahead market supply offer. This product works well for generators that are price takers or have a good forecast of what the next-day weighted average price will be.

2012. Beginning in that month, median trade execution times have increased in every month, compared with the same month in the prior year. The largest year-to-year increases occurred in March and November 2013, with median execution times moving 35 minutes later in the morning. April and June 2013 had the smallest increases in median times, changing by 7 and 10 minutes, respectively. The trend has been strongest since July 2013, with all the increases in median execution times ranging from 23 to 35 minutes.

Table 2-16
Median Execution Time (Algonquin Gas Transmission—Fixed Price) (a.m.)

Month	Year			
	2010	2011	2012	2013
Jan	9:16	9:28	9:15	9:30
Feb	9:16	9:23	9:13	9:28
Mar	9:15	9:09	9:09	9:44
Apr	9:20	9:11	9:07	9:14
May	9:20	9:08	9:04	9:20
Jun	9:17	9:20	9:10	9:20
Jul	9:14	9:14	9:10	9:33
Aug	9:17	9:16	9:06	9:37
Sep	9:17	9:15	9:04	9:36
Oct	9:22	9:18	9:19	9:46
Nov	9:18	9:04	9:22	9:57
Dec	9:27	9:14	9:30	9:59

The “box and whisker” graphs in Figure 2-21 show the time range when natural gas trades took place. The blue box in the graph is the interquartile range (25th percentile to the 75th percentile). The interquartile range accounts for the timeframe when most of the natural gas trading occurs. The error bars (or “whiskers”) account for the earliest trade and the latest trade time in the month. The figure indicates that the interquartile range has been moving later in the day since April 2013. A similar pattern occurred from August 2012 to March 2013.

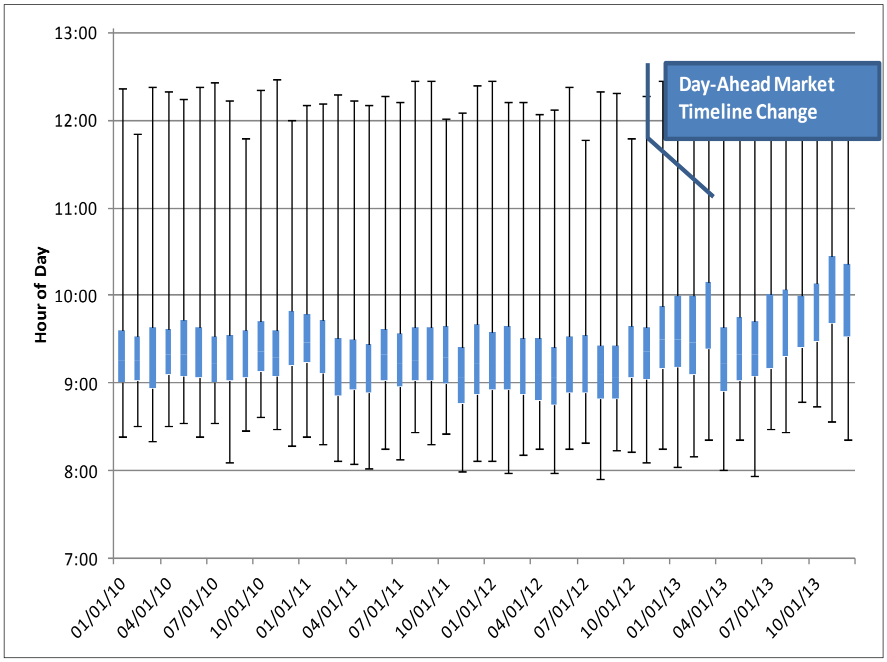

Figure 2-21: Fixed-price contract execution times for next-day Algonquin gas traded on the ICE, by month, January 2010 to December 2013.

Price-indexed contracts have shown no discernible change as result of the change in the ISO's market timeline. While the median trading times have increased modestly since late 2012, the data do not display a strong trend in trading times. See Figure 2-22.

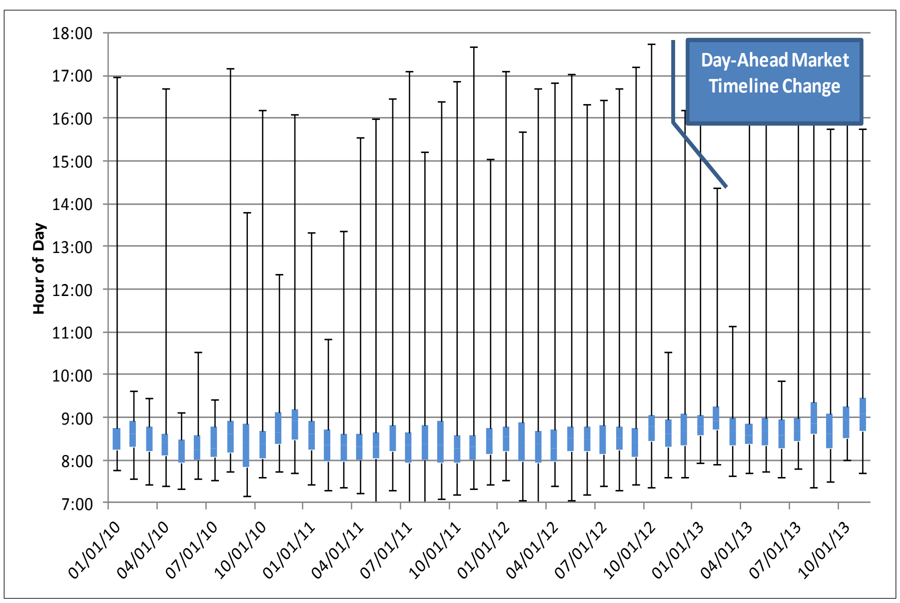

Figure 2-22: Index contract execution times for next-day Algonquin gas traded on the ICE, by month, January 2010 to December 2013.

Finally, the ISO's timeline change also has not affected trading volumes. The prominent long-term trend has been an increase in price-indexed contract volume and a decrease in fixed-price contract volume in 2013.[92] See Figure 2-23 and Figure 2-24.

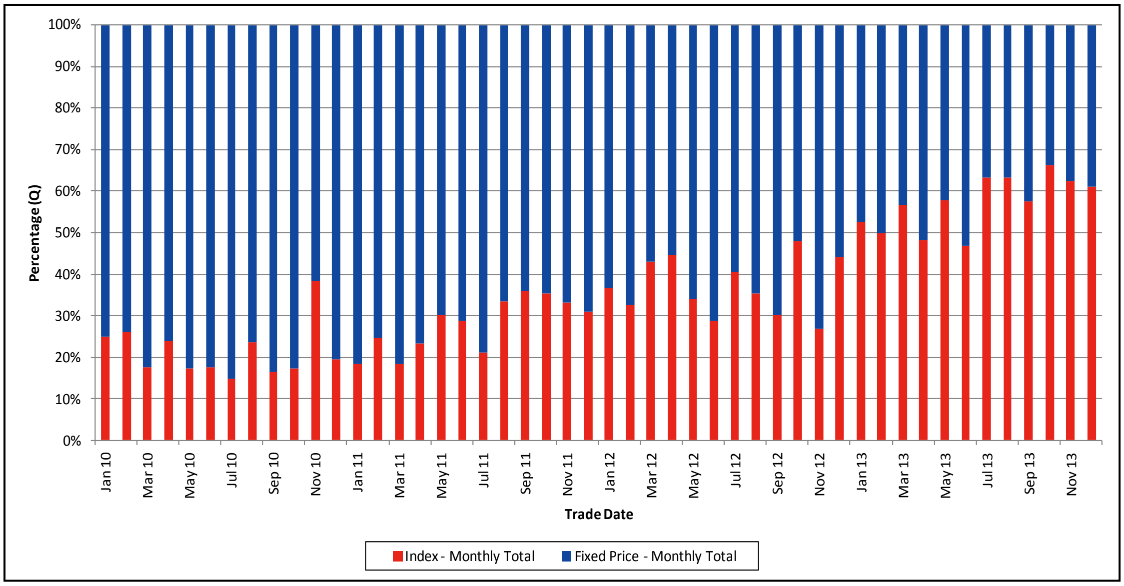

Figure 2-23: Monthly quantities of index and fixed-price next-day contracts for Algonquin Gas traded on ICE, January 2010 to December 2013 (%).

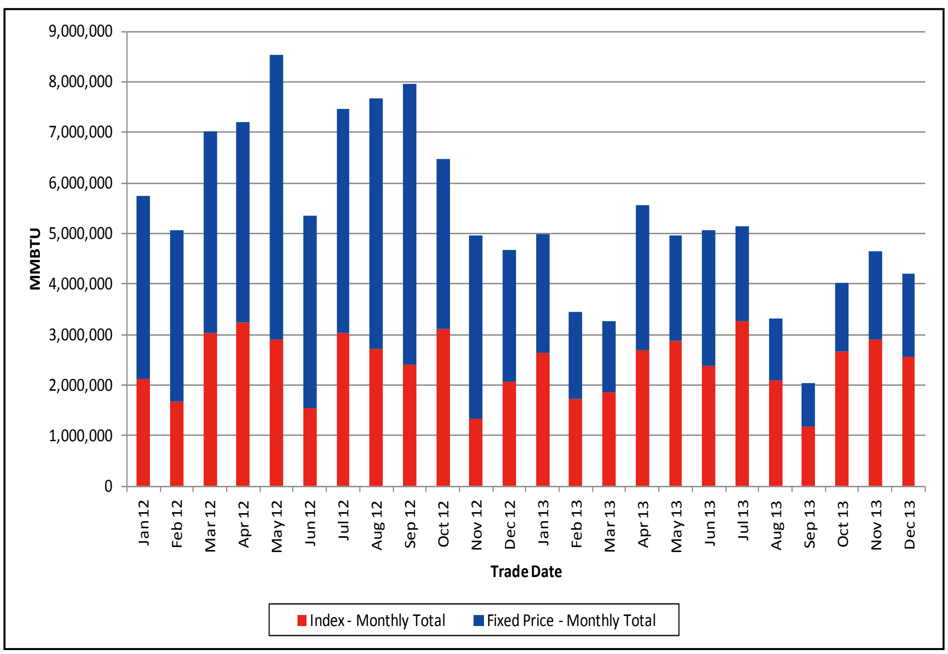

Figure 2-24: Monthly quantities of next-day Algonquin gas traded on the ICE, Janaury 2012 to December 2013 (MMBtu).

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[92] With the decrease in fixed-price gas trading volume, more weight is put on each fixed-price trade when determining the weighted average price. This can cause the market to move up or down very quickly, increasing the risks associated with buying fixed-price natural gas.

Of note, the total traded volumes for next-day Algonquin gas on the Intercontinental Exchange have declined significantly. This can be observed in the chart above of monthly traded volumes, and in Figure 2-25 below, indicating the annual volume of trades. Between 2012 and 2013, index contracts for Algonquin gas declined by approximately 1%, and fixed-price contract volumes decreased by 55%; leading to an overall 35% decline in next-day Algonquin contract volumes during 2013 on the Intercontinental Exchange. However, this decline in volume preceded the change in the day-ahead market timeline and appears unrelated to this change. This observation is consistent with national trends.[93]

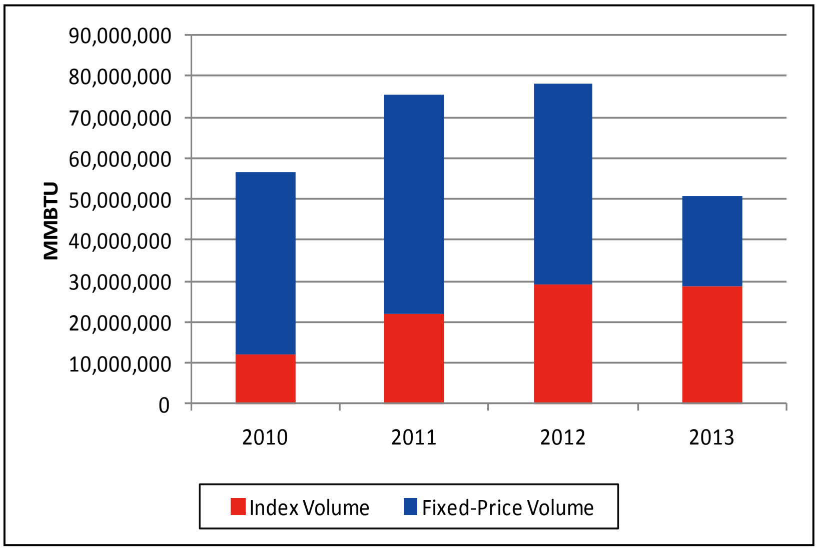

Figure 2-25: Annual quantities of next-day Algonquin Gas traded on ICE, 2010 to 2013.

Preliminarily, the data provide an ambiguous picture of the impact of moving the day-ahead market timeline on natural gas markets. Because the trading times for fixed-price contracts started moving later a full six months before the change in the day-ahead market timeline, this trend cannot be attributed to the day-ahead market timeline change, and it is unclear whether changing the day-ahead market timeline might have intensified this trend. Index gas has traded later but is still trading early in the day, well before the 10:00 a.m. day-ahead market closes. During volatile days, where the bid/ask spread is wide, very little price discovery takes place before the day-ahead market offer deadline. This causes participants purchasing fixed-price contracts to estimate what they expect to pay for gas when they are offering into the day-ahead market.

With the volatility and constraints in the Northeast natural gas market, much price uncertainty exists on a daily basis. Moving the day-ahead market deadline to 10:00 a.m. did not cause the natural gas market to trade earlier, resulting in earlier price discovery. Since the change in the day-ahead market offer deadline, fixed-price natural gas has also traded later in the morning, and at a deceasing volume, causing more price uncertainty for those who use fixed-price contracts than when the day-ahead market offer deadline was 12:00 p.m.

[93]FERC, *2013 State of the Markets*, presentation (Office of Enforcement, March 20, 2014), http://www.ferc.gov/market-oversight/reports-analyses/st-mkt-ovr/2013-som.pdf.

2.1.5 Performance and Conduct Measures

In this section, the IMM presents the results of two metrics that quantify the extent that participants can sustain profits above the competitive level by raising electric energy prices above marginal costs. The *gross margin* (GM) *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 day-ahead and real-time markets are single clearing price markets. In these markets, the price is set by the most expensive resource dispatched hourly in the day-ahead market, or the most expensive resource dispatched in each interval in the real-time market. The offer-based gross margin for a single resource for a single day is the sum of the resource's revenues for that day minus the sum of their offer-based costs to provide that energy for the day. The *gross margin* metric used by the IMM is the difference between two estimates of gross margin for all resources in the market for the entire year. Each estimate is based on two simulations of the market:[94]

- Simulation 1 is an *offer case* that uses the actual offers market participants submit for the Real-Time Energy Market.
- Simulation 2 is a *cost case* that assumes all market participants offer at the IMM's estimate of their short-run marginal cost

The difference between the gross margin based on resource offers (simulation 1) and the gross margin based on resource costs (simulation 2) provides an estimate of the percentage of market rents earned by generators, explained by bids above marginal cost. If all participants bid in a strictly competitive way, that is, offer all output at marginal cost, and the IMM's estimates of marginal costs were completely accurate, the measure would have a value of zero.[95]

Because each unit has a different marginal cost, in any given hour, some units will earn revenues above their marginal cost while others will break even. The units that break even are termed marginal units. As the load changes and the LMP fluctuates, the current marginal unit(s) might become inframarginal (when LMP rises), or current inframarginal unit(s) might become marginal (when LMP drops). The difference in costs between units means that low-cost units will have larger, possibly much larger, gross margins than higher-cost units.

To calculate the GM metric, the IMM first calculates the difference between the energy market revenues for all resources for the two cases and the difference between the total production

[94] The IMM uses 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.

[95] The gross margin is subject to two important caveats: first, the IMM's estimates of marginal cost may understate or overstate actual costs, and second, the simulations are subject to modeling error.

costs for all resources for the two cases.[96] The difference between the two values is then divided by the total system generation as follows:

$$GM = \frac{(Revenue^o - Revenue^c) - (Production\_Cost^o - Production\_Cost^c)}{Generation^o}$$

Where:

$Revenue^o$ is the resources' total energy market revenue for the offer case,

$Revenue^c$ is the resources' total energy market revenue for the cost case,

$Production\_Cost^o$ is the resources' total production cost for the offer case,

$Production\_Cost^c$ is the resources' total production cost for the cost case,

and $Generation^o$ is the resources' total generation for the offer case.

If the market is competitive, the difference in gross margin between the two cases should be small, and the resulting gross margin metric value will be small.

As shown in Table 2-17, for the previous three years, the GM above marginal cost that participants earned was approximately $5.4/MWh in 2011, $4.3/MWh in 2012, and $4.4/MWh in 2013.

Table 2-17
Gross Margin above Marginal Cost, 2011 to 2013 ($/MWh)

Year	Gross Margin above Marginal Cost
2011	5.4
2012	4.3
2013	4.4

The results in Table 2-17 show that, on average, the amount of gross margin earned above marginal cost has changed little over the last three years. These results are consistent with the structural analysis that shows limited ability for generators to exercise market power (see Section 2.1.2.2).

2.1.5.2 The Competitiveness Measure

This section analyzes market competitiveness and shows that the Real-Time Energy Market was competitive in 2013.

For this analysis, the IMM calculates a competitiveness measure that estimates the component of the price that is a consequence of offers above cost.[97] In a perfectly competitive market, all participant offers would equal their marginal cost. Whereas the gross margin is an average

[96] The IMM has improved the methodology used to calculate the gross margin metric compared with previous years.

[97] The IMM has improved the methodology used to calculate the competitiveness measure compared with previous years.

measure that indicates the impact of offers above cost on the aggregate gross margins available to suppliers in the market, the competitiveness measure assesses the impact of these offers by examining 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 difference between the generation-weighted average LMPs for both the offer case (1) and cost case (2) simulations on a daily basis. The competitiveness measure (L) is calculated as follows:

$$L = \frac{\sum_{t=1}^{n}[LMP_t^o \times Generation_t^o - LMP_t^c \times Generation_t^c]}{\sum_{t=1}^{n} Generation_t^o}$$

Where:

LMP_t^o is the offer-based LMP for day t,

LMP_t^c is the cost-based LMP for day t,

$Generation_t^o$ is the resources' total generation for the offer case for day t,

$Generation_t^c$ is the resources' total generation for the cost case for day t,

and n is the number of days in the year.

A larger L means that a larger component of the price is the result of marginal offers above cost. Unlike in the gross margin metric, 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.[98]

For 2013, offers above marginal cost added no more than approximately $6.3/MWh to the real-time price. Table 2-18 shows the summary results of the competitiveness measure.[99]

Table 2-18
Competitiveness Measure, 2011 to 2013 ($/MWh)

Year	Competitiveness Measure
2011	7.4
2012	7.2
2013	6.3

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

98 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.

99 The difference in actual generation-weighted average LMPs and modeled generation-weighted average LMPs is subject to modeling error.

levels in unconstrained areas without review. The size of these threshold limits allow for inaccuracies due to estimation errors and simplifications that must be made as part of the IMM's method of calculating each resource's marginal cost estimates. 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 $6.3/MWh on average to its offer, the market would observe a much larger adder above cost on the typical offer. 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 2013, the IMM did not identify behavior that suggested a more systematic attempt to use 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.

Total NCPC payments during the reporting period totaled $158.7 million. This total includes both daily-reliability NCPC payments and generator performance audit (GPA) NCPC payments. Details of the payments made within the reporting period are described below.

2.1.6.1 Daily Reliability NCPC Payments

The ISO is required to operate New England's wholesale power system to the reliability standards developed by NERC, the Northeast Power Coordinating Council (NPCC), and the ISO through open stakeholder processes.[100] 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:[101]

- Economic/first-contingency NCPC
- Local second-contingency NCPC
- Voltage reliability NCPC
- Distribution reliability NCPC

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[100] 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/pa/stand/Pages/default.aspx. For more information on NPCC standards, see https://www.npcc.org/Standards/default.aspx. The ISO's system operating procedures are available at http://www.iso-ne.com/rules_proceds/operating/isone/index.html.

[101] 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.

Daily Reliability Payments for 2013. As shown in Table 2-19, daily reliability payments totaled $158.0 million in 2013, or about 1.8% of the total wholesale cost of electricity.

Table 2-19
Total Daily Reliability Payments by Quarter, 2013 ($)

	2013	Q1	Q2	Q3	Q4
Total Daily Reliability Payments	157,974,468	74,824,800	21,966,245	31,707,795	29,475,629

As shown in Table 2-20, daily reliability payments increased by $70.9 million (81%) from 2012, and first-contingency NCPC payments increased by $38.3 million (64%) from 2012. Second-contingency payments increased by $29.3 million (335%) compared with 2012. This increase occurred primarily because of several unusual operating conditions during 2013 (see Section 2.1.3.4).

Table 2-20
Total Daily Reliability Payments, 2012 and 2013 ($)

Payment Type	2012	2013	Difference	% Change
Economic and first-contingency payments	59,813,306	98,139,235	38,325,929	64%
Second-contingency reliability payments	8,740,347	38,037,254	29,296,908	335%
Distribution	3,681,219	5,243,539	1,562,320	42%
Voltage	14,871,243	16,554,440	1,683,196	11%
Total	**87,106,115**	**157,974,468**	**70,868,354**	**81%**

Table 2-21 shows that approximately 70% of all reliability payments in 2013 were made in January, February, July, and December, months that had unusual operating conditions resulting in stress on the system (see Section 2.1.3.4):

- In January 2013, New England experienced a cold snap and an OP 4 event.
- In February 2013, New England was hit by a severe winter storm.
- In July 2013, New England experienced a heat wave and an OP 4 event.
- In December 2013, New England experienced unseasonably cold temperatures in the middle of the month and an OP 4 event.

Table 2-21
Daily Reliability Payments by Month, 2013 ($)

Month	Total Reliability Payment
Jan	21,959,340
Feb	45,853,367
Mar	7,012,093
Apr	6,987,728
May	5,214,162
Jun	9,764,354
Jul	22,039,437
Aug	4,881,850
Sep	4,786,508
Oct	2,380,358
Nov	7,083,139
Dec	20,012,132

2.1.6.2 Ex-Post Conduct Test

In 2013, the IMM determined that the conduct test for reliability commitment mitigation used in evaluating resources committed out-of-merit was susceptible to manipulation when a resource was committed beyond its minimum run time. Specifically, the IMM found that a market participant could structure a supply offer so that it passed the conduct test but nevertheless received NCPC payments significantly in excess of its costs (as reflected in the resource's reference levels) plus the 10% adder when its resource was committed for local reliability. The test presumed a market participant would structure its offer to recover all its start-up and no-load costs by the end of the resource's minimum run time. Accordingly, the conduct test evaluated the resource's performance only for the period of its minimum run time.

Because of the structure of this test, market participants could reduce the start-up fee and increase either or both the no-load fee or energy price parameters in the resource's supply offer, on the presumption that the resource would be operated to address the reliability need for longer than its minimum run time. This allowed a market participant whose resource was committed for local reliability beyond its minimum run time to receive NCPC payments well in excess of the reference levels (plus the 10% adder permitted under the conduct test). This result was only possible because the market participant's resource was needed for reliability.

To prevent this behavior, the IMM filed a market rule change with FERC on September 17, 2013, to apply an additional ex-post conduct test.[102] On November 15, 2013, FERC accepted the changes to the reliability commitment mitigation test to address the potential manipulation of the existing low-load cost test, with an effective date of September 18, 2013 (one day after the

[102] ISO New England and NEPOOL, *Reliability Commitment Mitigation Revisions to Appendix A of Market Rule 1*, Docket No. ER13-___-000, FERC filing (September 17, 2013), http://www.iso-ne.com/regulatory/ferc/filings/2013/sep/er13-2397-000_9-17-2013_rel_com_mit.pdf.

ISO's filing).[103] Under the new test, the IMM evaluates the supply offers of a resource over the entire period for which the resource is committed to address the local reliability issue. This new test is performed after the operation of the resource and, if violated, results in the mitigation of the supply offer to its reference levels on file with the IMM.

2.1.6.3 Generator Performance Audit NCPC Payments

NCPC payments for generator performance audits became effective on June 1, 2013.[104] NCPC payments to participants for this category are incurred for the following:

- Performance audits of on-line and off-line reserves and for seasonal claimed capability audits initiated by the ISO rather than the participant
- Dual-fuel testing services as part of the 2013/2014 Winter Reliability Program.[105]

Table 2-22 shows the total GPA NCPC payments made to generators during the reporting period by month.

Table 2-22
GPA Payments, 2013 ($)

Month	Real-Time Generator Performance Audit Payment
Jan	n/a
Feb	n/a
Mar	n/a
Apr	n/a
May	n/a
Jun	0
Jul	0
Aug	0
Sep	0
Oct	44,117
Nov	659,435
Dec	6,509
Total	**710,061**

Supplemental Commitments. Each day after the clearing of the Day-Ahead Energy Market, the ISO performs a reserve adequacy analysis and, if necessary, commits additional resources above

[103] FERC, *Order Accepting Proposed Tariff Revisions*, Docket No. ER13-2397-000 (November 15, 2013), http://www.iso-ne.com/regulatory/ferc/orders/2013/nov/er13-2397-000_11-15-13_order_accept_rel_commit_mit.pdf.

[104] ISO New England and NEPOOL, *Market Rule 1 Revisions Relating to Auditing of Generation Resources*, Docket No. ER13-1323-000 (November 6, 2012), http://www.iso-ne.com/regulatory/ferc/filings/2012/nov/er13-323-000_11-6-2012_audit_claim.pdf.

[105] See the ISO New England, *2013 Fourth Quarter Markets Report* (February 10, 2014) for an overview of the 2013/2014 Winter Reliability Program; http://www.iso-ne.com/markets/mkt_anlys_rpts/qtrly_mktops_rpts/2013/q4_2013_qmr.pdf.

those committed day ahead to meet capacity and reserve requirements and assure reliability in real time. The ISO commits resources in the RAA whenever insufficient capacity clears in the day-ahead market to meet the ISO load forecast plus operating-reserve requirement. These supplemental commitments made by the ISO are out-of-market commitments because they are not reflected in the day-ahead market prices. However, the amount of capacity on line affects real-time prices (i.e., 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.

The IMM observed that, in 2013, consistent with past years, most days have no supplemental commitments, and on the days with supplemental commitments, the megawatts committed are not large. Figure 2-26 shows that, overall, supplemental commitments occurred on less than half of the days in all months.

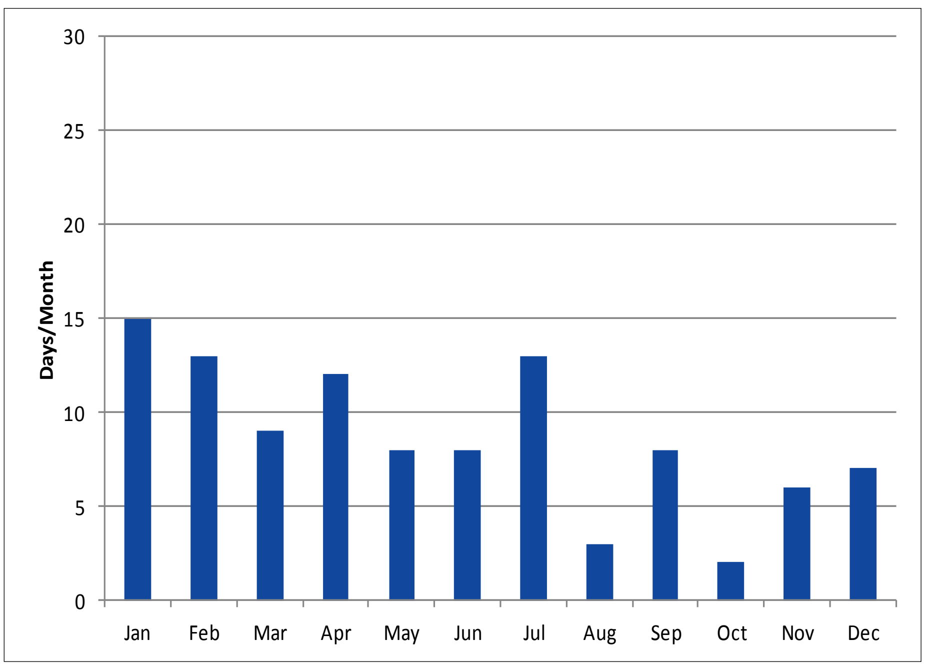

Figure 2-26: Number of days with supplemental commitments, 2013.

Table 2-23 shows the minimum, maximum, and quarterly percentiles of the days with supplemental commitments. Supplemental commitments exceeded 1,000 MW on seven days in 2013. Three of these days occurred in February. The day with the highest level of supplemental commitments in 2013 was February 11, when 2,879 MW of supplemental capacity was committed. Uncertainty regarding generator availability in the aftermath of the weekend blizzard (see Section 2.1.3.4) was the primary driver for the February commitments.

Table 2-23
Monthly Minimum, Maximum, and Quarterly Percentiles of Days with Supplemental Commitments for the Peak Hour, January to December 2013 (MW)

Month	Daily Supplemental Commitment MW[(a)]				
	Minimum	25th Percentile	50th Percentile	75th Percentile	Maximum
Jan	54	169	250	709	1,847
Feb	115	262	584	923	2,879
Mar	45	45	115	258	1,475
Apr	47	125	379	535	610
May	26	42	76	498	734
Jun	157	184	270	633	900
Jul	45	95	165	200	707
Aug	95	248	400	400	400
Sep	129	163	327	646	1,320
Oct	150	175	200	225	250
Nov	85	137	269	414	569
Dec	67	94	176	395	733

(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.

Section 3.1.6.2 presents an analysis of the relationship between day-ahead market prices and real-time market prices. That analysis shows that the days with more supplemental commitments have real-time prices that are lower, on average, than days with fewer supplemental commitments.[106]

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).[107]

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*.[108] 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

[106] The analysis in Section 3.1.6.1 uses a similar metric called "RAA commitments." While not the same as the supplemental commitments metric shown here that focuses on the peak hour only, the two are similar.

[107] 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.

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

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 (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.[109]
- **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.[110]
- 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:

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

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

[110] 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 the systemwide 30-minute reserve constraint, and $250/MWh for each local reserve constraint.

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.[111]

2.2.2 Real-Time Reserve Outcomes

Average annual reserve prices in dispatch intervals with positive reserve prices increased for all reserve products in 2013 compared with 2012. While the number of dispatch intervals with positive reserve pricing for TMSR decreased, the number of dispatch intervals with positive TMNSR and TMOR reserve prices increased. Although the percentage change in the number of dispatch intervals with positive prices is significant, the absolute number of dispatch intervals with positive prices was still quite low in 2013. See Table 2-24.

Table 2-24
Average Reserve Prices and Frequencies for Intervals with Positive Prices, 2012 to 2013[(a)]

Product	Year	Average Annual Price ($/MW/ 5-Min. Interval)	Frequency (% of Total 5-Min. Intervals)
10-minute spinning reserve	2012	$41.79	3.95%
	2013	$92.44	3.18%
	% change	***121.2%***	***−19.5%***
10-minute nonspinning reserve	2012	$118.58	0.82%
	2013	$212.34	1.14%
	% change	***79.1%***	***39.0%***
30-minute operating reserve	2012	$120.70	0.80%
	2013	$202.02	1.12%
	% change	***67.4%***	***40.0%***

(a) Prices are presented for the Rest-of-System reserve zone. Average reserve prices are based on the preliminary reserve prices and would not include any ex-post pricing adjustments. Ex-post adjustments to 5-minute reserve prices are not available.

Reserve pricing occurs when the system must redispatch resources away from the lowest-cost solution for satisfying energy requirements, and incur additional costs to meet the system reserve requirement. When this happens the reserve price is the opportunity cost of the least expensive resource whose energy output is reduced to provide reserves during redispatch. As a practical matter, the cost incurred to redispatch on-line 10-minute reserve assets is lower, on average, than the cost incurred to redispatch less flexible resources to provide the 30-minute reserves.

Table 2-24 shows that positive prices for TMSR occurred in three times as many intervals as positive pricing for TMOR, but prices, on average, were significantly lower than for the other

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111 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.

products. These low average prices are the result of low prices during the intervals when only the TMSR pricing occurred, and all other products were priced at $0/MWh. The TMSR interval price was relatively low, reflecting a lower average cost after redispatch.

Table 2-25 compares the frequency and average prices (during nonzero pricing intervals) across reserve zones for 2013. The frequency of binding constraints across zones was highly consistent in 2013. Only the NEMA/Boston reserve zone experienced binding constraints and prices that were slightly different from the Rest-of-System reserve zone.

Table 2-25
Real-Time Reserve Clearing Prices for Nonzero Price Intervals, 2013[a]

Product	Reserve Zone	Price ($/MW/ 5-Minute Intervals)	Frequency (% of 5-Minute Intervals)
TMSR	Connecticut	92.44	3.18%
	NEMA/Boston	92.33	3.22%
	Rest-of-System	92.44	3.18%
	Southwest Connecticut	92.44	3.18%
TMNSR	Connecticut	212.34	1.14%
	NEMA/Boston	207.95	1.18%
	Rest-of-System	212.34	1.14%
	Southwest Connecticut	212.34	1.14%
TMOR	Connecticut	202.02	1.12%
	NEMA/Boston	197.89	1.16%
	Rest-of-System	202.02	1.12%
	Southwest Connecticut	202.02	1.12%

(a) Average reserve prices are based on the preliminary reserve prices and would not include any ex-post pricing adjustments. Ex-post adjustments to 5-minute reserve prices are not available.

Table 2-26 summarizes reserve payments for 2011 to 2013. The payments in 2013 are the highest in the three years. The largest increases were in TMSR and TMNSR payments; TMNSR payments more than doubled.

Table 2-26
Real-Time Reserve Payments, 2011 to 2013 ($)

Year	Systemwide TMSR	Systemwide TMNSR	Systemwide TMOR	SWCT TMOR	CT TMOR	NEMA/Boston TMOR	Total
2011	5,931,552	2,373,489	220,483	535,377	354,335	56,249	9,471,485
2012	11,382,732	12,179,149	1,352,764	3,235,228	1,207,896	428,223	29,785,992
2013	17,989,684	26,097,061	2,867,692	4,928,025	1,414,744	742,115	54,039,322

In 2013, the total real-time reserve payments were $54.0 million. In 2012, real-time reserve payments totaled $29.8 million, a significant increase from $9.5 million in 2011. As discussed in the *2012 Annual Markets Report*, the increase in payments between 2011 and 2012 resulted from several changes in operating-reserve programs.[112]

Additionally, the IMM examined the increase in payments that occurred between 2012 and 2013 in detail. Several factors explain this increase in reserve payments:[113]

- The total 10-minute reserve requirement increased by 25% in the summer of 2012. This change did not affect the first six months of 2012, but did affect all of 2013.
- A market rule change increased the Reserve Constraint Penalty Factor for system TMOR from $100/MWh to $500/MWh in summer 2012.[114] This change did not affect the first six months of 2012, but did affect all of 2013.
- Several days of tight system conditions in July, September, October, and December 2013 coupled with higher natural gas prices in December 2013 than December 2012 prices, increased reserve payments in the last six months of 2013 compared with the same period for 2012.
    - Two capacity deficiency events (an OP 4 event on July 19, 2013, and an M/LCC2 event on September 11, 2013) resulted in $11.2 million in reserve payments during the third quarter of 2013 (see Section 2.1.3.4). If either one of these events had not occurred, the difference between payments in the third quarters of 2012 and 2013 would have been negligible (no OP 4 events occurred during 2012).
    - Several days of tight capacity conditions occurred between October 4 to 14, 2013, and between December 9 to 19, including an OP 4 event on December 14, 2013. The increase in reserve pricing and payments in December 2013 also resulted in part from higher natural gas prices during that month compared with December 2012.
- Beginning in October 2013, the addition of "replacement reserves" to the TMOR requirement increased the 30-minute reserve requirement by approximately 20 to 25%.[115]

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112 While changes in the ISO's reserve markets in 2012 and 2013 have increased payments, large year-to-year variation is not unusual for reserve payments. 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. The frequency and magnitude of these events vary each year.

113 The IMM reviewed several reserve market elements, including average pricing levels for each reserve product, the average megawatt designations available for each product during the pricing periods, and the frequency of nonzero prices for each product.

114 This increase went into effect beginning in the third quarter of 2012. 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. *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.

115 OP 8 states that in addition to the operating-reserve requirements, the ISO must maintain sufficient *replacement reserves* in the form of additional TMOR for meeting the NPCC requirement to restore its 10-minute reserve within 105 minutes if it becomes deficient as a result of a reportable contingency, and within 90 minutes if it becomes

Approximately 35% of the total difference in reserve payments is explained by the increase in the total 10-minute reserve requirement and the increase in the TMOR RCPF, along with a cold snap that occurred in January 2013. These factors resulted in increased reserve pricing for all reserve products during the first six months of 2013, compared with the same period for 2012.[116]

2.3 Regulation Market

This section presents data about the participation, outcomes, and competitiveness of the Regulation Market in 2013. The IMM concludes that the Regulation Market was competitive in 2013.

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).[117] 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%.[118]

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 regulation includes a regulation capacity payment, a service payment, and a make-whole payment.[119] Unit-specific opportunity cost payments are included as a component of the regulation clearing price.

2.3.1 Regulation Pricing

In 2013, the average regulation price of $11.60/MWh was 72% higher than the 2012 price of $6.75/MWh. See Table 2-27.

deficient for reasons other than a reportable contingency, as described in NPCC Directory #5, *Reserve* (October 11, 2013), https://www.npcc.org/Standards/Directories/Forms/Public%20List.aspx.

[116] See the IMM's Quarterly Market Reports for quarters 1 and 2 of 2013 at http://www.iso-ne.com/markets/mkt_anlys_rpts/qtrly_mktops_rpts/2013/index.html.

[117] This NERC standard (effective May 13, 2009) can be accessed at http://www.nerc.com/pa/Stand/Pages/AllReliabilityStandards.aspx?jurisdiction=United States. Additional information on NERC requirements is available at http://www.nerc.com (2013).

[118] 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).

[119] These make-whole payments ensure that units providing regulation service are compensated for the capacity cost, service cost, and unit-specific opportunity cost.

Table 2-27
Regulation Prices ($/MWh) and Total Payment (Million $), 2011 to 2013

Year	Minimum Price ($/MWh)	Average Price ($/MWh)	Maximum Price ($/MWh)	Total Payment (Million $)
2011	0	7.16	95.00	13.3
2012	0	6.75	70.33	11.6
2013	0	11.60	692.08	20.4

Payments to resources providing regulation service totaled $20.4 million in 2013, a 77% increase from the total regulation payment in 2012.

An interim Regulation Market solution was implemented on July 1, 2013, to address the major elements of FERC Order 755.[120] The interim solution incorporates regulation opportunity costs into the uniform regulation clearing price. Because a regulation unit's opportunity cost is affected by the Real-Time Energy Market price, the volatility of the regulation clearing price is closely related to the Real-Time Energy Market price. The maximum regulation price observed in 2013 of $692.08/MWh is consistent with the real-time price of $1,289.93/MWh in the same hour.

The market efficiency and competiveness are not affected by the interim solution. However, the increase of total regulation payments is largely attributable to the market rule change. The increase in the natural gas price over the course of the year has also contributed to the increase in regulation capacity and service costs, and therefore the total regulation payment.

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 59.54 MW in 2012 to 59.51 MW in 2013. 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 2013, the ISO achieved a minimum value of 92.7% and a maximum value of 95.3%.

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

[120] ISO New England Inc. and NEPOOL, *Regulation Market Opportunity Cost Change*, Docket No. ER13-1259-000, FERC filing (April 11, 2013), http://www.iso-ne.com/regulatory/ferc/filings/2013/apr/er13-1259-000_4-11-2013_reg_mkt_opp_cost_chg.pdf. FERC, *Regulation Market Opportunity Cost Change*, Docket No. ER13-1259-000, letter order (June 27, 2013), http://www.iso-ne.com/regulatory/ferc/orders/2013/jun/er13-1259-000_6-17-13_ltr_order_accept_reg_mrkt_rev.pdf.

to engage in economic or physical withholding. The IMM concludes that the Regulation Market was competitive in 2013.

Figure 2-27 shows the average and maximum regulation requirement (demand) and the average regulation supply for 2013 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.

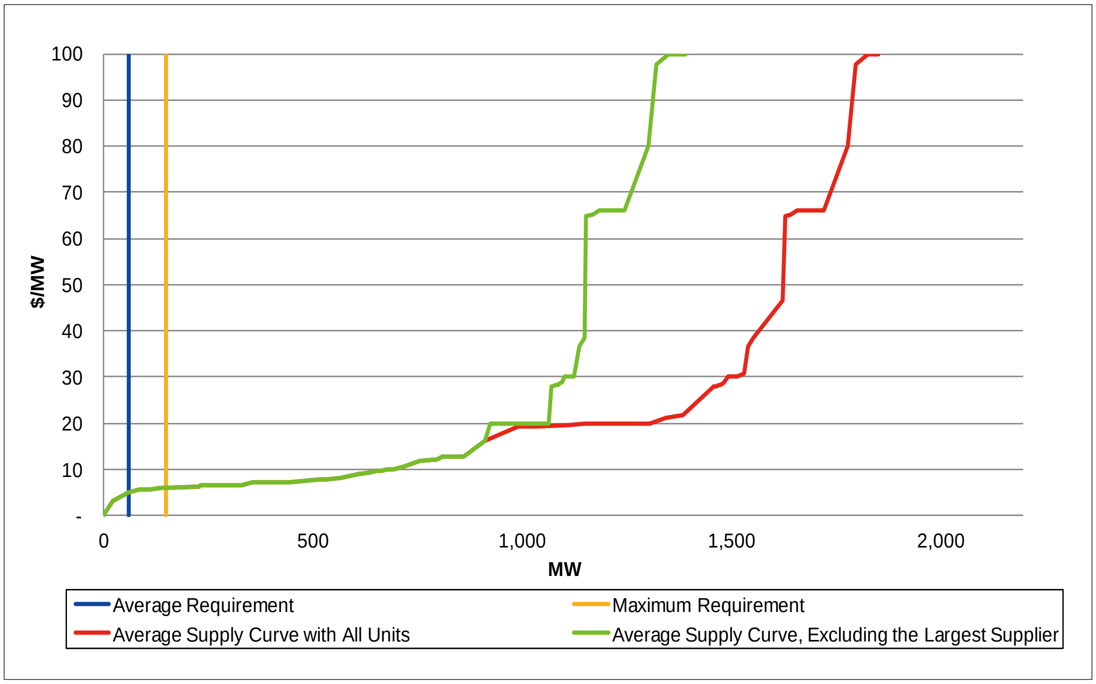

Figure 2-27: Regulation Market demand, average, and maximum requirements and supply curves with and without the largest supplier, 2013 (MW and $/MW).

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 2-28, the regulation requirement and RSI are inversely correlated. In 2013, 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.

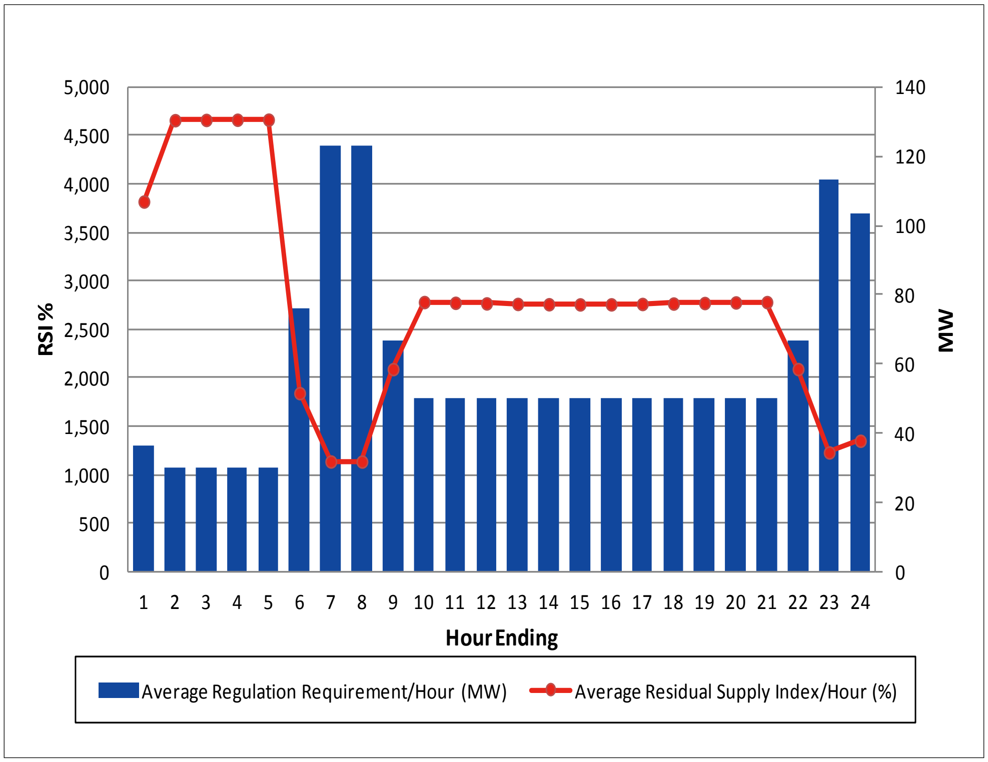

Figure 2-28: Average regulation requirement and residual supply index per hour, 2013.

Section 3
Forward Markets

This section describes the 2013 outcomes and recommendations regarding the ISO's forward markets, including the Day-Ahead Energy Market, Financial Transmission Rights, the Forward Reserve Market, and the Forward Capacity Market.

3.1 Day-Ahead Energy Market

This section provides information on the outcomes of the ISO's Day-Ahead Energy Market for 2013.

In the day-ahead market, load-serving entities (LSEs) may submit energy demand schedules, which express their willingness to pay for electric energy. 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 (i.e., decrement bids) or supply offers (increment offers) (see Section 3.1.4) 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 clears bids and offers to maximize social welfare, subject to transmission constraints. The day-ahead market results are posted no later them 1:30 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 the market receive day-ahead Net Commitment-Period Compensation.

3.1.1 Day-Ahead Pricing

The average day-ahead Hub price in 2013 was $56.42/MWh. As in real-time, this price is consistent with observed market conditions, including natural gas prices, load levels, and available supply. Price differences among the load zones primarily stemmed from marginal losses, with little congestion at the zonal level. Congestion was typically 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 $1.95/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 Northeastern Massachusetts (NEMA), Southeastern Massachusetts (SEMA), and Rhode Island load zones were $0.48, $0.60, and $1.37/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 2011, 2012, and 2013 ($/MWh)

Location/ Load Zone	2011	2012	2013
Hub	46.38	36.08	56.42
Maine	45.58	35.90	54.48
New Hampshire	45.94	35.92	55.98
Vermont	46.67	36.25	55.36
Connecticut	47.47	36.77	55.43
Rhode Island	45.77	36.24	57.79
SEMA	46.18	36.09	57.02
WCMA	46.92	36.98	56.37
NEMA	46.14	36.15	56.90

3.1.2 Price Setting in the Day-Ahead Market

As shown in Figure 3-1, in the day-ahead market, generators set price approximately 42% of the time in 2013, and virtual transactions (see Section 3.1.4) set price approximately 33% of the time. These percentages are similar to 2012, when generators set price approximately 45% of the time, and virtual transactions set price approximately 27% of the time.

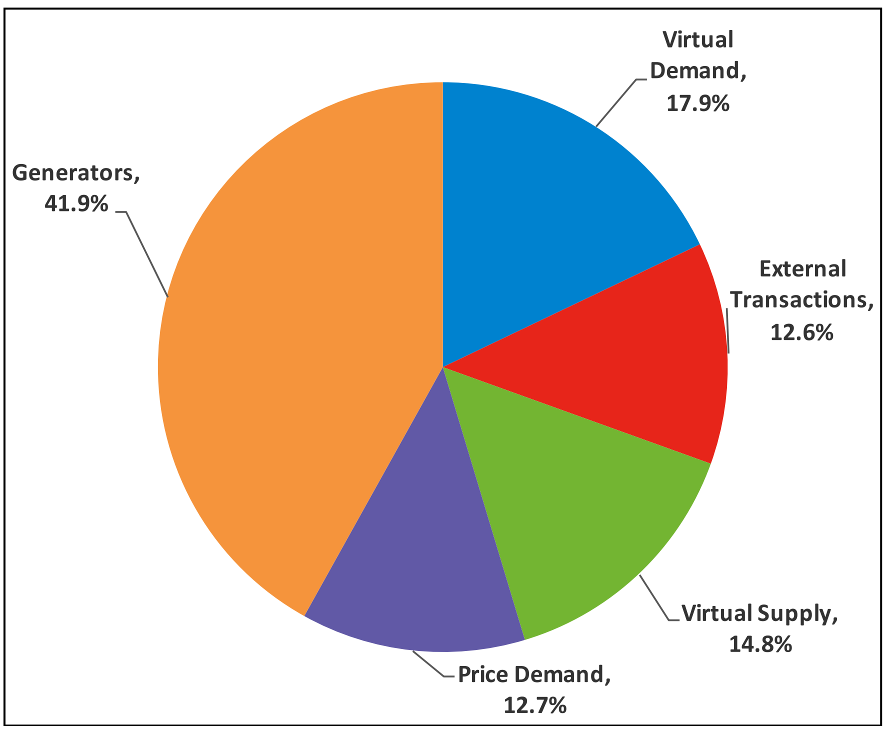

Figure 3-1: Percentage of price setting in the day-ahead market, 2013.

3.1.3 Day-Ahead Demand for Electric Energy

Fixed demand (i.e., load that LSEs purchase at any price) increased by 6,485 GWh in 2013 from 2012, which increased fixed demand as a percentage of total demand cleared in the day-ahead market from 65% in 2012 to 70% in 2013. Virtual demand and exports have decreased in both volume and as a percentage of total cleared demand over the most recent three-year period. Price-sensitive demand's share of total day-ahead cleared demand declined from 29% in 2012 to 25% in 2013. See Figure 3-2, which shows the total volume of day-ahead cleared demand for 2011 through 2013.

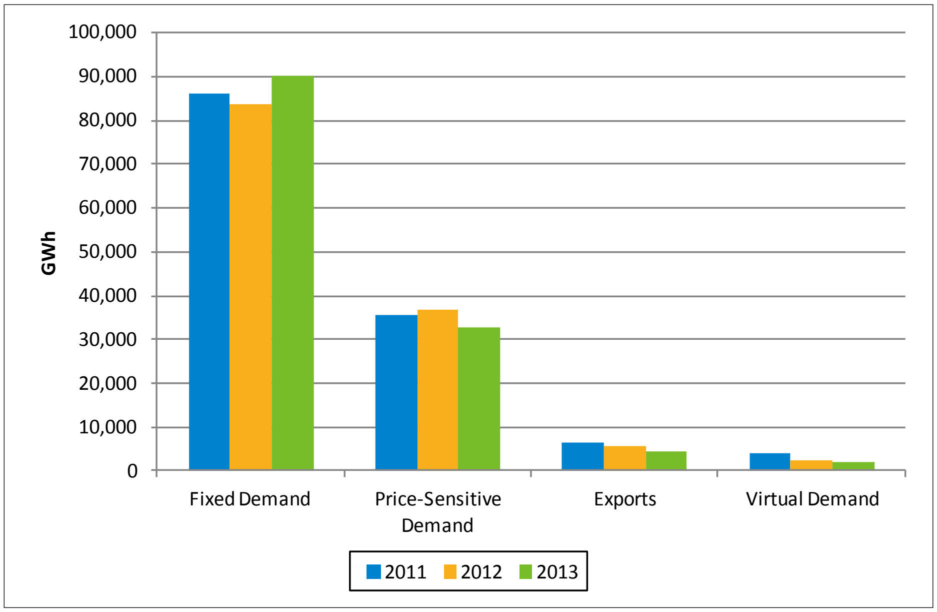

Figure 3-2: Total volume of day-ahead demand cleared, 2011 to 2013 (GWh).

3.1.4 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 2013, submitted and cleared virtual transactions continued to decline, as reported in the *2010, 2011,* and *2012 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 20,555 GWh in 2013, a decline of 25% compared with 2012 and a decline of 36% compared with 2011. Cleared virtual transactions totaled approximately 3,809 GWh in 2013, a 16% year-to-year decline compared with 2012 and a 50% decline compared with 2011. See Figure 3-4.

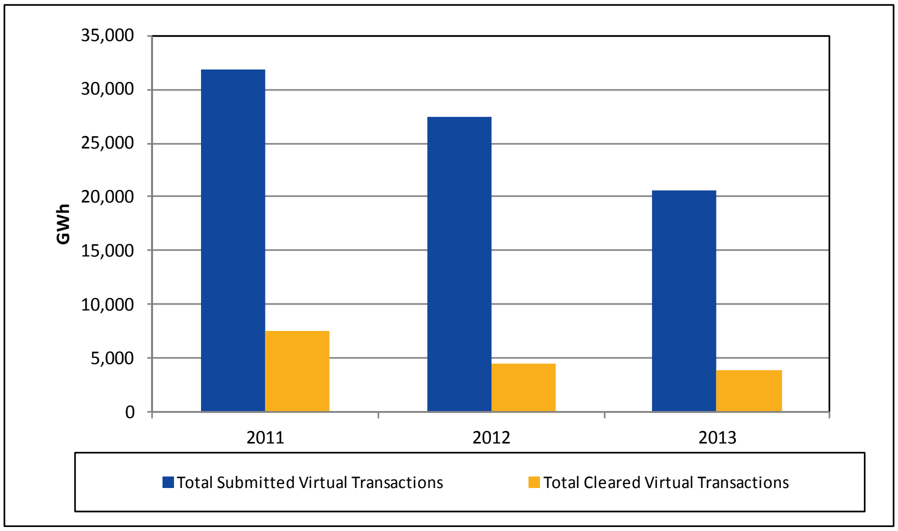

Figure 3-3: Total submitted and cleared virtual transactions, 2011 to 2013 (GWh).

The IMM analyzed trends in virtual trading at the Hub, load zones, internal network nodes, and the external interface nodes (the "node categories") for 2011 through 2013 (see Figure 3-4):

- Cleared volumes at the Hub declined by 35% from 2012 to 2013.
- Cleared volumes at the load zones declined by approximately 24% from 2012 to 2013.
- Cleared volumes at the internal network nodes have increased by approximately 21% from 2012 to 2013 but were still lower by 36% than the levels observed in 2011.
- Cleared volumes at external interface nodes increased by 71% in 2013 compared with 2012 but declined by 80% compared with 2011.

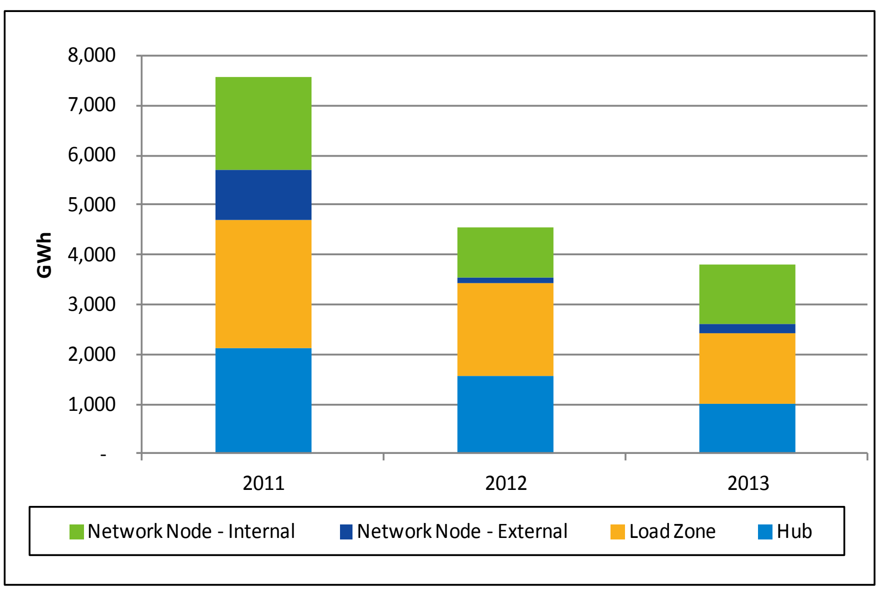

Figure 3-4: Total cleared virtual trade volumes by node category, 2011 to 2013 (GWh).

Summary of Virtual Transactions. Overall, the volume of trading for virtual transactions continued to decline in 2013. 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*.

In Section 3.1.6.2, the IMM reviews the relationship between day-ahead and real-time prices reported in this AMR. Further analysis of this relationship, with more focus on virtual transactions, may shed light on why prices continue to converge even as virtual transaction volumes continue to fall.

The IMM recommended in the *2010* and *2011 Annual Markets Reports* 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 *2012 Annual Markets Report* and continues to support this recommendation. Currently, the ISO is sponsoring market rule changes that will exclude decrement bids from receiving real-time NCPC charges. The IMM will be reviewing the results of these changes and may make additional recommendations for future improvements.

3.1.5 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 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 decreased by 2,674 GWh from 2012 to 2013. Day-ahead self-schedule volumes accounted for 55% of total volumes, down from 57% in 2012. In 2011, self-schedule volumes were 54% of total volumes. Economic supply offers decreased to 26% of the total, slightly lower than the levels observed in 2012. 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 comprised 18% of total cleared supply in 2013. See Figure 3-5.

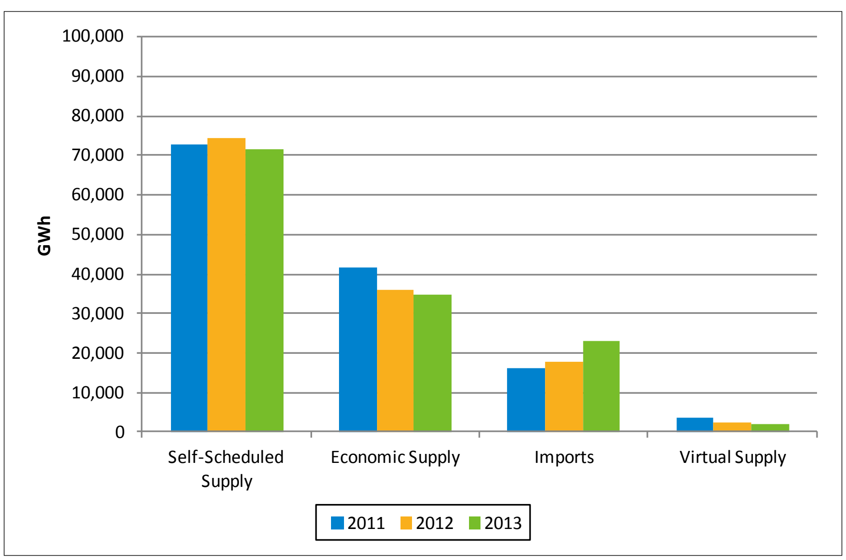

Figure 3-5: Total volume of day-ahead supply cleared, 2011 to 2013 (GWh).

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

This section compares day-ahead demand with real-time demand and analyzes the bidding behavior of load-serving entities in the day-ahead and real-time markets.

3.1.6.1 Comparison of Day-Ahead Demand with 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 analysis, referred to as RAA commitments (see Section 2.1.6.3).[121] On average, the percentage of demand purchased in the day-ahead market is fairly constant from month to month. The annual percentage of day-ahead demand cleared as a percentage of real-time demand has increased slightly, from 93% in 2012 to 94% in 2013.[122]

3.1.6.2 Analysis of the Day-Ahead and Real-Time Energy Markets

The Day-Ahead and Real-Time Energy Markets comprise a two-settlement system. However, each of the markets has limits on how accurately it prices electric energy and reliability. Prices in the day-ahead market do not always fully reflect the costs of a reliable real-time electric power system for at least two reasons:

- To assure reliability, the ISO makes out-of-market commitments through the RAA process (refer to Section 2.1.6.3)
- The assumptions in the day-ahead market do not fully reflect the conditions and factors needed to maintain reliability in real time.

Additionally, prices in the real-time energy market may not fully reflect the costs of maintaining reliability:

- When the system is operating normally, real-time prices can be understated because of OOM commitments and the difficulty of modeling and pricing generators' operating constraints, such as a resource's economic minimum output or its minimum run time.
- When the system is running short of capacity, price caps in the energy and reserve markets may not fully reflect the value of electricity to load (i.e., consumers).

Despite these imperfections, the day-ahead and real-time markets have produced results broadly consistent with the expected outcome of competitive markets. Specifically, the day-ahead energy market trading has been liquid, and day-ahead and real-time prices have stayed in convergence. From 2009 to 2013, the average divergence between day-ahead and real-time energy prices was modest—within the range of 0.01% to 1.4% each year. During the same period, the day-ahead and real-time energy prices were consistent with observed demand and supply conditions, including, among other factors, input fuel costs and loads. Further, the average out-of-market compensation or the total NCPC payment was a relatively small fraction of the total energy cost, ranging from 0.6% to 2.0%.

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[121] An *RAA commitment* is the difference between a cleared unit's RAA ecomax and day-ahead ecomax.

[122] 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).

However, average statistics can mask individual days that had significant differences between day-ahead and real-time prices. Some of these price differences were caused by differences between forecast load and actual load or the unexpected loss of a large generator in real time. Some of the differences were caused, in part, because the day-ahead and real-time prices did not provide adequate signals to the market to encourage sufficient resources to be available in real time to maintain reliability. The remainder of this section examines the amount of load clearing in the day-ahead market, as a percentage of real-time load, as well as the relationship between day-ahead prices and real-time market prices.

The percentage of real-time load clearing in the day-ahead market has been fairly constant since the introduction of the multisettlement system. In 2013, 94% of real-time load cleared in the day-ahead energy market. Over the previous five years, the average was 93%. Before the recent tightening of the region's natural gas supply (see Section 2.1.4), the percentage of real-time load clearing in the day-ahead market had a relatively small impact on real-time reliability. Until recently, the availability of natural gas intraday was sufficient to supply resources committed after the day-ahead market closed. As the region's natural gas market has tightened, natural gas resources that have not arranged ahead of time to purchase natural gas have faced more difficulty, especially during the winter months, in obtaining gas to support a real-time commitment. To address the uncertainty associated with intraday natural gas supply, the ISO has taken actions within the RAA process, such as committing oil units out of merit or committing additional units to maintain reliability in the event natural gas resources could not obtain fuel in the intraday market. These out-of-market actions distort prices and make it difficult for the markets to maintain reliability through price signals alone.

Load-Serving Entity Bidding Behavior in the Day-Ahead Market. To better understand the dynamics of load clearing in the day-ahead market, the IMM analyzed the bidding behavior of different LSEs from 2011 to 2013. Table 3-2 shows the percentage of real-time load cleared in the day-ahead market by large and small LSEs. A large LSE is defined as one with an average load obligation ≥100 MW and a small LSE is defined as one with an average load obligation <100 MW. The table also shows the LSEs' respective shares of real-time load. Large LSEs consistently cleared 97% to 98% of their real-time load in the Day-Ahead Energy Market over the three-year period. In contrast, small LSEs cleared noticeably less, averaging between 82% and 91% of their real-time load. The market share of large LSEs was greater than 80% during the period.

Table 3-2
Percentage of Real-Time Load Cleared in the Day-Ahead Market, by Load Size, 2011 to 2013

Year	Large Load-Serving Entity (Average Real-Time Load ≥100 MW)		Small Load-Serving Entity (Average Real-Time Load <100 MW)	
	Real-Time Load Share	Day-Ahead Load Clear Ratio[a]	Real-Time Load Share	Day-Ahead Load Clear Ratio
2011	84%	98%	16%	91%
2012	83%	98%	17%	82%
2013	81%	97%	19%	90%

(a) Day-Ahead Load Clear Ratio = Sum(Day-Ahead Load Obligation)/Sum(Real-Time Load Obligation).

LSEs can submit four types of bids in the day-ahead market:

- Fixed demand bids
- Price-sensitive demand bids
- Increment offers
- Decrement bids

Fixed demand bids and price-sensitive demand bids in the day-ahead market materialize as real-time load in the Real-Time Energy Market. Increments and decrements are financial transactions that do not materialize as real-time load or generation. Financial transactions settle at the difference between the day-ahead and real-time energy market prices. Table 3-3 illustrates the differences in demand bidding behavior between small and large LSEs.

Table 3-3
Percentage of Day-Ahead Market Bids and Offers, by Product and Load Size

Year	Large Load-Serving Entity (Average Real-Time Load ≥100 MW)				Small Load-Serving Entity (Average Real-Time Load <100 MW)			
	Decrements	Increments	Price-Sensitive Demand	Fixed Demand	Decrements	Increments	Price-Sensitive Demand	Fixed Demand
2011	2.3%	2.5%	29.9%	65.3%	21.2%	38.0%	6.5%	34.3%
2012	2.2%	2.3%	32.1%	63.4%	21.0%	30.5%	6.3%	42.3%
2013	0.4%	0.6%	28.5%	70.5%	18.6%	20.9%	8.2%	52.3%

Table 3-4 shows that, relative to large LSEs, small LSEs had a much higher percentage of their bids and offers in financial transactions (i.e., increments and decrements). Between 39.5% and 59.2% of their day-ahead bids and offers were financial transactions, while large LSE's submitted a maximum of 5% of their bids and offers in financial transactions.

Table 3-4
Average Load-Weighted Bids, by Load Size ($/MWh)

Year	Large Load-Serving Entity (Average Real-Time Load ≥100 MW)			Small Load-Serving Entity (Average Real-Time Load <100 MW)		
	Decrements	Increments	Price[(a)]	Decrements	Increments	Price[(a)]
2011	256.8	33.5	592.6	33.8	363.3	290.5
2012	114.7	40.8	594.2	13.1	546.7	290.7
2013	146.5	228.7	704.1	51.6	320.8	502.4

(a) Load-Weighted Bid Price = Sum (Bid Price × Segment MW)/Sum (Segment MW).

Figure 3-4 shows the average price by type of bid or offer for large and small LSEs. Large LSEs submitted high-priced decrement bids and low-priced increment offers until 2013 when their average increment bids increased from approximately $40/MWh to nearly $230/MWh. The large LSEs' strategy of submitting high decrements and price-sensitive demand bids appears to have been designed to increase the amount of their load clearing in the day-ahead energy market. The small LSEs' strategy of bidding low prices in decrements and high prices in increments is consistent with trying to arbitrage the price difference between the day-ahead and real-time energy markets.[123] Both large and small LSEs submitted high price-sensitive demand bids, which would clear in the day-ahead market in most hours. Both small and large LSEs increased their average price-sensitive demand bid prices in 2013, making the bids effectively the same as fixed demand bids.

The outcomes of the bidding and offering strategies are shown in Table 3-5. The results show that small LSEs cleared most of their load in fixed-demand transactions, and both small and large LSEs cleared a significant amount of their load in fixed-demand transactions. Small LSEs use price-sensitive demand bids less than the larger LSEs, relying instead on a greater amount of fixed demand bids and financial transactions.

Table 3-5
Percentage of Day-Ahead Market Cleared Bids and Offers, by Product and Load Size

Year	Large Load Serving Entity (Average Real-Time Load ≥100 MW)				Small Load Serving Entity (Average Real-Time Load <100 MW)			
	Decrements	Increments	Price-Sensitive Demand	Fixed Demand	Decrements	Increments	Price-Sensitive Demand	Fixed Demand
2011	1.7%	1.8%	29.5%	67.0%	9.3%	6.4%	12.7%	71.6%
2012	1.5%	0.8%	31.9%	65.8%	1.5%	4.3%	10.9%	83.3%
2013	0.2%	0.2%	28.3%	71.2%	6.2%	4.3%	11.6%	77.8%

RAA Commitment and Market Prices. Most days have few, if any, supplemental (out-of-market) commitments, and these few do not significantly distort energy prices. However, RAA commitments are needed on some days, such as when the ISO faces significant uncertainty about system conditions (e.g., concerns about resource availability, a highly variable weather forecast, or the threat of severe weather). For example, as discussed in Section 2.1.4, the tightening of natural gas supplies during winter 2013/2014 and the difficulties oil units faced maintaining sufficient on-site fuel resulted in increased uncertainty about unit availability. This led to several days with large RAA commitments. As discussed further below, large RAA commitments lower energy prices and send incorrect price signals during tight capacity situations.

The IMM calculated the difference between day-ahead and real-time Hub energy prices based on the amount of RAA commitment. As shown in Table 3-6, as the percentage of RAA commitment increased, the real-time price compared with the day-ahead price decreased. On days with little or no RAA commitment, the day-ahead price exceeded the real-time price by $0.50/MWh. When the RAA commitment increased to between 10 to 20% of actual load, real-time prices became $2.36 less on average than day-ahead prices. When the RAA commitment

[123] For example, an LSE's $20/MWh decrement will clear only if the Day-Ahead Energy Market price is below $20/MWh. The LSE will make money if the decrement clears and the real-time price exceeds $20/MWh.

was between 20% and 30% of actual load, real-time prices became $6.31 less on average than day-ahead prices. These last two conditions account for over 15% of the hours in the study period and often occurred when the risk of reliability problems was greater. The results of the analysis are consistent with the hypothesis that RAA commitments cause understated real-time prices relative to day-ahead prices, and they weaken the incentives for load to hedge in the day-ahead market.

Table 3-6
RAA Commitments/Actual Load Compared with Average Price Divergence, 2011 to 2013

RAA Commitment (Ecomax)/Actual Load (%)[(a)]	Average Price Divergence (Real-Time/Day-Ahead HUB LMP, $/MWh)	% of Hours
0–10	0.50	84.20
10–20	−2.36	13.14
20–30	−6.31	2.31
30–40	−19.18	0.33
40–50	−15.56	0.02

(a) The ecomax (economic maximum) 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.

In addition, the analysis shows that the day-ahead market systematically cleared less load than was realized in the real-time market. This is primarily the result of small LSEs purchasing a significantly lower percentage of their real-time load in the day-ahead market compared with large LSEs. This has at least two implications for market efficiency and reliability. First, when large amounts of RAA commitment are needed to maintain reliability (i.e., the day-ahead market does not clear sufficient capacity to support reliable operation in real time), real-time prices are noticeably lower than day-ahead prices. Because large RAA commitments often occur when the risk of reliability problems in real time are the greatest, real-time prices (and probably day-ahead prices as well) are not appropriately reflecting the reliability actions needed in real time.

Second, natural gas resources committed in the day-ahead energy market (and therefore presented with the opportunity to procure natural gas day ahead) have a much greater likelihood of obtaining natural gas than resources committed intraday. The fact that day-ahead load systematically clears less than real-time load increases the risk that natural gas resources may not be able to operate if called on in real time. In summary, the price signals sent by the Day-Ahead and Real-Time Energy Markets could be improved, such that the energy markets, rather than the ISO through the RAA process, provide market participants with the proper incentives needed to maintain reliability.

Recommendation. The IMM recommends that as part of the market development plan, the ISO study, develop, and implement a market-based reliability-commitment method to improve incentives for meeting reliability objectives and the efficiency of the Day-Ahead and Real-Time Energy Markets. A careful study of similar experiences at other domestic and international organized markets should be included as part of this project. The IMM recognizes that this is a long-term project requiring significant design work and software changes (see Section 3.1.6.2).

3.2 Financial Transmission Rights

This section summarizes the 2013 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.[124] 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.[125] 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.[126]

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 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

Forty-eight participants took part in at least one of the 13 FTR auctions in 2013, up slightly from the 47 participants who took part in at least one of the FTR auctions in 2012.

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

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

[126] *ISO New England Inc. Transmission, Markets, and Services Tariff*, Section III.5.2, *Market Rule 1* "Transmission Congestion Credit Calculation" (March 1, 2014), http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_sec_1-12.pdf.

The total megawatts bought and sold in the 2013 FTR auctions, regardless of directional flow, were 569,859 MW.[127] Of this total, the percentage of megawatts associated with counterflow positions was 16%, down from 24% in 2012. Counterflow FTR positions free up transmission capacity that otherwise would have been constrained. Figure 3-6 shows the volume of megawatts bought and sold in each monthly FTR auction in 2013.

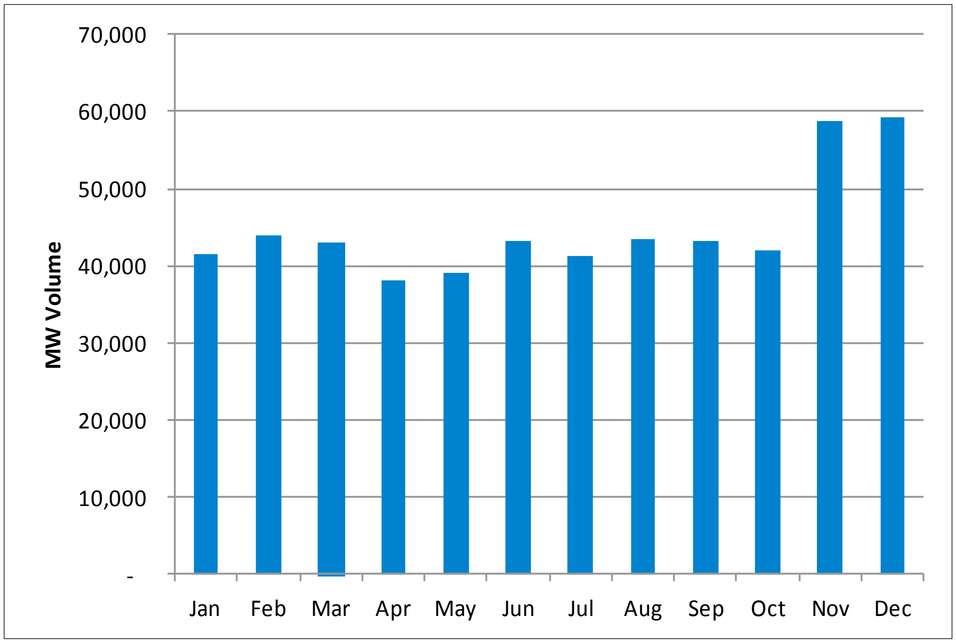

Figure 3-6: FTR monthly volumes, 2013 (MW).

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 $20.1 million, a 25% increase from 2012.[128] Of the $20.1 million in net revenue, $9.2 million was from the 12 monthly auctions.[129] See Figure 3-7.

[127] The totals were 536,630 MW in the 12 monthly auctions and 33,229 MW in the annual auction.

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

[129] Beginning in 2013, the FTR annual auction was revised from a single-round auction to a two-round auction. See ISO New England Inc. and NEPOOL, *FTR Annual and Monthly Auction Changes*, Docket No. ER12-2195-000, FERC filing (July 3, 2012), http://www.iso-ne.com/regulatory/ferc/filings/2012/jul/er12-2195-000_7-3-12_ftr_changes_part_1_of_2.pdf.

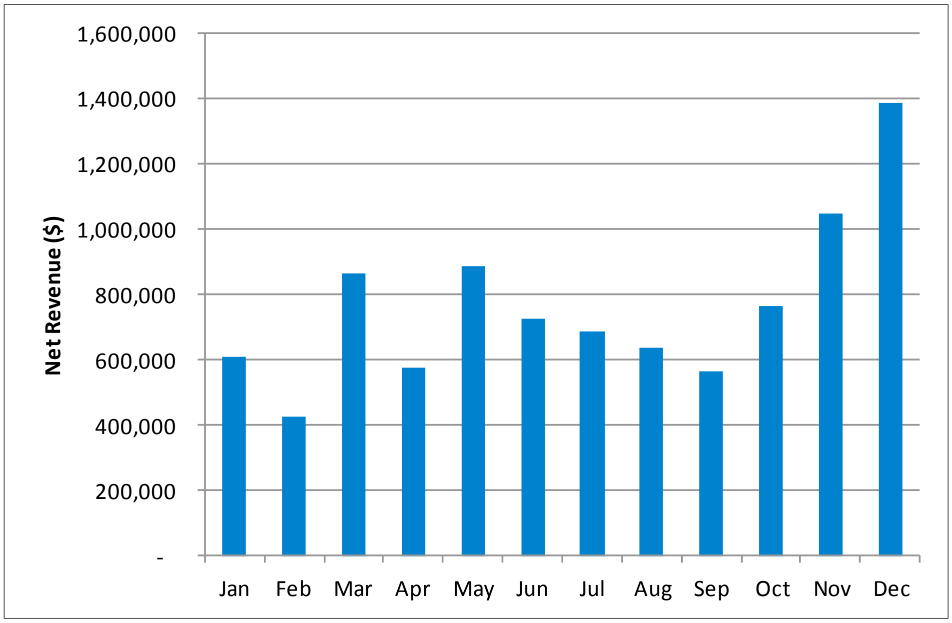

Figure 3-7: FTR monthly net revenues, 2013 ($).

If FTR participants had perfect foresight, the total auction revenue would equal the day-ahead congestion revenue; however, market prices, the actual availability of generators, and the actual outages on the transmission system differ from the assumptions in the FTR auction, causing actual congestion to be different from what cleared in the auction.

In 2013, the day-ahead congestion revenue was $46.2 million, an increase from the $29.3 million of day-ahead congestion revenue in 2012. 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, 48% of the day-ahead congestion revenue for 2013 resulted from just seven days. Five of these days occurred in the aftermath of a strong blizzard in February (Winter Storm Nemo) that caused unexpected outages and created congestion in pockets of New England (see Section 2.1.3.4). Although the day-ahead congestion revenue increased by 57% in 2013 compared with 2012, the total auction revenue increased by just 25% from $16.1 million in 2012 to $20.1 million in 2013. See Table 3-7.

Table 3-7
Comparison of Day-Ahead Congestion Revenue with Auction Revenue, 2011 to 2013

	Total Auction Revenue (Millions $)	Day-Ahead Congestion Revenue (Millions $)	Auction Revenue as % of Day-Ahead Congestion Revenue
2011	23.5	18.0	131%
2012	16.1	29.3	55%
2013	20.1	46.2	43%

The IMM reviewed the most active FTR participants in 2013. 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 most active participants with FTRs in 2013 were financial players who accounted for approximately 40% of total transacted megawatts. Financial players are more likely to buy and sell FTR positions many times as new information becomes available. See Figure 3-8.

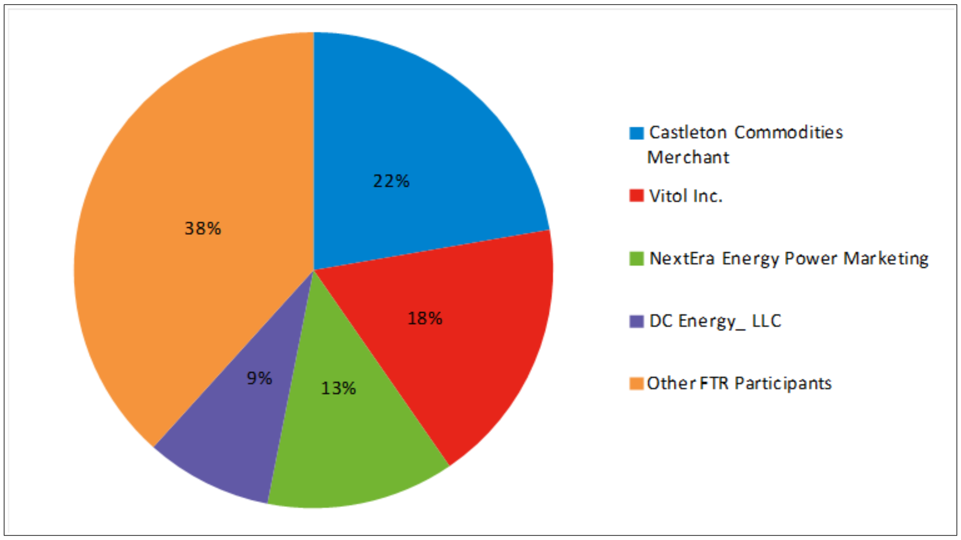

Figure 3-8: FTR participant activity, 2013 (%).

3.3 Forward Reserve Market

This section presents data about the outcomes of the two forward-reserve auctions conducted in 2013. The primary change in the Forward Reserve Market (FRM) in 2013 was a rule change that increased the system requirement for 10-minute nonspinning reserve, which caused an increase in clearing prices.[130]

To maintain system reliability, all bulk power systems maintain reserve capacity to respond to contingencies, such as unexpected outages (refer to Sections 2.1.1.2 and 2.1.6). The locational FRM procures operating-reserve capacity from participants with resources that can provide reserves, including 10-minute nonspinning reserve (TMNSR), 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

In 2013, FRM prices for the systemwide products increased in both the summer and the winter auctions. The 2013 summer systemwide TMNSR price increased 72.3% relative to the summer

[130] FERC, *Market Rule 1 Revision Relating to the Procurement of 10-Minute Nonspinning Reserve in the Forward Reserve Market*, *Docket No. ER13-465-000*, letter order (Issued February 8, 2013; effective March 1, 2013), http://www.iso-ne.com/regulatory/ferc/orders/2013/feb/er13-465-000_2-8-13_tmnsr_order.pdf.

of 2012. Similarly, the 2013 winter systemwide TMNSR price increased by 156%. These prices were the result of increases in the systemwide TMNSR requirements, as discussed below.

The clearing price in the FRM auction in summer 2013 was $5,946/MW-month. In the winter 2013/2014 auction, the clearing price for the TMNSR product was $8,451/MW-month, while the clearing price for the TMOR product was $6,290/MW-month. See Table 3-8.

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

Location	Product	Summer 2012	Winter 2012/2013	Summer 2013	Winter 2013/2014
CT	TMOR	3,450	3,301	5,946	6,290
NEMA/Boston	TMOR	3,450	3,301	5,946	6,290
SWCT	TMOR	3,450	3,301	5,946	6,290
Systemwide	TMNSR	3,450	3,301	5,946	8,451
Systemwide	TMOR	3,450	3,301	5,946	6,290

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 2013/2014 capacity commitment period (see Section 3.4) was $2,950/MW-month; the net payment received by reserve providers was $2,996/MW-month for the summer 2013 auction and $5,501/MW-month and $3,340/MW-month for TMNSR and TMOR, respectively, for the winter 2013/2014 auction. The winter 2013/2014 auction had price separation with the TMNSR and TMOR products, which is attributable to the increased systemwide reserve requirements.

3.3.2 Market Requirements

The ISO defines locational requirements, as well as a systemwide requirement, for each reserve product procured in the auction.[131] As noted above, in 2012 the ISO filed rules to increase the forward-reserve requirements in alignment with other efforts to improve system recovery from contingencies.[132] As a result, the systemwide requirements for TMNSR increased. The summer 2012 and winter 2012/2013 requirements were 815 MW and 820 MW, respectively. In summer 2013 and winter 2013/2014, these requirements increased to 1,349 MW and 1,532 MW, respectively. This represents a 65.5% increase in the summer requirements and an 86.8% increase in the winter requirements. See Table 3-9.

131 The TMNSR and TMOR requirements are based on first- and second-contingency losses (refer to Sections 2.1.6 and 2.2.1). The methodology to calculate these requirements is described in OP 8 (Section 2.2.1) and *the ISO New England Manual for Forward Reserve* (Manual M-36) (September 13, 2013), http://www.iso-ne.com/rules_proceds/isone_mnls/index.html.

132 The ISO proposed higher reserve requirements in 2012 to address risks identified in its Strategic Planning Initiative. This increase in reliability was acquired through the markets, including the local Forward Reserve Market. The increased requirement went into effect for the summer 2013 auction.

Table 3-9
Local Reserve Requirements
Summer 2013 and Winter 2013/2014 Forward Reserve Auctions (MW)

Location Name	Product	Summer 2012	Winter 2012/2013	Summer 2013	Winter 2013/2014
CT	TMOR[a]	765	837	747	578
NEMA/Boston	TMOR[a]	0	0	0	0
SWCT	TMOR[a]	0	50	0	155
Systemwide	TMNSR	815	820	1,349	1,532
Systemwide	TMOR[a]	1,565	1,595	723	915

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

The additional systemwide requirement increased the amount of TMNSR that would be procured during the summer 2013 and winter 2013/2014 periods. The 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 2013. For SWCT, the local reserve requirement was zero for the summer auction but was 155 MW for the winter 2013/2014 auction.

3.3.3 External Reserve Support

Through external reserve support (ERS), 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. See Table 3-10.

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

Location Name	Summer 2012	Winter 2012/2013	Summer 2013	Winter 2013/2014
CT	447	399	464	650
NEMA/Boston	822	1,080	1,224	2,109
SWCT	1,107	214	1,172	347

3.4 Forward Capacity Market

This section provides information on the 2013 outcomes of the Forward Capacity Auctions (FCAs), trends in capacity supply obligations, FCM performance, and the IMM's recommendations for the FCM.

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. 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 are held each year 40 months in advance of when 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).[133] 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 (see Section 2.1.3.4). 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.[134]

3.4.1 Capacity Market Auction Outcomes

This section reviews the outcomes and performance for the third through seventh 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 3-11 shows the following data for FCA #3 through FCA #7:

- Total amount of capacity cleared in each auction
- Amount of capacity needed (i.e., the net ICR [NICR])

[133] 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 *NPCC Regional Reliability Reference Directory #1 Design and Operation of the Bulk Power System*. This criterion states that the probability of disconnecting any firm load because of resource deficiencies shall be, on average, not more than 0.1 day per year.

[134] 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.

- Amount of surplus capacity
- Net capacity additions for that period
- Capacity price

Table 3-11
FCM Capacity Commitment Period Results, 2012/2013 to 2016/2017
(MW and $/kW-month)

Factor	FCM Capacity Commitment Period[a]				
	2012/ 2013	2013/ 2014	2014/ 2015	2015/ 2016	2016/ 2017
Cleared capacity resources (MW)	36,996	37,500	36,918	36,309	36,220
Net ICR (MW)	31,965	32,127	33,200	33,456	32,968
Surplus (MW)	5,031	5,373	3,718	2,853	3,252
Net capacity additions (MW)[b]	1,329	1,490	1,176	2,041	2,763
Capacity price ($/kW-month)	2.95	2.95	3.21	3.13	3.15 [c]

(a) The FCM period began June 1, 2010; the capacity commitment period 2012/2013 is for the third FCA.

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

(c) NEMA/BOSTON capacity price administratively set to $14.999/kW-mo. for new resources. All other resources were paid $3.15/kW-mo.

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 3-12 shows that the clearing prices in the annual reconfiguration auctions increased steadily and were significantly lower than the prices in the corresponding FCAs (shown in Table 3-11). The clearing price, while still less than the corresponding FCA, has closed the gap between the prices.

Table 3-12
Annual Reconfiguration Auction Clearing Prices and Quantities, 2012/2013 to 2015/2016 (MW and $/kW-month)

Commitment Period	Auction	Cleared CSOs (MW)	Clearing Price ($/kW-month)
2012/2013	ARA #2	636	0.94
	ARA #3	623	0.55
2013/2014	ARA #2	920	0.50
	ARA #3	767	0.59
2014/2015	ARA #2	653	1.75
2015/2016	ARA #1	419	1.31

Table 3-13 shows the clearing prices and quantities in the monthly reconfiguration auctions; prices in the monthly auctions also have increased for the 2013/2014 commitment period.

Table 3-13
Clearing Prices and Quantities in the Monthly Reconfiguration Auctions, 2012/2013 to 2013/2014 (MW and $kW-month)

Commitment Period	Average of Monthly Cleared CSOs (MW)	Weighted Average of Monthly Clearing Price ($/kW-month)
2012/2013	553	0.28
2013/2014	789	0.90

(a) All the monthly reconfiguration auctions have not been completed for all months in the 2013/2014 capacity commitment period.

For the 2012/2013 commitment period, the monthly prices ranged from $0.10/kW-month to $0.46/kW-month, and cleared volumes ranged from 273 MW (for August 2012) to 754 MW (for July 2013). The 2013/2014 commitment period, to date, has obtained prices ranging from $0.29/kW-month to $2.00/kW-month, whereas cleared volumes have ranged from 169 MW (for June 2013) to 1,344 MW (for February 2014).

3.4.2 Trends in Capacity Supply Obligations

Table 3-14 presents data for generation, demand response, and import capacity cleared in the FCA for each capacity commitment period from 2012/2013 to 2016/2017.

Table 3-14
FCA Cleared Capacity Resources for Each FCM Capacity Commitment Period, 2012/2013 to 2016/2017 (MW)

Factor	FCM Capacity Commitment Period				
	2012/ 2013	2013/ 2014	2014/ 2015	2015/ 2016	2016/ 2017
Installed generation[(a)]	32,228	32,247	31,439	30,757	31,641
Demand resources (capacity obligation)[(b)]	2,868	3,261	3,468	3,628	2,748
External capacity contracts[(a)]	1,900	1,992	2,011	1,924	1,830
Surplus above the ICR	5,031	5,373	3,718	2,853	3,252
Total capacity resources	36,996	37,500	36,918	36,309	36,220

(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 cap for real-time emergency generation (RTEG); see Section 3.5.1.

One trend has continued through the auction periods covered in Table 3-14: more capacity is clearing than is needed to meet the Installed Capacity Requirement. The surplus capacity rose to 5,373 MW after FCA #4 and dropped to 2,853 MW for FCA #6, before rising to 3,252 MW for FCA #7.

However, as shown in Table 3-15, resources have shed a portion of their CSO obtained in the FCA in advance of the CCP. The changes in CSOs are due to various actions a participant or the

ISO can take from the time of the FCA to the start of the CCP. These actions include the following:

- Electing to prorate (i.e., reduce) a resource's CSO in the event excess capacity is obtained in the FCA[135]
- Submitting offers in the ARA due to changes in the ICR[136]
- Participating in the ARA and monthly reconfiguration auctions to increase or decrease the CSOs between resource types
- Receiving a flag for having a significant decrease in capacity, which may result in a reduction in a resource's CSO
- Terminating a resource in accordance with *Market Rule 1*, Section III.13.3.4 or III.13.1.4.6.2, [137]

Obligations can also be reduced or eliminated, if capacity, previously held in the FCA for reliability, is released after the reliability constraint has been addressed.

Table 3-15 shows the change from FCA qualified capacity, from obtaining the initial obligation, to the result in the delivery month at the beginning of the commitment period. The June obligations shown in the table reflect the CSOs as of February 21, 2014, and the levels of activity that have occurred for that obligation month. Not all annual and monthly reconfiguration auctions have occurred for the 2014/2015, 2015/2016, and 2016/2017 commitment periods. For example, no reconfiguration auctions have occurred for the 2016/2017 commitment, while ARA #1 and a bilateral period have occurred for the 2015/2016 commitment period.

[135] As described in *Market Rule 1*, Section III.13.2.7.3, resources can elect to prorate the FCA CSO if the capacity clearing price floor was reached in the FCA and capacity in excess of the ICR was procured.

[136] As described in *Market Rule 1*, Section III.13.4.3, the ISO may submit supply offers and demand bids in ARAs to address year-to-year changes in the ICR.

[137] *Market Rule 1*, Section III.13.3.4 is "Covering Capacity Supply Obligation where Resource Will Not Achieve Commercial Operation by the Start of the Capacity Commitment Period." Section III.13.4.2.1.3 is "Significant Decrease in Capacity."

Table 3-15
FCA Qualified Capacity and Obligations, FCA #3 to FCA #7 (MW)

FCM Capacity Commitment Period	Resource Type	FCA Qualified Capacity	FCA Obligation[(a)]	June Obligation
2012/2013	Demand resource	3,364	2,898	2,012
	Generation	35,466	32,228	30,275
	Import	3,915	1,900	541
2013/2014	Demand resource	4,147	3,349	1,665
	Generation	33,665	32,247	29,702
	Import	2,600	1,992	1,258
2014/2015	Demand resource	4,146	3,590	2,209
	Generation	32,863	31,439	29,313
	Import	2,352	2,011	1,636
2015/2016	Demand resource	4,257	3,645	2,686
	Generation	32,209	30,757	29,162
	Import	2,135	1,924	1,642
2016/2017	Demand resource	3,674	2,748	2,464
	Generation	32,463	31,641	29,030
	Import	2,435	1,830	1,607

(a) This represents the FCA obligation before a resource's proration election and does not account for the 600 MW RTEG cap.

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.[138] 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; the first seven FCAs have 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 (CONE) can be attributed to several factors:[139]

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[138] The first year of service for FCM resources did not begin until June 2010, so, from December 1, 2006, to May 31, 2010, these resources were paid a flat-rate transition payment for maintaining their availability and developing new capacity. After the transition period ended, resources with CSOs obtained in the FCAs have been paid the Forward Capacity Auction clearing prices.

[139] The CONE is an estimate of the expected cost of adding new resources.

- **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 rate of approximately 1.0% per year from the 2006/2007 commitment period to the 2016/2017 commitment period.[140]
- **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 3-16 shows the new generation and new demand resources and the megawatts and percentages provided by OOM resources that cleared in FCA #3 to FCA #7.

Table 3-16
New In-Market and Out-of-Market Generation, New Demand Resources, and OOM Resources as a Percentage of these New Resources (MW, %)[(a)]

Type of Resource	FCA #3	FCA #4	FCA #5	FCA #6	FCA #7	Total
New generation and demand resources	512	659	305	393	1,045	2,914
In-market resources	239	111	124	257	970	1,776
Out-of-market resources	273	548	181	136	75	1,213
% OOM	53%	83%	59%	35%	7%	42%

(a) Net of repowerings and excluding imports.

Table 3-16 shows that 42% of new generation and new demand resources that have cleared in FCA #3 to FCA #7 have been out of market and that the percentage has ranged from 7% (FCA #7) to 83% (FCA #4). While both generation and demand resources both have cleared out-of-market capacity in the FCAs, Table 3-17 shows that a lower percentage of generation has been out of market.

[140] ISO New England, "Summary of ICR, LSR & MCL for FCM and the Transition Period," Excel worksheet, http://www.iso-ne.com/markets/othrmkts_data/fcm/doc/summary_of_icr_values%20expanded.xls.

Table 3-17
Percentage of Out-of-Market New Capacity,
by Resource Type, FCA #3 to FCA #7 (MW, %)[(a)]

Type of Resource	Total New Capacity Added (MW)	Total OOM Added (MW)	% OOM
Generation	1,268	429	34%
Demand	1,646	784	48%

(a) Net of repowerings and excluding imports

Because the capacity surplus at the start of each auction has been sufficient to cause the auction to clear at the floor price, OOM entry has not affected the market clearing price.

The Minimum Offer Price Rule (MOPR), which eliminated the auction floor price and included rule changes to implement a new buyer-side offer-floor mitigation mechanism into the auction, went into effect beginning FCA #8.[141] A part of this change is that new generation and new demand-resource capacity can no longer clear the auction as out-of-market capacity.

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.[142] 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 effective date (December 2010)of the February 17, 2011, FERC order through the end of 2012 (and in particular, for all of 2012), no hours had a positive hourly PER.[143] As a result, the PER adjustment fell to zero in December 2011, when all effects from a gas-based, calculated strike price ended.[144] PER adjustments increased in 2013 because of increased energy prices, which coincided with increased fuel input costs. See Table 3-18.

[141] 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.

[142] See FERC, *Order Accepting Tariff Provisions in Part, and Rejecting Tariff Provisions in Part*, 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.

[143] FERC order, February 17, 2011; see above note.

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

Table 3-18
Monthly PER Adjustments, 2011 to 2013 ($)

Month	2011	2012	2013
January	17,623,453	0	0
February	17,181,012	0	402,516
March	16,790,839	0	402,499
April	16,336,232	0	399,501
May	16,325,239	0	400,446
June	14,042,658	0	386,849
July	12,131,439	0	492,365
August	7,936,773	0	1,922,261
September	2,866,970	0	1,904,229
October	267,586	0	1,997,017
November	208,255	0	2,004,120
December	0	0	2,262,088
Total	121,710,456	0	12,573,891
Total 2011 to 2013			134,284,347

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 to 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.

3.4.3.3 Results of the Seventh Forward Capacity Auction

This section presents the results of the IMM's review of FCA #7, which covers the commitment period from June 1, 2016 to May 31, 2017. This was the first FCA to model import-constrained capacity zones, specifically the NEMA/Boston and the Connecticut zones. One of the modeled import-constrained zones, NEMA/Boston cleared at $14.999/kW-month for new resources, $11.849/kW-month higher than the floor price of $3.150/kW-month. All new resources received this clearing price. All existing resources received $6.661/kW-month. The pricing for existing resources was determined using administrative pricing rules designed to protect the market from the exercise of market power. These administrative pricing provisions were used for the NEMA/Boston zone because competition among new resources was insufficient for setting a competitive price.[145]

Requirements. Table 3-19 shows the system and local capacity requirements for FCA #7. Approximately 33,000 MW of capacity were needed to ensure systemwide resource adequacy. At the local level, capacity purchases from the Maine zone were limited to 3,709 MW because of an export constraint. The Connecticut and NEMA/Boston zones are import-constrained zones. A local-sourcing requirement for CT of approximately 7,600 MW and an LSR for NEMA/Boston of approximately 3,200 MW were included for each region in the auction.

[145] *Market Rule 1*, Section III.13.2.8.2, details the conditions that determine *insufficient competition*.

Table 3-19
Capacity Requirements or Limits for FCA #7 (MW)

Auction	Net Installed Capacity Requirement	Maximum Capacity Limit	Local-Sourcing Requirement	
	Systemwide	Maine	CT	NEMA/Boston
FCA #7	32,968	3,709	7,603	3,209

Resource Qualification. Table 3-20 summarizes the existing and new qualified capacity for FCA #7 by zone and compares this capacity to the relevant capacity requirement (i.e., NICR, MCL, and LSR). Systemwide, existing capacity (35,117 MW) was approximately 2,100 MW greater than the NICR of 32,968 MW. For the local zones, existing capacity slightly exceeded the MCL for Maine; new capacity in Maine added to this excess. In the import-constrained areas, Connecticut was able to satisfy its local capacity requirement with existing capacity, and proposed new capacity for Connecticut added a small amount to the area totals. NEMA/Boston lacked sufficient existing capacity to satisfy the local capacity requirement; therefore, the NEMA/Boston zone required new capacity to meet its LSR.

Table 3-20
Qualified Capacity Compared with Requirement or Limit, FCA #7 (MW)

Zone	Existing	New	Total	Capacity Requirement or Limit
Connecticut	9,012	70	9,082	7,603
Maine	3,771	334	4,104	3,709
NEMA/Boston	3,033	721	3,754	3,209
Rest-of-Pool	19,301	2,332	21,633	n/a
Total	35,117	3,456	38,573	32,968

Table 3-21 shows the breakdown of qualified capacity by resource type for each zone. Proposed new additions to capacity were small compared with import resources in the Rest-of-Pool zone and generator resources in NEMA/Boston. Consistent with the ISO tariff rules, import capacity qualifies as new capacity in each auction. Therefore, import capacity receives an annual, rather than long-term, obligation to supply capacity to the New England market if it clears. For FCA #7, almost all the "new" capacity within the Maine zone was import capacity.

Table 3-21
Qualified Capacity by Resource Type and Qualification Status, FCA #7 (MW)

Zone	Existing			Existing Total	New			New Total	Total
	Demand	Generator	Import		Demand	Generator	Import		
Connecticut	970	8,042	0	9,012	63	7	0	70	9,082
Maine	500	3,271	0	3,771	26	0	308	334	4,104
NEMA/Boston	476	2,558	0	3,033	47	674	0	721	3,754
Rest-of-Pool	1,474	17,714	112	19,301	119	197	2,015	2,332	21,633
Total	3,419	31,585	112	35,117	255	878	2,323	3,456	38,573

Auction Results. Table 3-22 summarizes the auction results by round for the system. Except for NEMA/Boston, all zones descended to the floor price with surplus capacity remaining at the auction's conclusion.

Table 3-22
Results by Auction Round, FCA #7

Auction Round	Systemwide Pricing ($/kW-mo)	Systemwide Capacity Excess (MW)
Round 1	15.00–9.00	4,430
Round 2	9.00–7.50	4,430
Round 3	7.50–6.00	4,321
Round 4	6.00–4.84	4,221
Round 5	4.84–4.54	3,128
Round 6	4.54–3.85	3,056
Round 7	3.85–3.15	3,048
Auction price for new capacity	3.15	
Auction price for existing capacity	3.15	

The descending clock for NEMA/Boston stopped in the auction's first round when new capacity, needed to meet the reliability need, sought to withdraw from the auction at $14.998/kW-month. Because existing capacity within the zone was insufficient to meet the LSR, and a single new generation resource proposed for NEMA/Boston could determine that zone's ability to meet the LSR, the zone was deemed to have insufficient competition.[146] Under the ISO's tariff applicable to FCA #7, new and existing capacity resources within the NEMA/Boston zone received different prices from the other zones in the auction. The *new* capacity in NEMA/Boston was given the capacity clearing price (i.e., $14.999/kW-month), while existing capacity in NEMA/Boston, also needed to meet the LSR, was given 1.1 times the CONE, or $6.661/kW-month for FCA #7.

For FCA #7, 268 delist bids from existing capacity resources were entered in the auction. The ISO accepted all these bids for a total of 1,660 MW, provided by both demand resources (916 MW) and generation resources (744 MW). All the delist bids were for a single year, allowing these resources to retain the option of re-entering the capacity market during FCA #8. See Table 3-23.

[146] Insufficient competition also could apply under other circumstances.

Table 3-23
Delisted Capacity by Zone and Resource Type, FCA #7 (MW)

Zone	Demand	Generator	Total
Connecticut	355	348	703
Maine	63	83	146
NEMA/Boston	17	21	38
Rest-of-Pool	481	292	773
Total	916	744	1,660

Cleared Capacity Summary. Table 3-24 summarizes the cleared capacity (MW) from the auction, by zone and resource type. Generators represented approximately 87% of cleared capacity, while demand and import resources represented 8% and 5%, respectively.

Table 3-24
Cleared Capacity Compared to Local Requirement or Limit, FCA #7 (MW)

Capacity Zone	Demand Resource	Generator	Imports	Total	Local Requirement or Limit at Auction's Conclusion	Excess Capacity
Connecticut[(a)]	677	7,694	0	8,372	7,703	669
Maine	454	3,188	308	3,950	3,709	241
NEMA/Boston	505	3,211	0	3,716	3,209	507
Rest-of-Pool[(b)]	1,112	17,548	1,522	20,182	17,840	2,342
Total	2,748	31,641	1,830	36,220	n/a	n/a

(a) Pursuant to the *Market Rule 1*, Section III.13.2.3.3(e), the LSR for Connecticut increased by 100 MW, as result of a 100 MW administrative export bid passing through the Connecticut zone.

(b) The capacity requirement and excess capacity values are implied values for the Rest-of-Pool zone because these values are not explicitly modeled for the auction. The requirement for Rest-of- Pool is implied by the NICR minus the zonal requirements and the excess capacity in NEMA/Boston. Excess Rest-of-Pool capacity is simply the difference between the total cleared capacity and the requirement.

3.4.3.4 FCM Performance Incentives

As discussed in the *2012 Annual Markets Report*, design features of the FCM, built to ensure that resources perform when system reliability is at risk, have not been effective. Through the end of 2013, only one shortage event has occurred, and peak energy rent deductions remain low compared with total FCM payments (see Section 2.1.3.4).

The ISO has undertaken several actions to strengthen the FCM incentive structure:

- **Definition of the FCM Shortage-Event Trigger (implemented November 2013):** On November 1, 2013, FERC issued an order that accepted expanding the definition of an FCM shortage event.[147] Effective November 3, 2013, a shortage event can be triggered when the Reserve Constraint Penalty factor for 30-minute operating reserves is

[147] FERC, *ISO England Inc. and New England Power Pool Order on Proposed Tariff Revisions*, Docket No. ER13-2313-000, letter order (Issued November 1, 2013), http://www.iso-ne.com/regulatory/ferc/orders/2013/nov/er13-2313-000_11-1-13_order_shortage_events.pdf.

activated for 30 or more contiguous minutes and Action 2 under OP 4 is implemented for the same 30 contiguous minutes. Under the prior rule, a shortage-event was triggered only when an RCPF was activated for 10-minute nonspinning reserves for 30 or more contiguous minutes.

- **FCM Pay-for-Performance (PFP) Market Design (proposed on January 17, 2014, with a requested effective date for the 2018/2019 capacity commitment period):** On January 17, 2014, the ISO filed a proposal to modify the FCM design to more strongly link capacity payments to resource performance during scarcity conditions.[148] The pay-for-performance design is based on the two-settlement logic generally used in forward markets, which entails two key elements. The first element is a forward position in which a quantity of capacity is obligated, or sold, in the capacity auction. Each megawatt is paid at the auction clearing price, and the sale creates a resource-specific physical obligation and forward financial position in the capacity market. A resource's forward financial position is a share of the system's energy and reserve requirements during reserve deficiencies. The second element includes a settlement for deviations. A resource that delivers more than its share of the system's requirements during a reserve deficiency (i.e., an overperformer) will be paid for that incremental production. If it delivers less than its share (i.e., it underperforms), it will "buy out" of its position by paying other resources that did deliver. Positive and negative deviations are paid or charged at the same rate prespecified in the tariff.

  The two-settlement approach is standard in forward contracts, both for electricity and commodities, ranging from oil to pork bellies to iron ore. In fact, the two-settlement design underlies the design of New England's day-ahead and real-time electricity markets and is well understood by stakeholders.

  Under PFP, consumers will pay the auction clearing price to all resources that clear in the auction. Because the overperformers will be paid by the underperformers, consumers will not bear the short-run risk of covering any unexpectedly high performance payments. This will continue to provide consumers with a predictable capacity price three years out, after the close of each Forward Capacity Auction. Having underperformers pay overperformers will also provide strong incentives for each resource to perform as needed and for overperformers to benefit by helping meet the system's needs. These incentives will place performance risk on all FCM resources, and each resource will need to price this risk in its future capacity auction bids.

3.4.4 Update on Forward Capacity Market Recommendations

In the *2011 Annual Markets Report and the 2012 Annual Markets Report*, the IMM made several recommendations:

- Eliminate the price floor in upcoming auctions and implement the Minimum Offer Price Rule (MOPR)
- Align FCM and energy market incentives through several means:
  - Implement hourly offers and intraday offers

[148] ISO New England Inc. and NEPOOL, *Filings of Performance Incentives Market Rule Changes*, Docket No. ER14- -000, FERC filings, parts 1 and 2 (January 17, 2013), http://www.iso-ne.com/regulatory/ferc/filings/2014/jan/index.html.

- Provide stronger performance incentives, such as penalties for failing to deliver energy in real-time
- Implement a demand curve, along with design features intended to add elasticity to the curve (to dampen capacity price volatility).

The MOPR, which eliminated the auction floor price and included rule changes to implement a new buyer-side offer-floor mitigation mechanism into the auction, went into effect beginning FCA #8.[149]

As discussed previously, the ISO has filed enhancements to both the energy markets and the Forward Capacity Market to help align the FCM and energy market incentives. The IMM supports these proposals.

With respect to the implementation of a demand curve, the ISO made a compliance filing on April 1, 2014, in response to a FERC order requiring the ISO to develop a demand curve for inclusion in FCA #9.[150]

3.5 Demand Response

The following section reviews the participation and outcomes of demand resources in New England for 2013. The section also continues the IMM's analysis of the accuracy of the ISO's methodology for determining an asset's baseline and load reductions.

3.5.1 Background and 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 FCM where they compete in the Forward Capacity Auctions, take on capacity supply obligations, and receive capacity payments comparable to other supply-side resources. 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.

In addition to *real-time demand response* (RTDR) resources, which reduce load within 30 minutes of receiving an ISO dispatch instruction, active demand resources include *real-time emergency generation* (RTEG) resources, which reduce load by transferring load that otherwise

[149] 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.

[150] The ISO and NEPOOL jointly filed tariff changes to establish a systemwide sloped demand curve and related parameters for use in the FCM. The changes will become effective on June 1, 2014, and will be used in FCA #9 to be held in February 2015. ISO New England Inc. and NEPOOL, *Demand Curve* Change, Docket No. ER14-___-000, FERC filing (April 1, 2014), http://www.iso-ne.com/regulatory/ferc/filings/2014/apr/index.html. FERC, *ISO New England Inc., Order on Tariff Filing*, Docket No. ER14-463-000 (January 24, 2014), http://www.iso-ne.com/regulatory/ferc/orders/2014/jan/er14-463-000_1-24-14_exigent_circum_order.pdf.

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* (DG) that reduce load during predefined periods, and seasonal-peak resources, such as energy-efficiency projects where the project's load reduction is weather sensitive.[151]

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). An optional program, the Transitional Price-Responsive Demand (TPRD) Program, designed to comply with FERC Order 745, replaced both the RTPR program and the DALRP and is currently in effect.[152] Similar to the DALRP, the TPRD program allows market participants with assets registered as RTDR resources to offer load reductions in response to day-ahead LMPs. Market 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 will 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.[153]

3.5.2 Demand Resources in the Forward Capacity Market

As shown in Table 3-25, the total CSO for all demand resources participating in the FCM decreased by 11% in 2013 compared with 2012, a loss of 189 MW. The CSOs of active demand resources accounted for a reduction of 350 MW (47%). The large reduction in CSOs over the year is mainly attributable to the retirement of assets for the current commitment period by a lead participant.

[151] 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). RTEG is distributed generation the ISO calls on to operate during a 5% voltage reduction that requires more than 10 minutes to implement (i.e., OP 4 Action 6 or more severe actions) but must limit its operation to 600 MW to comply with the generation's federal, state, or local air quality permit(s) and the ISO's market rules.

[152] 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.

[153] 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.

Table 3-25
Capacity Supply Obligations by Demand-Resource Type, December 2012 and December 2013 (MW)

	Active Demand Resources			Passive Demand Resources			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	
Dec 2012	446	299	745	723	256	979	**1,724**
Dec 2013	268	127	395	812	328	1,140	**1,535**
2012 to 2013 % change	−40%	−58%	−47%	12%	28%	16%	**−11%**

Two participants accounted for nearly 75% of the RTDR and RTEG resources. Figure 3-9 illustrates the market participants with active demand resources as of December 2013, as well as the percentage of CSOs (in MW) represented by these participants.

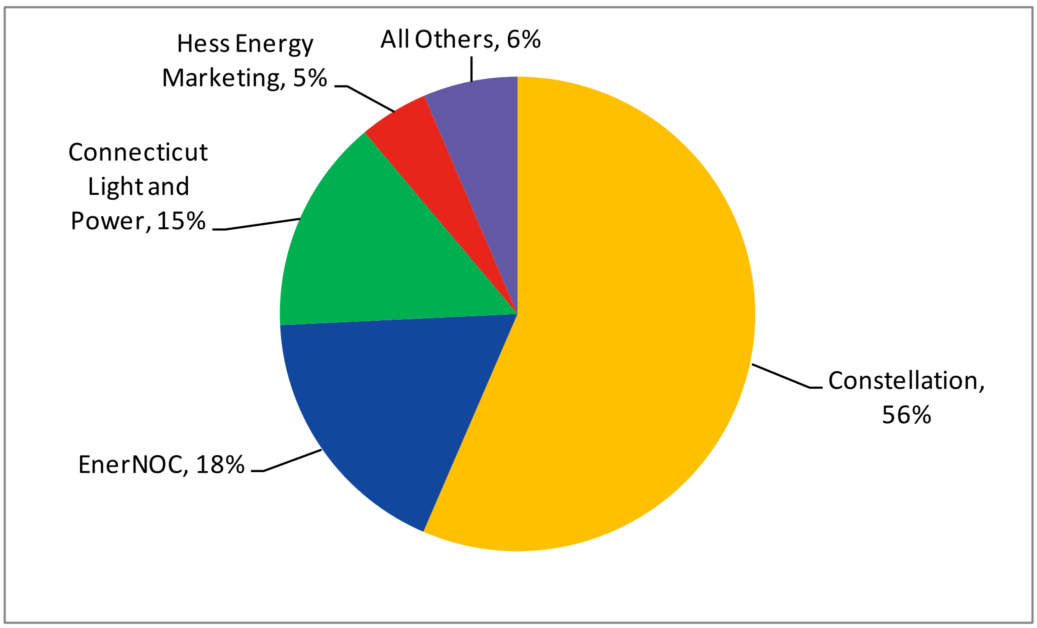

Figure 3-9: Distribution of active demand-resource CSOs (in MW) by lead participant, as of December 2013 (%).

Figure 3-10 illustrates the market participants with passive demand resources as of December 2013, as well as the percentage of CSOs (in MW) represented by these participants. Similar to December 2012, the top two participants accounted for approximately 40% of the total.

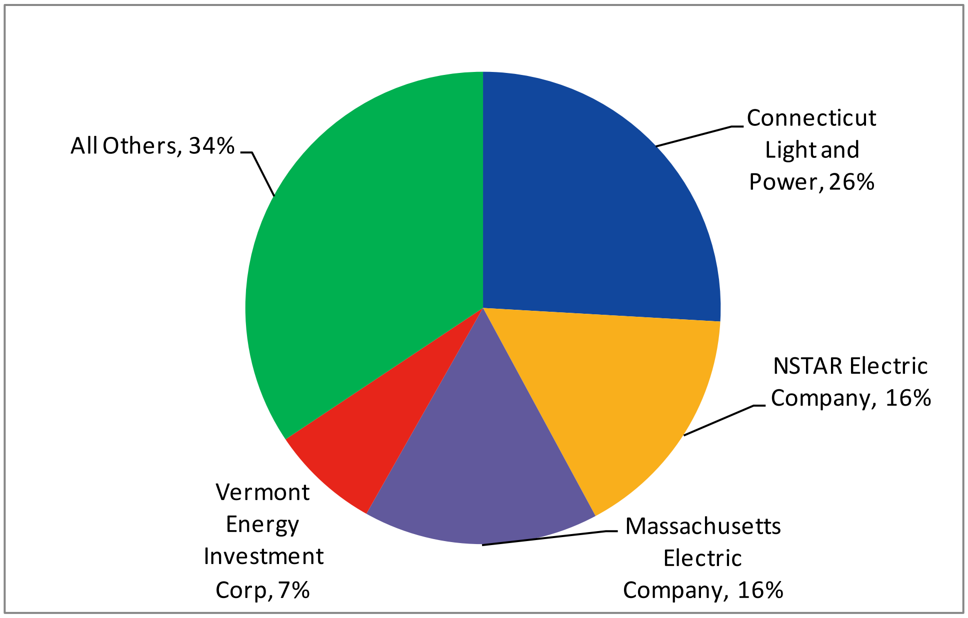

Figure 3-10: Distribution of passive demand-resource CSOs (in MW) by lead participant, as of December 2013 (%).

Typically, the market participants that provide demand-response services offer most of the active demand resources, while the market participants that are investor-owned utilities and part of state-sponsored energy-efficiency programs offer most of the passive demand resources.

3.5.3 Demand-Resource Payments

As shown in Table 3-26, demand-resource payments totaled $92.2 million in 2013 compared with $91.6 million in 2012, an increase of 0.7%. Capacity payments are based on the FCM capacity clearing price and capacity values determined pursuant to the rules of the FCM. Total demand-resource capacity payments were slightly lower in 2013 compared with 2012. Capacity payment rates ($/kW-month) were lower in 2013 relative to 2012.

Table 3-26
Total Payments to Demand-Response Resources, 2012 and 2013 ($)

Year	Capacity Payments	DALRP Payments[(a)]	RTPR Payments[(a)]	Transitional PRD Payments[(a)]	Total Payments
2012	89,324,240	527,046	51,767	1,681,447	91,584,500
2013	87,476,470	0	0	4,723,496	92,199,966
Change	−1,847,770	−527,046	−51,767	3,042,049	615,466
% Change 2012 to 2013	−2.1%				0.7%

(a) The DALRP and the RTPR programs 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 2013, approximately 5%, was for load reductions in the current transitional Price-Responsive Demand Program.

3.5.4 Accuracy in Estimating Baseline Load Reductions

A baseline is used to forecast an asset's typical hourly load during periods when the asset is not reducing load in response to a price signal or an ISO dispatch instruction, such as for an audit or an OP 4 event (see Section 2.1.3.4). To estimate the asset's load reduction during an event, the ISO compares the asset's reduced load to the baseline.[154]

In 2012, the ISO made several changes to the methodology for determining the baseline loads for active demand resources. The changes were made to improve the accuracy of the baseline as well as the load-reduction estimates. The initial baseline calculation, the adjustment of the baseline, and how baselines are refreshed were revised. *Market Rule 1* contains additional details on the calculation of baselines.[155]

The accuracy of an asset's baseline is paramount in determining a reliable estimate of the asset's load reduction as well as proper compensation for the load reduction. Also, accurate baselines and load reductions provide ISO system operators with a reliable estimate of the total megawatts reduced during ISO OP 4 events. Beginning in June 2012, and following up in 2013, the IMM assessed how well the baselines forecast an asset's load over a specified period.

Methodology. For any given day, the IMM calculated an asset's baseline using a method similar to the ISO's methodology described in Section III.8A of *Market Rule 1*. The asset's baseline was then compared with the asset's actual metered load. 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:

- **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 somewhat cancel out, resulting in a near zero bias.
- **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

[154] OP 4 is available at http://www.iso-ne.com/rules_proceds/operating/isone/op4/ (October 5, 2013).

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

distribution. To understand the magnitude-of-forecast error, the IMM calculates the mean absolute percentage error (MAPE).

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. Additional details on the calculations and the methodology used to analyze the accuracy of the baseline is included in the *2012 Annual Markets Report*.[156]

The data used for the IMM analysis includes daily data from January 1, 2013, through December 31, 2013. 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.[157] As of December 2013, the system had approximately 600 load-only assets.

Results. Figure 3-11 illustrates the daily baseline-bias percentage from January 1, 2013, through December 31, 2013. Each point represents the median value of all the calculated bias values for each load-only asset by day for the predefined hours of noon to 6:00 p.m. A median value of zero for a particular day indicates 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 within plus or minus 1%, the October baseline projections do have a slight positive bias. A possible explanation is the change of season, where the end of the cooling season (less air-conditioning usage) would lead to lower usage relative to where the baseline would be projected. Overall, however, the data indicate that the current methodology for determining baselines performs well throughout the year.

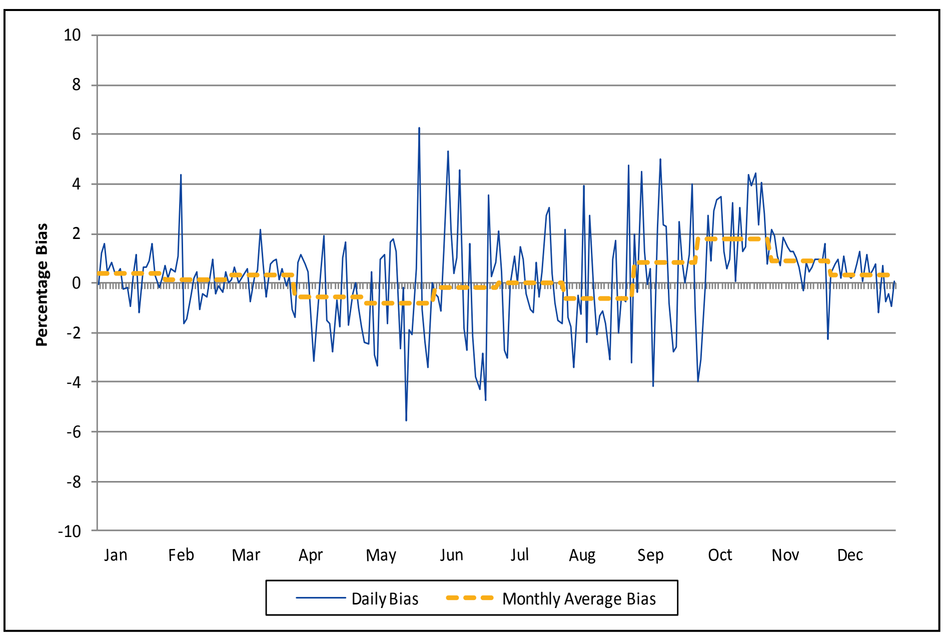

Figure 3-11: Daily baseline forecast bias, January through December 2013.

[156] *2012 Annual Markets Report* (May 15, 2012), Section 2.1.4.4, http://www.iso-ne.com/markets/mktmonmit/rpts/other/index.html.

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

By month, for each load-only asset for each nonevent day, a MAPE was calculated over the hours from noon to 6:00 p.m. Then, a monthly distribution of the MAPEs was constructed. Table 3-27 illustrates several percentiles of these monthly distributions. For example, in April, for half the assets, the current baseline methodology forecasts the actual hourly energy from noon to 6:00 p.m. within 7.5% of the actual values. For the other half of the assets, the forecast MAPE is greater than 7.5%. The median MAPE by month is fairly consistent, ranging from a low of 6.9% in August to a high of 9.1% in February. However, the current baseline methodology does not work well for some assets; assets where the MAPE is at the 90th percentile have forecast errors of 30% or greater.

Table 3-27
Mean Absolute Percentage Error by Month and Percentile, 2013

Month	10th Percentile	25th Percentile	Median	75th Percentile	90th Percentile
Jan	1.9	3.6	7.7	15.5	30.0
Feb	2.1	4.0	9.1	18.6	35.0
Mar	1.9	3.8	7.5	15.2	32.3
Apr	1.9	3.8	7.5	15.2	32.3
May	3.9	5.8	9.2	15.7	30.2
Jun	3.9	5.4	8.3	16.5	33.1
Jul	3.5	4.8	7.7	16.6	41.7
Aug	3.3	4.4	6.9	15.5	38.3
Sep	3.9	5.2	8.5	16.1	33.8
Oct	3.3	4.5	7.9	15.4	37.3
Nov	2.3	3.6	7.7	17.4	45.9
Dec	1.8	3.2	9.0	20.8	51.4

The above findings suggest that the changes the ISO implemented beginning June 2012 in calculating baselines (the initial baseline calculation, the symmetric adjustment of baselines, and how baselines are refreshed) have had the desired result for most load-only assets. The baseline forecast is typically within 5% of actual load values for a quarter of the assets and under 10% for half the assets. These assets typically have stable daily load shapes, and the current baseline methodology works extremely well in predicting their energy consumption. However, for assets with MAPEs in the 90th percentile and beyond, the ISO's baseline methodology produces a forecast that does not accurately predict the asset's actual load. Some of these assets have highly variable daily loads, such that the current baseline calculations cannot construct a baseline with the degree of accuracy needed for estimating an asset's load reduction. In other cases, the ISO has received erroneous data or no data, which also would lead to an inaccurate prediction.

To give a sense of the impact that the baseline error can have on the overall estimated load reductions, the IMM summed the estimated load reductions during the July 19, 2013, OP4 event for all load-only assets that had large baseline errors (i.e., MAPE at the 90th percentile or above).[158] Assets with large baseline errors accounted for about 20 MW, or 17% of the total

[158] *Q3 2013 Quarterly Markets* Report (November 13, 2013), Section 2.1.1.2, http://www.iso-ne.com/markets/mkt_anlys_rpts/qtrly_mktops_rpts/index.html.

load reduction from load-only assets on that day. Therefore, as a result of the large baseline error, it is difficult to have confidence in the 20 MW estimated load reduction from this group of assets.

3.5.5 Demand-Response Recommendations

The ISO has several recommendations regarding the determination of the baselines for demand-response assets with highly variable loads and the submission of meter data by market participants.

3.5.5.1 Recommendation on Highly Variable Loads

The ISO is currently researching alternative baseline methodologies to specifically address those assets that have highly variable load profiles. Given the findings from the above analysis, the IMM recommends that the ISO continue researching other methods in constructing baselines for those assets that do not meet a specific threshold for accuracy.

3.5.5.2 Recommendation on the Submission of Meter Data

The IMM has observed instances of market participants' either submitting inaccurate meter data to the ISO or missing meter data 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.[159]

Inaccuracies resulting from the submittal of erroneous data can be remedied by process changes. The IMM recommends, as in the *2012 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 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.

[159] *ISO New England Manual for Measurement and Verification of Demand Reduction Value from Demand Resources*, (Manual M-MVDR) (November 8, 2013), http://www.iso-ne.com/rules_proceds/isone_mnls/index.html.

Section 4
Other Market Information

In 2013, 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.

4.1 SOC 1 Type 2 Examination

In November 2013, the ISO successfully completed a SOC 1 Type 2 examination, which resulted in an "unqualified opinion" about the description of the market administration 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 user entities in evaluating their internal controls over financial reporting.

The 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, 2012, through September 30, 2013. The SOC 1 Type 2 examination reviews the following:

- The auditor's opinion on the fairness of the description of the market administration 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 user entities 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 2013 SOC 1 Type 2 report is available to participants upon request through the ISO external website.[160]

4.2 Market-System Software Recertification

The ISO has committed to 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.[161] This recertification takes place every two years or sooner, in

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[160] 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, 2012, to September 30, 2013*. 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.

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

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 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 2013, PA Consulting issued the following certifications:

- Auction Revenue Rights Market Software, November 27, 2013
- Financial Transmission Rights Market Software, November 27, 2013
- Locational Forward Reserve Market Software, February 19, 2013
- Locational Marginal Price Calculator Market Software, May 22, 2013
- Simultaneous Feasibility Test Market Software, March 21, 2013 and November 27, 2013
- Scheduling, Pricing, and Dispatch—Day-Ahead Market Software, May 22, 2013
- Scheduling, Pricing, and Dispatch—Unit Dispatch and Scheduling Market Software, May 22, 2013
- Forward Capacity Auction Market Clearing Engine Software, October 31, 2013
- Forward Capacity Reconfiguration Auction Clearing Engine Software, December 5, 2013

4.3 Internal Audits

The ISO New England Internal Audit Department conducted a number of internal controls and compliance audits in the Forward Capacity Market, demand-resource, and information technology areas.

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
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
CCGT	combined-cycle gas turbine
CCP	capacity commitment period
CONE	cost of new entry
CPS 2	NERC *Control Performance Standard 2*
CSO	capacity supply obligation
CT	State of Connecticut, Connecticut load zone, Connecticut reserve zone
CTS	Coordinated Transaction Scheduling
DALRP	Day-Ahead Load Response Program
DG	distributed generation
DOE	US Department of Energy
DOJ	US Department of Justice
ecomax	economic minimum limit
ecomin	economic maximum limit
EIA	US Energy Information Administration (of DOE)
EMM	External Market Monitor
ERS	external reserve support
F	fahrenheit
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
FPA	fuel-price adjustment
FRM	Forward Reserve Market
FTR	Financial Transmission Right
GM	gross margin

Acronyms and Abbreviations	Description
GPA	generator performance audit
GWh	gigawatt-hour
HE	hour ending
HHI (also H)	Herfindahl-Hirschman Index
ICE	Intercontinental Exchange, Inc.
ICR	Installed Capacity Requirement
IMM	Internal Market Monitor
ISO	Independent System Operator, ISO New England
ISO tariff	*ISO New England Transmission, Markets, and Services Tariff*
kV	kilovolt
kW	kilowatt
kWh	kilowatt-hour
kW-mo	kilowatt-month
L	symbol for the competitiveness level of the LMP
LEG	limited-energy generator
LMP	locational marginal price
LMPc	LMP calculator
LSE	load-serving entity
LSR	local sourcing requirement
M-36	*ISO New England Manual for Forward Reserve*
MAPE	mean absolute percent error
MCL	maximum capacity limit
MDE	maximum daily energy
ME	State of Maine and Maine load zone
Min Gen	Minimum Generation (Min Gen Emergency)
M/LCC2	Master/Local Control Center Procedure No. 2, *Abnormal Conditions Alert*
MMBtu	million British thermal units
MMcf/d	Million cubic feet per day
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

Acronyms and Abbreviations	Description
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
NICR	net Installed Capacity Requirement
NPCC	Northeast Power Coordinating Council
NY	State of New York
NYISO	New York Independent System Operator
OATT	*Open Access Transmission Tariff*
OOM	out of market
OP 4	ISO Operating Procedure No. 4
OP 8	ISO Operating Procedure No. 8
PER	peak energy rent
PFP	pay for performance
PJM	PJM Interconnection, L.L.C.
PNGTS	Portland Natural Gas Transmission System
pnode	pricing node
PRD	price-responsive demand
Q	quarter
RAA	reserve adequacy analysis
RCP	regulation clearing price
RCPF	Reserve Constraint Penalty Factor
RI	State of Rhode Island, Rhode Island load 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
SEMA	Southeast Massachusetts load zone
SOC 1	present audit of market operations and settlement systems
SWCT	Southwest Connecticut
TMNSR	10-minute nonspinning reserve
TMOR	30-minute operating reserve
TMSR	10-minute spinning reserve

Acronyms and Abbreviations	Description
TPRD	transitional price-responsive demand
TTC	total transfer capability
UDS	unit dispatch and scheduling
US	United States
VT	Vermont and Vermont load zone
WCMA	Western/Central Massachusetts