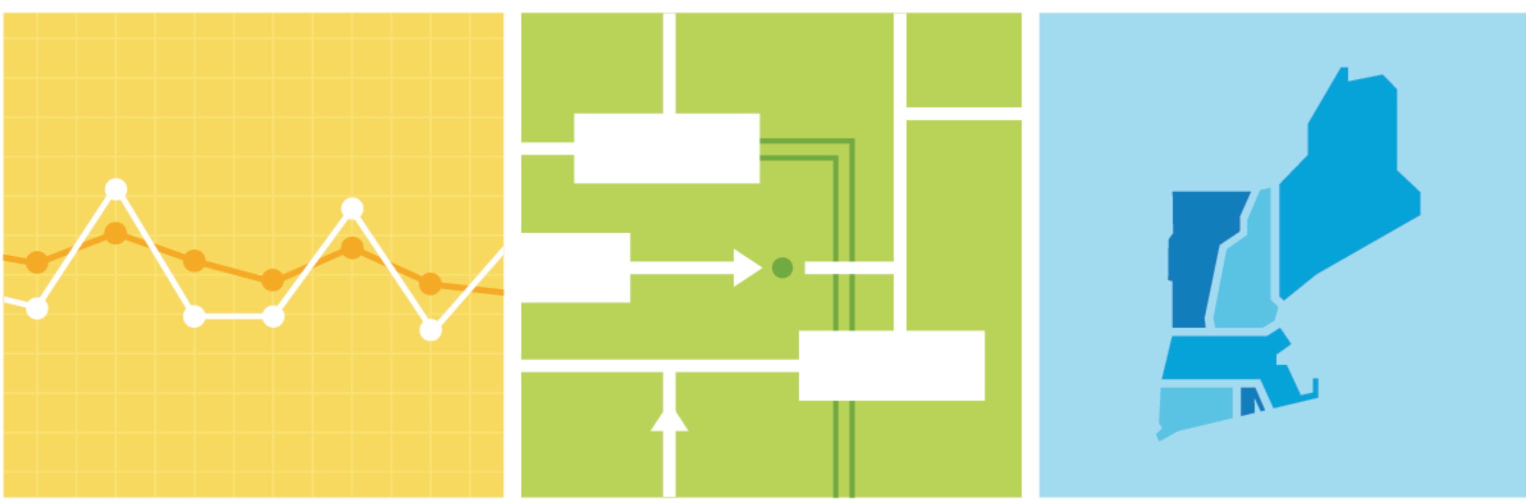
# Spring 2018
# Quarterly Markets Report

## By ISO New England's Internal Market Monitor



JULY 13, 2018

ISO-NE PUBLIC



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# Preface

The Internal Market Monitor ("IMM") of ISO New England Inc. (the "ISO") publishes a Quarterly Markets Report that assesses the state of competition in the wholesale electricity markets operated by the ISO. The report addresses the development, operation, and performance of the wholesale electricity markets 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, Appendix A, Section III.A.17.2.2, *Market Monitoring, Reporting, and Market Power Mitigation*:

> The Internal Market Monitor will prepare a quarterly report consisting of market data regularly collected by the Internal Market Monitor in the course of carrying out its functions under this *Appendix A* and analysis of such market data. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. The format and content of the quarterly reports will be updated periodically through consensus of the Internal Market Monitor, the Commission, the ISO, the public utility commissions of the six New England States and Market Participants. The entire quarterly report will be subject to confidentiality protection consistent with the ISO New England Information Policy and the recipients will ensure the confidentiality of the information in accordance with state and federal laws and regulations. The Internal Market Monitor will make available to the public a redacted version of such quarterly reports. The Internal Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The Internal Market Monitor shall keep the Market Participants informed of the progress of any report being prepared pursuant to the terms of this *Appendix A.*

All information and data presented here are the most recent as of the time of publication. Some data presented in this report are still open to resettlement.[1]

Underlying natural gas data furnished by:

ICE Global markets in clear view[2]

Oil prices are provided by Argus Media

[1] Capitalized terms not defined herein have the meanings ascribed to them in Section I of the ISO New England Inc. Transmission, Markets and Services Tariff, FERC Electric Tariff No. 3 (the "Tariff").

[2] Available at http://www.theice.com.

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# Section 1
# Executive Summary

This report covers key market outcomes and the performance of the ISO New England wholesale electricity and related markets for Spring 2018 (March 1, 2018 through May 31, 2018).[3]

***Wholesale Costs:*** The total estimated wholesale market cost of electricity was $1.87 billion, an increase of 45% compared to $1.29 billion in Spring 2017, and a decrease of 46% over the previous quarter (Winter 2018).

- Rising Forward Capacity Market (FCM) prices substantially drove the increase in wholesale market costs relative to Spring 2017. Capacity costs totaled $767 million, up 167% (by $479 million) compared to last spring. June 2017 marked the beginning of the FCA 8 capacity commitment period, which had tighter system conditions due to a number of generator retirements. Capacity prices for existing resources outside of NEMA/Boston increased 123%, from $3.15/kW-month to $7.03/kW-month compared to the prior auction.
- Spring 2018 energy costs were $1.06 billion; a 10% (or $94 million) increase relative to Spring 2017 costs. Increased energy costs were driven by higher natural gas prices, which increased by 8% relative to Spring 2017.

***Energy Prices:*** Day-ahead and real-time energy market prices at the Hub averaged $34.69 and $33.27/MWh, respectively. Day-ahead prices were 13% higher ($3.92/MWh) and real-time prices were 4% higher ($1.35/MWh) than Spring 2017 prices, on average.

- Day-ahead and real-time energy prices continue to track with natural gas prices.
- March 2018 saw the greatest price divergence between average real-time and day-ahead prices for the quarter, with day-ahead prices about $2.50/MWh or 8% above real-time prices. Lower real-time prices in March were driven by significant negative price spikes that took place on several days throughout the month. During these periods, additional renewable generation in the real-time market (compared to the day-ahead market) and actual loads less than the forecast contributed to depressed real-time prices.
- Energy market prices did not differ significantly among the load zones, with the exception of Maine. Maine, an export-constrained region, had the highest deviation with consistently lower prices relative to the other zones. In the day-ahead market, the Maine price averaged $2.21/MWh (6%) lower than the average Hub price. Price separation in Maine was more notable in the real-time market, with prices $3.06/MWh (9%) lower than Hub prices, on average.
- On May 15, storms in the region resulted in a significant drop-off of estimated behind-the-meter photovoltaic output, and higher wholesale load than anticipated. Between 3 and 6 p.m., 1,300 to 2,000 MW of fast-start generation was required to meet load and reserve requirements. Coinciding with the storm, the ISO had taken a planned outage of the market software, meaning that commitments were made manually by ISO Operators and LMPs were determined administratively after the event. Day-ahead prices averaged $31.45/MWh, while real-time prices averaged $46.24/MWh on that day.

[3] In Quarterly Markets Reports, outcomes are reviewed by season as follows: Winter (December through February), Spring (March through May), Summer (June through August) and Fall (September through November).

***Net Commitment Period Compensation:*** NCPC payments totaled $20.6 million, up by $7.2 million compared to Spring 2017. NCPC payments represented 1.9% of total wholesale energy costs in Spring 2018, slightly up from 1.4% in Spring 2017. The majority of NCPC (56%) was for first contingency protection. One of the largest components of first contingency protection NCPC in Spring 2018 was real-time external transaction NCPC ($1.7 million). Most of these payments were a result of imports at the New Brunswick interface that were scheduled based on the ISO-forecasted price, but ended up being uneconomic in the real-time. This is discussed further in Section 3.4.

At $7.4 million, local second-contingency protection (LSCPR) payments accounted for 36% of total NCPC payments. LSCPR payments increased by 322% (or $2.4 million) relative to Spring 2018, and were primarily paid to generators in NEMA/Boston that were required to support outages on the 345-kV transmission system.

***Real-time Reserves:*** Real-time reserve payments totaled $7.1 million, a 19% decrease relative to the Spring 2017 total of $8.8 million. The frequency of non-zero ten-minute spinning reserve (TMSR) pricing was similar to that of Spring 2017. Lower real-time LMPs in May, the month in which a majority of the quarter's non-zero TMSR pricing occurred, relative to May of 2017, decreased TMSR clearing prices and helped reduce real-time reserve payments. Overall, the average hourly TMSR price decreased relative to Spring 2017, from $15.85 to $12.85/MWh.

Real-time reserve payments to generators designated to satisfy forward reserve obligation are reduced by a forward reserve obligation charge so that a generator is not paid twice for providing the same service. Total forward reserve obligation charges were $1.3 million, bringing net real-time time reserve payments down to $5.8 million.

***Regulation*:** Total regulation market payments were $4.9 million, down 21% from $6.2 million in Spring 2017. This decrease was driven by lower regulation capacity prices, which resulted from a reduction in incremental cost savings.[4]

***Summer 2018 Forward Reserve Market Auction*:** In April 2018, ISO New England held the forward reserve auction for the Summer 2018 delivery period (i.e., June 1 to September 30, 2018). System-wide supply offers in the Summer 2018 auction exceeded the requirements for both ten-minute non-spinning reserve (TMNSR) and thirty minute operating reserve (TMOR), and there were no pivotal suppliers at the system level. The net clearing prices for offline thirty- and ten-minute reserves for the system were both $1,780/MW-month. The TMNSR clearing price was slightly lower than the Summer 2017 price ($2,000/MW-month), while the TMOR clearing price was higher than the 2017 price ($1,000/MW-month). Of the three local reserve zones, only NEMA/Boston had a different price than the system. Because of inadequate supply (meaning all suppliers were pivotal suppliers), a portion of the highest-priced supply was needed and the TMOR price for NEMA/Boston was set at $6,225/MW-month. This is consistent with previous auction results, as the NEMA/Boston TMOR price has been higher than the system price since the Summer 2015 auction.

[4] Incremental cost savings are adjustments made by the ISO to the regulation capacity clearing price. They represent the reduction in total system cost provided by a specific regulation offer, when compared to the next most expensive offer.

# Section 2
# Overall Market Conditions

This section provides a summary of key trends and drivers of wholesale electricity market outcomes from Winter 2016 through Spring 2018. Selected key statistics for load levels, day-ahead and real-time energy market prices, and fuel prices are shown in Table 2-1 below.

**Table 2-1: High-level Market Statistics**

| Market Statistics | Spring 2018 | Winter 2018 | Spring 2018 vs Winter 2018 (% Change) | Spring 2017 | Spring 2018 vs Spring 2017 (% Change) |
|---|---|---|---|---|---|
| **Real-Time Load (GWh)** | 28,009 | 32,003 | -12% | 28,493 | -2% |
| **Peak Real-Time Load (MW)** | 17,457 | 20,662 | -16% | 20,250 | -14% |
| **Average Day-Ahead Hub LMP ($/MWh)** | $34.69 | $74.33 | -53% | $30.78 | 13% |
| **Average Real-Time Hub LMP ($/MWh)** | $33.27 | $76.04 | -56% | $31.92 | 4% |
| **Average Natural Gas Price ($/MMBtu)** | $3.84 | $10.20 | -62% | $3.55 | 8% |
| **Average Oil Price ($/MMBtu)** | $11.60 | $10.68 | 9% | $8.56 | 36% |

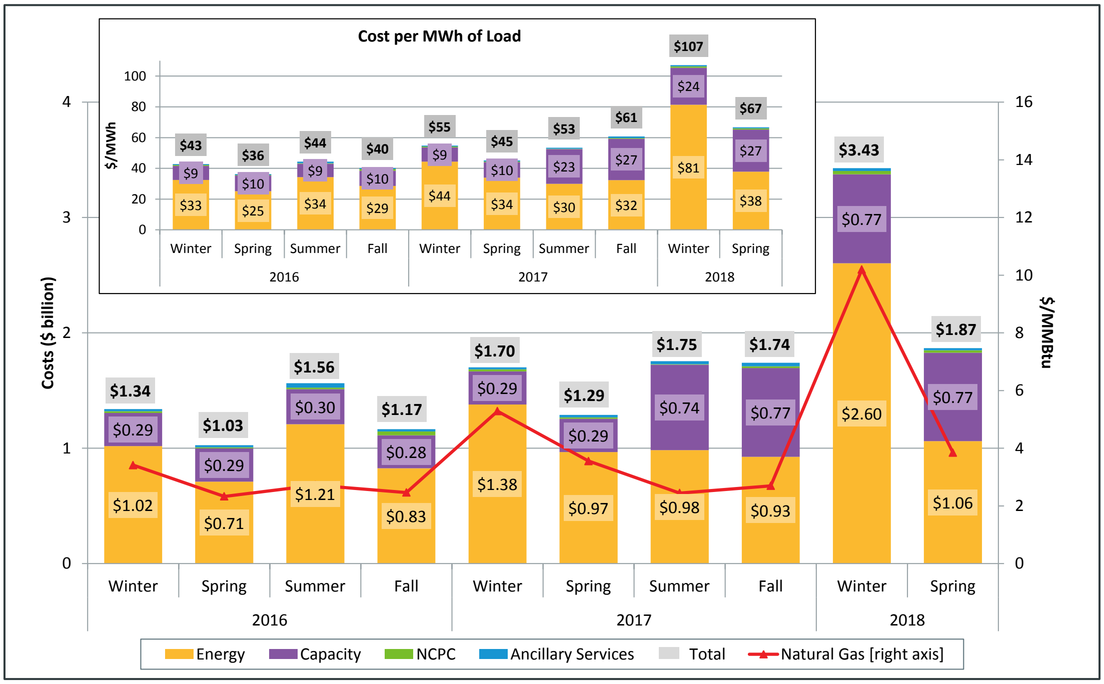
Gas prices fell in Spring 2018 compared to Winter 2018, which led to lower day-ahead and real-time LMPs. Peak load was lower in Spring 2018 compared to Spring 2017 due milder temperatures at the end of May. In summary:

- Average gas prices in Spring 2018 were $3.84/MMBtu, down 62% from Winter 2018, and up 8% from Spring 2017. The decline from Winter 2018 was due to fewer constraints and lower demand on New England gas pipelines. The increase from Spring 2017 was primarily due to lower temperatures driving higher gas prices in April 2018. April 2018 prices averaged $5.03/MMBtu, 57% higher than prices in April 2017, while the average temperature (43°F) was 8°F lower than in April 2017 (51°F).
- Peak load in Spring 2018 reached 17,457 MW, 14% lower than the peak load in Spring 2017. A few hot and humid days in May 2017 resulted in elevated peak load levels in Spring 2017. Load is discussed further in Section 2.2 below.
- Average day-ahead LMPs in Spring 2018 were $34.94/MWh, 13% higher compared to Spring 2017 prices. As mentioned above, April 2018 was a cold month with higher gas prices, leading to higher generation costs. The average day-ahead LMP in April 2018 was $46.55/MWh, 55% higher than the average price in April 2017 ($30.03/MWh).

## 2.1 Wholesale Cost of Electricity

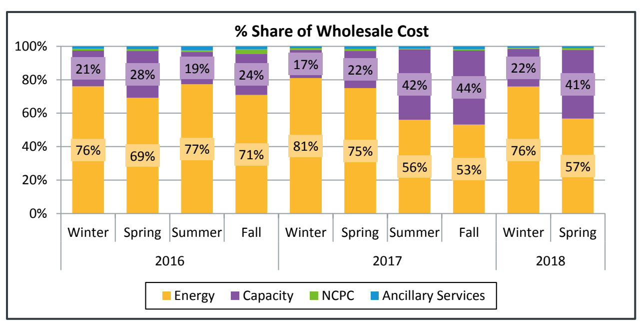
The estimated wholesale electricity cost (in billions of dollars) for each season by market, along with average natural gas prices (in $/MMBtu) is shown in Figure 2-1 below. The inset graph shows the wholesale cost per megawatt hour of real-time load served. [5,6]

**Figure 2-1: Wholesale Market Costs and Average Natural Gas Prices by Season**




In Spring 2018, the total estimated wholesale market cost of electricity was $1.87 billion (or $67/MWh), an increase of 45% compared to $1.29 billion in Spring 2017, and a decrease of 46% over the previous quarter (Winter 2018). Natural gas prices continued to be the key driver of energy prices. Energy costs were $1.06 billion ($38/MWh) in Spring 2018, 10% higher than Spring 2017 costs and consistent with the 8% increase in natural gas prices. Energy costs made up 57% of the total wholesale cost. The share of each wholesale cost component is shown in Figure 2-2.

**Figure 2-2: Percentage Breakdown of Wholesale Cost Components**




[5] The total cost of electric energy is approximated as the product of the day-ahead load obligation for the region and the average day-ahead locational marginal price (LMP) plus the product of the real-time load deviation for the region and the average real-time LMP. Transmission network costs as specified in the Open Access Transmission Tariff (OATT) are not included in the estimate of quarterly wholesale costs.

[6] Unless otherwise stated, the natural gas prices shown in this report are based on the weighted average of the Intercontinental Exchange next-day index values for the following trading hubs: Algonquin Citygates, Algonquin Non-G, Portland and Tennessee gas pipeline Z6-200L. Next-day implies trading today (D) for delivery during tomorrow's gas day (D+1). The gas day runs from hour ending 11 on D+1 through hour ending 11 on D+2.

Capacity costs are driven by clearing prices in the primary capacity auctions, and totaled $0.77 billion ($27/MWh), comprising 41% of total costs. Beginning in Summer 2017, rising capacity market costs contributed to the higher wholesale costs relative to previous quarters. Up to June 2017, capacity prices were relatively low because the region had an excess of supply compared to the capacity requirements. Capacity prices from the eighth Forward Capacity Auction (FCA 8), which went into effect beginning in June 2017, reflected a system-wide capacity deficiency of 143 MW due to a number of generator retirements. Due to the capacity shortfall, prices in FCA 8 were administratively set at $7.03/kW-month for existing (non-NEMA/Boston) resources, and at a price of $15.00/kW-month for new and existing resources in NEMA/Boston. This compares to a rest-of-pool clearing price of $3.15/kW-month in the prior auction, FCA 7.

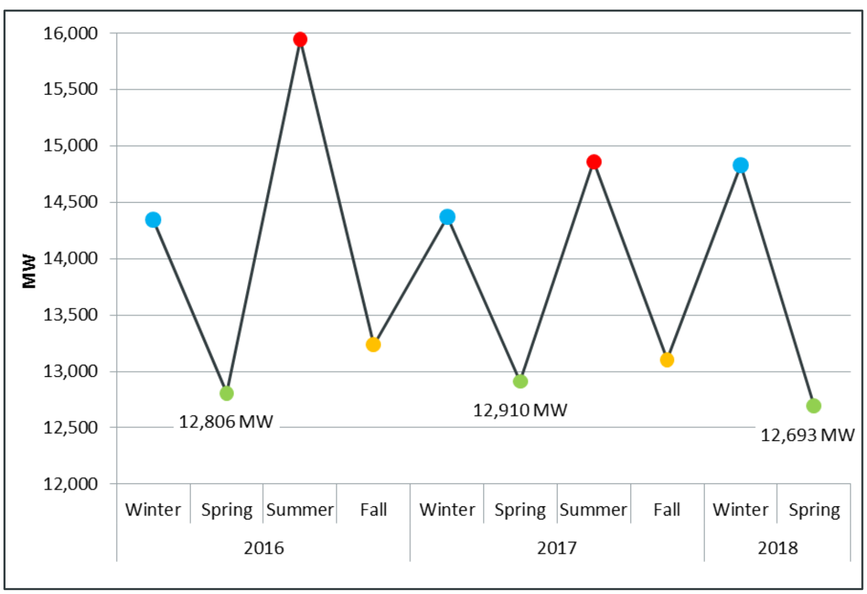
At $20.6 million ($0.74/MWh), Spring 2018 Net Commitment Period Compensation (NCPC) costs represented around 2% of energy costs, a similar share compared to other quarters in the reporting horizon. In dollar terms, NCPC costs were $7.2 million higher than Spring 2017 NCPC costs, and $8.7 lower than Winter 2018 NCPC costs. Section 3.4 contains further details on NCPC costs.

Ancillary services, which include operating reserves and regulation, totaled $19.5 million ($0.70/MWh) in Spring 2018, representing 1% of total wholesale costs. Ancillary service costs decreased by 7% compared to Spring 2017, and decreased by 21% compared to Winter 2018.

## 2.2 Load

Warmer spring temperatures brought a sharp decline in average load relative to Winter 2018. Figure 2-3 below highlights the seasonal swings in load over the previous nine quarters, with load peaking in summer (shown as red dots) and winter (blue dots) and dropping during the milder weather of fall (yellow dots) and spring (green dots).

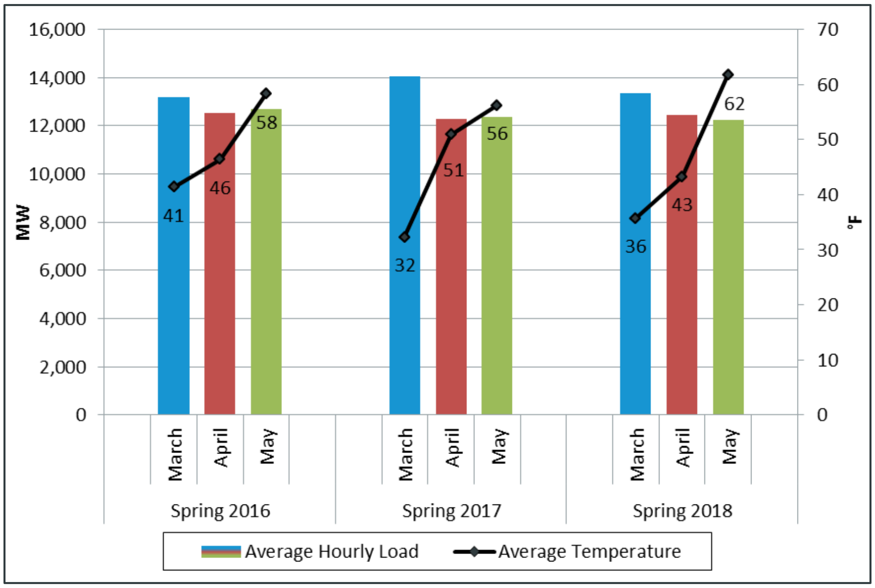
**Figure 2-3: Average Hourly Real Time Load**




Spring 2018 load averaged 12,693 MW per hour, a 1.7% decrease from Spring 2017 and 0.9% below Spring 2016. The monthly breakdown of load over the last three spring seasons is shown in

Figure 2-4 below; the columns illustrate monthly average load (left axis) and the lines illustrate monthly average temperature (right axis).

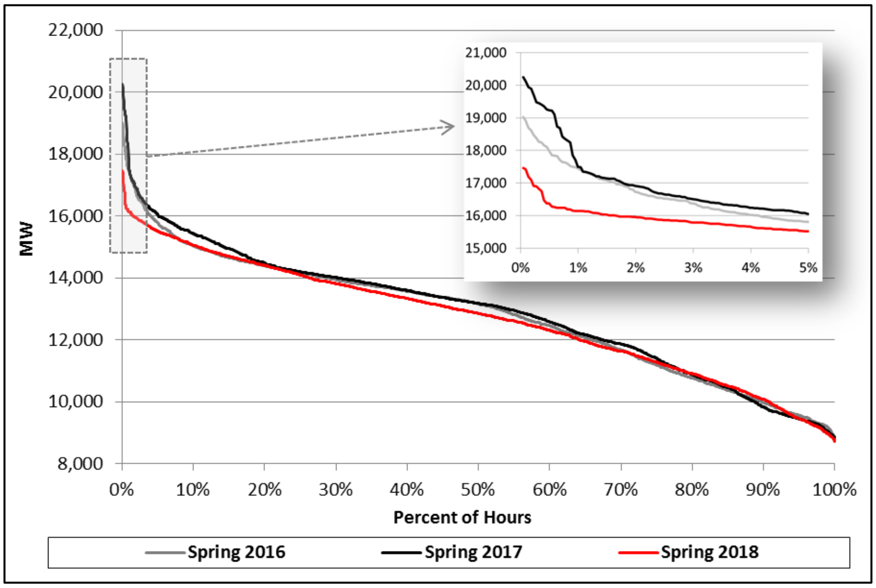
**Figure 2-4: Monthly Average Load and Temperature**




Warmer temperatures in March and May of 2018 drove the decline in average load from Spring 2017 to Spring 2018. March's average temperature of 36°F, compared to 32°F for March 2017, contributed to a 5% decrease in load from March 2017 to March 2018. The decline in average load from Spring 2016 to Spring 2018 can be partly explained by a warmer May. May 2018 was 4°F warmer, on average, than May 2016, which drove May's average load 3% below average load for May 2016.

Load duration curves, which show the percent of total hours in which load is greater than or equal to a given level, are presented for the last three spring seasons in Figure 2-5 below. The inset graph within Figure 2-5 highlights the 5% of total hours with the highest load levels.

**Figure 2-5: Seasonal Load Duration Curves**




The Spring 2018 load duration curve shown in red is frequently below the duration curves for Spring 2017 (black curve) and Spring 2016 (gray curve). This is consistent with average load in Spring 2018 being lower than the two prior spring seasons. As previously discussed, this decrease in load is due in part to warmer temperatures. Additionally, greater energy efficiency and, to a lesser extent growth in behind-the-meter solar generation, have contributed to the long-term trend of declining loads over time.[7]

Spring 2018 generally had lower peak loads than the prior two spring seasons. This can be seen in Figure 2-5 as the gap between the three load duration curves widens in the hours with the highest load levels. The average load in the top 5% of hours of Spring 2018 was 15,946 MW, a decrease of 1,115 MW from the average of 17,061 MW in Spring 2017. This decline can be partly explained by weather. March 2017 was relatively cold with several very cold days, and there were a few hot and humid days in May 2017 that elevated peak loads during Spring 2017.

## 2.3 Supply

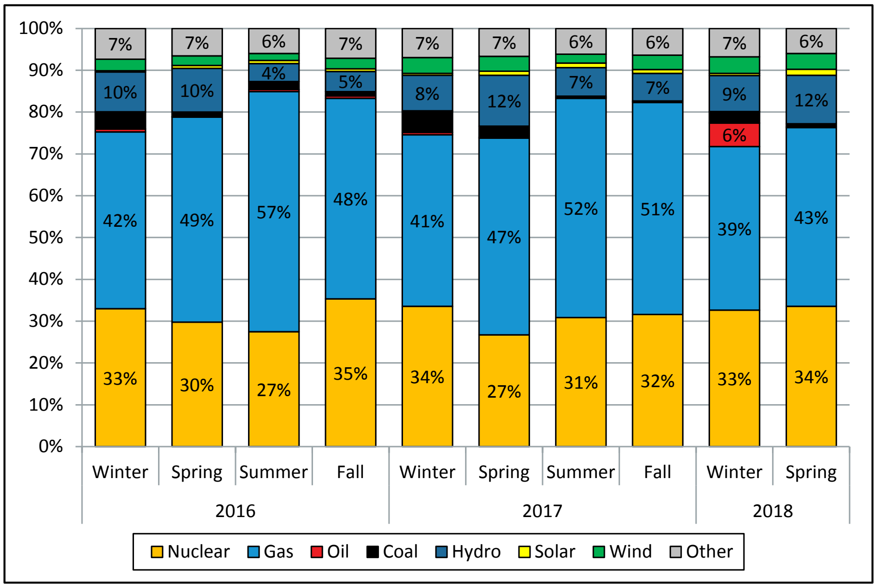
This subsection summarizes actual energy production by fuel type, and flows of power between New England and its neighboring control areas.

### 2.3.1 Native Generation by Fuel Type

The breakdown of actual energy production by fuel type provides useful context for the drivers of market outcomes. The share of energy production by generator fuel type for Winter 2016 through Spring 2018 is illustrated in Figure 2-6 below.

[7] Section 2.3 of the 2017 Annual Markets Report discusses the impacts of behind-the-meter solar and energy efficiency on wholesale load levels: https://www.iso-ne.com/static-assets/documents/2018/05/2017-annual-markets-report.pdf

**Figure 2-6: Share of Native Electricity Generation by Fuel Type**




Seasonal fluctuations in fuel mix occur due to market economics and generator availability. Overall, the fuel mix in Spring 2018 was within a normal range. Comparing Spring 2018 to Spring 2017, the two periods were reasonably similar, except for an increase in nuclear generation and a decline in gas generation in Spring 2018. Nuclear generation accounted for 34%, an increase from 27% in Spring 2017. The lower share of nuclear generation in Spring 2017 was due to multiple planned refueling outages during the quarter.

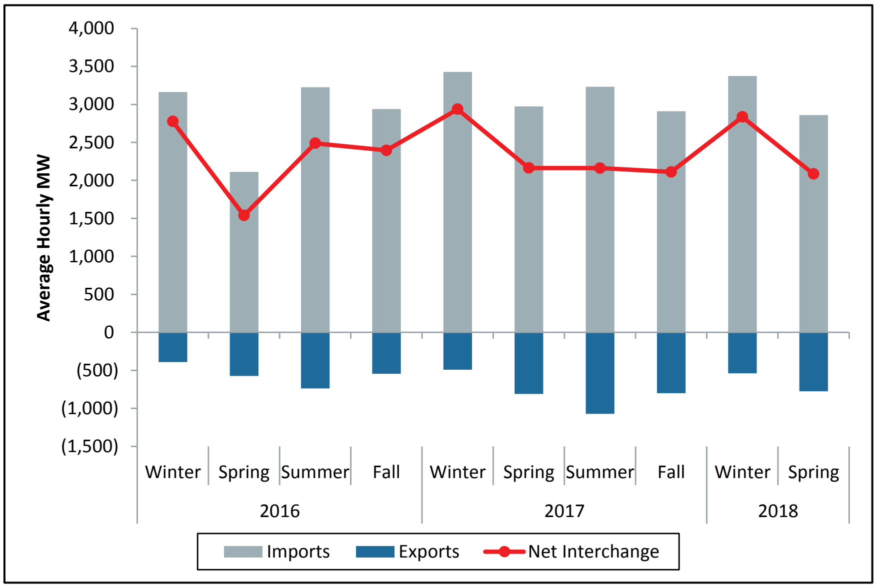
The largest share of New England's generation comes from gas-fired generators, which accounted for 43% of total native energy production during Spring 2018, up from 39% in the prior quarter. The increase in gas generation coincides with the decrease in oil generation (less than 1% in Spring 2018). Oil generation declined due to higher relative generation costs compared to gas. In Winter 2018, average oil prices were $10.68/MMBtu, compared to $10.20/MMBtu for gas. The spread between the two fell dramatically in Spring 2018. This is generally the case when natural gas demand declines in New England. Oil prices in Spring 2018 were $11.60/MMBtu, more than three times the average natural gas price of $3.84/MMBtu.

### 2.3.2 Imports and Exports

New England was a net importer of power from its neighboring control areas of Canada and New York during Spring 2018.[8] On average, the net flow into New England was about 2,085 MW per hour (imported). The average hourly gross import and export power volumes and the net interchange amounts for the last ten quarters are shown in Figure 2-7 below.

[8] There are six external interfaces that interconnect the New England system with these neighboring areas. The interconnections with New York are the New York North interface, which comprises several AC lines between the regions, the Cross Sound Cable, and the Northport-Norwalk Cable. These last two run between Connecticut and Long Island. The interconnections with Canada are the Phase II and Highgate interfaces, which both connect with the Hydro-Québec control area, and the New Brunswick interface.

**Figure 2-7: Average Hourly Real-Time Imports, Exports, and Net Interchange**




On average, 16% of New England's real-time load was met by imported power from New York and Canada; this is in line with the ten-season average of 17%. Figure 2-7 illustrates that net interchange and imports are generally lower in the spring when New England energy prices and demand tend to be lower than other quarters. Energy prices are discussed in more detail in Section 3.1 below. The hourly average Spring 2018 net interchange value of 2,085 MW was comparable with the prior spring when net interchange was 2,163 MW per hour. Spring 2016 had the lowest average hourly real-time imports and net interchange of all ten quarters shown in Figure 2-7. The average net interchange in Spring 2016 was lower than the Spring 2018 value by 547 MW per hour. The large Spring 2016 difference was due to a planned outage of the Phase II tie line (power from Hydro Quebec) that took the path out-of-service from April 1 through May 30, 2016 (two thirds of the spring quarter).[9]

[9] New England imports more MW on an hourly average from the Phase II external node than any of the other external nodes. For Spring 2018, New England imported 1,457 MW per hour, on average, from the Phase II external node.

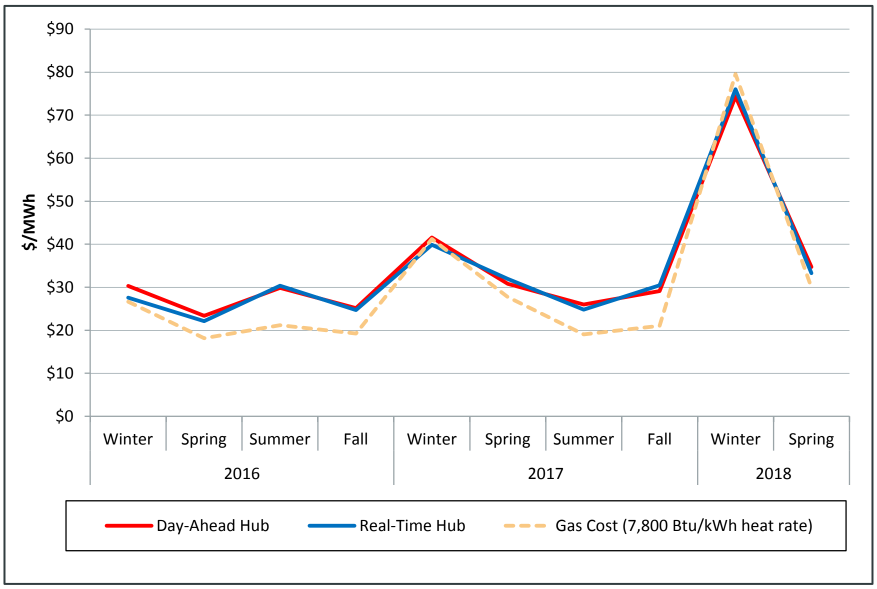
# Section 3
# Day-Ahead and Real-Time Markets

This section covers trends in, and drivers of, spot market outcomes, including the energy markets, and markets for ancillary services products: operating reserves and regulation.

## 3.1 Energy Prices

The average real-time Hub price for Spring 2018 was $33.27/MWh. This was 4%, or $1.42/MWh, lower than the average day-ahead price of $34.69/MWh. Day-ahead and real-time prices, along with the estimated cost of generating electricity using natural gas, are shown in Figure 3-1 below. The natural gas cost is based on the average natural gas price each season and a generator heat rate of 7,800 Btu/kWh.[10]

**Figure 3-1: Simple Average Day-Ahead and Real-Time Hub Prices and Gas Generation Costs**




As Figure 3-1 illustrates, the seasonal movements of energy prices (solid lines) are generally consistent with changes in natural gas generation costs (dashed line). The spread between the estimated cost of a typical natural gas-fired generator and electricity prices tends to be highest during the summer months as less efficient generators, or generators burning more expensive fuels, are required to meet the region's higher demand. Average electricity prices were slightly higher than average estimated gas costs in Spring 2018 , a trend that was consistent with Spring 2017 and Spring 2016. Gas costs averaged $30/MWh in Spring 2018.

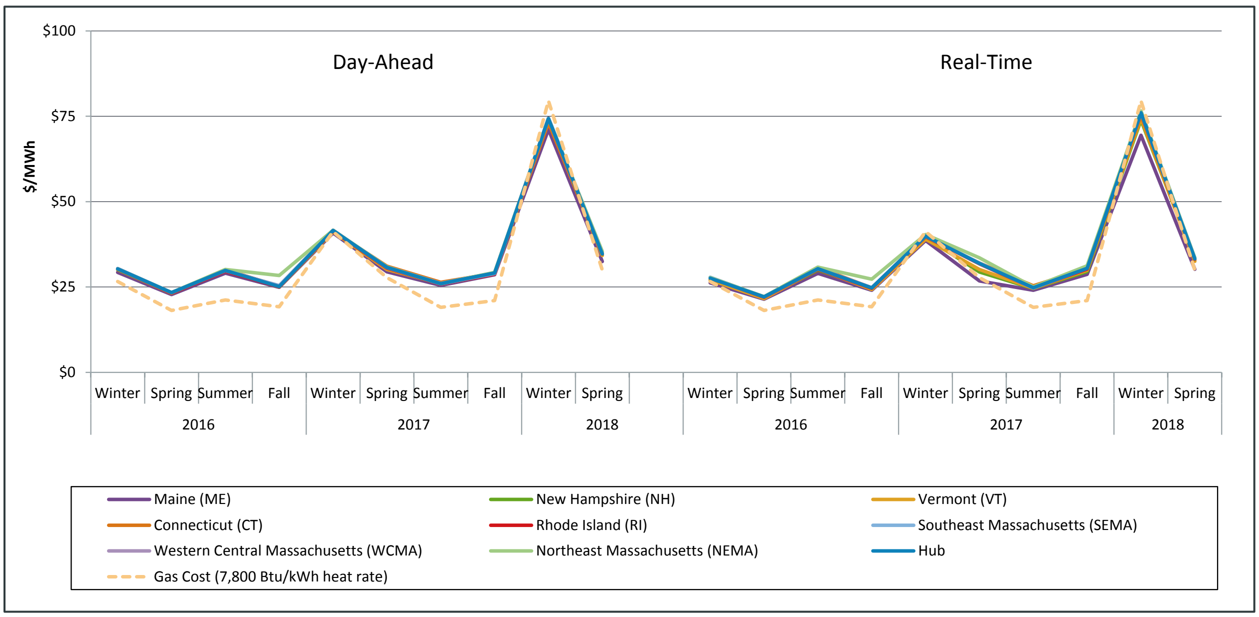
In Spring 2018, the month of March saw the greatest day-ahead to real-time price divergence, with average real-time prices $2.51/MWh less than average day-ahead prices. Lower real-time prices in March were driven by significant negative price spikes that took place on several days throughout the month. During these periods, additional renewable generation on the system led to depressed real-time prices. Renewable (such as wind and solar) generators do not always offer into the day-

[10] The average heat rate of combined cycle gas turbines in New England is estimated to be 7,800 Btu/kWh.

ahead market due to their intermittent nature, but they frequently offer low-priced generation into the real-time market. Therefore, large quantities of real-time low-priced renewable generation can lead to depressed real-time prices. Additionally, there were multiple days in March where actual loads were significantly below forecasted loads. Actual loads came in under the forecast for 80% of hours in March, and the monthly load forecast accuracy goal was not met.[11] The forecast error contributed to depressed real-time prices, since more expensive generation that cleared in the day-ahead market to meet the anticipated higher load is backed down in real-time when actual loads fall significantly short of the forecast.

The seasonal average day-ahead and real-time energy prices for each of the eight load zones in New England and for the Hub are shown below in Figure 3-2.

**Figure 3-2: Simple Average Day-Ahead and Real-Time Prices by Location and Gas Generation Costs**




Day-ahead prices did not differ significantly among the load zones, with the exception of Maine. The Maine average day-ahead price was $2.21/MWh (6%) lower than the Hub price. Price separation in Maine was even more notable in the real-time market, with prices $3.06/MWh (9%) lower than Hub prices. Lower prices in Maine were driven by a planned line outage that reduced the export capability of Maine to the rest of the system for several weeks. Additionally, renewable generators with lower marginal costs are located in export-constrained areas of northern New England and frequently set real-time prices in Maine. The discount in energy prices in Maine was similar during the previous quarter (Winter 2018).

Real-time energy prices in the NEMA zone averaged $33.51/MWh during Spring 2018, which was $0.24/MWh (1%) higher than the average Hub price. Most of the premium in the average NEMA

[11] To meet the monthly forecast accuracy goal, the mean absolute percent error for all hours cannot exceed predefined thresholds, which vary by time of year. The March goal was 1.8%, while the actual mean absolute percentage error was 2.05% for all hours and 1.91% for peak hours. The load forecast accuracy information for March is from the April 2018 NEPOOL Participants Committee Report, available at https://www.iso-ne.com/static-assets/documents/2018/04/april-2018-coo-report.pdf

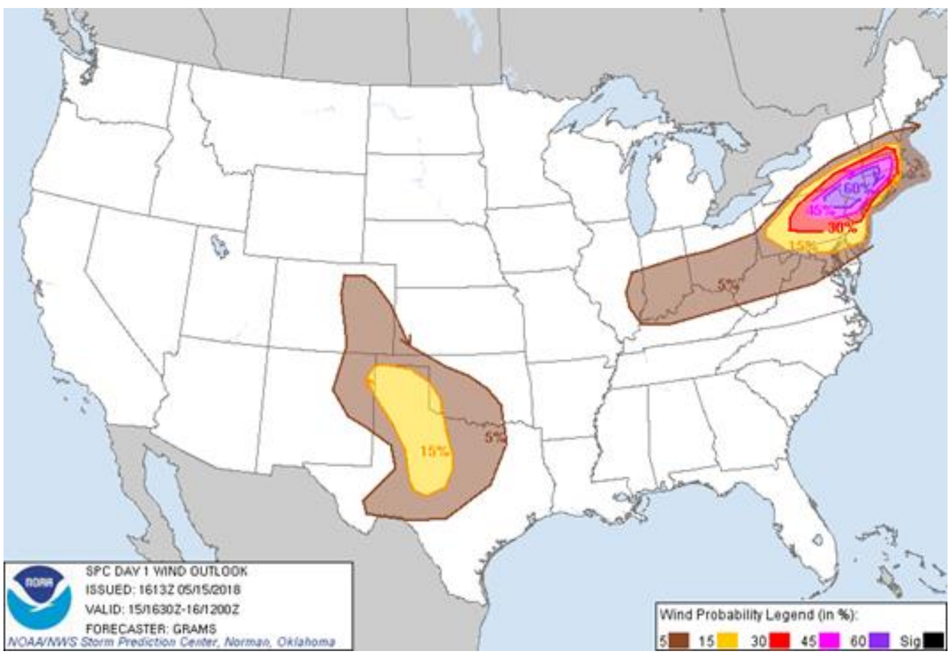
energy price was due to price separation related to an emergency line outage that occurred in early March.

### *Real-time Prices on May 15, 2018*

In this reporting period, system conditions and market outcomes on May 15 were particularly notable. While average daily prices were not the highest of the season (real-time prices averaged $46.24/MWh, the 18th highest day of the season, and day-ahead prices averaged $31.45/MWh), average hourly prices were amongst the highest, with a high of $280.95/MWh, including thirty-minute operating reserve pricing.

On May 15 a series of violent thunderstorms swept through New England, producing 100 mph winds and spawning four tornadoes in Connecticut. A rare "moderate" risk tornado warning was issued by the Storm Prediction Center by midday, and by the afternoon, areas of New England experienced one of the worst thunderstorm outbreaks in decades. According to meteorologists at the Connecticut Weather Center, it was one of the five most notable storms of the last few centuries for the number of tornadoes it created. Figure 3-3 shows the strong winds forecast for New England that afternoon.

**Figure 3-3: Wind Forecast as of 4 p.m. on May 15, 2018**[12]




As thunderstorms moved across the region, cloud cover obstructed the sun and reduced the output of wholesale and behind-the-meter solar generation. Shortly before the storm reached New England, behind-the-meter and settlement-only solar generation was producing around 1,600 MW at around 2 p.m.[13] As the storm progressed over the next hour, solar generation declined to around

[12] The wind forecast graphic is from the Storm Prediction Center on the National Oceanic and Atmospheric Administration website, available at: https://www.spc.noaa.gov/products/outlook/archive/2018/day1otlk_20180515_2000.html

[13] These figures represent the total volume of solar generation that the ISO does not dispatch. The volume of behind-the-meter solar generation is estimated, as the ISO does not have access to telemetry data for resources that are not connected to the grid, and subject to revision. Settlement-only generators are units that produce less than 5 MW, which are entitled to receive capacity credit, but are not centrally dispatched by the ISO control room and are not monitored in real time.

1,050 MW and decreased further down to just 330 MW by 4 p.m. Additionally, the ISO expected humidity to decrease as the thunderstorms passed, but humidity remained high, resulting in significant load forecast error. The loss of solar generation and the relatively high humidity contributed to actual loads running higher than the forecast, by 844 to 1,405 MW from 3 to 5 p.m. (as shown in the inset graph in Figure 3-4 below).

The severe weather resulted in tight system conditions but no deficiencies in operating reserves. Multiple transmission elements tripped due to high winds, and the large load forecast error caused the amount of available reserves to decline at around 2:55 p.m. The operating reserve margin (the, amount of reserves available in excess of the reserve requirement) dropped to nearly 0 MW at around 4 p.m. The ISO committed additional generation to maintain adequate operating reserves. Between 3 and 6 p.m., 1,300 to 2,000 MW of fast-start generation was required to meet load and operating reserve requirements.

Prior to the thunderstorms entering New England, the ISO took a planned software outage of the Energy Management System/Market power system beginning at 1:35 p.m. to update the network model.[14] During the outage all of the reliability tools required to operate the system remained in service and were used.[15] However, the outage removed the market software that determines economic commitment and pricing. While the software was unavailable, no LMPs were automatically calculated or published during the storm. Commitments were managed manually in economic order by the ISO Operators.

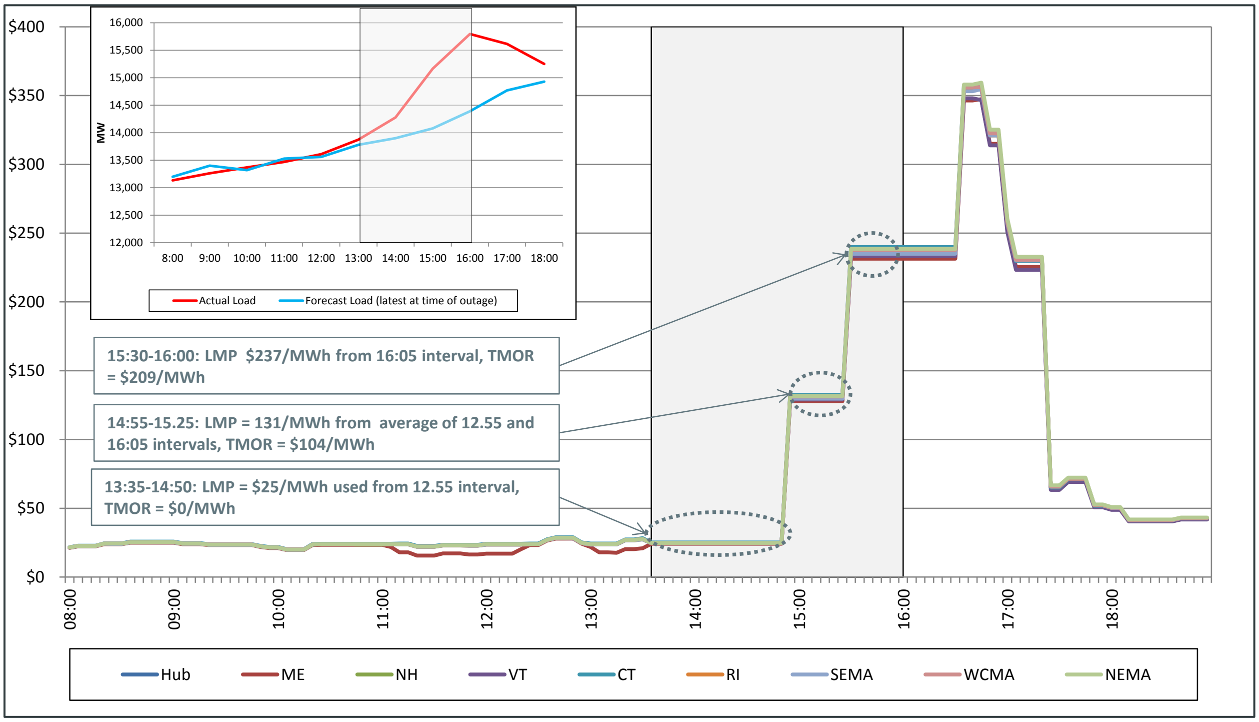
Afterwards, the ISO used established protocols to recreate the prices as is the case during market software outages. Given the large load forecast error towards the end of the software outage, LMPs were relatively low going into the outage ($27.62/MWh at 1:30 p.m.), and very high once the software came back online ($237/MWh at 4:05 p.m.). There was no notable reserve pricing in the intervals immediately preceding the outage, but by the time the software returned the reserve price was $213.49/MWh ($4.89/MWh TMSR, $208.60/MWh TMOR).

To estimate prices, the ISO considered the LMPs before and after the software outage, as well as the load levels, reserve margins, and manual fast-start generator commitments during the outage. Below, Figure 3-4 shows LMPs for several hours on May 15, with the time of the outage highlighted in gray.

[14] Network model updates generally occur three times per year. The ISO typically schedules the updates and software outages during the day. This network model upgrade was critical to the implementation of Pay for Performance and Price Responsive Demand and was scheduled to be completed prior to the storms entering the area.

[15] The outage to the ISO's energy management software was much shorter (minutes) than the market software, which allowed the Operators to continue to monitor and operate the system reliably during the storm.

**Figure 3-4: Forecast Error and Reconstituted 5-Minute LMPs on May 15, 2018**




From 1:35 to 2:50 p.m., information from the 12:55 p.m. market case was used to set the LMP at $24.66/MWh and reserve pricing at $0/MWh. From 2:55 to 3:25 p.m., the 12:55 and 4:05 p.m. case prices were averaged to create an LMP of $130.92/MWh, with a TMSR price of $2.45/MWh and a TMOR price of $104.30/MWh. From 3:30 to 4 p.m., the 4:05 p.m. price was used to set the LMP at $237.19/MWh, with a TMSR price of $4.89/MWh and a TMOR price of $208.60/MWh. The times at which the LMP increased during the outage correspond to changing reserve margins and commitments: At 2:55 p.m., the operating reserve surplus dropped, prompting the first round of manual fast-start commitments. At 3:30 p.m., the operating reserve margin declined again, and additional fast-start generators were manually committed.

## 3.2 Marginal Resources and Transactions

The LMP at a pricing location is set by the cost of the next megawatt (MW) the ISO would dispatch to meet an incremental change in load at that location. The resource that sets price is "marginal". Analyzing marginal resources by transaction type can provide additional insight into day-ahead and real-time pricing outcomes.

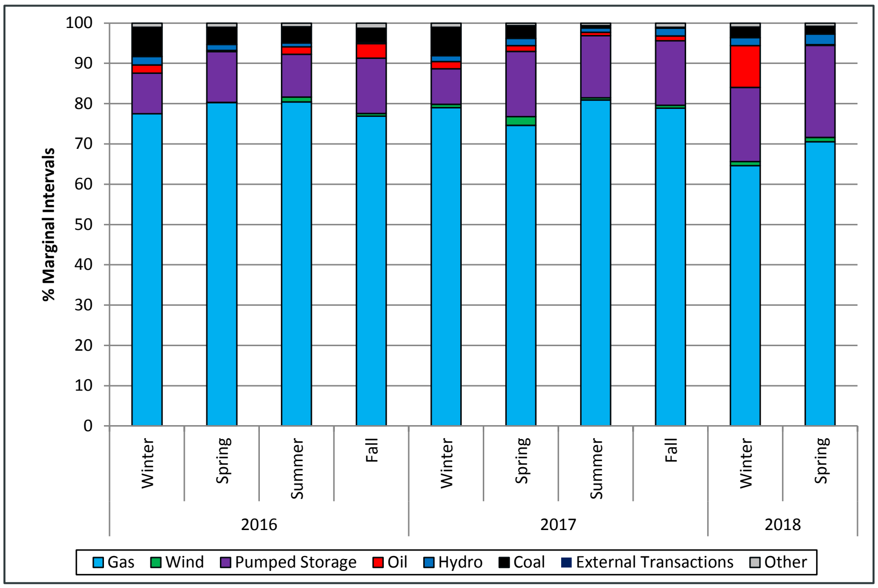
Previous reports showed the percentage of marginal intervals for a fuel type under the assumption that multiple marginal resources within an interval split the load equally. However, when more than one resource is marginal the system is typically constrained and marginal resources likely do not contribute equally to meeting load across the system. For example, resources within an export-constrained area are not able to fully contribute to meeting the load for the wider system.

Consequently, the impact of these resources on the system LMP is muted. For this reason, the graphs below now show results for load-weighted marginal resources.[16]

In the day-ahead market, a greater number of transaction types can be marginal; these include virtual bids and offers, fixed and priced-demand, generator supply offers and external transactions. By contrast, only physical supply, pumped-storage demand, and external transactions can set price in the real-time market. In practice, marginal resources in the real-time market are typically generators (predominantly natural gas-fired generators) and pumped-storage demand.

The percentage of time resources of different fuel types were marginal in the real-time market by season is shown in Figure 3-5 below.[17]

**Figure 3-5: Real-Time Marginal Units by Fuel Type**




Natural gas-fired generators set price about 70% of the time. Energy from gas-fired generators also accounts for almost half of native generation, and is often the cheapest fossil fuel type generation. This implies that gas-fired generators will typically operate more often than coal- or oil-fired generators, as generators are committed and dispatched in merit order. Most of the time, more expensive coal- and oil-fired generators are not required to meet system demand. Because gas-fired generators are often the most expensive units operating, they set price frequently.

In addition to their relative cost, many gas-fired generators are eligible to set price due to their dispatchable range. By contrast, nuclear generation accounts for about one third of native generation in New England, but does not set price. Nuclear generators in New England are offered at a fixed output, meaning once they are brought online they can only produce at one output level. By definition, if load changed by one megawatt they could not increase or decrease their output to meet the demand, and are therefore ineligible to set price.

[16] Quarterly Markets Reports and Annual Markets Reports prior to this publication did not apply this new load-weighted methodology.

[17] "Other" category contains wood, biomass, black liquor, fuel cells, landfill gas, nuclear, propane, refuse, and solar.

Pumped-storage units (generators and demand) set price about 14% of the time in the reporting period. Pumped-storage units generally offer energy at a price that is close to the margin. They are often called upon when conditions are tight due to their ability to start up quickly and their relatively low commitment costs compared with fossil fuel-fired generators. Because they are online relatively often and priced close to the margin, they can set price frequently. The percentage of time pumped-storage units set price in Spring 2018 was consistent with previous seasons.

In this report, the marginal resources during an interval are weighted by their contribution to load. In this way, the impact of the marginal resources on the LMP can be seen more clearly. For example, in recent reports wind was often the second most frequent marginal fuel type. However, despite the high percentage of time wind generators were marginal, they only set price for the entire system 0.5% of the time. This is due to the limitations of the transmission system in delivering output from their locations to the rest of New England. Wind generators are often in export-constrained areas and can only deliver the next increment of load in a small number of locations because the transmission network that moves energy out of their constrained area is at maximum capacity. Load that is outside the export-constrained area has no way of consuming another megawatt of the relatively inexpensive wind output.

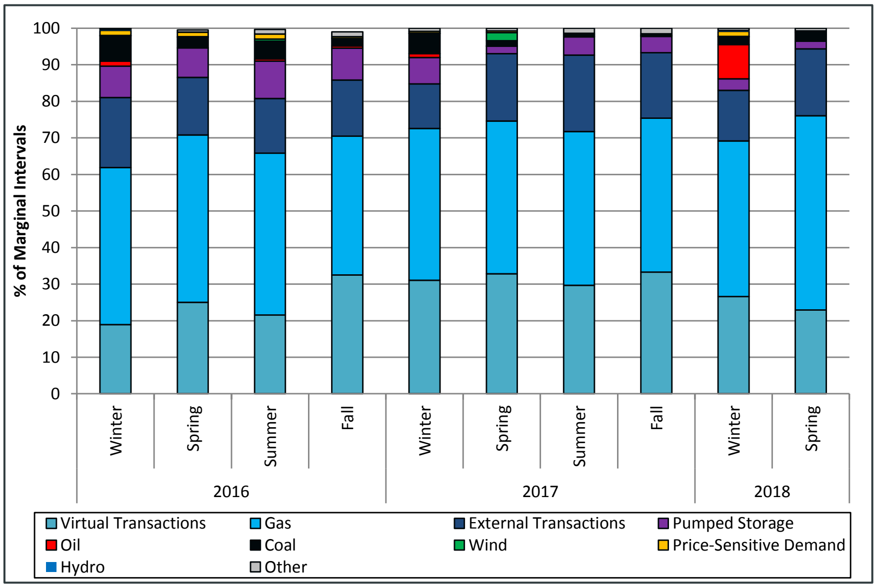
In these instances the remainder of the region experiences prices set by other, usually more expensive, generators. Compared with those of other fuel types, wind generators have a lower marginal cost. Wind generators are often offered into the real-time market at negative prices and are rarely the most expensive generators online.

The higher frequency of marginal wind generators that began in Summer 2016 is driven by the Do Not Exceed (DNE) dispatch rules, which went into effect on May 25, 2016 (at the end of the Spring 2016 reporting period).[18] DNE improves the modeling of wind and hydro intermittent generators in the real-time market. These generators are now dispatched by the unit dispatch software and are eligible to set price. Previously, these generators were essentially fixed in the pricing process, and therefore unable to set price.

The percentage of time that each transaction type set price in the *day-ahead market* since Spring 2016 is illustrated in Figure 3-6 below.

[18] *ISO New England Inc. and New England Power Pool*, Do Not Exceed ("DNE") Dispatch Changes, ER15-1509-000 (filed April 15, 2015); Order Conditionally Accepting, In Part and Rejecting, In Part, Tariff Revisions and Directing Compliance Filing*,* 152 FERC ¶ 61,065 (2015). In a subsequent filing, the Filing Parties modified the DNE Dispatch changes to remove the exclusion of DNE Dispatchable Generators from the regulation and reserves markets, to comply with the Commission's order on the original rule changes. The Commission accepted the ISO's compliance filing in a subsequent order. *ISO New England Inc. and New England Power Pool*, Compliance Filing Concerning DNE Dispatch Changes, ER15-1509-002 (filed August 21, 2015); Letter Order Accepting DNE Dispatch Compliance Filing, ER15-1509-002 (issued October 1, 2015).

**Figure 3-6: Day-Ahead Marginal Units by Transaction and Fuel Type**




Gas-fired generators were the most frequent marginal resource type in the day-ahead market; they set price in 53% of hours. Just as gas-fired generators are the most frequent marginal fuel type in the real-time market, they make up most of the marginal *generation* in the day-ahead market as well. Generators as a group comprised close to 60% of all marginal entities in the day-ahead market.

Virtual transactions set day-ahead prices about 23% of the time in the reporting period, down slightly on previous seasons. Virtual transactions are a day-ahead market product that profit by arbitraging differences between day-ahead and real-time energy prices. When a systematic difference between the day-ahead and real-time markets emerges, virtual transactions are one mechanism through which the day-ahead market can adjust to better reflect real-time conditions. Virtual transactions can offer at any price and many are offered around the margin. Virtual transactions also have a high propensity to be marginal because they do not have operational constraints, which generally limit the ability to be marginal.[19]

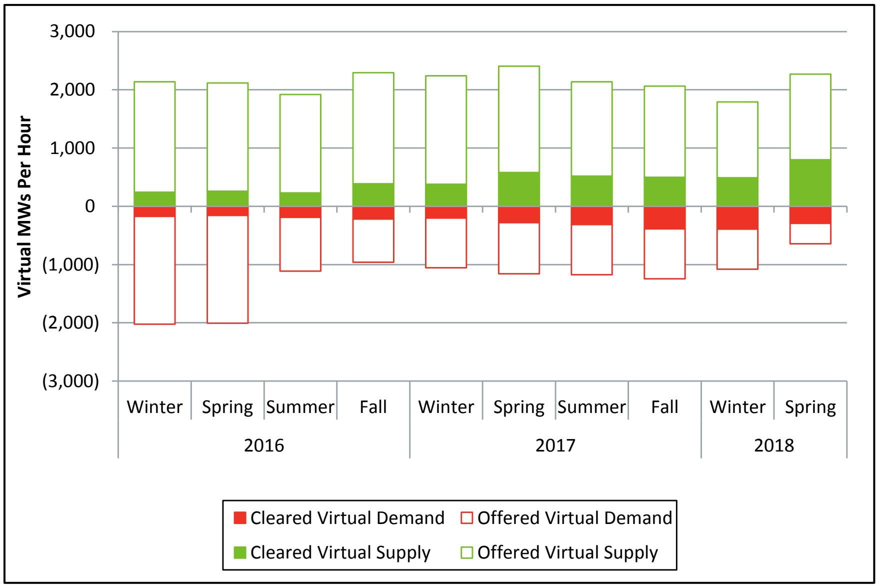
In Fall 2016, the frequency of virtual transactions began increasing, a pattern which has persisted through the most recent quarter. The increase has been driven by virtual traders responding to differences between day-ahead and real-time offer behavior of wind generators that can now set price in the real-time market. As discussed above, at the end of the Spring 2016 reporting period, Do Not Exceed (DNE) dispatch rules were introduced to allow intermittent wind and hydro generators to set price in the real-time energy market. The change resulted in an increase in price-setting wind generators in the real-time market – at consistently low prices. A majority of wind generators clear much less energy in the day-ahead market compared to real-time; this puts downward pressure on real-time prices relative to day-ahead prices. This difference provides an opportunity for virtual traders to profit by "replacing" the wind energy with low-priced incremental offers, improving the day-ahead market's scheduling in the process.

[19] For example, a committed 100 MW block-loaded resource must clear 100 MW and is generally incapable of setting price. It is fixed and cannot increase its output to deliver another increment of load. A 100 MW virtual transaction can be cleared at any quantity between 0 and 100 MW. If it is cleared at any quantity less than 100 MW it can deliver the next increment of load and is eligible to set price.

## 3.3 Virtual Transactions

Offered and cleared virtual transaction volumes from Winter 2016 through Spring 2018 are shown in Figure 3-7 below.

**Figure 3-7: Total Offered and Cleared Virtual Transactions (Average Hourly MW)**




In Spring 2018, total submitted virtual transactions averaged approximately 2,911 MW per hour, which was in line with the average amount submitted in Winter 2018 (2,871 MW per hour) but 18% less than the average amount submitted in Spring 2017 (3,560 MW per hour). On average, 1,094 MW per hour of virtual transactions cleared in Spring 2018, which represents an increase of 24% compared to Winter 2018 (880 MW per hour) and an increase of 27% compared to Spring 2017 (865 MW per hour).

Beginning in Summer 2016, the average offer prices of virtual transactions have converged towards actual LMPs, resulting in higher percentages of virtual transactions clearing. In general, the percent of virtual transactions that have cleared has grown nearly every quarter over the reporting period, rising from 10% in Winter 2016 to 38% in Spring 2018. A reduction in transaction costs, in the form of reduced NCPC costs that are charged in part to virtual transactions, may have contributed to this offer behavior.[20]

Additionally, beginning in May 2016 certain wind and hydro generators became dispatchable under the Do Not Exceed (DNE) dispatch market rule. Under this change, DNE resources can set price in the real-time energy market. Prior to the change, DNE resources could only set price in the day-ahead energy market. DNE resources tend to offer higher-priced energy in the day-ahead market due to uncertainty surrounding environmental and production conditions. Because there is more certainty in real-time, DNE resources reduce their offers and frequently set price.

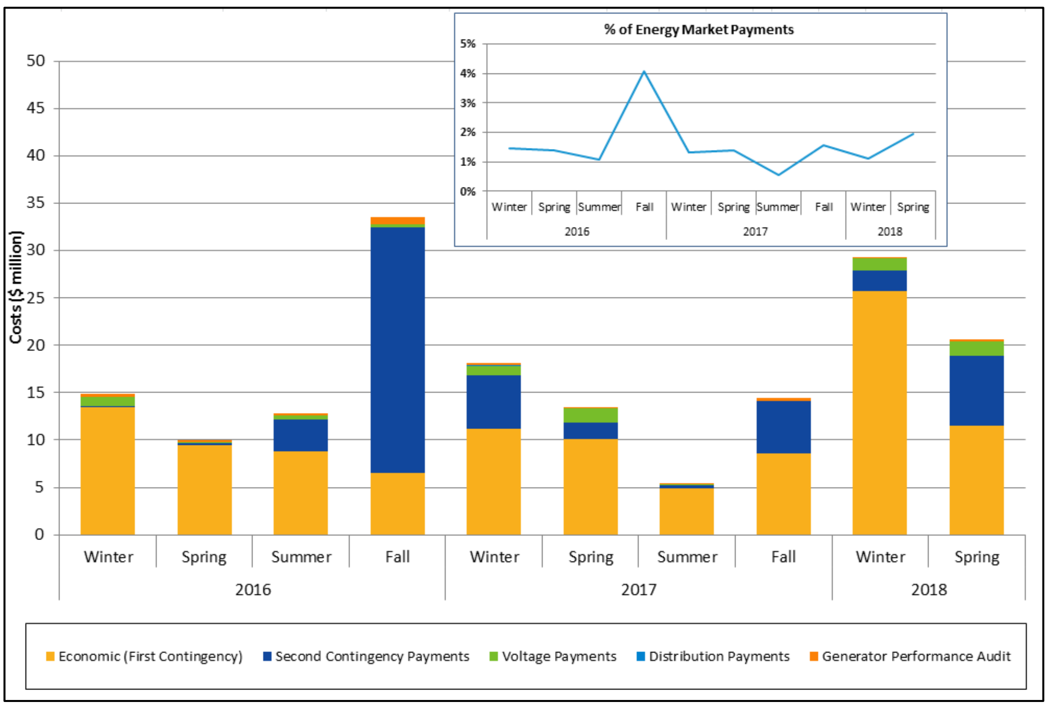
[20] In February 2016, real-time economic NCPC payments made to generators that received a day-ahead commitment were eliminated, reducing the total pool of real-time economic NCPC paid. The fast-start pricing rules implemented in March 2017 also had a downward effect on real-time economic NCPC. For more information about fast-start pricing, see Section 5 of the IMM's Summer 2017 Quarterly Markets Report: https://www.iso-ne.com/static-assets/documents/2017/12/2017-summer-quarterly-markets-report.pdf

This creates the opportunity for virtual supply to take advantage of the difference in day-ahead and real-time offer behavior. Since the implementation of DNE, the volume of cleared virtual supply has increased and is frequently marginal in areas with DNE resources. In real-time, DNE resources are frequently marginal in these same areas.

## 3.4 Net Commitment Period Compensation

Net Commitment Period Compensation (NCPC) is a method of providing make-whole payments to resources when energy prices are insufficient to cover production costs. Resources committed and dispatched economically (in-merit), as well as resources dispatched out of economic-merit order for reliability purposes, may require NCPC payments. NCPC is paid to resources for providing a number of services, including first- and second-contingency protection, voltage support, distribution system protection, and for generator performance auditing.[21] NCPC payments by season and category are illustrated in Figure 3-8 below. The inset graph shows NCPC payments as a percentage of total energy payments.

**Figure 3-8: NCPC Payments by Category ($ millions)**




Total NCPC payments made in Spring 2018 fell close to 30% from the level observed in Winter 2018, dropping from $29.3 million to $20.6 million. However, NCPC payments increased relative to the same quarter last year; the Spring 2018 payment is 54% larger than the $13.4 million payment made in Spring 2017. As shown in the inset graph in Figure 3-8, the total NCPC payment in Spring 2018 is greater than both the previous winter and spring when

21 NCPC payments include *economic/first contingency NCPC payments*, *local second-contingency NCPC payments* (reliability costs paid to generating units providing capacity in constrained areas), *voltage reliability NCPC payments* (reliability costs paid to generating units dispatched by the ISO to provide reactive power for voltage control or support), *distribution reliability NCPC payments* (reliability costs paid to generating units that are operating to support local distribution networks), and *generator performance audit NCPC payment* (costs paid to generating units for ISO-initiated audits).

expressed as a percentage of total wholesale energy market costs. Spring 2018 NCPC payments represent 1.9% of the total wholesale energy market costs that occurred during this quarter, up from 1.1% in Winter 2018 and 1.4% in Spring 2017. As explained in detail below, two notable factors largely explain the increase in NCPC payments: local reliability commitments of relatively expensive generators in the NEMA/Boston zone required to support transmission outages, and to a lesser extent, an increase in NCPC paid to out-of-rate external transactions due to ISO price forecast error.

The majority of NCPC (56%) incurred during the reporting period was for first contingency protection ($11.5 million). Just over half of the total first contingency NCPC ($6.3 million) was paid out in the real-time market, while the other 45% ($5.2 million) was paid out in the day-ahead market. This represents a fairly significant shift in the make-up of first contingency NCPC payments from Winter 2018, when the split between real-time and day-ahead economic payments was closer to 75-25.[22] However, this split is comparable to the split from Spring 2017, when the real-time market accounted for 59% of the total first contingency payments ($6.0 million) and the day-ahead market accounted for the other 41% ($4.1 million).

One of the largest components of economic NCPC in Spring 2018 was real-time external transaction NCPC, which totaled $1.7 million. Import and export transactions get scheduled in the real-time market based on forecasted prices but the transactions are settled based on actual prices. This NCPC credit is intended to make external transactions that end up being out-of-rate (based on actual prices) whole to their bid or offer.[23] Over 95% of the real-time external transaction NCPC paid out in Spring 2018 was paid to imports at the New Brunswick interface. Over this period, numerous imports at the New Brunswick interface that were scheduled based on the ISO-forecasted price ended up being uneconomic in the real-time, thus requiring NCPC to be made whole to their offers. The quarter with the next highest amount of real-time external NCPC in the ten-quarter reporting horizon was Spring 2017, when real-time external NCPC amounted to $1.2 million.

The second largest category of NCPC (36%) incurred during the reporting period was for local second-contingency protection (LSCPR). Total LSCPR payments of $7.4 million were 235% higher than the $2.2 million paid out in Winter 2018 and 322% higher than the $1.7 million paid out in Spring 2017. The vast majority (95%) of LSCPR NCPC paid out this reporting period was in the day-ahead market as the need for local reliability protection can often be anticipated based on planned transmission outages. Nearly all of the LSCPR NCPC payments in Spring 2018 (93%) were paid to units located in NEMA/Boston that were required to support planned outages on 345-kV transmission system.

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[22] One of the primary reasons for the higher proportion of real-time economic NCPC payments in Winter 2018 was resource posturing. From late December 2017 through early January 2018, an extended period of extremely low temperatures led to increased energy output from coal- and oil-fired units. Over this time, numerous oil-fired units began to encounter fuel limitations (i.e., difficulty procuring replacement fuel) that prevented them from operating at full output on a daily basis. In order to maintain system reliability, many of these oil-fired units were postured by the ISO (i.e., had their output reduced below their economic dispatch level) to preserve their limited fuel supply for future time periods. Resources that are postured by the ISO for reliability are eligible for posturing NCPC credits that are intended to make them no worse off than the scenario where they were not postured. In total, posturing NCPC credits totaled $7.9 million in Winter 2018, while they only amounted to $0.5 million in Spring 2018.

[23] Most pool-scheduled external transactions are eligible for this form of credit. However, external transactions at the Roseton interface, also called coordinated external transactions (CETs), are not eligible for this form of NCPC nor are external transactions that wheel energy through the New England Control Area.

Voltage NCPC payments in the quarter totaled $1.5 million. This was a modest increase compared to $1.2 million in Winter 2018 and the $1.4 million in Spring 2017. Like LSCPR commitments, generator commitments for voltage support can often be anticipated in the day-ahead market based on planned transmission outages. In Spring 2018, 80% of the voltage NCPC payments were made in the day-ahead market, while the remaining 20% occurred in the real-time market. Most of the voltage NCPC paid out during this reporting period (96%) was received by one generator in NEMA/Boston during the period of March 1 to March 4. This generator was required to provide voltage support as the result of a 345-kV transmission line outage.

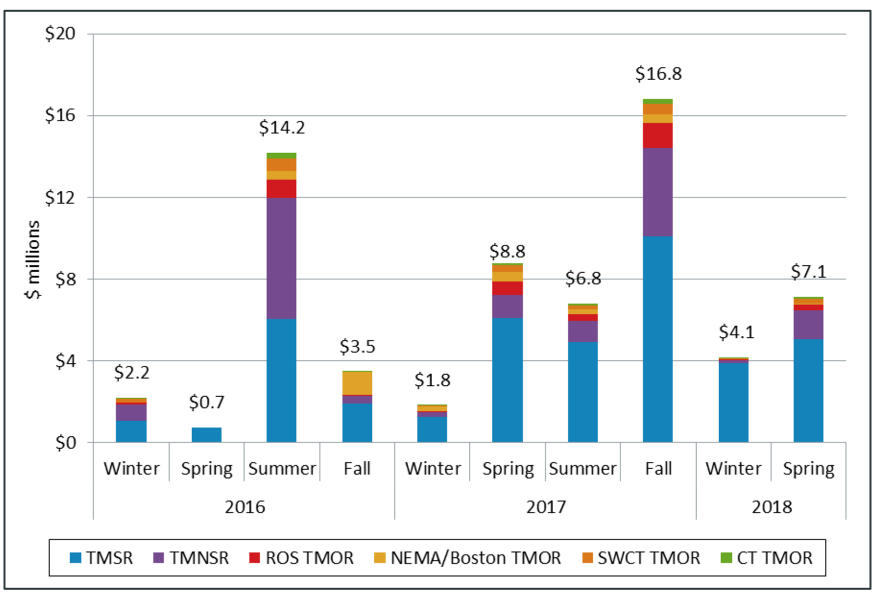
Generator performance audit (GPA) NCPC payments totaled $208,000 in Spring 2018. This reflects an 87% increase from the total paid in Winter 2018 ($111,000) and a 251% increase from the $59,000 paid in Spring 2017. Distribution NCPC payments were very small in Winter 2017, amounting to under $20,000.

## 3.5 Real-Time Operating Reserves

Real-time reserve payments totaled $7.1 million in Spring 2018, a $1.7 million (19%) decrease from Spring 2017. The decline is largely due to a $1.1 million reduction in payments for ten-minute spinning reserve (TMSR), which was driven by a fall in TMSR clearing prices. Lower real-time LMPs in May, the month in which a majority of the quarter's non-zero TMSR pricing occurred, relative to May of 2017, decreased TMSR clearing prices and helped reduce real-time reserve payments. Real-time reserve payments to generators designated to satisfy forward reserve obligation are reduced by a forward reserve obligation charge so that a generator is not paid twice for providing the same service. Total forward reserve obligation charges were $1.3 million, bringing net real-time time reserve payments down to $5.8 million.

Real-time reserve payments by product and by zone are illustrated in Figure 3-9 below.

**Figure 3-9: Real-Time Reserve Payments by Product and Zone**



In Spring 2018, real-time reserve payments for TMSR were $5.0 million, making up about 70% of total real-time reserve payments. Ten-minute non-spinning reserve (TMNSR) payments were $1.4 million (20% of total payments), which was an increase of $0.3 million from Spring 2017. TMOR payments aggregated across all reserve zones fell by $0.9 million, from $1.5 million in Spring 2017 to $0.7 million. The largest decline occurred for the local TMOR product in NEMA/Boston, which decreased from $478,000 to $63,000.

The frequency of non-zero reserve pricing by product and by zone along with the average price during these intervals for the past three spring seasons is provided in Table 3-1 below. [24]

**Table 3-1: Hours and Level of Non-Zero Reserve Pricing**

| Product | Zone | Spring 2016 | | Spring 2017 | | Spring 2018 | |
|---|---|---|---|---|---|---|---|
| | | *Hours of Non-zero Pricing* | *Avg. Price $/MWh* | *Hours of Non-zero Pricing* | *Avg. Price $/MWh* | *Hours of Non-zero Pricing* | *Avg. Price $/MWh* |
| TMSR | System | 175.5 | $8.72 | 399.7 | $15.85 | 451.0 | $12.85 |
| TMNSR | System | 0.0 | $0.00 | 0.7 | $4.20 | 1.7 | $2.94 |
| TMOR | System | 0.0 | $0.00 | 13.5 | $4.13 | 8.5 | $2.11 |
| | NEMA/Boston | 0.0 | $0.00 | 30.6 | $11.08 | 0.0 | $2.11 |
| | CT | 0.0 | $0.00 | 0.0 | $4.13 | 0.0 | $2.11 |
| | SWCT | 0.0 | $0.00 | 0.0 | $4.13 | 0.0 | $2.11 |

The TMSR clearing price was greater than zero (i.e., there was non-zero reserve pricing) in 451 hours (20% of total hours) during Spring 2018. The frequency of non-zero pricing was comparable to Spring 2017 but more than double the 175.5 hours in Spring 2016. For the hours where there was non-zero TMSR pricing, the TMSR clearing price averaged $12.85/MWh, compared to the $15.85/MWh average for Spring 2017. There was a total of 12 hours during Spring 2018 where the TMSR clearing price equaled the reserve constraint penalty factor (RCPF) of $50/MWh.[25] This is similar to Spring 2017, where the TMSR price equaled the RCPF for 11.4 hours.

There was non-zero TMNSR pricing for about 2 hours in Spring 2018, compared to 1 hour in Spring 2017. The TMNSR clearing price averaged $2.94/MWh in Spring 2018, compared to $4.11/MWh in Spring 2017. There were 10 minutes in which the TMNSR RCPF was triggered during Spring 2018; the TMNSR RCPF was not triggered in either of the prior two spring seasons.

Both the frequency and level of non-zero TMOR pricing decreased from Spring 2017 to Spring 2018. Non-zero pricing declined from 13.5 hours in Spring 2017 to 8.5 hours in Spring 2018, and the average TMOR reserve price fell from $4.13/MWh to $2.11/MWh. The TMOR RCPF was triggered for 20 minutes in Spring 2018, an increase relative to 10 minutes in Spring 2017.

There were no hours of non-zero TMOR pricing for NEMA/Boston, CT, or SWCT because the TMOR constraints for these zones were not binding in any hour during Spring 2018. The average TMOR

[24] Non-zero reserve pricing occurs when there is an opportunity cost associated with dispatching the system in order to hold generators back for reserves or a reserve deficiency in the energy and reserve co-optimization process.

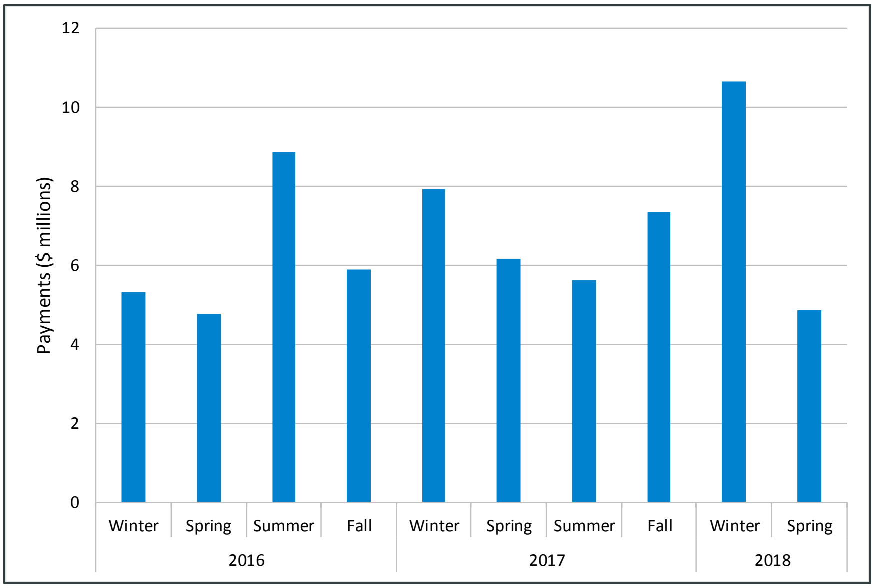
[25] The reserve constraint penalty factors are limits on the re-dispatch costs the system will incur to satisfy reserve constraints and will function as the reserve clearing price during a reserve deficiency. The penalty factors for the respective reserve products and their application are defined in Market Rule 1 Section III.2.7.A.

price for these zones, however, was equal to the system-wide TMOR average price of $2.11/MWh. This occurs because a zone's TMOR clearing price equals the system TMOR price when the zone's TMOR constraint is not binding but the system TMOR constraint is binding.

## 3.6 Regulation

Regulation is an essential reliability service provided by generators and other resources in the real-time energy market. Generators providing regulation allow the ISO to use a portion of their available capacity to match supply and demand (and to regulate frequency) over short-time intervals. Quarterly regulation payments are shown in Figure 3-10 below.[26]

**Figure 3-10: Regulation Payments ($ millions)**




Total regulation market payments were $4.9 million during the reporting period, down 54% from $10.7 million in Winter 2018, and down 21% from $6.2 million in Spring 2017. Regulation payments declined relative to the earlier periods primarily as a result of lower regulation capacity prices; additionally, decreases in service payments in each period were offset by increases in uplift (make-whole) payments. The capacity price decreases resulted primarily from lower energy market opportunity cost and incremental cost saving components of regulation capacity clearing prices.[27] An increase in regulation uplift payments reflects regulation capacity clearing prices being less adequate for fully compensating actual energy market opportunity costs compared to earlier quarters; the decline in service payments reflects lower regulation service offer prices by participants in the current quarter, compared to earlier quarters.

[26] As noted in the Spring 2016 Quarterly Markets Report, both regulation capacity and service requirements were increased due to the modification of calculations performed in accordance with NERC standard BAL-003, Frequency Response and Frequency Bias Setting. These changes were implemented in April 2016.

[27] Energy market opportunity costs and incremental cost savings are adjustments made by the ISO to the regulation capacity clearing price. The energy market opportunity cost reflects an estimate of foregone energy compensation resulting from providing regulation; incremental cost savings represents the reduction in total system cost provided by a specific regulation offer, when compared to the next most expensive offer.

# Section 4
# Forward Markets

This section covers activity in the Forward Capacity Market (FCM), the recent Forward Reserve Market (FRM) auction  and in Financial Transmissions Rights (FTRs).

## 4.1 Forward Capacity Market

The Forward Capacity Market (FCM) is a long-term market designed to procure the resources needed to meet the region's local and system-wide resource adequacy requirements.[28] The region developed the FCM in recognition of the fact that the energy market alone does not provide sufficient revenue to facilitate new investment or, in many cases, cover the cost of maintaining and operating existing resources. A central objective of the FCM is to create a revenue stream that replaces the "missing" revenue and thereby induces suppliers to undertake the investments necessary for reliable electric power service.

During any three-month period there can be FCM activity for up to four commitment periods. The initial capacity auction occurs three years and three months before the commitment period begins.[29]  Between the initial auction and the commitment period, there are six discrete opportunities to adjust annual capacity supply obligations (CSOs). Three of those are bilateral auctions where obligations are traded between resources at an agreed upon price and approved by the ISO. The other three are reconfiguration auctions run by the ISO, where participants can submit supply offers to take on obligations, or submit demand bids to shed obligations.

Monthly reconfiguration auctions and bilateral trading begin a month after the third annual reconfiguration auction, and occur two months before the relevant delivery month. Like the annual auctions, participants can buy or sell obligations. Buying an obligation means that the participant will provide capacity during a given period. Participants selling capacity reduce their CSO. Trading in monthly auctions adjusts the CSO position for a particular month, not the whole commitment period. The following sections summarize FCM activities during the reporting period, including total payments and trading of CSOs specific to each commitment period.

The Spring 2018 reporting period falls within the capacity commitment period (CCP) that started on June 1, 2017 and ended on May 31, 2018. In the corresponding Forward Capacity Auction (FCA 8), generator retirements resulted in a system-wide capacity deficiency of 143 MW.  Administrative pricing rules were triggered due to the shortfall, resulting in a price of $7.03/kW-month for existing (non-NEMA/Boston) resources and a price of $15.00/kW-month for all new resources. Existing resources in NEMA/Boston were also paid $15.00/kW-month due to administrative rules.[30]

Total FCM payments as well as the clearing prices for Winter 2016 through Spring 2018 are shown in Figure 4-1 below. The black lines (corresponding to the right axis, "RA") represent the FCA clearing prices for existing resources in the Rest-of-Pool capacity zone. The orange, blue, and green

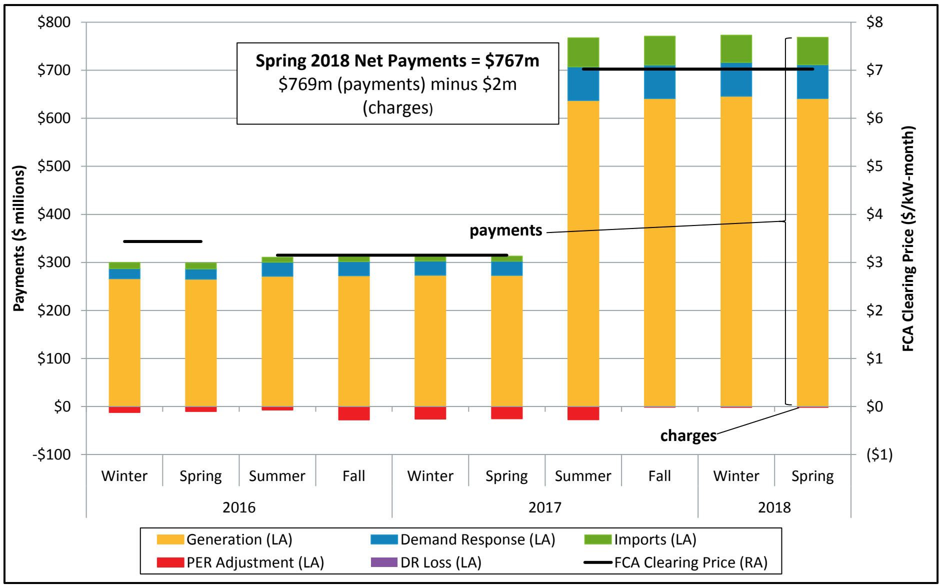
[28] In the capacity market, resource categories include generation, demand response and imports.

[29] Each capacity commitment period is a twelve-month period starting on June 1 of a year and ending on May 31 of the following year.

[30] The specific rule is the "capacity carry forward" rule. See pages 11-15 of the FCA 8 filing with FERC: https://www.iso-ne.com/static-assets/documents/regulatory/ferc/filings/2014/feb/er14_1409_000_fca8_results_filing_2_28_2014.pdf

bars (corresponding to the left axis, "LA") represent payments made to generation, demand response, and import resources, respectively.

**Figure 4-1: Capacity Payments ($ millions)**




In Spring 2018, capacity payments totaled $767 million, which accounts for adjustments to primary auction CSOs.[31] Payments continue to be higher than payments in previous FCAs due to the higher clearing prices in FCA 8.

Secondary auctions allow participants the opportunity to buy or sell capacity after the initial auction. Table 4-1 below provides a summary of prices and volumes associated with reconfiguration auction and bilateral trading activity that occurred during Spring 2018, alongside the results of the relevant primary FCA.

[31] Adjustments include annual reconfiguration auctions, annual bilateral periods, monthly reconfiguration auctions, monthly bilateral periods, peak energy rent adjustments, performance and availability activities, and reliability payments.

**Table 4-1: Primary and Secondary Forward Capacity Market Prices for the Reporting Period**

| FCA # (Commitment Period) | Auction Type | Period | Systemwide Price ($/kW-mo)** | Cleared MW | Capacity Zone/Interface Prices: NEMA/Bos | SEMA/RI | Phase I/II HQ Excess | New York AC Ties | New Brunswick |
|---|---|---|---|---|---|---|---|---|---|
| FCA 8 (2017-18) | Primary | 12-month | 15/7.03* | 33,712 | 15/15* | | | | |
| | Monthly Reconfiguration | May-18 | 1.05 | 738 | 5.00 | | | | |
| | Monthly Bilateral | May-18 | 3.23 | 322 | | | | | |
| FCA 9 (2018-19) | Primary | 12-month | 9.55 | 34,695 | | 17.73/11.08* | 3.94 | 7.97 | |
| | Annual Reconfiguration (3) | 12-month | 4.06 | 275/281*** | | | | 1.70 | |
| | Monthly Reconfiguration | Jun-18 | 3.50 | 255 | | | 2.00 | 3.30 | |
| | Monthly Bilateral | Jun-18 | 4.56 | 292 | | | | | |
| | Monthly Reconfiguration | Jul-18 | 4.50 | 228 | | | | 3.86 | |
| | Monthly Bilateral | Jul-18 | 3.99 | 332 | | | | | |
| FCA 10 (2019-20) | Primary | 12-month | 7.03 | 35,567 | | | | 6.26 | 4 |
| | Annual Bilateral (2) | May-18 | 5.23 | 24 | | | | | |

**price paid to new resources/price paid to existing resources*
***bilateral prices represent volume weighted average prices*
****cleared supply/cleared demand*

The third Annual Reconfiguration Auction (ARA) for CCP 9 took place in March 2018 and cleared 275 MW of supply and 281 MW of demand. The system-wide price was $4.06/kW-month, which is 57% lower than the clearing price for existing resources in FCA 9.[32] This marks the first ARA 3 without ISO participation. In place of ISO participation, the ISO implemented a sloped system demand curve in addition to participant demand bids and supply offers, consistent with other ARAs for CCP 9 or later.[33] The sloped demand curve allows cleared supply to differ from cleared demand. If there is an abundance of inexpensive supply, the auction can clear more supply than demand. Conversely, if participants offer high demand bids, more demand can clear than supply.

Three monthly reconfiguration auctions took place in Spring 2018. There were lower trade volumes and higher prices in the two summer periods (June and July) compared to the winter period (May). This is consistent with prior summer auctions due to lower generation qualified capacity during the summer months.[34]

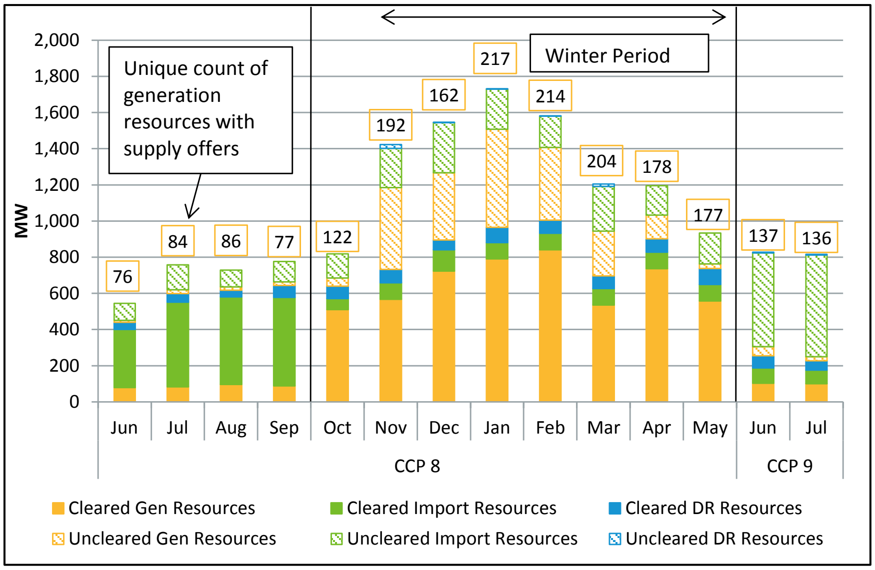
Supply offers, segmented by resource type, for CCPs 8 and 9 are shown in Figure 4-2 below. The solid bars represent cleared offers, while the striped bars represent uncleared offers. Generator, import, and demand response resources are purple, orange, and blue, respectively. The purple text boxes above each bar represent the number of unique generator resources that offered supply into the monthly reconfiguration auction.

[32] There was price separation at the New York AC ties due to interface limits. The interface cleared at $1.70/kW-month.

[33] The demand curve is designed to procure sufficient capacity to maintain resource adequacy and reduce price volatility over time. The demand curve used in ARA 3 was revised downward from the curves used in the FCA, ARA 1, and ARA 2 to reflect changes in system conditions.

[34] The summer CCP consists of June through September. This differs from the summer reporting period definition of June through August typically used in this report.

**Figure 4-2: Monthly Reconfiguration Auction Supply Offers During CCPs 8 and 9**




The figure highlights decreased cleared generation capacity in the summer period. Generator resources take advantage of their increased winter capability discussed in the paragraph above. An average of 99 generation resources participated during the summer period. This is roughly half the average of 183 during winter periods. The average volume weighted Rest-of-Pool price in summer months was $4.44/kW-month. The average price declined to $1.14/kW-month during the winter period.

## 4.2 Forward Reserve Market

Twice each year, ISO New England holds forward reserve auctions. The ISO uses forward reserve auctions to enter into forward obligations with participants to provide operating reserves in the real-time energy market. These forward obligations are intended to ensure the delivery of adequate operating reserves for both the ISO New England system-wide and local reserve zones. During April 2018, the ISO held the forward reserve auction for the Summer 2018 delivery period (i.e., June 1, 2018 to September 30, 2018).[35]

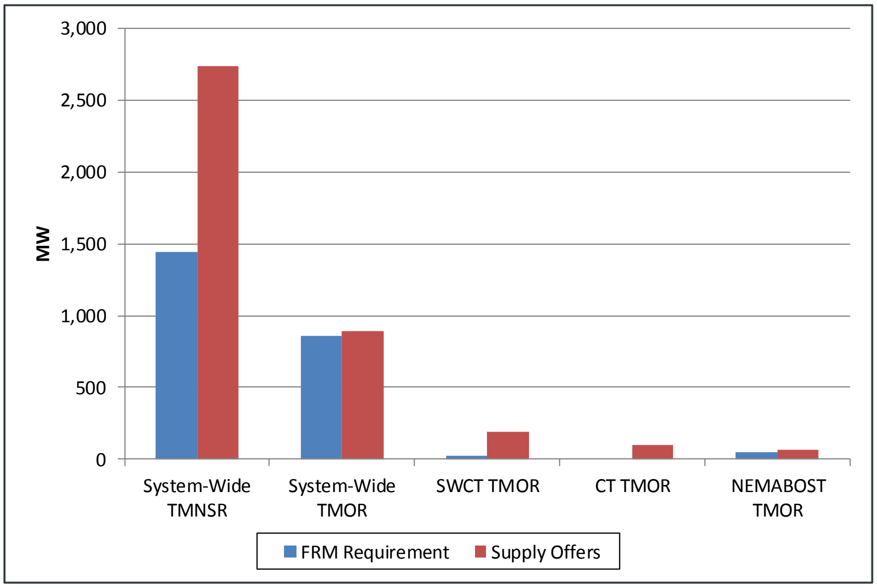
### 4.2.1 Auction Reserve Requirements

Prior to each auction, the ISO establishes the amount of forward reserves, or requirements, for which it will enter into forward obligations. These requirements are set at levels intended to ensure adequate reserve availability in real-time, based on possible system and local reserve zone contingencies (unexpected events such as the forced outage of a large generator or loss of a large transmission line).

[35] The Forward Reserve Market has two delivery ("procurement") periods per year: Summer (June 1 to September 30) and Winter (October 1 to May 31).

Figure 4-3 below illustrates the requirements for the Summer 2018 auction. These requirements were specified for the ISO New England system and three local reserve zones.[36] The figure also illustrates the total quantity of supply offers available in the auction to satisfy the reserve needs.[37]

**Figure 4-3: Forward Reserve Requirements and Supply Offer Quantities**




For the system, requirements were set for two reserve products, ten-minute non-spinning reserve (TMNSR) and thirty-minute operating reserve (TMOR). The ISO bases the requirements for each product on possible system contingencies. For TMNSR, the requirement was based on the expected single contingency of the Hydro Quebec Phase II Interconnection, and was estimated as a 1,443 MW TMNSR reserve need. The system-wide TMOR requirement was based on the expected single contingency of the Mystic 8 and 9 generators, and was estimated as an 857 MW TMOR need.[38]

[36] The local reserve zones are Connecticut (CT), Southwest Connecticut (SWCT), and NEMA/Boston (NEMABOST).

[37] Because TMOR supply offers within local reserve zones also provide TMOR to the system, the system-wide TMOR offers shown in the figure include the local reserve zone supply offers. Hence, the system-wide TMOR offers represent the total offers throughout the system.

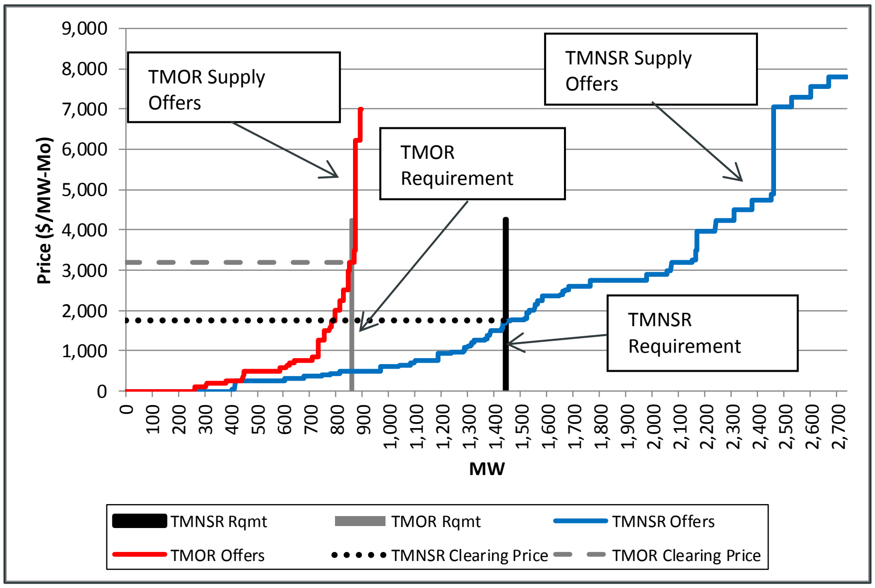
[38] ISO New England Memorandum to Market Participants (Subject: Assumptions and Other Information for the Summer 2018 Forward Reserve Auction), published March 16, 2018, indicates the system-wide and local reserve zone requirements. For the system-wide requirements, the final requirement may reflect ISO adjustments, such as biasing the requirement, increasing a requirement to reflect historical resource non-performance, and adjusting the TMOR requirement to reflect the replacement reserve requirement.

For the local reserve zones, only a TMOR requirement is specified. The ISO bases the local requirements on local second contingencies, adjusted for the availability of transmission capacity (which can also effectively supply reserves to the local area).[39] After adjustments, the Connecticut reserve zone was found to need no local reserve requirement, as "external reserve support" (available transmission capacity) exceeded the local second contingency requirements; the Southwest Connecticut and NEMA/Boston reserve zones, however, needed 21 MW and 44 MW of local reserves, respectively.

### 4.2.2 System Supply and Auction Pricing

As noted previously, system-wide supply offers in the Summer 2018 auction exceeded the requirements for both TMNSR and TMOR. Adequate supply ensures that the ISO can successfully obtain forward obligations to meet expected reserve needs in the auction. Figure 4-4 provides the requirements and initial system-wide supply curves for both TMNSR and TMOR.

**Figure 4-4: Requirements and Initial Supply Curves, System-Wide TMOR & TMNSR**

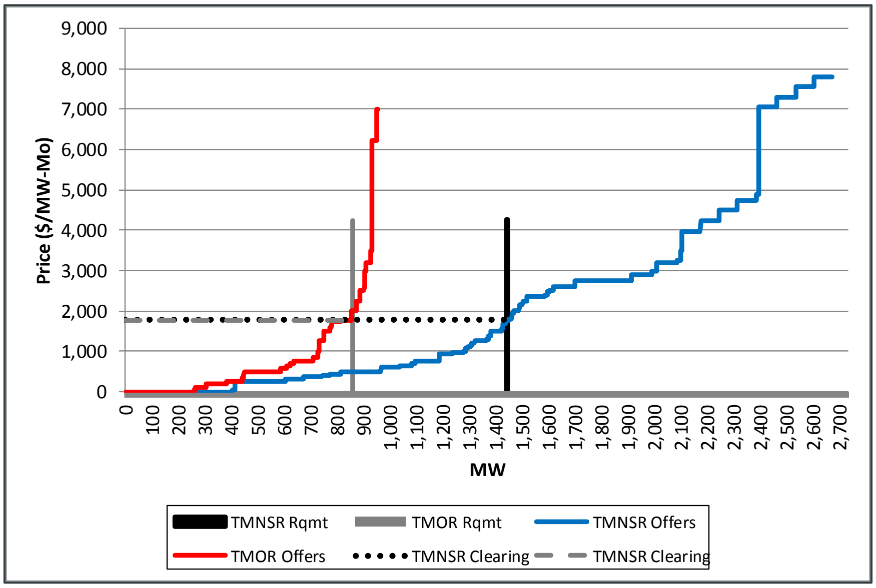



The figure indicates the prices that would have been obtained if TMNSR could not be substituted for TMOR. The supply curve for TMOR is above (i.e., more expensive than) the supply curve for TMNSR. However, ten-minute reserves are a higher-quality product and so the auction clearing software substitutes the lower-quality 30-minute reserve product with it when it is economical to do so. Without substitution, the clearing prices for TMNSR and TMOR would be $3,200/MW-month since the higher-quality TMNSR product cannot have a lower price than the lower-quality TMOR product by auction design.

Figure 4-5 shows the clearing prices for TMNSR and TMOR with substitution. In this instance, TMNSR is substituted for TMOR until the prices for the two products become equal, while ensuring that the requirement for each product is fully satisfied. Only a small quantity of TMNSR needs to be substituted for TMOR for each product's price to become equal.

[39] See the ISO New England Manual for Forward Reserve and Real-Time Reserve for a more detailed indication of the determination of local reserve requirements (Manual M-36, Sections 2.2.3 – 2.2.5). The transmission capacity used to adjust the local requirement is referred to as "external reserve support."

**Figure 4-5: Supply Curves, Requirements and Clearing Prices, System-Wide TMOR & TMNSR**




With system-wide requirements of 857 MW for TMOR and 1,443 for TMNSR, system-wide supply offers for the two products, with substitution, resulted in a clearing price for each product of $1,780/MW-month (gray and black dashed/dotted lines in the figure).[40]

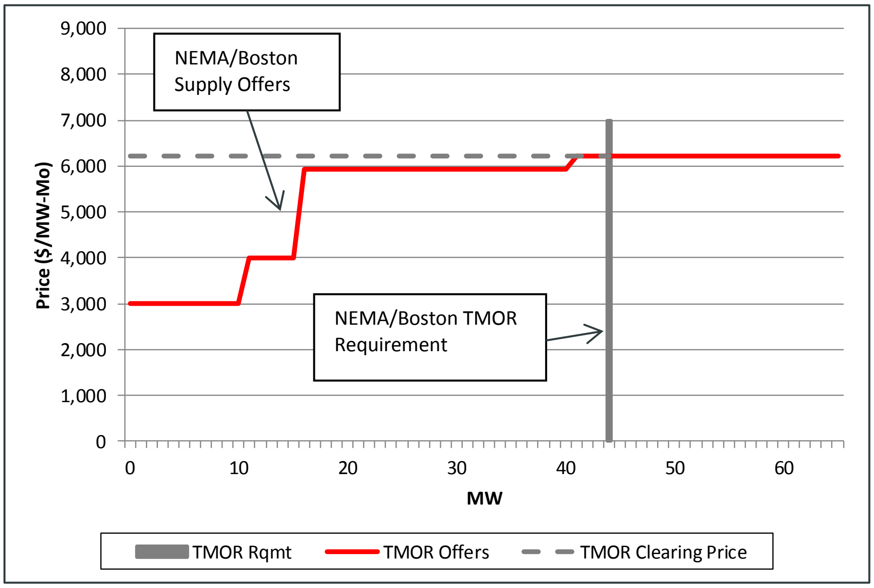
*Local Reserve Zone Supply and Auction Pricing*

For the local areas, both Southwest Connecticut and NEMA/Boston required the procurement of local reserves. In Southwest Connecticut, local supply exceeded the local requirement (21 MW) and the available local supply could satisfy that requirement at an offer price below the system TMOR price. The clearing price for procuring local supply in Southwest Connecticut was set equal to the system TMOR price, since local TMOR supply also counts toward meeting the system requirement and cannot have a price that is below the system TMOR price.

In NEMA/Boston, local supply was also sufficient to satisfy the local requirement (44 MW) for Summer 2018. NEMA/Boston supply relative to the local reserve requirement is shown in Figure 4-6 below.

[40] Because local reserve zone TMOR supply can be used to satisfy the system-wide requirement, local TMOR supply that was cleared to satisfy local TMOR requirements is shown as unpriced (at $0/MW-month) supply on the system-wide supply curve. This results from local TMOR supply being needed irrespective of the system's reserve requirement and clearing price. The same result could be produced by using an adjusted "rest of system" requirement and supply curve that excluded the procurement of supply in local reserve zones.

**Figure 4-6: Supply Curve and Requirement, NEMA/Boston TMOR**



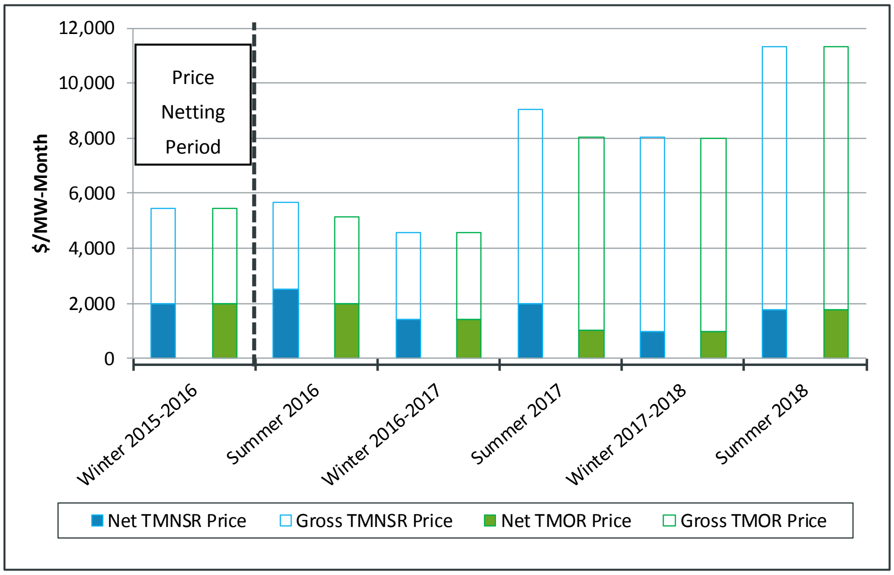

Unlike Southwest Connecticut, the local offers in NEMA/Boston did not allow a clearing price at the system TMOR price of $1,780/MW-month. NEMA/Boston offer prices ranged from $3,000 to $6,225/MW-month for satisfying the local requirement. Although the local requirement was only 44 MW, the requirement could not be met without procuring a portion of the highest-priced supply, and the clearing price was set at $6,225/MW-month.

### 4.2.3 Price Summary

The gross and net forward reserve prices for the system-wide TMNSR and TMOR products are shown in Figure 4-7 below; for periods prior to Summer 2016, FRM auction prices were netted against FCM clearing prices, and the net price represents the FRM auction income for participants. Beginning with Summer 2016, FRM auction prices are no longer netted. In the figure, the gross price indicates the FRM auction income plus the FCA price (both stated as $/MW-month values), while the net price shows the FRM-only income.[41] The net price provides the effective TMNSR and TMOR compensation rates for FRM system-wide resources for all periods in the graph. The gross price represents the FRM auction clearing price for 2015 and earlier periods. The net price represents the auction clearing price for later auctions.

[41] The FCA rest-of-pool clearing price is used in the calculations.

Figure 4-7: Gross and Net FRM Clearing Prices for System-Wide TMNSR and TMOR




In the Summer 2018 auction, TMOR and TMNSR cleared at the same price and at somewhat higher prices than in earlier, recent auctions. The clearing prices rose in this auction compared to earlier auctions primarily as a result of TMOR offer prices having increased significantly.

### 4.2.4 Structural Competitiveness

The structural competitiveness of the FRM can be measured by the Residual Supply Index (RSI). RSI measures the extent to which an individual participant has market power and controls enough supply to be able to increase price above a competitive level. In other words, the RSI measures the percentage of the forward reserve requirement that can be met without the largest FRM portfolio offer. If the requirement cannot be met without the largest supplier, then that supplier is pivotal. The RSI is calculated based on the FRM offer quantities.

The RSI for TMNSR is computed at a system level based on the total quantity of TMNSR offers across all reserve zones, excluding the largest TMNSR offer quantity by a single market participant. The RSI for TMOR is computed similarly for each reserve zone with a non-zero TMOR local reserve requirement. Given that TMNSR can also satisfy the TMOR requirement, the TMNSR offer quantity in a zone is included in the total TMOR offer quantity within that zone.

The heat map table – Figure 4-8 below – shows the offer RSI for TMNSR for the system and TMOR for zones with a non-zero TMOR requirement.[42] The colors indicate the degree to which structural market power was present, starting with low RSIs shown in red, followed by white and green colors, with the latter indicating that there was still ample offered supply without the largest supplier.

[42] Note that some of the historical values reported in the table have changed since last being reported (re RSIs for TMNSR, TMOR ROS, and TMOR SWCT). An error in the algorithm used to calculate the RSI was discovered, resulting in the changed values. The change in values, however, did not result in a change to earlier conclusions about the structural competitiveness of each auction. The correction resulted in reduced levels of competitiveness for some auctions, but the revised data continue to indicate that the auctions were structurally competitive.

**Figure 4-8: Offer RSI in the FRM for TMNSR (system-wide) and TMOR (zones)**

| Procurement Period | Offer RSI TMNSR (System-wide) | Offer RSI TMOR (ROS) | Offer RSI TMOR (SWCT) | Offer RSI TMOR (CT) | Offer RSI TMOR (NEMA) |
|---|---|---|---|---|---|
| Winter 2015-16 | 109 | 154 | 228 | 382 | N/A |
| Summer 2016 | 112 | 139 | 76 | N/A | 23 |
| Winter 2016-17 | 148 | 222 | 302 | N/A | N/A |
| Summer 2017 | 110 | 197 | 183 | N/A | 21 |
| Winter 2017-18 | 127 | 209 | N/A | N/A | 24 |
| Summer 2018 | 112 | 214 | 438 | N/A | 34 |

An RSI value less than 100 (shown in red) indicates the presence of at least one pivotal supplier, which means the auction was not structurally competitive. Pivotal suppliers may be able to strategically offer reserves at uncompetitive prices. Generally, the RSI values can fluctuate significantly from auction to auction. These fluctuations can be partly explained by the significant variation in the reserve requirement. For instance, the TMOR RSI value for the SWCT zone jumped from 76 (a structurally uncompetitive level) in Summer 2016 auction to 302 (a structurally competitive level) in Winter 2016-17 period. This resulted from the local TMOR requirement declining from 250 MW to 32 MW, with local suppliers competing to fill a lower requirement.

From the Winter 2015-16 through the Summer 2018 procurement periods, the TMNSR RSI values were greater than 100. These values suggest that the TMNSR offer quantities in these auctions were consistent with a structurally competitive level.

Similarly, the TMOR RSI values for the Rest-of-System (ROS) zone were consistent with a structurally competitive level.[43] The Southwest Connecticut (SWCT) zone was structurally competitive for all auction periods except Summer 2016. The Connecticut zone was competitive for the one recent auction when it had a local requirement. NEMA/Boston, however, has been structurally uncompetitive for all recent auctions for which it had a requirement. In these auctions, every participant that offered forward reserves in NEMA/Boston was needed to meet the local requirement.

## 4.3 Financial Transmission Rights

Financial Transmission Rights (FTRs) are financial instruments that entitle the holders to receive compensation for congestion costs that occur in the day-ahead energy market.[44] FTRs are sold in annual and monthly auctions, both of which conduct separate auctions for on-peak and off-peak hours. The amount of FTRs awarded in each auction is based on a market feasibility test that ensures that the transmission system can support the awarded set of FTRs during the period. FTRs awarded in one of the two annual auctions have a term of one year. The remaining feasible FTRs are

[43] The "Rest-of-System" zone is simply the portion of the system that excludes the local reserve zones (CT, SWCT, and NEMABOST).

[44] FTRs are valued based on the FTR MW quantity and the difference between congestion components of the day-ahead LMP at the point of delivery (where power is drawn from the New England grid) and the point of receipt (where power is withdrawn from the New England grid) designated in the FTR; FTRs can provide financial benefit, but can also be a financial liability resulting in additional charges to the holder.

made available in monthly auctions, each having a term of one month. FTR auction revenue is distributed to Auction Revenue Rights (ARRs) holders, who are primarily congestion-paying Load Serving Entities (LSEs) and transmission customers.

All FTR holders are compensated on a monthly basis through the congestion revenue fund, which is the collection of congestion costs in the day-ahead and real-time energy market for that month. Because congestion costs are based on actual system conditions, the congestion revenue fund can be larger or smaller than the positive target allocations to FTR holders, which are derived in FTR auctions.[45] If the congestion revenue fund for a month is less than the total positive FTR target allocation for that month, the payments to FTR holders would be prorated. If there is excess revenue in the congestion revenue fund at the end of the year, any monthly deficiency would be made up to the extent possible.

The monthly auctions for March 2018, April 2018, and May 2018 resulted in combined total of 98,100 MW of FTR transactions. The total auction revenue for these three months was $4.0 million, which represents a 22% increase compared to Winter 2018 ($3.3 million) and a 97% increase compared to Spring 2017 ($2.0 million). The increase in auction revenue can be a function of many factors, including: (i) higher levels of anticipated congestion on the system and (ii) an increase in auction participant's willingness to pay for FTRs. Thirty-one bidders participated in the March and April 2018 auctions, while 28 bidders participated in May 2018. The level of participation was consistent with recent auctions. FTRs in March 2018, April 2018, and May 2018 were fully funded, meaning that enough congestion revenue was collected to pay the positive target allocations in those months. In fact, there was a surplus in each of these months; the congestion revenue fund exceeded positive target allocations by $906 thousand in March 2018, $877 thousand in April 2018, and $247 thousand in May 2018. These surpluses are carried over until the end of the year, when they are used to pay any unpaid monthly positive target allocations. Any remaining excess is then allocated to those entities that paid the congestion costs.

[45] Target allocations for each FTR are calculated on an hourly basis by multiplying the MW amount of the FTR by the difference in the day-ahead congestion components of the FTR's sinking and sourcing locations. Positive target allocations (credits) occur when the congestion component of the sinking location is greater than the congestion component of the sourcing location. Negative target allocations (charges) occur in the opposite situation.