2013 Fourth Quarter

Quarterly Markets Report

Internal Market Monitor
February 10, 2014

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Section 1
Executive Summary

The Internal Market Monitor[1] has analyzed the performance in the fourth quarter of 2013 of the region's wholesale electric energy, reserve and capacity markets using supply offers, demand bids, fuel prices, market results, and other economic data. Overall, market prices reflected the cost of providing energy, and energy market outcomes have been competitive. The market performance during the Operational Procedure #4 (OP4) event on December 14 is described in detail in Section 2 of this report. Section 3 details market outcomes over the period.[2]

1.1 Summary of Market Outcomes and Performance

- The total cost of electric energy in the Reporting Period was $2.33 billion, a 37% increase over the same period in 2012 (see Section 3.1.1).
    - Average gas prices were the primary driver in the increase in total energy costs in the Reporting Period. Natural gas prices during the Reporting Period averaged $7.74/MMBtu (see Section 3.1.2). This is a 41% increase from Q4 2012.
    - Higher ancillary service costs resulted from the implementation of rule changes that increased the amount of reserves purchased in the Forward Reserve Market, the implementation of replacement reserves which effectively increased the real-time system 30-minute requirements, and rule changes that included opportunity costs in the calculation of the Regulation Clearing Price.
- Day-Ahead Energy Market prices during the Reporting Period averaged $57.50/MWh at the Hub, and Real-Time prices averaged $60.24/MWh (see Section 3.1.2). Day-Ahead prices were 27% higher than Q4 2012, and Real-Time prices were 35% higher than Q4 2012.
    - Higher natural gas prices in the fourth quarter were the primary driver for higher Day-Ahead and Real-Time prices when compared to Q4 2012.

[1] Capitalized terms used but not defined in this report are intended to have the meanings given to such terms in the ISO New England Inc. Transmission, Markets and Services Tariff ("ISO Tariff") or in ISO operating procedures. The ISO Tariff is available at www.iso-ne.com/regulatory/tariff/index.html. Market Rule 1 is Section III of the ISO Tariff.

[2] This report fulfills the requirement of Market Rule 1, Appendix A, Section III.A.17.2.2, *Market Monitoring, Reporting, and Market Power Mitigation.* Some data presented in this report are still open to resettlement. Underlying natural gas data furnished by:

ICE Global markets in clear view

Oil prices are provided by Argus Media.

- Total real-time reserve payments were $19.7 million in the Reporting Period, a 133% increase from Q4 2012 (see Section 3.1.3.2), and Regulation payments totaled $6.5 million, an 88% increase from Q4 2012 (see Section 3.1.3.3).
- Total Net Commitment Period Compensation ("NCPC") reliability payments during the Reporting Period totaled $29.5 million, a 7% decrease from Q4 2012 (see Section 3.2.1).

    - Additional capacity was committed in December to supply energy during extremely cold days. More than half of the NCPC payments in the Reporting Period were paid between December 12 and December 31 (see Section 3.2.1.1).

- The Internal Market Monitor concluded that the energy market was competitive during the Reporting Period. The system-wide concentration of supply ownership remains low. Energy market prices are consistent with input costs (see Section 3.3).

Section 2
OP4 Event on December 14, 2013

On Saturday, December 14, 2013, New England experienced unseasonably cold temperatures and snow, resulting in a capacity deficiency that was exacerbated when Hydro-Quebec reduced imports into New England in order to maintain Hydro-Quebec's own operating reserve requirement. The IMM analyzed market conditions and performance on December 14, 2013 during the hours when the actions of Operating Procedure No.4 ("OP4") were implemented to address the capacity deficiency.[3] The following is a summary of the main observations:

- Overall, the markets performed as expected. Most participants acted competitively. Several participants with off-line resources submitted supply offers determined to be non-competitive and, therefore, were subject to shortage event penalties.
- Actual loads exceeded forecast loads in the late afternoon and evening. Higher than expected loads, along with limited imports, resulted in capacity and reserve deficiencies.
- The ISO implemented Actions 1, 2, and 5 of OP4 to help resolve the capacity deficiency.
- The capacity deficiency resulted in binding reserve constraints at various times of the day and a discrete Forward Capacity Market ("FCM") shortage event between 16:50 and 18:15.
- Real-Time binding reserve constraints during OP4 hours resulted in elevated Real-Time LMPs.
- The ISO received approximately 31 MW of Real-Time Demand Response from three demand response assets participating in the Winter 2013-14 Reliability Solutions program ("Winter Program") and approximately 248 MW of Real-Time Demand Response from demand response assets not participating in the Winter Program
- In total, the ISO obtained approximately 77% of the requested load reduction from both RTDR resources and Winter Program assets.
- Sufficient imports and resources were available after the evening peak occurred which allowed for the cancellation of OP4 at 21:30.

2.1 Price Analysis

On December 14, 2013, Real-Time Hub LMPs rose in hours-ending 17:00 and 18:00 (HE 17 and HE 18) due to a reserve and capacity deficiency. The reserve deficiency resulted in positive reserve pricing in HE 17 through HE 19. The hourly Ten Minute Spinning Reserve ("TMSR") price peaked at $1,025.82/MWh in HE 18. The positive reserve pricing resulted in a peak Real-Time Hub LMP for the day of $1,289.93/MWh in HE 18. See Figure 2-1.

[3] "OP 4" refers to ISO New England Operating Procedure No. 4, Action during a Capacity Deficiency, http://www.iso-ne.com/rules_proceds/operating/isone/op4/op4_rto_final.pdf

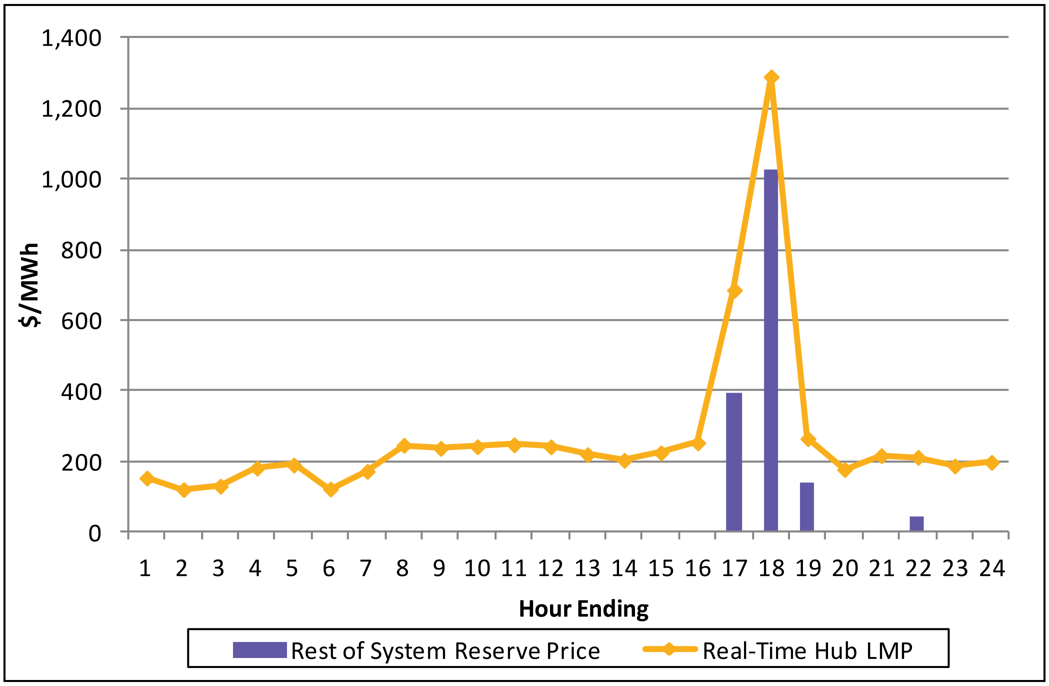

Figure 2-1: Real-Time Hub LMP and Ten-Minute Spinning Reserve Price, December 14, 2013.

2.2 Operational Analysis

During the afternoon through early evening of Saturday, December 14, 2013, New England experienced unseasonably cold temperatures and snow. In HE 17, the eight-city weighted actual temperature was approximately three degrees below the forecast temperature of 17 degrees, and the actual system-wide electric load was higher than the forecasted system load by approximately 760 MW.[4] See Figure 2-2 and Figure 2-3.

[4] The eight-city weighted average temperature includes the cities of Boston, MA, Worcester, MA, Hartford, CT, Bridgeport, CT, Concord, NH, Portland, ME, Burlington, VT, Providence, RI.

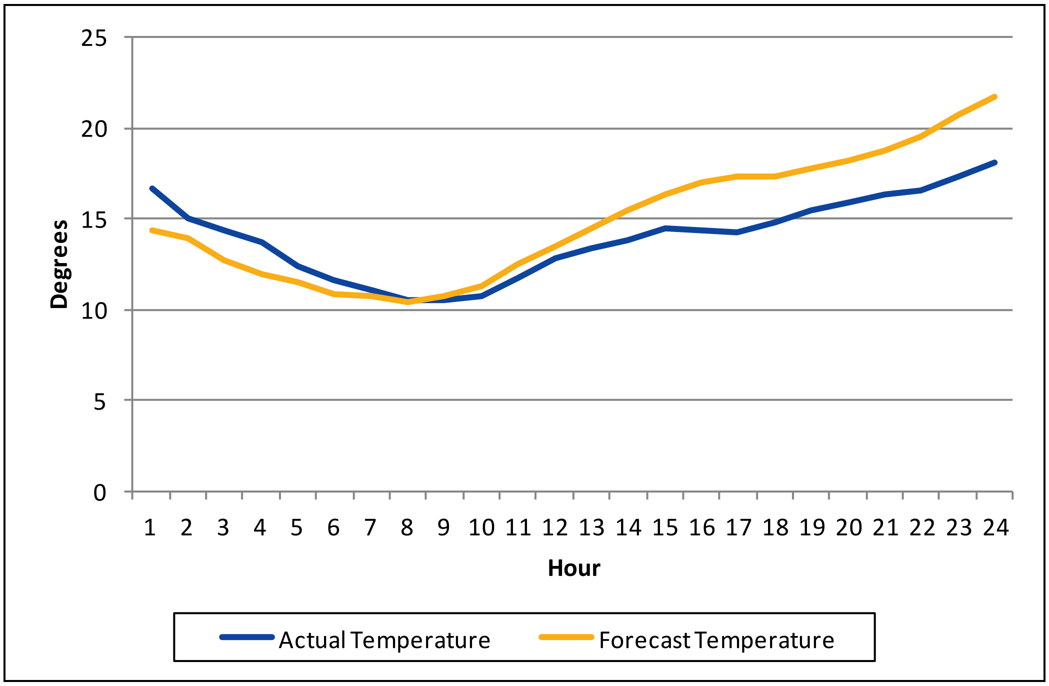

Figure 2-2: Actual vs. Forecast Hourly Temperatures in Degrees Fahrenheit, December 14, 2013.

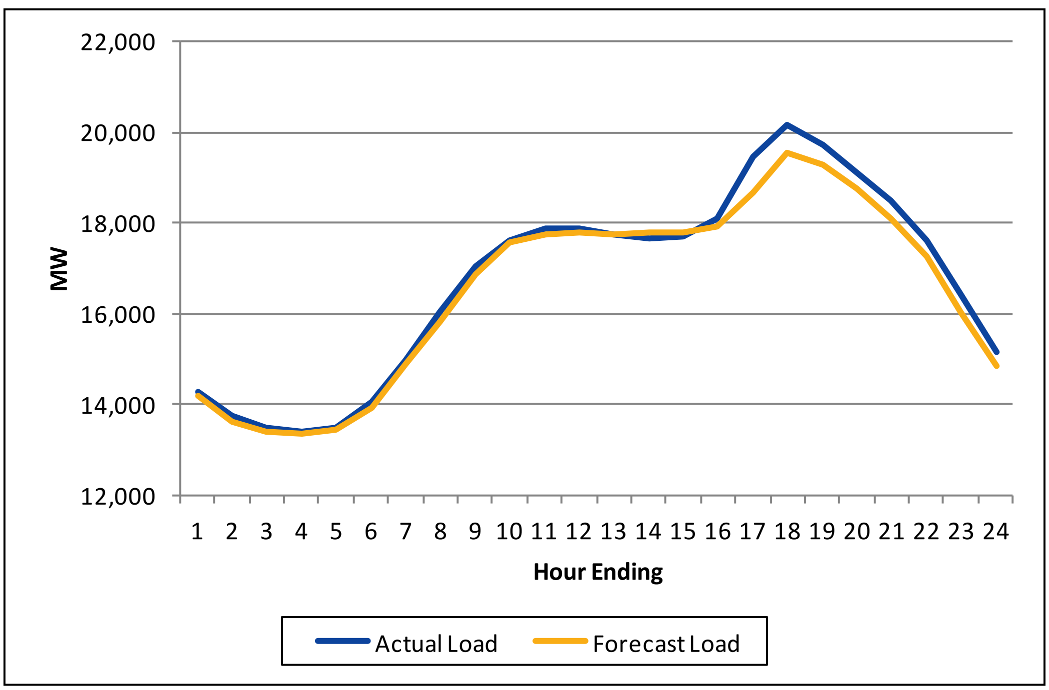

Figure 2-3: Actual vs. Forecast Hourly Load, December 14, 2013.

In addition to the higher than expected loads, Hydro-Quebec reduced imports into New England around 17:00 in order to maintain Hydro-Quebec's own operating reserve requirement. See Figure 2-4.

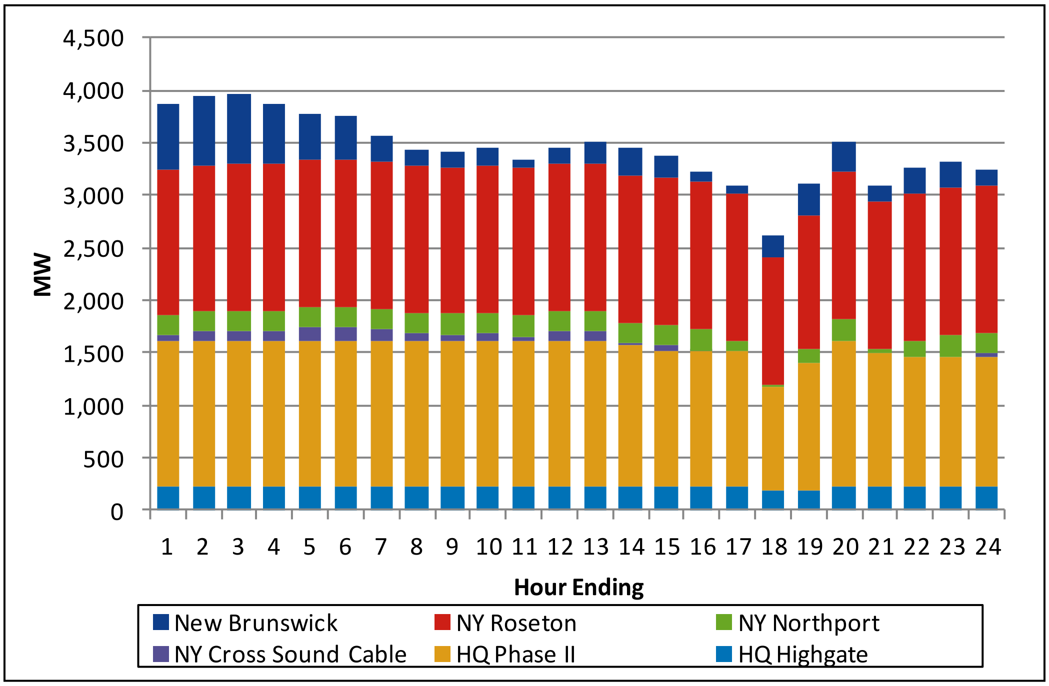

Figure 2-4: Hourly Net Interchange by Interface, December 14, 2013.

The curtailment of imports into New England coupled with the higher than expected evening loads resulted in the declaration of M/LCC 2 and OP4 Action 1 at 17:00.[5] By that time, the system operating reserves had fallen below the operating reserve requirement by 413 MW. Figure 2-5 below shows the times at which the various actions of OP4 were declared, along with the actual operating reserves and reserve requirements throughout the OP4 event. Additionally, the section of the chart highlighted in red illustrates the period of time between 16:50 and 18:15, in which there was a discrete FCM shortage event for the system.[6]

1. **M/LCC 2 and OP4 Action #1: M/LCC2 (Abnormal Conditions Alert) and OP4 Action 1**. The latter action calls for the implementation of a Power Caution, advises resources with a capacity supply obligation (CSO) to prepare to provide all associated operable capacity, and allows the depletion of 30-minute reserves. Additionally, the ISO notifies "Settlement Only" Generators with real-time obligations and a CSO to monitor reserve pricing and be prepared to meet their obligation under the "Shortage Event" definitions in the tariff.

[5] Prior to entering OP4, 100% of the demand response assets included in the Winter 2013-14 Reliability Solutions program were dispatched. See Section 2.4.

[6] See Section 2.3 below for more details on the Shortage Event.

2. **OP4 Action #2: Dispatch Real-Time Demand Resources ("RTDR") in the amount and location required.** The ISO dispatched all RTDR at 17:07 totaling approximately 248 MW. Performance during the 100% dispatch was approximately 191 MW, 77% of the requested load reduction from both RTDR resources and Winter Program assets.[7]

3. **OP4 Action #5: Schedule Market Participant-submitted emergency Energy Transactions ("EETs") and arrange to purchase Control-Area-to-Control Area emergency energy**. At 17:40, Action 5 of OP4 was declared and 300 MW of Control Area to Control Area emergency capacity was scheduled from 17:42 to 18:30.

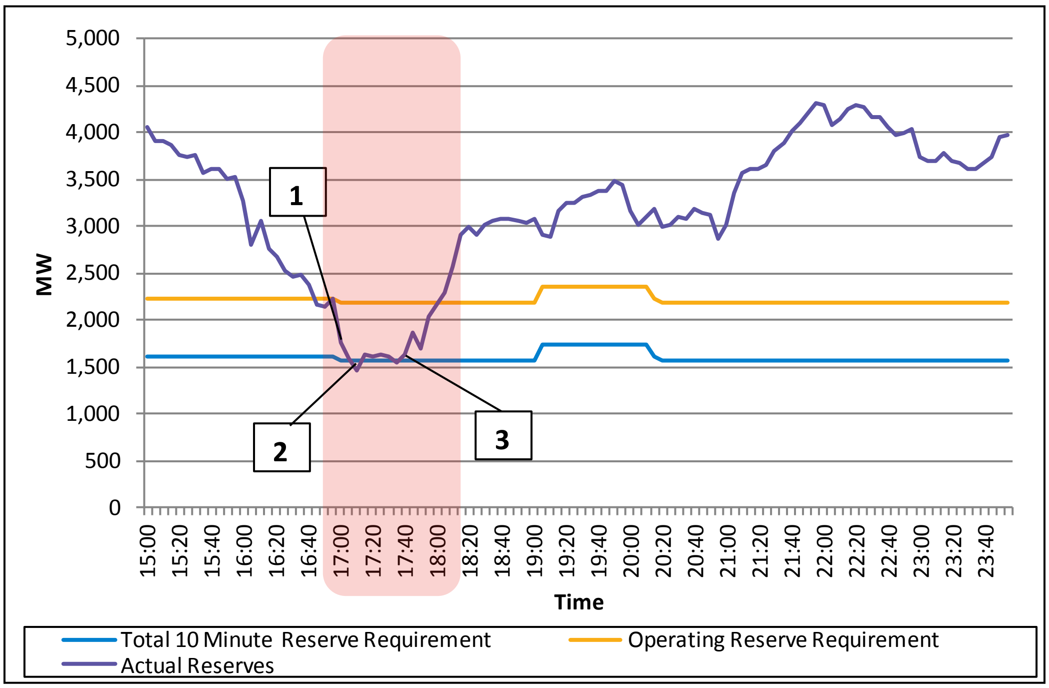

Figure 2-5: Operating Reserves and Requirements during OP4 Event, December 14, 2013.

At 18:30, an increase in the previously curtailed imports and a decrease in the New England load allowed for the cancellation of OP4 Action 5. OP4 Action 2 was cancelled at 20:45 and OP4 Action 1 was later cancelled at 21:30.The system wide M/LCC 2 was canceled on Sunday morning, December 15, 2013, at 10:00 after the winter storm had moved out of New England.

2.3 Shortage Event

On December 14, 2013, a discrete shortage event under the FCM was triggered. This was the first shortage event to be triggered since the start of the FCM in 2010.

[7] See Section 2.5 for more details on Demand Response performance.

The shortage event was triggered based on the Market Rules in effect on November 3, 2013. A shortage event is triggered if:

1) There is a period of thirty or more contiguous minutes of Reserve Constraint Penalty Factor ("RCPF") activation for Ten-Minute Non-Spinning Reserves ("TMNSR"); or,
2) For periods prior to June 1, 2017, there is a period of thirty or more contiguous minutes of RCPF activation for the "minimum TMOR" requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement (described in Section III.2.7A(c) of Market Rule 1) when Action 2 under Operating Procedure No. 4 has also been implemented for the entire Capacity Zone. [8]

The shortage event on December 14, 2013 was initially triggered by meeting condition 1) above. At 16:50, the TMNSR RCPF of $850 was reached, and this price remained in effect until 17:30, more than the required thirty minutes.[9] When the TMNSR price dropped below $850 at 17:30, condition 2) above was still met, and therefore the shortage event remained in effect until 18:15, when the TMOR price dropped to $139.91. At that time, the shortage event concluded. See Table 2-1.

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[8] This section references information from Section III.13.7.1.1.1 of Market Rule 1 (http://www.iso-ne.com/regulatory/tariff/sect_3/index.html), and "Order Accepting Shortage Events Revisions,"Docket No. ER13-2313-000, http://www.iso-ne.com/regulatory/ferc/orders/2013/nov/index.html.

[9] In reserve pricing, the TMOR price cascades into the TMNSR price, so the TMNSR RCPF of $850 can be deduced by subtracting TMOR price from TMNSR price in Table 2-1 above.

Table 2-1
Rest of System Reserve Pricing During FCM Shortage Event, December 14, 2013

Time	TMSR ($/MWh)	TMNSR ($/MWh)	TMOR ($/MWh)
16:45	500.00	500.00	500.00
16:50	1,350.00	1,350.00	500.00
16:55	1,350.00	1,350.00	500.00
17:00	1,350.00	1,350.00	500.00
17:05	1,350.00	1,350.00	500.00
17:10	1,350.00	1,350.00	500.00
17:15	1,350.00	1,350.00	500.00
17:20	1,350.00	1,350.00	500.00
17:25	1,350.00	1,350.00	500.00
17:30	785.84	785.84	500.00
17:35	785.47	785.47	500.00
17:40	500.00	500.00	500.00
17:45	500.00	500.00	500.00
17:50	500.00	500.00	500.00
17:55	500.00	500.00	500.00
18:00	500.00	500.00	500.00
18:05	500.00	500.00	500.00
18:10	500.00	500.00	500.00
18:15	139.91	139.91	139.91

During an FCM shortage event, resources with a CSO are subject to penalties in the event of non-performance and unavailability.[10]

The penalties assessed from the shortage event totaled $6.6 million. Table 2-2 below breaks down the total shortage event penalty into three categories:

1) The "Non-Competitive Offers" category includes FCM resources that were not producing energy during the shortage event, and had supply offers that were determined to be non-competitive pursuant to Section III.A.8 of Market Rule 1.[11]
2) The "MWs on Outage/Reductions" category captures penalties associated with unavailable capacity from FCM resources during the shortage event, as described in Section III.13.7.2.7.1.2 of Market Rule 1.
3) "Imports" may also be subject to shortage event penalties, as described in Section III.13.7.1.2 of Market Rule 1.

[10] Details on FCM Shortage Events and how available MWs are determined for capacity resources are included in Section III.13.7.1 of Market Rule 1.

[11] The capacity from the listed portion of the resource was offered above the appropriate reference level plus the applicable conduct threshold.

Table 2-2
FCM Shortage Event Penalties, December 14, 2013

Category	Penalty ($ Millions)
Non-Competitive Offers	$ 3.60
MWs on Outage/Reductions	$2.96
Imports	$ 0.05
Total	**$ 6.60**

2.4 Winter 2013-14 Reliability Solutions Program: Demand Response Assets Performance

Three demand response assets participating in the Winter Program were activated on December 14, 2013. The ISO implemented the Winter Program in response to increasing winter demands on the system. The Winter Program covers December 2013 through February 2014, and is designed to procure increased fuel oil inventory service, demonstrated ability by dual fuel generators to operate on a secondary fuel, and additional reductions in demand and/or provision of net supply by demand response assets for the ISO New England control area. The rules governing the program are contained in Appendix K of Market Rule 1.[12]

The demand response component of the Winter Program is intended to provide TMOR to the system when conditions are tight. To participate within the program, demand assets must have a minimum interruption of at least 100 kW and must be interruptible between HE 06 and HE 23. In addition, demand assets with MWs that have a Capacity Supply Obligation ("CSO") in the FCM may not utilize those same MWs to satisfy obligations received under the Winter Program.

As part of the procurement process, ISO-NE acquired three demand response assets for participation within the Winter Program. Based on the energy amounts accepted as part of the procurement process, it was expected that the assets would be able to provide 21 MW of load reduction when called upon to operate. Unlike other Real-Time Demand Response assets that can only be dispatched during OP4 Action 2, the ISO has the ability to activate these Winter Program assets *prior* to implementing OP4 in order to maintain the required operating reserves.

Prior to entering OP4 Action 1 on December 14, the three Winter Program assets were activated. During the dispatch period, the three assets interrupted approximately 31 MW of demand, 10 MW more than the expected amount. Based on the rules governing the Winter Program, the 21 MW of expected load reduction were paid the greater of $250/MWh or the hourly Real-Time LMP for the Load Zone in which the asset is located over the dispatch period. The 10 MW that were received in excess of the expected value were compensated at the real-time LMP rate.

[12] *See* Market Rule 1, Appendix K, http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-k.pdf.

2.5 Demand Response Performance

On December 14, 2013, between 17:07 and 20:45, the ISO dispatched all RTDR resources with a positive net CSO on a system wide basis. The net CSO of the RTDR resources totaled approximately 248 MW.[13,14] RTDR resources are required to respond within 30 minutes of receiving the ISO's dispatch instruction.[15] On average, the RTDR resources and Winter Program resources together delivered approximately 77% of the total load reduction the ISO dispatched, helping to mitigate the capacity deficiency on the system. By comparison, in a previous winter OP4 event that occurred on December 19, 2011, the performance also measured 77% of dispatch.[16] See Table 2-3.

Table 2-3
Demand Response Performance by Load Zone, December 14, 2013 (17:40 to 20:50)

Load Zone	Dispatched MW (Net CSO)	Event Performance (MW) [17]	Percent
Connecticut	52.1	19.3	37.0%
Maine	126.9	133.5	105.2%
NEMA	3.5	1.6	44.0%
New Hampshire	3.2	1.4	45.1%
Rhode Island	10.2	6.1	59.6%
SEMA	7.0	0.3	3.9%
Vermont	25.9	23.2	89.5%
WCMA	19.0	6.0	31.8%
New England	**247.8**	**191.3**	**77.2%**

[13] The net capacity supply obligation excludes the transmission and distribution factor added to demand response resource capacity for FCM settlement purposes.

[14] Demand Response findings are preliminary and are subject to resettlement.

[15] See *Demand Reduction Values for Real-Time Demand Response Resources*, http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_sec_13-14.pdf (in Section III.13.7.1.5.7).

[16] See *2011 Fourth Quarter Quarterly Markets Report*, http://www.iso-ne.com/markets/mkt_anlys_rpts/qtrly_mktops_rpts/2011/imm_q4_2011_qmr.pdf.

[17] The event performance MW also includes the performance that is attributable to Winter Reliability Program (31 MW).

Section 3 Summary of Market Outcomes and System Conditions

This section summarizes the region's wholesale electricity market outcomes, system conditions, and measures of market performance and competitiveness from October 1 through December 31, 2013 (the "Reporting Period").

3.1 Market Outcomes

3.1.1 Total Wholesale Electricity Costs

Table 3-1 shows wholesale electricity costs (in dollars and dollars/megawatt-hour; $/MWh) by type and market in the Reporting Period compared with Quarter 4 of 2012. Total costs increased by about 37% between Q4 2012 and the Reporting Period, and energy costs increased by about 43%.[18] Average gas prices, which increased by 41% compared to Q4 2012 were a large contributor in the increase in total energy costs in the Reporting Period. Ancillary service costs, including NCPC payments, reserve payments, and regulation payments, increased by 91% when compared to Q4 2012. There were higher ancillary service payments in the Reporting Period due to the implementation of rule changes governing the requirements in the Forward Reserve Market in Q3 2013 and a change in the calculation of opportunity costs in the Regulation Market relative to the Regulation Clearing Price (see Section 3.1.3.3). In addition, Real-Time reserve payments increased when compared to Q4 2012 (see Section 3.1.3.2).

Table 3-1
Wholesale Market Cost Summary

	Total Costs ($ Billions)			Average Costs ($/MWh)		
Type	**Q4 2013**	**Q4 2012**	**% Change**	**Q4 2013**	**Q4 2012**	**% Change**
Energy	1.99	1.39	43%	63.35	45.29	40%
Capacity	0.26	0.27	-6%	8.20	8.89	-8%
Ancillary Services	0.08	0.04	91%	2.63	1.40	87%
Total	2.33	1.71	37%	74.17	55.59	33%

3.1.2 Key Market Statistics

Table 3-2 shows selected key statistics for loads, Real-Time and Day-Ahead Energy Market prices, and fuel prices.

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

Table 3-2
Key Statistics on Load, LMPs, and Input Fuels

	4th Quarter 2013	3rd Quarter 2013	Percent Change Q3 2013 to Q4 2013	4th Quarter 2012	Percent Change Q4 2012 to Q4 2013
Real-Time Load (GWh)	31,484	35,332	-11%	30,831	2%
Weather Normalized Real-Time Load (GWh)	31,236	34,239	-9%	30,955	1%
Peak Real-Time Load (MW)	21,448	27,378	-22%	19,132	12%
Average Day-Ahead Hub LMP ($/MWh)	$57.50	$42.42	36%	$45.41	27%
Average Real-Time Hub LMP ($/MWh)	$60.24	$42.89	40%	$44.75	35%
Average Natural Gas Price ($/MMBtu)	$7.74	$4.00	94%	$5.49	41%
Average #6 Oil Price 1% sulfur ($/MMBtu)	$15.41	$15.31	1%	$16.29	-5%

The following factors contributed to the market outcomes:

- Higher natural gas prices in the fourth quarter were the primary driver for higher Day-Ahead and Real-Time prices when compared to Q3 2013 and Q4 2012.
  - Natural gas prices during the Reporting Period increased by 41% from the fourth quarter of 2012.
  - Real-Time and Day-Ahead LMPs were 35% and 27% higher than the fourth quarter of 2012 respectively.
- Net Energy for Load ("NEL") was approximately 1% higher than the fourth quarter of 2012.
- The Peak load, which occurred on December 17, 2013 during the Reporting Period, was 21,448 MW, 12% higher than the peak load observed in the fourth quarter of last year.

3.1.3 Real-Time Markets

3.1.3.1 Real-Time Energy Market

In the Reporting Period, the average real-time Hub price was $60.24/MWh, up 35% from $44.75 MWh in Q4 2012.[19] Price differences among the load zones stemmed primarily from marginal losses, with little congestion at the zonal level.[20] Congestion was restricted primarily to smaller, more transient load pockets that formed when transmission or generation elements were out of service.

In the Reporting Period, units burning natural gas were marginal for 69% of the pricing intervals, followed by pump storage units (including pumping demand), which were marginal in 13% of the pricing intervals and coal burning units, which were marginal in 10% of the pricing intervals. Generating resources burning wood, oil or diesel were marginal 6% of the time and hydro units were marginal approximately 2% of the time.

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

[20] A *load zone* is an aggregation of load pricing nodes (pnodes) within a specific area. The loss component of the LMP is the marginal cost of additional losses caused by supplying an increment of load at the location.

3.1.3.2 Real-Time Operating Reserves

In the Reporting Period, the total real-time reserve payments were $19.7 million; a 133% increase relative to Q4 2012's $8.4 million of payments.[21] A higher frequency of reserve pricing combined with higher average prices for all reserve products, compared with Q4 2012, increased total payments. The higher pricing frequency follows the ISO's addition of "replacement reserves" to the system thirty minute reserve requirement. The replacement reserves effectively increase the system thirty-minute reserve requirement by approximately 20-25%.[22] There also was a reserve shortage (OP4) event on December 14, 2013 (see Section 2.3 above) which resulted in $2.5 million in real-time reserve payments being made to generators on that day.

Real-time reserve payments decreased from Q3 2013. This can be expected given that Q3 includes high summer electrical demand periods where operating margins are typically at their lowest and therefore, reserves are priced more frequently. This change can be observed in the difference between Q3 2013 and the Reporting Period: real-time payments for Ten Minute Spinning Reserve ("TMSR") decreased by 41%, Ten Minute Non Spinning Reserve ("TMNSR") increased by 9%, and Systemwide Thirty Minute Operating Reserve ("TMOR") decreased by 31%. See Table 3-3.

Table 3-3
Real-Time Reserve Payments ($ and %)

Product	4th Quarter 2013	3rd Quarter 2013	Percent Change Q3 2013 to Q4 2013	4th Quarter 2012	Percent Change Q4 2012 to Q4 2013
Systemwide TMSR	5,334,802	8,995,989	-41%	3,030,331	76%
Systemwide TMNSR	10,984,332	10,070,775	9%	3,544,780	210%
Systemwide TMOR	1,013,095	1,467,288	-31%	375,113	170%
SWCT TMOR	1,840,881	1,918,904	-4%	1,087,365	69%
CT TMOR	224,309	1,012,213	-78%	292,659	-23%
NEMA/Boston TMOR	309,993	334,044	-7%	111,198	179%
Total	19,707,412	23,799,213	-17%	8,441,446	133%

3.1.3.3 Regulation Market

Total Regulation Market payments during the Reporting Period were $6.5 million, up 35% from $4.8 million in Q3 2013, and 88% from $3.4 million in Q4 2012. The increase in regulation payments is attributable to the following:

- Both the fuel cost and real-time energy price were higher in the Reporting Period when compared to Q3 2013. When fuel costs and real-time energy prices are high, the regulation service cost and the regulation opportunity cost also increase.

[21] Payment data represent total payments for real-time reserves, and are not net of settlement adjustments for forward reserve obligation charges.

[22] The replacement reserve requirement is 160 MW during Daylight-Savings Time periods and 180 MW during Eastern Standard Time periods, and became effective in October 2013.

- Second, a market rule change implemented on July 1, 2013 changed the methodology used to calculate opportunity costs in the Regulation market relative to the Regulation Clearing Price. [23]

3.1.4 Forward Markets

3.1.4.1 Day-Ahead Energy Market

The average day-ahead Hub price in the Reporting Period was $57.50/MWh. As in real-time, this price is consistent with observed market conditions. Price differences among the load zones stemmed primarily from marginal losses, with little congestion at the zonal level. Congestion was restricted primarily to smaller, more transient load pockets that formed when transmission or generation elements were out of service.

Generators set price approximately 41% of the time in the Reporting Period in the day-ahead market. Virtual transactions set price approximately 37% of the time. In comparison, generators set price 47% of the time in the day-ahead market and virtual transactions set price 29% of the time in the fourth quarter of 2012.

In the Reporting Period, submitted and cleared virtual transactions continued the declining trend (year over year comparison) reported in the *2012 Annual Markets Report*. Submitted virtual demand bids and virtual supply offers totaled approximately 4,860 GWh in the Reporting Period, a decline of 34% when compared with the fourth quarter of 2012. However, the submitted virtual transactions increased by 16% compared to the third quarter of 2013. Cleared virtual transactions showed similar year-over-year and sequential trends. The cleared virtual transactions totaled approximately 1,158 GWh in the Reporting Period, a decline by 3% compared with the fourth quarter 2012 but a 16% increase over the third quarter of 2013. See Table 3-4.

Table 3-4
Total Submitted and Cleared Virtual Transactions, (GWh)

	4th Quarter 2013	3rd Quarter 2013	Percent Change Q3 2013 to Q4 2013	4th Quarter 2012	Percent Change Q4 2012 to Q4 2013
Total Submitted Virtual Transactions	4,860	4,174	16%	7,310	-34%
Total Cleared Virtual Transactions	1,158	997	16%	1,193	-3%

3.1.4.2 Financial Transmission Rights

Three Financial Transmission Rights ("FTR") auctions were conducted during the Reporting Period for a combined total of 160,044 MW of FTR transactions. The total amount distributed as Auction Revenue Rights ("ARRs") was $3.2 million. Thirty-four bidders in October, thirty-seven bidders in November and thirty-seven bidders in December participated in the monthly auctions for the quarter. The level of participation was consistent with prior auctions.

[23] See *Regulation Market Opportunity Cost Change*, ER13-1259-000 (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.

3.1.4.3 *Forward Capacity Market*

Several monthly reconfiguration auctions and bilateral contract periods were conducted during the Reporting Period; no annual reconfiguration auctions or bilateral contract periods concluded during the reporting period.

Monthly reconfiguration auctions and bilateral trades for the months of December 2013 to February 2014 ended during the reporting period. The reconfiguration auctions obtained pricing of $0.29, $0.85, and $1.72 per kW-month during each month, respectively, with cleared capacity in the 572 to 947 MW range. Bilateral trading exchanged MWs in the 402 to 543 MW range, with average prices for the periods ranging from $0.46 to $0.90 per kW-month.

3.1.4.4 *Demand Resources*

Demand resource payments totaled $20.7 million in the Reporting Period, which was 15.5% lower than the previous quarter's payments of $24.5 million. Payments were 3.7% lower than the same quarter last year. The Reporting Period includes payments made for the transitional Price Responsive Demand ("PRD") program, which began on June 1, 2012.

3.2 System Conditions

3.2.1 Net Commitment Period Compensation

Total Net Commitment Period Compensation ("NCPC") payments during the Reporting Period totaled $30.2 million. This total includes both Reliability NCPC Payments and Generator Performance Audit ("GPA") NCPC payments. Details of the payments made within the Reporting Period are detailed below.

3.2.1.1 *Reliability NCPC Payments*

Total Reliability NCPC payments during the Reporting Period totaled $29.5 million, as shown in Table 3-5. The majority of the NCPC incurred during the Reporting Period was economic (also called "first contingency") NCPC. Economic NCPC is the difference between the cost of committing and operating a generating resource to meet capacity and energy needs in the day-ahead and real-time markets and the energy revenues the resource realizes during the market day. In the Reporting Period, additional capacity was committed in December to supply energy during extremely cold weather days. More than half of the NCPC payments in the reporting period were paid between December 12 and December 31.

Table 3-5
Total NCPC Payments by Quarter and Category ($)

NCPC Category	Q4 2013	Q3 2013	Q4 2012
Economic (i.e., First Contingency) Payments	23,611,579	14,089,460	22,514,468
Second Contingency Payments	2,843,887	4,411,178	2,834,433
Voltage Payments	2,896,265	8,847,351	6,380,736
Distribution Payments	123,898	4,261,035	1,841
Total	29,475,629	31,609,024	31,731,479

3.2.1.2 GPA NCPC Payments

GPA is a category of NCPC payments that became effective on June 1, 2013 and totaled $710K in the Reporting Period.[24] See Table 3-6. NCPC payments for this category are incurred for

- Performance audits for online/offline reserves and for Seasonal Claimed Capability audits that are initiated by the ISO rather than the participant, and
- Payments made to participants for dual fuel testing services as part of the 2013-2014 Winter Reliability Program.[25]

Table 3-6
GPA Payments ($)

Month-Year	Real-Time Generator Performance Audit Payment
Oct-2013	44,117
Nov-2013	659,435
Dec-2013	6,509
Total	**710,061**

3.2.2 Supplemental Commitments for Capacity and Reserves

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

[24] See *Market Rule 1 Revisions Relating to Auditing of Generation Resources*, ER13-1323-000, http://www.iso-ne.com/regulatory/ferc/filings/2012/nov/er13-323-000_11-6-2012_audit_claim.pdf.

[25] See Attachment K of Market Rule 1 at http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-k.pdf.

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 Energy Market exceeds the real-time load), self-schedules, or the supplemental commitment performed as a result of the RAA. Thus, the market and supplemental commitments made by the ISO for reliability both contribute to the surplus.

Table 3-7 shows the minimum, maximum, and percentiles of the daily supplemental commitments for 2013 by month. The day with the highest level of supplemental commitments (733 MW) during the reporting period occurred on December 17, 2013, when additional units were committed due to actual system loads running higher than forecast.

Table 3-7
Monthly Minimum, Maximum, and Quarterly Percentiles of Daily Supplemental Commitments for the Peak Hour, January 2013 to December 2013 (MW)

Month	Daily Supplemental Commitment MW[26]				
	Minimum	25th Percentile	50th Percentile	75th Percentile	Maximum
Jan	0	0	0	250	1,847
Feb	0	0	0	548	2,879
Mar	0	0	0	45	1,475
Apr	0	0	0	250	610
May	0	0	0	26	734
Jun	0	0	0	157	900
Jul	0	0	0	109	707
Aug	0	0	0	0	400
Sep	0	0	0	129	1,320
Oct	0	0	0	0	250
Nov	0	0	0	0	569
Dec	0	0	0	0	733

3.2.3 Net Interchange

In the Reporting Period, New England was a net importer of power. Net imports from Canada exceeded net exports to New York ("NY"). Net interchange with neighboring balancing authority areas totaled 5,318 GWh for the Reporting Period, a 29% increase compared with the previous quarter.

3.2.4 Unusual Operating Conditions

On December 14, 2013, New England experienced a capacity deficiency that resulted in OP4 actions 1, 2, and 5, as well as a discrete Forward Capacity Market (FCM) shortage event. This was the first time that a shortage event under the FCM was triggered in New England. For more information on these events, see Section 2.

[26] For this analysis, *supplemental commitments* are defined as the capacity of non-fast-start generators the ISO committed outside the day-ahead market for the peak hour, dispatched at their economic minimum.

3.3 Market Performance

The Internal Market Monitor calculated the following performance metrics to assess the competitiveness of the wholesale electricity market. Based on the results of the HHI and RSI metrics, the Internal Market Monitor has concluded that the energy market was competitive during the Reporting Period. System-wide concentration remains low. Energy market prices are consistent with costs.

- The *Herfindahl-Hirschman Index* ("HHI") is a commonly used measure of market concentration. The HHI is calculated by squaring the market share of each firm competing in the market and then summing the resulting numbers.[27] The HHI takes into account the relative size distribution of the firms in a market. It approaches zero when a market is occupied by a large number of firms of relatively equal size and reaches its maximum of 10,000 points when a market is controlled by a single firm. The HHI increases both as the number of firms in the market decreases and as the disparity in size between those firms increases.[28] The median quarterly system-wide HHI for New England internal resources during the daily peak load hours, based on online generation and the resources' Lead Market Participants, was 687 in the Reporting Period. The highest HHI calculated based on online generation during the daily peak load was 864. The results indicate that the wholesale electric energy markets in New England are well within the "not concentrated" range.[29]

- The systemwide *Residual Supply Index* ("RSI") measures the percentage of demand in a given hour (in megawatt-hours) that can be met without any capacity from the largest supplier. The RSI also measures the number of hours in which one or more suppliers is pivotal, or can price above the competitive level, subject only to offer caps, mitigation measures, and the price elasticity of demand.[30] Overall, the RSI analysis for the Reporting Period suggests that suppliers at the system level had limited ability to exercise market power. The system-level analysis shows that pivotal suppliers did not exist during any of the hours in the Reporting Period.

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[27] 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 percents are used as whole numbers, as in 75 instead of 0.75, the index can range up to 100^2, or 10,000.

[28] 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.

[29] HHI ignores transmission constraints and contractual entitlements to generator output, which would have the effect of increasing and decreasing concentration, respectively. The net effect has not been measured; however, given the low level of overall concentration even if these effects produced a net increase in concentration, the impact would not change our assessment.

[30] When the RSI exceeds 100%, the system has sufficient capacity from other suppliers 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 unilaterally set prices above competitive levels decreases. RSIs generally are lowest during periods of high demand, indicating a drop in the level of competition as the system approaches its capacity limit.