



2013 First Quarter Quarterly Markets Report

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Internal Market Monitor
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Section 1

Executive Summary

The Internal Market Monitor has analyzed the performance in the first 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 ancillary services and energy and ancillary market outcomes have been competitive. However, price signals in the wholesale market are not yet sufficient for resources to put in place arrangements to assure fuel is available to follow dispatch instructions at all times. There were two periods of unusual weather, a cold snap from January 21 to January 28 and a winter blizzard on February 8 – 9. There were four instances in which resources failed to follow dispatch instructions because of a lack of fuel supply during the cold snap and there were 6 such instances during the blizzard. During both periods, natural gas prices spiked to levels above the cost of #6 oil. Market performance during these events is described in detail in Section 2 of this report. FCA 7 was held on February 4. It was the first FCA in which zones were modeled. The results of FCA 7 are discussed in detail in Section 3 of this report. Section 4 details market outcomes over the period.¹

1.1 Summary of Market Outcomes and Performance

- A combination of cold temperatures, severe weather, and high natural gas prices during two periods in the Reporting Period created unusual operating conditions. The IMM concludes 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 weekend blizzard, continue to be of concern. The IMM continues to recommend a number of market rule changes to address this problem (see Section 2).
- The seventh Forward Capacity Auction (FCA 7) was held on February 4-5, 2013. The NEMA-Boston zone cleared at \$14.999/kW-month for new resources, \$11.849/kW-month higher than the floor price of \$3.150/kw-month. Administrative pricing rules were invoked for NEMA-Boston in FCA 7 because there was insufficient competition among new resources to set a competitive price (see Section 3).
- Day-Ahead Energy Market prices during the Reporting Period averaged \$86.16/MWh at the Hub, and Real-Time prices averaged \$81.28/MWh (see

¹This 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:



Oil prices are provided by Argus Media.

Section 4.1.2). The total energy value in the Reporting Period was \$2.45 billion.² This is a 173% increase in costs from the first quarter of 2012, the largest such increase since the start of locational markets in 2003.

- Natural gas prices during the Reporting Period averaged \$11.57/MMBtu (see Section 4.1.2).
- Total real-time reserve payments were \$5.7 million in the Reporting Period (see Section 4.1.3.2), and regulation payments totaled \$6.2 million (see Section 4.1.3.3).
- Total Net Commitment Period Compensation (NCPC) payments during the Reporting Period totaled \$74.7 million (see Section 4.2.1). More than half of the NCPC payments were directly associated with generator commitments during a period of cold weather in January and a February weekend blizzard.
- The Internal Market Monitor has 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 4.3).

² The *total energy value* is the Real-Time Hub LMP times the net energy for load.

Section 2

Winter 2013 Events

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.³

During the first event, there were no major power outages reported, however, Operating Procedure #4 (OP4) emergency actions were required on Monday, January 28 to manage unplanned generator outages and load forecast errors 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 effecting retail customers, wholesale power system conditions did not require the ISO to implement any emergency procedures.

The IMM reviewed the system and market operations during these two winter events and concludes that the wholesale power system operated reliably but that wholesale prices do not provide sufficient incentives for generators to reliably procure the fuel needed to meet the terms of their supply offers. As noted in the *2012 Annual Markets Report*, the IMM observed issues regarding fuel procurement and unit availability, especially during the weekend blizzard. During the two events, it was observed that 10 units did not provide energy when called upon by the ISO. The IMM continues to recommend a number of market rule changes to address these fuel procurement and unit availability problems.

2.1 January 21-28, 2013

2.1.1 Overview of Market Conditions, Outcomes, and Operational Challenges

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/MMBtu. In contrast, natural gas prices across much 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 .3% sulfur No. 6 oil. These higher fuel prices were directly reflected in the wholesale Day-Ahead and Real-Time electricity prices. See Table 2-1, which shows the impact of the higher fuel prices on the electric price for the cold stretch and for January 2013.

Table 2-1
Average Gas and Electric Prices, January 21-28, 2013, January 2013, and January 2012

	Algonquin Price	Real-Time Electric Price
1/21/2013-1/28/2013 Average	19.45	175.28
January 2013 Average	10.59	84.17
January 2012 Average	5.35	37.10

³ See “Winter Operations Summary: January-February 2013” for additional information, 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, economics caused some dual fuel generators to burn 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 of the natural gas that would have been needed for the entire operating day. As a result of these events, the ISO committed additional generation.

2.1.2 Market Competitiveness

The IMM analyzed whether or not market participants were able to increase prices during the period of January 21 through January 28 by offering above their resource's marginal cost.⁴ The IMM used a unit-commitment and dispatch simulation model to simulate market outcomes and prices for benchmark and offer cases, respectively. The *benchmark case* assumed that all market participants offered to supply energy at their marginal cost. The *offer case* used the actual offer prices market participants submitted during the week.⁵

The simulation results, summarized in Table 2-2, show that LMPs were, on average, 9.4% higher for the offer case than the benchmark case. The relatively small difference between the two cases during the January 21 – 25 period indicates that market participants did not significantly increase prices by offering above marginal cost. As illustrated in Table 2-2, over the weekend period of January 26 – 28, the difference between the two cases was higher than the preceding five days. Because gas markets are closed over the weekend, gas generators typically submit offers for Saturday, Sunday and Monday on Friday. A review of participant's offers revealed that the offers submitted on this cold snap Friday reflected the prices of gas traded earlier in the week during the cold period, rather than the price of the weekend strip which is used in the benchmark case. These offers, when taken in the context of the unusual gas market conditions at the time, seem to be a reasonable offer strategy to reflect price volatility and uncertainty risk that can exist in the intra-day gas markets. This is especially true for participants who purchase gas in the intra-day market. Based on the results of this analysis, the IMM concludes that the prices reasonably reflected market conditions during the timeframe of January 21-28.

⁴ The benchmark case was based on the IMM's estimates of market participant's marginal costs using unit characteristics provided by participants to the IMM and index fuel prices.

⁵ The IMM used the PROBE, or "Portfolio Ownership and Bid Evaluation," simulation model for this analysis. The software simulates the Day-Ahead and Real-Time LMP-based market clearing. See <http://www.power-gem.com/PROBE.htm>.

**Table 2-2
Day-Ahead Market Simulation Results**

Date	Average LMP (\$/MWh)			
	Offer Case	Benchmark Case	Difference (Offer - Benchmark)	Percent Change (%)
21-Jan-2013	87.10	91.56	-4.46	-5.1
22-Jan-2013	126.92	115.52	11.40	9.0
23-Jan-2013	170.61	187.03	-16.42	-9.6
24-Jan-2013	196.31	198.77	-2.46	-1.3
25-Jan-2013	222.77	223.77	-1.00	-0.4
26-Jan-2013	180.63	134.47	46.16	25.6
27-Jan-2013	193.82	131.02	62.80	32.4
28-Jan-2013	169.08	138.27	30.81	18.2
Average	168.41	152.55	15.85	9.4

2.1.3 Committed System Capability

The IMM reviewed the ISO's commitment during the week. Committing generation in excess of what is required to reliably operate the system can result in out-of-merit units being paid uplift to recover their short-run operating costs. The IMM reviewed system operations for the week, performed simulations of the real-time market, and compared the results with the actual market outcomes. The real-time simulation results represent an ideal scenario based on perfect information about the operating day. The simulated results can only be achieved if system conditions, such as unit performance, system loads, area interchange, transmission outages, and constraints occur exactly as predicted. Thus, while the simulation results cannot be achieved in practice, they have value as a best case scenario which can provide insight into the performance of the real-time market. For both the actual and simulation cases, the unit commitment decisions were measured using the economic maximum of each generator with a non-zero dispatch during each hour. The sum of all these units is the total capability of the system committed during each day. The results show that, on average, an additional 256 MW per hour was committed in Real-Time when compared to the simulated case. At the daily level, this metric was the greatest at 1,121 MW per hour on January 25. January 25 was the coldest day of the week, and had some of the highest fuel prices. When compared with the simulated (best case) scenario, the actual commitments on January 25 were greater than what they would otherwise have been, had the operators had perfect information about the operating day when making their commitment decisions. These results show that in general the level of commitments was reasonable over the period. See Table 2-3.

**Table 2-3
Real-Time Operating Day Actual and Simulation Unit Commitment (UC) Results**

Date	Actual UC (MW)	Simulation UC (MW)	Difference (Actual - Simulation) (MW/h)
21-Jan-2013	363,037	363,411	-15.6
22-Jan-2013	411,823	401,887	414.0
23-Jan-2013	442,901	451,905	-375.2
24-Jan-2013	469,185	466,335	118.7
25-Jan-2013	439,435	412,532	1,121.0
26-Jan-2013	376,756	370,160	274.9
27-Jan-2013	346,512	342,990	146.8
28-Jan-2013	384,139	375,324	367.3
Average	404,224	398,068	256.5

2.1.4 The Implied Heat Rate of the Marginal Fuel

The IMM calculated the daily implied heat rate of the marginal fuel for each day of the period. The implied heat rate was calculated by dividing the average daily real-time LMP at the Hub by the average daily fuel price. The average daily fuel price used was the Algonquin natural gas price, with the exception of January 23-25 when the .3% sulfur No. 6 fuel oil price was used instead because it was below the cost of natural gas. The figure shows that implied marginal heat rates were reasonably consistent with the heat rate of a combined cycle unit when gas was on the margin and with an oil steam unit when oil was on the margin. The high implied heat rate on January 26 is caused by reserve pricing which increased LMPs on that day. See Figure 2-1.

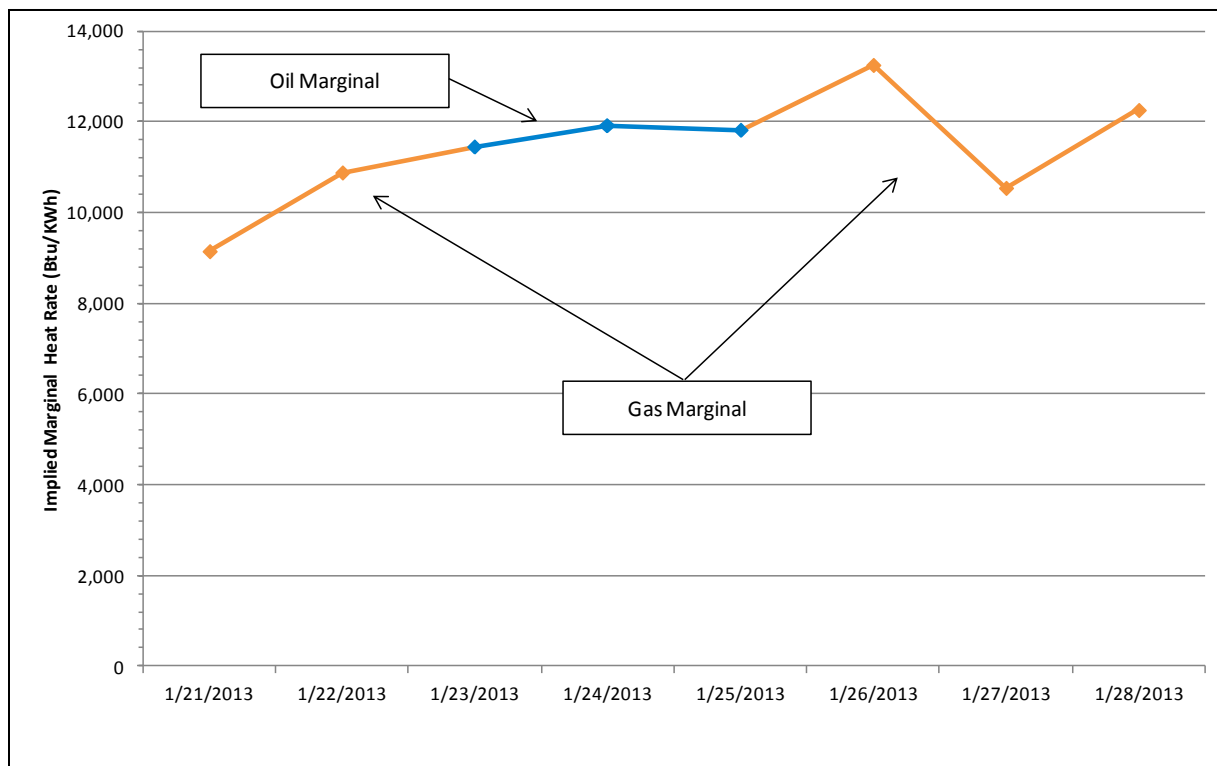


Figure 2-1: Average daily implied heat rates of the marginal fuel, January 21 to January 28, 2013.

2.1.5 Net Commitment Period Compensation

Net Commitment Period Compensation (“NCPC”) payments were higher during this week than previous weeks, especially on January 25. Table 2-4 shows the breakdown of NCPC payments to generators by day. The large amount of NCPC is due in large part to three factors. First, because NCPC is a make whole payment to generators to assure they recover all of their offers, higher fuel prices cause higher offers which result in higher NCPC payments. Second, oil units were cheaper than gas units on three days. This caused oil units to run more frequently than usual. Oil units typically have long minimum run times and therefore must continue to operate when energy prices alone do not pay their costs. These long run times increase NCPC payments. Third, about 10% of the NCPC was paid for voltage support, a much higher number than normal.

**Table 2-4
Total NCPC Payments to Generators, January 21 to January 28, 2013**

Date	First Contingency NCPC (\$1,000)	Distribution NCPC (\$1,000)	LSCPR ⁶ NCPC (\$1,000)	Voltage NCPC (\$1,000)	Total (\$1,000)
21-Jan-2013	452	0	0	202	654
22-Jan-2013	1,554	0	0	419	1,972
23-Jan-2013	1,511	0	0	350	1,861
24-Jan-2013	2,519	0	0	110	2,629
25-Jan-2013	3,859	0	0	146	4,004
26-Jan-2013	1,233	0	0	0	1,233
27-Jan-2013	910	0	0	0	910
28-Jan-2013	1,000	0	0	157	1,157
Total	13,037	0	0	1,383	14,420

2.1.6 January 28, 2013 OP-4 Event

The IMM analyzed market conditions and performance on January 28, 2013 during the hours when the actions of Operating Procedure No. 4 (OP4) were implemented.⁷ The following is a summary of the main observations:

- Overall, participants acted competitively. No suppliers were pivotal.⁸
- Lower than forecasted afternoon temperatures resulted in higher than expected loads.
- Actual loads greater than forecast loads, along with generator performance issues, resulted in capacity and reserve shortages.
- The ISO implemented Actions 1 and 2 of OP4 to resolve the capacity deficiency.
- Real-time binding reserve constraints during OP4 hours raised real-time LMPs.
- The ISO dispatched 373 MW of real-time demand response resources. The ISO obtained nearly 95% of the requested load reduction.
- Sufficient resources were available after the evening peak occurred, and loads declined, which allowed for the cancellation of OP4 at 21:30.

2.1.6.1 Price Analysis

On January 28, 2013, real-time Hub LMPs rose in hours-ending 18:00 and 19:00 (HE 18 and HE19) due to a reserve and capacity deficiency. The reserve deficiency resulted in positive reserve pricing in HE18 and HE19. The hourly ten-minute spinning reserve (TMSR) price peaked at \$516.84 in HE18 and was \$125.00 in HE 19. The positive reserve pricing resulted in a real-time Hub LMP of \$780.89 in HE18.

⁶ Local Second Contingency Protection Resource – Reliability costs paid to resources providing adequate capacity in constrained areas to respond to a local second contingency. They are committed based on second contingency protocols.

⁷ OP4 refers to ISO New England Operating Procedure No. 4, Action during a Capacity Deficiency (April 29, 2010), http://www.iso-ne.com/rules_proceeds/operating/isone/op4/OP4_RTO_FIN.doc.

⁸ Suppliers are pivotal when they are necessary to meet demand and can set prices.

2.1.6.2 Operational Analysis

During the afternoon and through the early evening of Monday, January 28, 2013, New England experienced lower than forecasted temperatures. In HE 16, the average hourly New England temperature was approximately 4 degrees F below the forecasted value of 30 degrees F, and the actual system load was higher than the forecasted system load by approximately 630 MW.⁹ In addition to the electric load exceeding the forecasted load, the following operational issues with generators occurred that resulted in system operating reserves falling below the required amount occurred that resulted in system operating reserves falling below the requirement.¹⁰

1. At about 16:00, a 250 MW generator experienced a forced outage.
2. At 17:00, the ISO curtailed real-time only transactions to mitigate an imminent operating reserve deficiency.
3. At about 17:17, a 450 MW generator tripped.
4. In response, at 17:30 the ISO declared M/LCC 2, and OP4 Actions 1 and 2 to manage a reserve deficiency.
 - a. The implementation of Action 2 of OP4 dispatched all of the real-time demand resources (RTDR) with a positive net capacity supply obligation (CSO) estimated to be 373 MW. The RTDR activation resulted, on average, in 353 MW of total load reduction.
5. At about 17:45, a large fast start resource was postured to prevent further depletion of the operating reserve. See Figure 2-2.

⁹ The New England temperature is a weighted value of eight New England weather stations, calculated using factors derived from historical electricity sales data. The weather stations are located in the cities of Boston, MA, Worcester, MA, Hartford, CT, Bridgeport, CT, Concord, NH, Portland, ME, Burlington, VT, and Providence, RI.

¹⁰ The actual reserves fell below the operating reserve requirement between 17:40-17:55 and below the 10 minute requirement between 17:45 and 17:50.

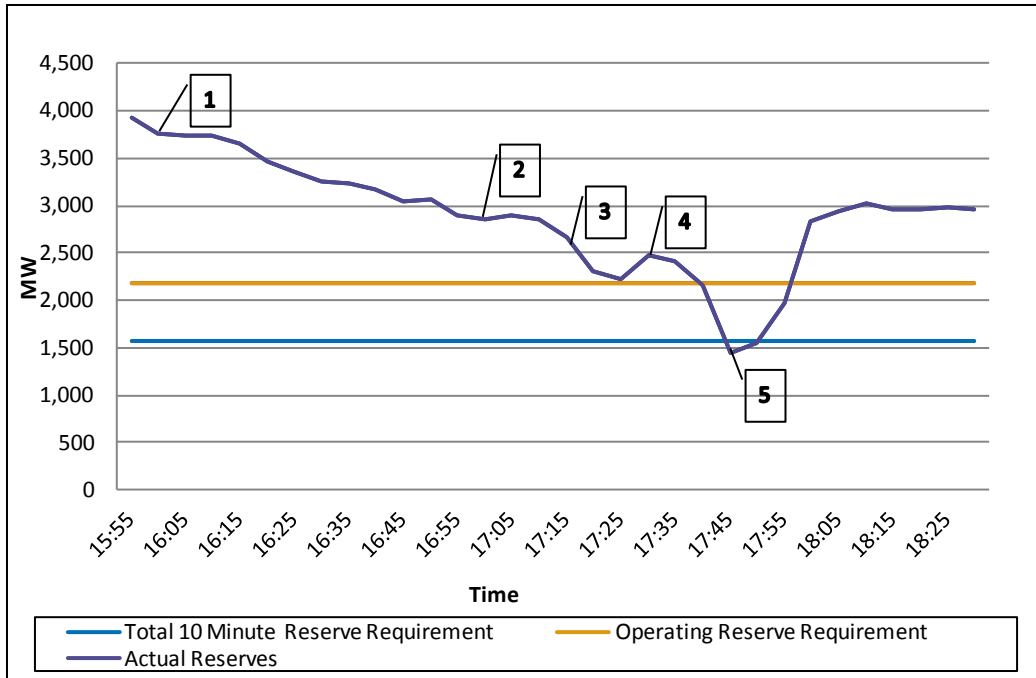


Figure 2-2: Actual operating reserves and requirements during the OP4 event, January 28, 2013.

By 21:00, sufficient resources were available which allowed for the cancellation of OP4 Action 2. As load continued to decrease, the ISO cancelled OP4 Action 1 and M/LCC2 at 21:30.

2.2 February Blizzard

2.2.1 Overview of Market Conditions, Outcomes, and Operational Challenges

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 \$31.00/MMBtu. In comparison, natural gas prices during this time were about \$3.30/MMBtu across much 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 .3% sulfur No. 6 fuel oil price, which remained relatively constant throughout the period at approximately \$20/MMBtu. See Table 2-5, which shows the impact of the higher fuel prices on the electric price for the blizzard and for February 2013.

**Table 2-5
Average Gas and Electric Prices, February 8-12, 2013, February 2013, and February 2012**

	Algonquin Price	Real-Time Electric Price
2/8/2013-2/12/2013 Average	\$27.95	\$206.84
February 2013 Average	\$18.01	\$108.25
February 2012 Average	\$3.64	\$30.14

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 system-wide for one hour. The Minimum Generation Emergency event was caused by the actual peak load being 1200 MW under 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 both 115 and 345 kilovolt 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 and New England west-to-east power-system transfers. Early Saturday morning, February 9, a half dozen 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 exacerbated concerns about the fuel supply to natural-gas-fired generating facilities. These problems indicate that the market is not providing sufficient incentives for generators to get gas under these conditions. These concerns have been noted in the *2012 Annual Markets Report*, and the IMM continues to recommend a number of market rule changes to address this problem.

2.2.2 The Implied Heat Rate of the Marginal Fuel

The IMM calculated the daily implied heat rates of the marginal fuel for each day of the period. As with the analysis used in the January 21-28 period, this calculation uses the lower fuel price of natural gas or No. 6 (30% sulfur) oil. The implied heat rate of the marginal fuel was low on February 8 and 9 when compared to the average heat rate of the marginal unit (Oil unit). Implied heat rates were lower on February 8 and 9, due to low off-peak prices on the morning of February 8 and, on February 9, the hours when the Minimum Generation Emergency was declared. See Figure 2-3.

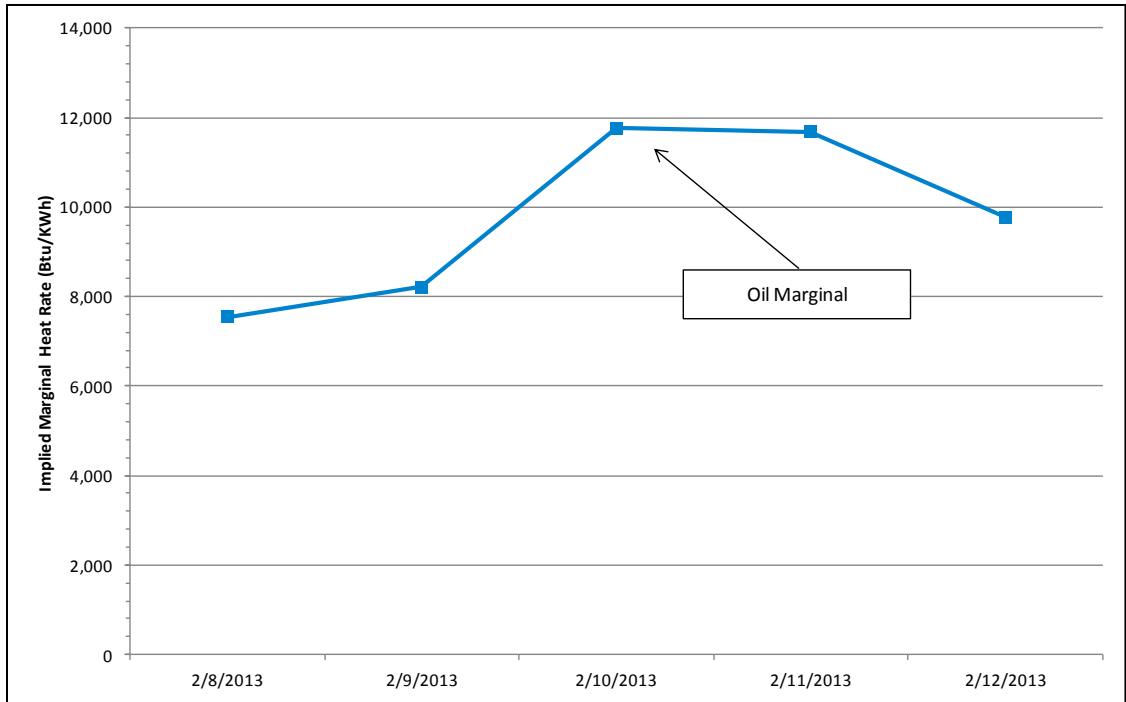


Figure 2-3: Average daily implied heat rate of the marginal fuel, February 8 to February 12, 2013.

2.2.3 Committed System Capability

There were a large number of generator and transmission line outages throughout the storm. As a result, the ISO committed many generators out-of-merit to maintain local reliability. The need to commit these generators caused over \$25 million of total NCPC. \$16 million of the \$25 million was paid for real-time local second contingency protection because of the loss of generation and transmission in the SEMA and RI areas. The NCPC payments on February 9 were impacted by the excess online generation during the Minimum Generation Emergency event. Almost 25% of the total First Contingency NCPC payments on that day were made between hour ending 13 and hour ending 16. See Table 2-6 and Table 2-7.

**Table 2-6
Total NCPC Payments to Generators, February 8 to February 12, 2013**

Date	First Contingency NCPC (\$)	LSCPR ¹¹ NCPC (\$)	Other NCPC (\$)	Total (\$)
8-Feb-2013	1,624,963	870,605	194,404	2,689,972
9-Feb-2013	4,298,920	5,300,875	0	9,599,795
10-Feb-2013	1,482,985	2,855,811	0	4,338,796
11-Feb-2013	1,302,738	4,955,573	1,095	6,259,406
12-Feb-2013	585,167	2,299,502	0	2,884,669
Total	9,294,773	16,282,366	195,499	25,772,638

**Table 2-7
Total NCPC Payments to Generators by Load Zone, February 8 to February 12, 2013**

Date	CT	ME	NEMA/BOSTON	NH	RI	SEMA	VT	WCMA
8-Feb-13	10%	12%	55%	0%	3%	7%	0%	13%
9-Feb-13	12%	4%	34%	4%	21%	15%	0%	9%
10-Feb-13	17%	2%	37%	4%	13%	28%	0%	0%
11-Feb-13	8%	1%	14%	2%	35%	35%	0%	5%
12-Feb-13	8%	2%	0%	8%	49%	31%	0%	3%
Total	11%	4%	28%	4%	24%	23%	0%	6%

¹¹ Local Second Contingency Protection Resource – Reliability costs paid to resources providing adequate capacity in constrained areas to respond to a local second contingency. They are committed based on second contingency protocols.

Section 3

Review of the Seventh Forward Capacity Auction

This section presents the results of the IMM’s review of the seventh Forward Capacity Auction (FCA), 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 – Northeastern Massachusetts - Boston (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 there was insufficient competition among new resources to set a competitive price.¹²

3.1 Requirements

Table 3-1 shows the system and local capacity requirements for FCA 7. About 33,000 megawatts 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 (CT) and NEMA-Boston zones are import-constrained zones. Local sourcing requirements, approximately 7,600 and 3,200 MW respectively, were included for each region in the auction.

Table 3-1
Capacity Requirements or Limits for FCA 7 (MW)

Auction	Net Installed Capacity Requirement (NICR)	Maximum Capacity Limit (MCL)	Local Sourcing Requirement (LSR)	
	System-wide	Maine	CT	NEMA-Boston
FCA 7	32,968	3,709	7,603	3,209

3.2 Resource Qualification

Table 3-2 summarizes the existing and new qualified capacity for FCA 7 by zone and compares that 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. 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.

¹² See section 3.3.

Table 3-2
Qualified Capacity Compared to 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 3-3 shows the breakdown of qualified capacity by resource type for each zone. Proposed new additions to capacity were small compared to import resources in the Rest-of-Pool and generator resources in NEMA-Boston. It is useful to note that, consistent with the ISO-NE 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 of the “new” capacity within the Maine zone was import capacity.

Table 3-3
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

3.3 Auction Results

Table 3-4 below 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.

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.”¹³ 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

¹³ Section III.13.2.8.2 of the Tariff defines “insufficient competition.” Note that insufficient competition also could apply under other circumstances.

meet the LSR, was given 1.1 times the “cost of new entry” (an estimate of the expected cost of adding new resources), or \$6.661/ kW-month for FCA 7.

Table 3-4
Results by Auction Round, FCA 7

Auction Rounds	Systemwide
Round 1 Pricing ^(a)	15.00 - 9.00
<i>Round 1 Capacity Excess^(b)</i>	4,430
Round 2 Pricing	9.00 - 7.50
<i>Round 2 Capacity Excess</i>	4,430
Round 3 Pricing	7.50 - 6.00
<i>Round 3 Capacity Excess</i>	4,321
Round 4 Pricing	6.00 - 4.84
<i>Round 4 Capacity Excess</i>	4,221
Round 5 Pricing	4.84 - 4.54
<i>Round 5 Capacity Excess</i>	3,128
Round 6 Pricing	4.54 - 3.85
<i>Round 6 Capacity Excess</i>	3,056
Round 7 Pricing	3.85 - 3.15
<i>Round 7 Capacity Excess</i>	3,048
Auction Price for New Capacity	3.15
Auction Price for Existing Capacity	3.15

(a) \$/kW-month

(b) MW

For FCA 7, 268 delist bids from existing capacity resources were entered in the auction. The ISO accepted all of these bids for a total of 1,660 MW; these bids were provided by both demand resources (916 MW) and generation resources (744 MW). All of 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 3-5.

Table 3-5
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

3.4 Cleared Capacity Summary

Table 3-6 below 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 3-6
Cleared Capacity Compared to Local Requirement or Limit, FCA 7**

Capacity Zone	Demand Resource (MW)	Generator (MW)	Imports (MW)	Total (MW)	Local Requirement or Limit at Auction's Conclusion (MW)	Excess Capacity (MW)
Connecticut ¹⁴	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 ¹⁵	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

¹⁴ Pursuant to the ISO-NE Tariff 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.

¹⁵ The capacity requirement and excess capacity values are implied values for Rest-of-Pool, as those values are not explicitly modeled for the auction. The requirement for Rest-of-Pool is implied by the NICR less 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.

Section 4

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 January 1, 2013 to March 31, 2013 (the “Reporting Period”).

4.1 Market Outcomes

4.1.1 Total Wholesale Electricity Costs

Table 4-1 shows wholesale electricity costs (in dollars and dollars/megawatt-hour; \$/MWh) by type and market in the Reporting Period compared with Quarter 1 of 2012. As a result of a large increase in natural gas prices in the Reporting Period (see Table 4-2 below), compared to the first quarter of 2012, total costs increased by about 127%, and energy costs increased by about 173%.¹⁶ This is the largest year over year increase in costs since the start of locational markets in 2003. However, total costs increased less than energy and ancillary service costs because, in percentage terms, capacity costs dropped by 19%.¹⁷

Table 4-1
Wholesale Market Cost Summary

Type	Total Costs (\$ Billions)			Average Costs (\$/MWh)		
	Q1 2013	Q1 2012	% Change	Q1 2013	Q1 2012	% Change
Energy	2.66	0.98	173%	82.80	31.30	165%
Capacity	0.27	0.33	-19%	8.47	10.73	-21%
Ancillary Services	0.09	0.02	409%	2.69	0.55	394%
Total	3.02	1.33	127%	93.96	42.57	121%

4.1.2 Key Market Statistics

Table 4-2 shows selected key statistics for loads, Real-Time and Day-Ahead Energy Market prices, and fuel prices, Real-Time Reserve Payments, Regulation Payments, NCPC Payments and Forward Capacity Market Payments during the Reporting Period.

¹⁶ 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.

¹⁷ Capacity in the Reporting Period was paid at the FCA3 rate of \$2.53/kW-Month, in Q1 2012 capacity was paid at the FCA2 rate of \$3.12/kW-Month.

**Table 4-2
Key Statistics on Load, LMPs, and Input Fuels**

	1st Quarter 2013	4th Quarter 2012	Percent Change Q4 2012 to Q1 2013	1st Quarter 2012	Percent Change Q1 2012 to Q1 2013
Real-Time Load (GWh)	32,291	30,821	5%	31,470	3%
Weather Normalized Real-Time Load (GWh)	32,474	30,955	5%	32,187	1%
Peak Real-Time Load (MW)	20,775	19,119	9%	19,926	4%
Average Day-Ahead Hub LMP (\$/MWh)	\$86.16	\$45.41	90%	\$32.59	164%
Average Real-Time Hub LMP (\$/MWh)	\$81.28	\$44.75	82%	\$30.90	163%
Average Natural Gas Price (\$/MMBtu)	\$11.57	\$5.49	111%	\$3.94	194%
Average #6 Oil Price 1% sulfur (\$/MMBtu)	\$16.40	\$16.29	1%	\$17.86	-8%

The following factors contributed to the market outcomes:

- High natural gas prices and higher demand in the winter months were the primary driver for increased Day-Ahead and Real-Time prices in the Reporting Period.
 - Natural gas prices during the Reporting Period increased by 194% from the first quarter of 2012.
 - Real-Time and Day-Ahead LMPs were 163% and 164% higher than the first quarter of 2012 respectively.
- Net energy for load (“NEL”) was 3% higher than load in the first quarter of 2012.¹⁸
- Peak load during the Reporting Period was 20,775 MW, and occurred on January 23.

4.1.3 Real-Time Markets

4.1.3.1 Real-Time Energy Market

In the Reporting Period, the average real-time Hub price was \$81.28/MWh, up 163% from \$30.90/MWh in Q1 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 57% of the pricing intervals, followed by pump storage units (including pumping demand), which were marginal in 17% of the pricing intervals. Generating resources burning wood, oil or diesel were marginal 9% of the time. Hydro units were marginal approximately 3% of the time.

¹⁸ 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.

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.

4.1.3.2 Real-Time Operating Reserves

In the Reporting Period, the total real-time reserve payments were \$5.7 million; a 33% reduction relative to Q4 2012. From Q4 2012 to Q1 2013, real-time payments for Ten Minute Spinning Reserve (TMSR) decreased by 34%, Ten Minute Non Spinning Reserve (TMNSR) decreased by 25%, and Thirty Minute Operating Reserve (TMOR) decreased by 46%.²¹ See Table 4-3.

When compared to Q1 2012, reserve payments have increased. Several factors explain the large increase in reserve payments during the third and fourth quarters of 2012 and in the Reporting Period:

- The amount of total 10-minute reserve requirement increased by 25% in summer 2012.
- The Reserve Constraint Penalty Factor for system 10-minute operating reserve (TMOR) increased from \$100/MWh to \$500/MWh.²²
- Weather had an impact on reserve payments in the Reporting Period. Approximately 35-40% of the reserve payments were made during the cold snap period (January 21-28). In addition, Q1 2012 was a much warmer period with lower loads.

Table 4-3
Real-Time Reserve Payments (\$ and %)

Product	Q1 2013	Q4 2012	% Change (Q4 2012 to Q1 2013)	Q1 2012	% Change (Q1 2012 to Q1 2013)
Systemwide TMSR	1,996,281	3,030,331	-34%	787,385	153.53%
Systemwide TMNSR	2,674,528	3,544,780	-25%	88,196	2932.48%
Systemwide TMOR	210,823	375,113	-44%	3,915	5285.01%
SWCT TMOR	679,501	1,087,365	-38%	28,780	2261.02%
CT TMOR	83,499	292,659	-71%	6,008	1289.80%
NEMA/Boston TMOR	38,930	111,198	-65%	1,988	1858.25%
Total	5,683,562	8,441,446	-33%	916,272	520.29%

4.1.3.3 Regulation Market

Total Regulation Market payments during the Reporting Period were \$6.2 million, and the average regulation price in the Reporting Period was \$9.87/MWh. See Table 4-4. The increase in regulation payments in the Reporting Period relative to the fourth quarter 2012 and the first quarter 2012 is attributable to the high natural gas prices during the Reporting Period.

²¹ This is on a weighted-average basis, given the reductions in Southwest Connecticut and Connecticut.

²² See the *2012 Annual Markets Report* located at http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/index.html for the IMM's analysis that describes these changes.

**Table 4-4
Regulation Market Outcomes (\$)**

	Q1 2013	Q4 2012	% Change (Q4 2012 to Q1 2013)	Q1 2012	% Change (Q1 2012 to Q1 2013)
Capacity Credit	\$1,600,816	\$1,095,500	46.1%	\$973,588	64.4%
Opportunity Cost	\$3,027,678	\$1,315,544	130.1%	\$705,553	329.1%
Service Credit	\$1,540,490	\$1,043,886	47.6%	\$931,231	65.4%
Total Regulation Payments	\$6,168,985	\$3,454,930	78.6%	\$2,610,372	136.3%

4.1.4 Forward Markets

4.1.4.1 Day-Ahead Energy Market

The average day-ahead Hub price in the Reporting Period was \$86.16/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 53% of the time in the Reporting Period in the day-ahead market. Virtual transactions set price approximately 21% of the time. In comparison, virtual transactions set price 28% of the time in the first quarter of 2012.

In the Reporting Period, submitted and cleared virtual transactions continued the declining trend reported in the *2012 Annual Markets Report*. Submitted virtual demand bids and virtual supply offers totaled approximately 5,889 GWh in the Reporting Period, a decline of 22% when compared with the first quarter of 2012, and a decline of 19% compared with the fourth quarter of 2012. Cleared virtual transactions totaled approximately 675 GWh in the Reporting Period, a 41% decline compared with the first quarter 2012, and a 43% decline compared with the fourth quarter of 2012. See Table 4-5.

**Table 4-5
Total Submitted and Cleared Virtual Transactions, (GWh)**

	Q1 2013	Q4 2012	% Change (Q4 2012 to Q1 2013)	Q1 2012	% Change (Q1 2012 to Q1 2013)
Total Submitted Virtual Transactions	5,889	7,310	-19%	7,581	-22%
Total Cleared Virtual Transactions	675	1,193	-43%	1,140	-41%

4.1.4.2 Financial Transmission Rights

Three Financial Transmission Rights ("FTR") auctions were conducted during the reporting period for a combined total of 128,288 MW of FTR transactions. The total amount distributed as Auction Revenue Rights ("ARRs") was \$1.9 million. Twenty-eight bidders participated in the January monthly auction, 33 bidders participated in the February auction, and 34 bidders participated in the March auction. The level of participation was consistent with prior auctions.

4.1.4.3 Forward Capacity Market

The ISO held the New England region's seventh Forward Capacity Auction (FCA 7) for the 2016/2017 Capability Year on February 4-5, 2013. It was the first FCA in which import constrained capacity zones, in this case the NEMA Boston zone and the Connecticut zone, were modeled. One of the modeled import constrained zones – Northeastern Massachusetts - Boston (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. The NEMA-Boston price was set at the price that the new capacity needed to meet the reliability need sought to leave the auction.

There are administrative pricing rules in the FCA designed to protect the market from the exercise of market power. These provisions were invoked for NEMA-Boston in the FCA 7 because there was insufficient competition among new resources to set a competitive price.

4.1.4.4 Demand Response

Demand response payments totaled \$21.43 million in the Reporting Period, which was nearly flat when compared to the previous quarter's payments of \$21.45 million. The Reporting Period includes payments made for the new transitional Price Responsive Demand (PRD) program, which began on June 1, 2012. The transitional PRD program that went into effect brought about the end to both the Day Ahead Load Response Program (DALRP) and the Real-Time Price-Response (RTPR) program.

4.2 System Conditions

4.2.1 Net Commitment Period Compensation

Total Net Commitment Period Compensation (NCPC) payments during the Reporting Period totaled \$74.7 million, as shown in Table 4-6. 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. Most economic NCPC is associated with generating resource operation in real-time and is paid to resources that operate at Economic Minimum for some portion of their minimum run time. In the Reporting Period, additional capacity was committed in January and February to supply energy during the cold snap and blizzard periods. These events accounted for more than half of the total NCPC paid during the quarter.

Table 4-6
Total NCPC Payments by Quarter and Category (\$)

NCPC Category	Q1 2013	Q4 2012	Q1 2012
Economic and First Contingency Payments	\$49,157,795	\$22,431,282	\$7,533,278
Second Contingency Payments	\$21,976,402	\$2,834,433	\$958,024
Voltage Payments	\$3,156,351	\$6,380,348	\$1,680,245
Distribution Payments	\$450,073	\$1,695	\$57,918
Total	\$74,740,622	\$31,647,758	\$10,229,465

4.2.2 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 market to meet the ISO load forecast plus operating reserve requirement. The amount of capacity on line affects LMPs and NCPC costs. When too much capacity is on line and units are operating at their economic minimum levels, LMPs are likely to be lower and NCPC costs higher than what they otherwise would be. Too little capacity on line may compromise reliable operation and lead to artificially high prices.

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

Table 4-7 illustrates the minimum, maximum, and quarterly percentiles of the daily supplemental commitments for the Reporting Period. The day with the highest level of supplemental commitments (2,982 MW) occurred on February 11th. Uncertainty regarding generator availability in the aftermath of the weekend blizzard was the primary driver for the February commitments.

Table 4-7
Monthly Minimum, Maximum, and Quarterly Percentiles of Daily Supplemental Commitments for the Peak Hour, January 2013 to March 2013 (MW)

Month	Daily Supplemental Commitment MW ²³				
	Minimum	25th Percentile	50th Percentile	75th Percentile	Maximum
Jan 2013	0	0	0	268	1,847
Feb 2013	0	0	38	548	2,982
Mar 2013	0	0	0	45	1,475

4.2.3 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 5,614 GWh for the Reporting Period, a 32% increase compared with the previous quarter.

4.3 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

²³ 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.

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.²⁴ 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.²⁵ 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 741 in the Reporting Period. The highest HHI calculated based on online generation during the daily peak load was 963. The results indicate that the wholesale electric energy markets in New England are well within the "not concentrated" range.²⁶
- 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.²⁷ 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 as the RSI value remained above 100% for all hours.

²⁴ 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.

²⁵ 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>.

²⁶ 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.

²⁷ 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.