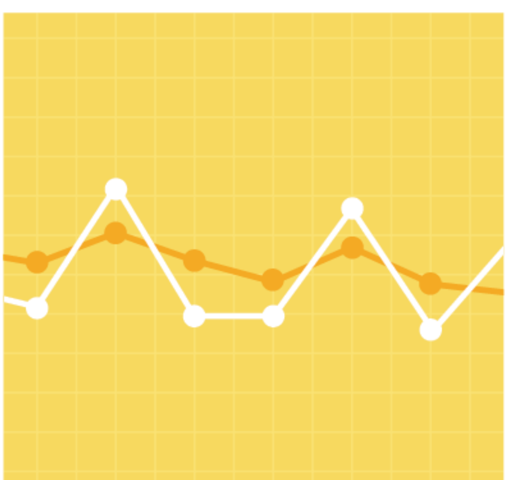
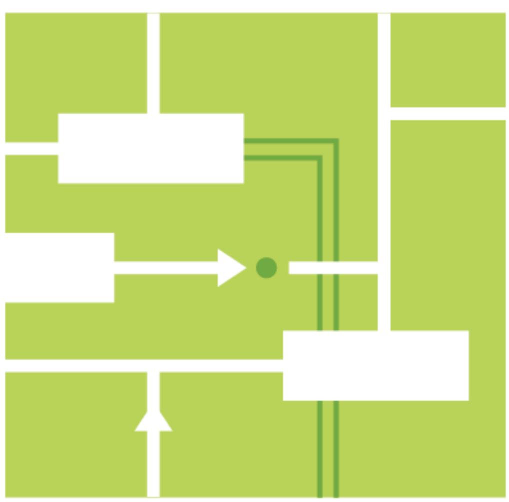
Winter 2018 Quarterly Markets Report

By ISO New England’s Internal Market Monitor

MAY 2, 2018





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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 Winter 2018 (December 1, 2017 through February 28, 2018).[3]

Wholesale Costs: The total estimated wholesale market cost of electricity was $3.43 billion, an increase of 101% compared to $1.70 billion in Winter 2017, and an increase of 97% over the previous quarter (Fall 2017).

- Winter 2018 energy costs were $2.60 billion; an 89% (or $1.23 billion) increase relative to Winter 2017 costs. Higher energy costs were driven by a historic 15-day Cold Snap period from December 26, 2017 through January 9, 2018, when frigid temperatures led to soaring natural gas prices and elevated LMPs.
- Rising Forward Capacity Market (FCM) prices also contributed to the increase in wholesale market costs relative to Winter 2017. Capacity costs totaled $770 million, up 168% ($483 million) compared to last winter. 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.

Energy Prices: Day-ahead and real-time energy market prices at the Hub averaged $74.33 and $76.04/MWh, respectively. Day-ahead prices were 79% higher ($32.76/MWh) and real-time prices were 91% higher ($36.15/MWh) than Winter 2017 prices.

- Winter 2018 natural gas costs exceeded energy prices on average. Natural gas prices averaged $10.20/MMBtu (or $79.53/MWh[4]), up 93% on the Winter 2017 price of $5.28/MMBtu. This was due to the Cold Snap in late December and early January, when oil- and coal-fired generation was economic, relative to natural gas generation, for several days. Oil and coal-fired generation helped soften the impact of higher gas prices
- Energy market prices did not differ significantly among the load zones. 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 $3.17/MWh (4%) lower than the average Hub price. Price separation in Maine was more notable in the real-time market, with prices $6.60/MWh (9%) lower than Hub prices, on average.

Net Commitment Period Compensation: NCPC payments totaled $29.2 million, up by $14.4 million compared to Winter 2017. NCPC payments represented about 1% of total wholesale energy costs; this was similar to the previous winter. The majority of NCPC (88%) was for first contingency protection. Several oil-fired units were postured during the Cold Snap and received NCPC payments to recover lost opportunity costs. The $7.9 million in posturing credits led to an increase in real-time first contingency payments relative to the previous winter.

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[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).

[4] Assuming a generator heat rate of 7,800 Btu/kWh.

At $2.2 million, local second-contingency protection (LSCPR) payments accounted for 8% of total NCPC payments. Nearly three-quarters of LSCPR payments was paid to one unit in NEMA/Boston during the Cold Snap. LSCPR payments decreased by 62% compared to the previous winter, primarily as a result of increased transmission import capability into NEMA/Boston.

Real-Time Reserves: Real-time reserve payments totaled $4.1 million, a large increase relative to the Winter 2017 total of $1.8 million. The frequency of ten-minute spinning reserve (TMSR) pricing was much higher due to lower operating reserve margins. The average hourly TMSR price increased relative to Winter 2017, from $11.46 to $17.47/MWh. The fast-start pricing rules, which were not in effect last winter, contributed to the increase in reserve payments.

***Regulatio*n:** Total regulation market payments were $10.7 million, up 35% from $7.9 million in Winter 2017. The main driver of this increase was higher regulation capacity prices and uplift payments in December 2017 and January 2018. During the Cold Snap period, tight system conditions resulted in higher LMPs and energy market opportunity costs, which were reflected in higher regulation capacity clearing prices.

Cold Snap Event: The system experienced abnormal conditions from December 26, 2017 through January 9, 2018 as a result of cold weather, a constrained natural gas and oil system and the switch in economic merit-order between gas- and oil-fired generation. The 12-day period from December 26, 2017 through January 7, 2018 was the coldest 12-day stretch observed since 1980 in New England. During this period, high natural gas prices and unplanned generator outages led to high energy prices, with day-ahead and real-time LMPs averaging $165/MWh and $179/MWh, respectively.

- The cold temperatures increased demand for natural gas and drove gas prices up to a four-year high of $61/MMBtu. The average natural gas price during the 15-day period was $27.10/MMBtu.
- Oil and coal-fired generators were economic, relative to natural gas-fired generators, for several days.
- Electricity demand averaged 16,935 MW per hour, about 2,150 MW above the Winter 2018 average.
- Several unplanned generator outages occurred during this time period, mostly due to mechanical issues attributable to the cold temperatures.
- The constrained fuel system (gas and oil) did not translate into scarcity conditions in the electricity market, despite generator availability issues. There were 28 hours of (non-zero) spinning reserve pricing but no instances of non-spinning (non-zero) reserve pricing.
- NCPC costs were $19.3 million, 66% of the season total. Of this, $8.6 million related to out-of-merit reliability actions: 1) posturing payments of $7.0 million, mainly to oil-fired generation, and 2) $1.6 million in local reliability payments to one generator in NEMA/Boston on January 5.

The Twelfth Forward Capacity Auction (FCA12): FCA 12 was held in February 2018 and procured sufficient capacity for the capacity commitment period (CCP) beginning June 1, 2021 through May 31, 2022. Below are the highlights from the auction:

- There was a surplus of qualified and cleared capacity compared to the Net Installed Capacity Requirement (NICR).
    - The auction cleared 34,828 MW, a surplus of 1,103 MW over NICR, at a price of $4.63/kW-month.
    - This results in projected FCA 12 payments of $2.07 billion, down 13% on FCA 11 projected payments of $2.38 billion.
- The auction closed in the fourth round for all capacity zones, with no price separation among the zones. However, there was price separation at two external interfaces due to excess import capacity after Round 4, resulting in lower prices.
    - New Brunswick and Phase I/II cleared in Round 5 at prices of $3.16 and $3.70/kW-month, respectively.
- During Round 4, ≈2,800 MW of resources submitted one-year dynamic de-list bids and required reliability reviews.
    - Mystic 7 and 8 (1,278 MW) were rejected for reliability, 30 resources (1,430 MW) shed their obligation
- About 700 MW of new entry cleared. New entry included demand response (mainly passive), a simple cycle gas generator, and incremental energy from two pumped-storage resources.
- 520 MW of existing capacity retired including Bridgeport Harbor 3 (383 MW oil resource)
- The auction reflected a competitive outcome. Sufficient existing and new capacity participated relative to NICR, and headed into Round 4, no participant could effectively exercise market power.

Section 2
Overall Market Conditions

This section provides a summary of key trends and drivers of wholesale electricity market outcomes from Winter 2016 through Winter 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	Winter 2018	Fall 2017	Winter 2018 vs Fall 2017 (% Change)	Winter 2017	Winter 2018 vs Winter 2017 (% Change)
Real-Time Load (GWh)	31,928	28,631	12%	31,048	3%
Peak Real-Time Load (MW)	20,605	20,999	-2%	19,647	5%
Average Day-Ahead Hub LMP ($/MWh)	$74.33	$29.11	155%	$41.57	79%
Average Real-Time Hub LMP ($/MWh)	$76.04	$30.45	150%	$39.89	91%
Average Natural Gas Price ($/MMBtu)	$10.20	$2.69	278%	$5.28	93%
Average Oil Price ($/MMBtu)	$10.68	$9.53	12%	$9.25	16%

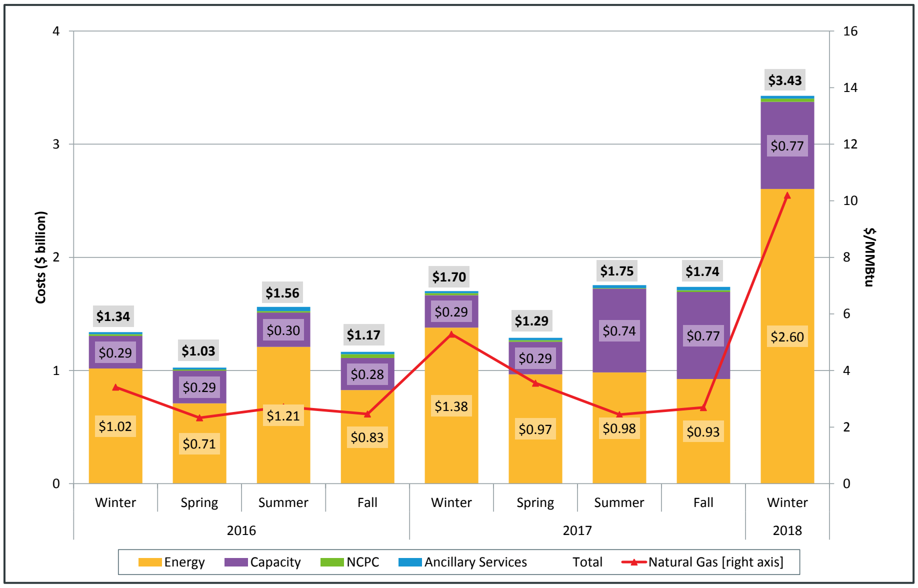
Gas prices, locational marginal prices (LMPs), and loads were all higher in Winter 2018 compared to Fall 2017 and Winter 2017. In summary:

- A period of extremely cold weather in late December and early January led to higher gas prices, LMPs, and loads in Winter 2018. We refer to this period as the “Cold Snap” in this report, which is covered in detail in Section 4 below.
- Gas prices in Winter 2018 averaged $10.20/MMBtu, up 278% from Fall 2017, and up 93% from Winter 2017. Average natural gas prices during Winter 2018 were only $0.48/MMBtu lower than average No. 6 Oil prices. The price convergence of the two fuel types was driven by increased gas prices during the Cold Snap, which peaked at $62/MMBtu.
- Average day-ahead and real-time LMPs increased as gas prices rose, but the impact of high gas prices was softened by relatively lower-cost coal- and oil-fired generation. During the Cold Snap the system committed high levels of economic oil-fired generation. LMPs increased 150-155% compared to Fall 2017, and 79-91% compared to Winter 2018.
- Lower temperatures in Winter 2018, in particular during the Cold Snap, led to higher gas demand and prices, but also higher energy loads. Total wholesale electricity demand increased 12% compared to Fall 2017, and 3% compared to Winter 2017.

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.[5,6]

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



In Winter 2018, the total estimated wholesale market cost of electricity was $3.43 billion, an increase of 101% compared to $1.70 billion in Winter 2017, and an increase of 97% over the previous quarter (Fall 2017).

Despite the displacement of gas-fired generation by coal and oil-fired generation during the cold snap period, natural gas prices continued to be the key driver of energy prices. During Winter 2018, a period of extremely cold weather led to higher natural gas prices. Energy costs were $2.60 billion in Winter 2018, 89% higher than Winter 2017 costs. The impact of the 93% increase in average gas price between Winter 2017 and Winter 2018 was somewhat mitigated by relatively cheaper oil- and coal-fired generation, particularly during the Cold Snap.

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-

[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.

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.

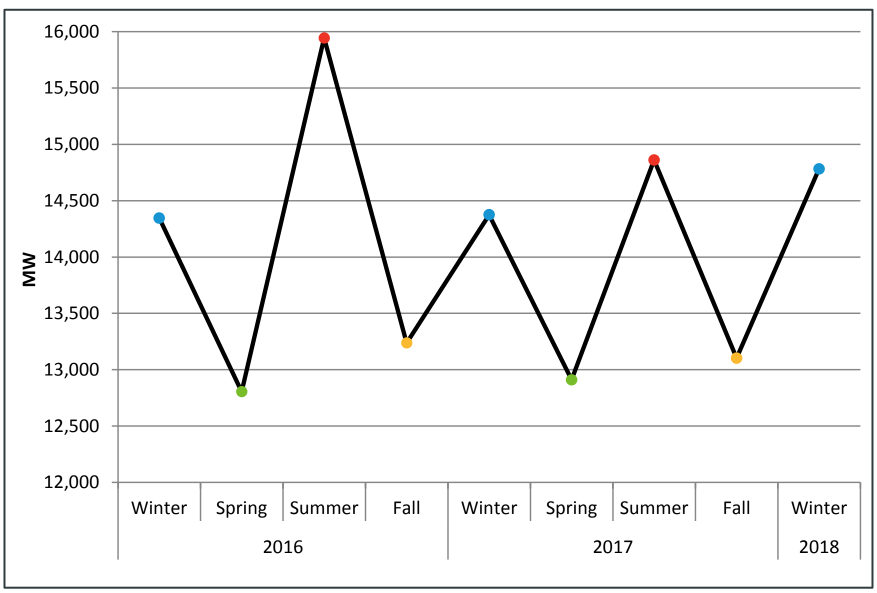
At $29.2 million, Winter 2018 Net Commitment Period Compensation (NCPC) costs represented around 1% of energy costs, a similar share compared to other quarters in the reporting horizon. In dollar terms, NCPC costs were $11.1 million higher than Winter 2017 NCPC costs, and $14.8 higher than Fall 2017 NCPC costs. Section 3.4 contains further details on NCPC costs.

Ancillary services, which include operating reserves and regulation, totaled $24.7 million in Winter 2018, representing just under 1% of total wholesale costs. Ancillary service costs increased by 39% compared to Winter 2017, and decreased by 19% compared to Fall 2017.

2.2 Load

Lower temperatures in Winter 2018 resulted in higher electricity demand. Average hourly load by season is illustrated in Figure 2-2 below. The blue dots represent winter, the green dots represent spring, the red dots represent summer, and the yellow dots represent fall.

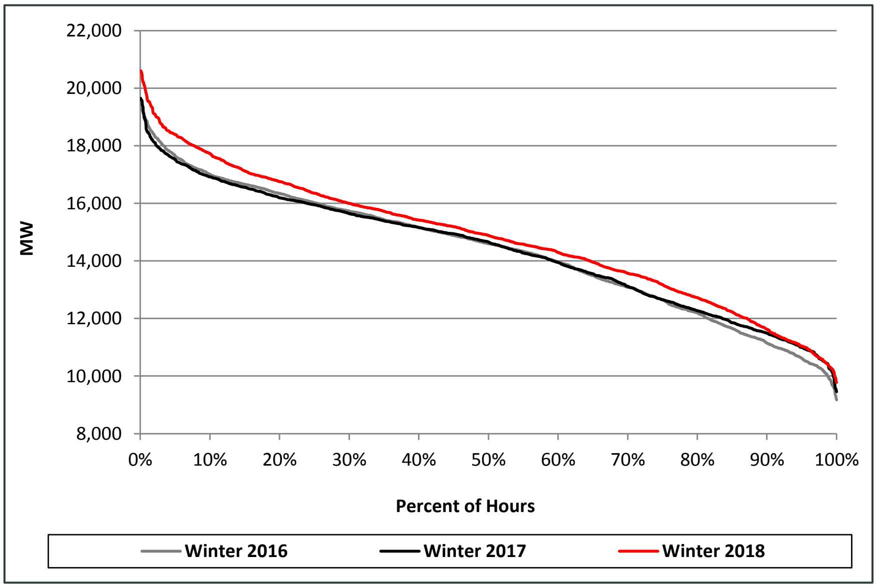
Figure 2-2: Average Hourly Demand



Average hourly load during Winter 2018 was 14,782 MW, a 3% increase compared to Winter 2017. The average temperature in Winter 2018 was 29°F, compared with 33°F in Winter 2017. The average New England temperature was below freezing in 45 days this winter (out of 90 days), compared with 38 days in 2017. Additionally, there was a period of historically cold weather from late December through early January that is covered in detail in Section 4 of this report.

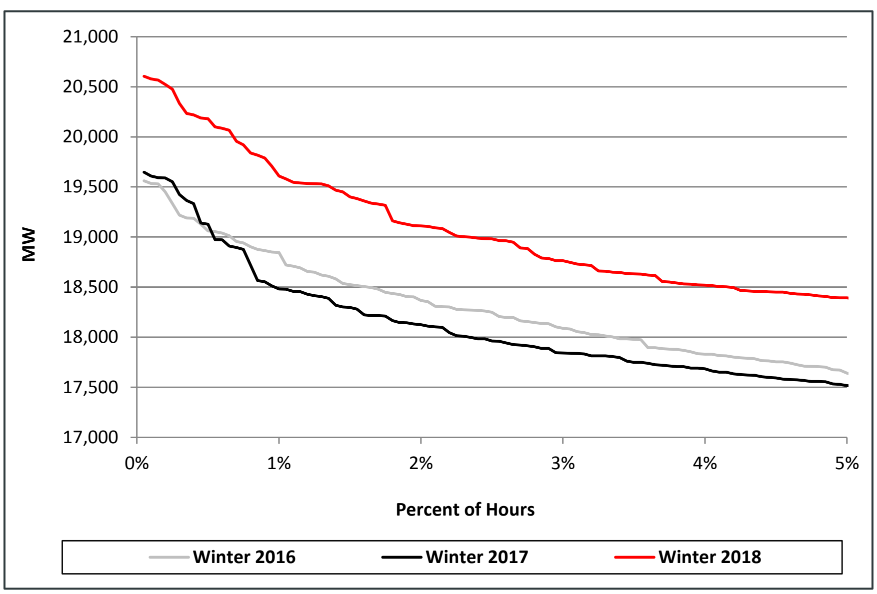
The system load for New England over the last three winter seasons is shown as load duration curves in Figure 2-3 below. A load duration curve depicts the relationship between load levels and the frequency that load levels occur. Plotting several seasonal load duration curves can help illustrate differences between periods. The red line shows Winter 2018, the black line is Winter 2017 and the gray line is Winter 2016.

Figure 2-3: Seasonal Load Duration Curves



The higher red line shows Winter 2018 had consistently higher loads than both Winter 2017 and Winter 2016. About 30% of the time, loads were above 16,000 MW in Winter 2018 compared with only 24% of the time in Winter 2017. Loads were especially higher in the highest load times in Winter 2018. For this reason, the load duration curves for the top 5% of hourly observations for the last three winter seasons are shown in Figure 2-4.

Figure 2-4: Seasonal Load Duration Curves – Top 5% of Hours



The load for the top 5% of hours in Winter 2018 was 965 MW higher than in Winter 2017, on average. The 100 coldest hours in Winter 2018 had an average temperature of 2°F, compared with an average of 12°F in Winter 2017. As mentioned, historically cold winter weather from December 26 through January 9 is discussed in Section 4.

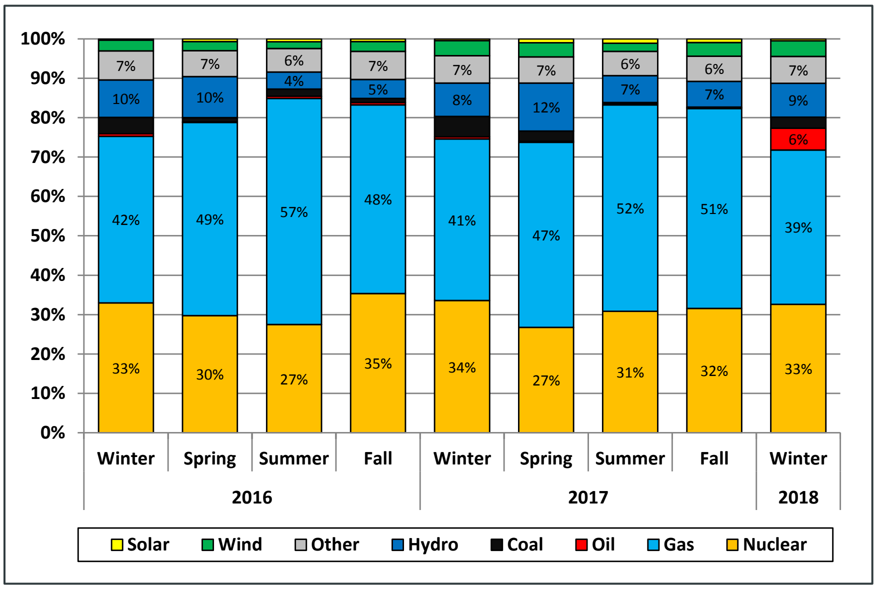
2.3 Supply

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. Actual energy production by generator fuel type for Winter 2016 through Winter 2018 is illustrated in Figure 2-5 below.

Figure 2-5: Share of Native Electricity Generation by Fuel Type

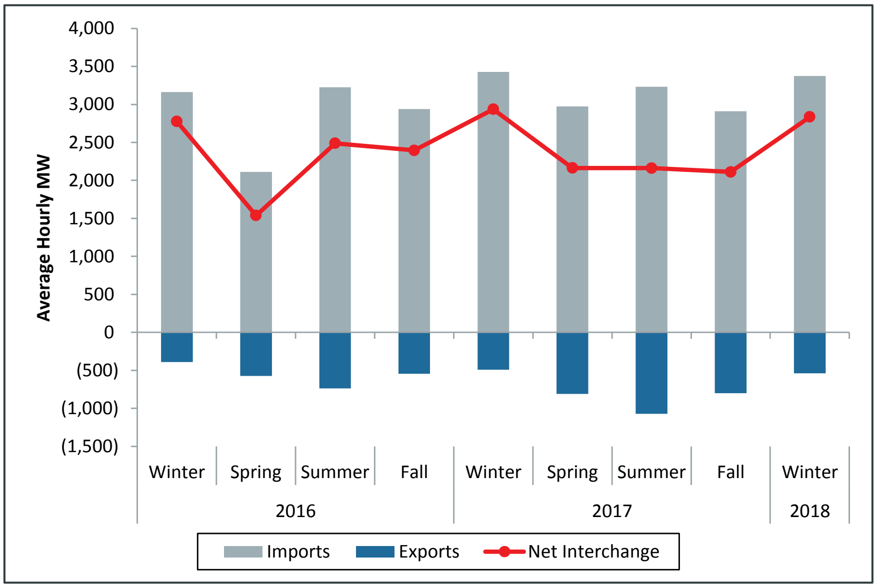


Seasonal fluctuations in fuel mix occur due to market economics and generator availability. Overall, the fuel mix in Winter 2018 was within a normal range. The majority of New England's generation comes from gas-fired generation, which accounted for 39% of total native energy production during Winter 2018, down from 51% in the prior quarter. The decrease in gas-fired generation coincides with the increase in oil- (6%) and coal-fired (3%) generation in Winter 2018 as high natural gas prices impacted market economics. Nuclear generation accounted for 33%, while wind and solar generation made up 5% of native energy production during Winter 2018.

2.3.2 Imports and Exports

New England was a net importer of about 2,800 MW per hour, on average, during Winter 2018. The average hourly gross import and export power volumes and the net interchange amounts for the last nine quarters are shown in Figure 2-6 below.

Figure 2-6: Average Hourly Real-Time Imports, Exports, and Net Interchange



New England is typically a net importer of power from the neighboring control areas in Canada and New York (red line).[7] Figure 2-6 illustrates that net interchange is typically higher in the winter when energy prices in New England have a tendency to be at their highest levels due to natural gas prices. This is discussed in more detail in Section 3.1 below. Higher energy prices typically result in more transactions from importers and exporters seeking to profit from price spreads between New England and neighboring control areas. The hourly average Winter 2018 net interchange value of 2,836 MW was comparable with the prior two winters; Winter 2017 net interchange was 101 MW per hour higher than Winter 2018, and Winter 2016 was lower by 61 MW per hour.

[7] 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.

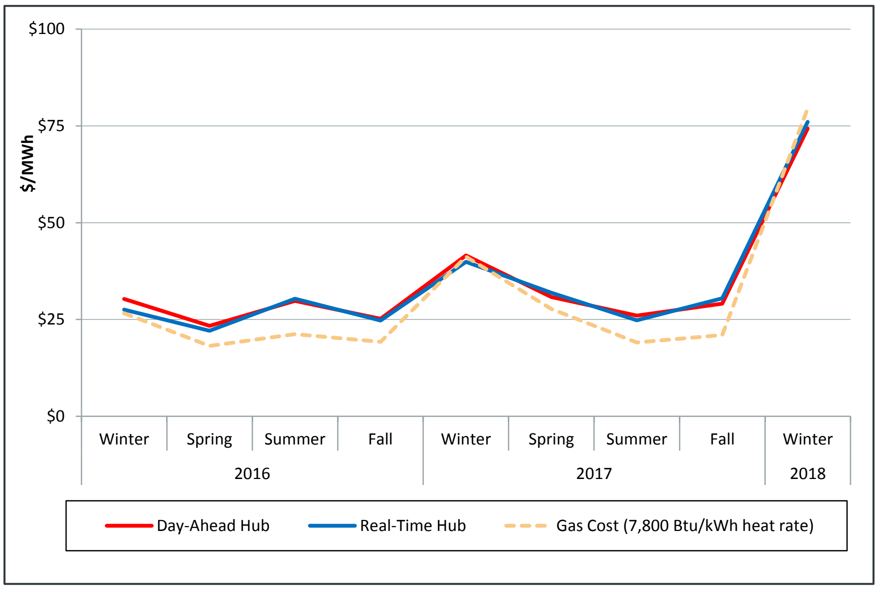
Section 3
Day-Ahead and Real-Time Markets

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

3.1 Energy Prices

The average real-time Hub price for Winter 2018 was $76.04/MWh. This was 2%, or $1.71/MWh, higher than the average day-ahead price of $74.33/MWh. Day-ahead and real-time prices, along with the estimated cost of a natural gas-fired generator, 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.

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

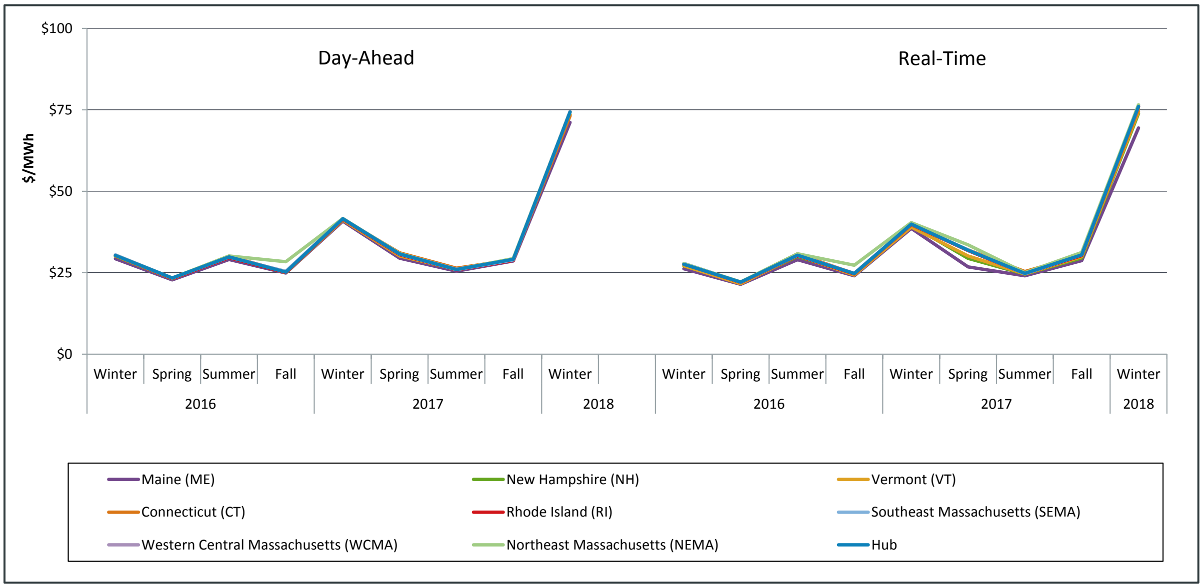


As Figure 3-1 illustrates, the seasonal movements of energy prices (solid lines) are generally consistent with changes in natural gas generation costs (dashed line). The spread between estimated cost of a typical natural gas-fired generator and electricity prices tends to be highest during the summer months as less efficient generators, or generators burning more expensive fuels, are required to meet the region's higher demand.

In Winter 2018, the estimated cost of a natural gas-fired generator costs exceeded both average day-ahead and real-time energy prices. The average gas cost was about $4/MWh higher than average real-time Hub prices. This was the result of market conditions during several days of the Cold Snap, when high natural gas demand and prices, relative to the price of competing fuels, made gas-fired generation relatively expensive and uneconomic. During this period, oil- and coal-fired generation was economic relative to natural gas-fired generation.

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. The Maine average day-ahead price was \$3.17/MWh (4%) lower than the Hub price. Price separation in Maine was more notable in the real-time market, with prices \$6.60/MWh (9%) lower than Hub prices. New Hampshire and Vermont load zone prices were also, on average, lower than the Hub price in real-time, by 3% and 2% respectively. Renewable-type generation resources with lower marginal costs are located in export-constrained areas of northern New England and frequently set real-time prices in these areas. The discount in energy prices in Maine, Vermont, and New Hampshire was similar during the previous quarter (Fall 2017).

Real-time energy prices in the NEMA zone averaged \$76.54/MWh during Winter 2018, which was \$0.50/MWh (1%) higher than the Hub. Most of the premium in NEMA energy prices was due to price separation related to a planned transmission line outage that occurred from January 18 through January 21.

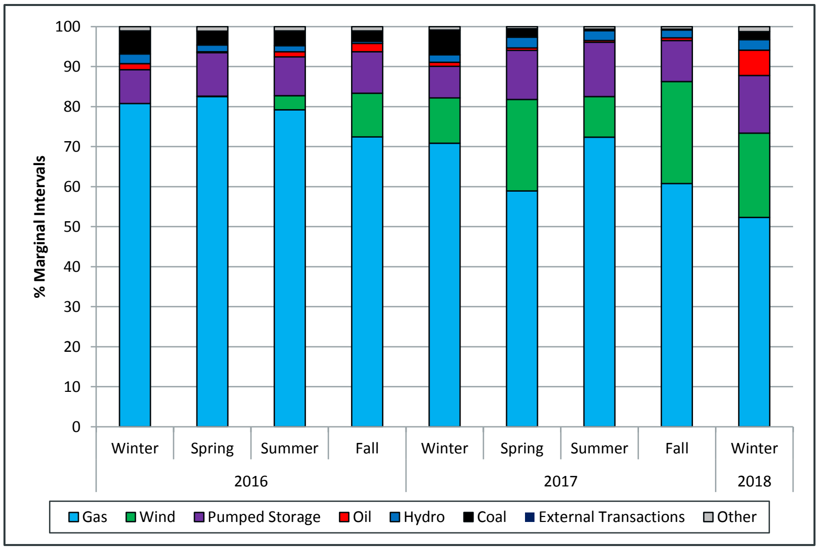
3.2 Marginal Resources and Transactions

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 type of transaction can provide additional insight into day-ahead and real-time pricing outcomes.

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 3-3 below.[8]

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



Natural gas-fired units set price about 50% of the time. Energy from gas-fired generators also accounts for approximately 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 operating units, they set price frequently.

In addition to their relative cost, many gas-fired generators are eligible to set price due to their dispatchable range. On the other hand, 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.

Wind was the second most frequent marginal fuel type. In Winter 2018, wind generators were marginal in a similar percentage of intervals as Fall 2017, about one quarter of intervals. 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

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

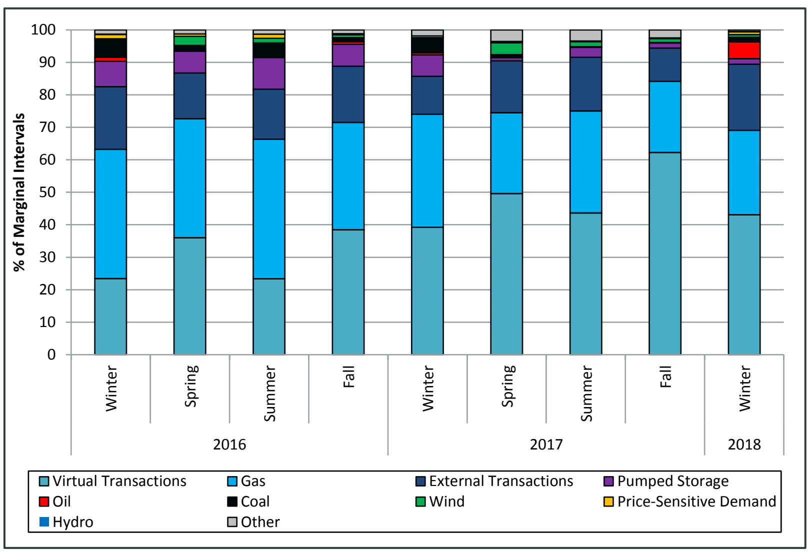
marginal cost. Wind generators are often offered into the real-time market at negative prices and are rarely the most expensive generators online.

The higher frequency of marginal wind units 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).[9] 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.

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 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 Winter 2018 was consistent with previous seasons.

The percentage of time that each transaction type set price in the *day-ahead market* since Winter 2016 is illustrated in Figure 3-4 below.

Figure 3-4: Day-Ahead Marginal Units by Transaction and Fuel Type



Virtual transactions set day-ahead prices about 40% of the time in the reporting period, similar to 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

[9] *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.

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.[10]

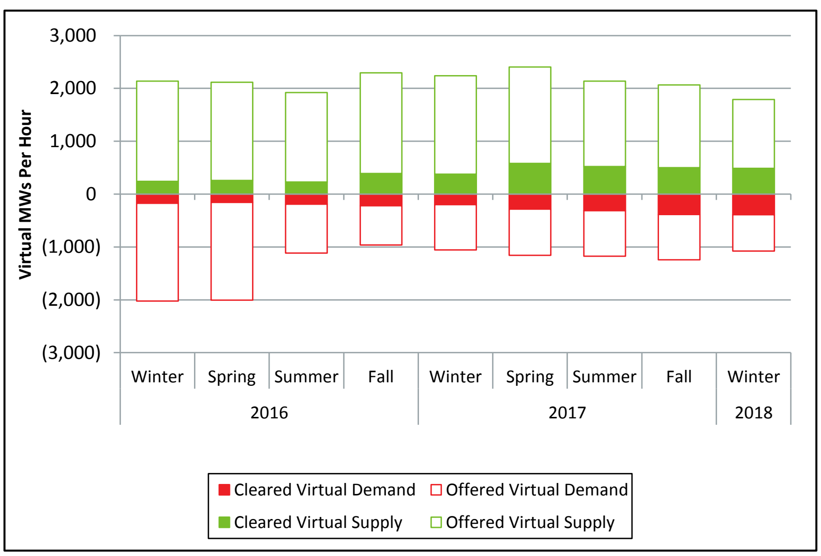
In Fall 2016, the frequency of virtual transactions began increasing, a pattern which has persisted through the most recent quarter. The increase has been driven by virtual traders responding to differences between day-ahead and real-time offer behavior of wind generators that can now set price in the 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.

Gas-fired generators were the second most frequently marginal resource type in the day-ahead market; they set price in 26% 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 36% of all marginal entities in the day-ahead market.

3.3 Virtual Transactions

Offer and cleared virtual transaction volumes from Winter 2016 through Winter 2018 are shown in Figure 3-5 below.

Figure 3-5: Total Offered and Cleared Virtual Transactions (Average Hourly MW)



[10] 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.

In Winter 2018, *submitted* virtual demand bids and supply offers averaged approximately 2,900 MW per hour, which was 13% below both Winter 2017 and Fall 2017. Total volumes of *cleared* virtual transactions increased by 51% compared to Winter 2017 and were unchanged from Fall 2017.

Beginning in Summer 2016, the average offer prices of virtual transactions have converged towards actual LMPs, resulting in higher percentages of virtual transactions clearing. 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. 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.[11] In Winter 2016, the average real-time NCPC charge was $2.64/MW. This value has declined substantially to $1.62/MW in Winter 2018.

Additionally, beginning in May 2016 certain wind and hydro resources became dispatchable under the Do Not Exceed (DNE) Dispatch Points 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. When there is more certainty in real-time, DNE resources reduce their offers and frequently set price.

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.

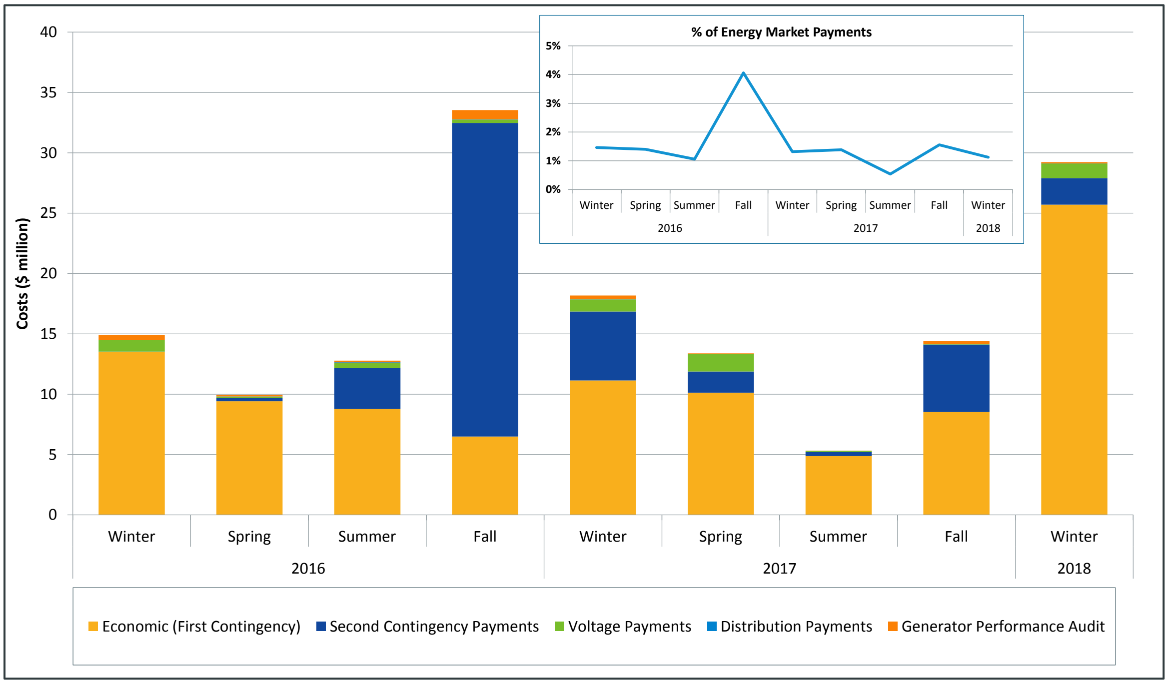
3.4 Net Commitment Period Compensation

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.[12] NCPC payments by season and category are illustrated in Figure 3-6 below. The inset graph shows NCPC payments as a percentage of total energy payments.

[11] 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

[12] 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 payments*.

Figure 3-6: NCPC Payments by Category ($ millions)



The total NCPC payments made in Winter 2018 more than doubled the level observed in Fall 2017, rising from $14.4 million to $29.2 million. NCPC payments also increased significantly this quarter compared to the same quarter last year; the Winter 2018 payment is 61% larger than the $18.2 million payment made in Winter 2017. Although the total NCPC payment in Winter 2018 is greater than the corresponding value from the previous fall and winter in absolute terms, it is smaller when expressed as a percentage of total wholesale energy market costs. Winter 2018 NCPC payments represent only 1.1% of the total wholesale energy market costs that occurred during this quarter, down from 1.3% in Winter 2017 and 1.6% in Fall 2017. The reason this ratio fell this quarter is because the increase in total wholesale energy market costs – due to extremely cold weather – outstripped the increase in NCPC payments.

The majority of NCPC (88%) incurred during the reporting period was for first contingency protection. Over three-quarters of the total first contingency NCPC ($19.9 million) was paid out in the real-time market, while the other 22% ($5.8 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 2017, when the split between real-time and day-ahead economic payments was much closer to 50-50. The real-time first contingency payments in Winter 2018 are 236% higher than they were in Winter 2017, while the day-ahead first contingency payments are only 11% higher relative to the same period.

One of the primary reasons for the elevated real-time economic NCPC payments in Winter 2018 was resource posturing. From late December through early January, an extended period of extremely low temperatures (Cold Snap) caused the price of natural gas in New England to increase as the region experienced pipeline supply constraints. The pipeline constraints were primarily due to increased heating demand from local distribution companies. As natural gas prices increased, natural gas-fired generators became uneconomic relative to lower cost coal- and oil-fired generators. This led to an increased energy output from coal- and oil-fired units. As the Cold Snap progressed, numerous oil-fired units began to encounter fuel limitations of their own (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. The credits are intended to make the resource owners no worse off than the counterfactual scenario where they were not postured. Put simply, the credit calculation compares the actual revenues the resource earned as a result of being postured against the estimated revenues the resource *could* have earned had it not been postured. An NCPC credit is provided if the resource could have earned more "profit" in the counterfactual scenario. As noted in more detail in Section 4, the real-time price of energy was very high for most of the period from late December to early January. For resources that were postured during this period, this meant that the opportunity cost of being postured was also often very high. In other words, the postured resources *could* have earned significantly more if they had not been postured and, instead, been allowed to produce more energy when LMPs were high.

As a result, the posturing NCPC credits received by resources over this period were sizable. In total, posturing NCPC credits totaled $7.9 million in Winter 2018.[13] This exceeds the total for this type of credit in Winter 2017 ($0.5 million) and Fall 2017 ($0.2 million) by an order of magnitude and accounts for a significant amount of the increased first contingency NCPC shown in Figure 3-6. More information about the NCPC payments made during Cold Snap can be found in Section 4.

The second largest category of NCPC (8%) incurred during the reporting period was for local second-contingency protection (LSCPR). Total LSCPR payments of $2.2 million were 62% lower than the $5.7 million paid out in Winter 2017 and 61% lower than the $5.6 million paid out in Fall 2017. Nearly three-quarters ($1.6 million) of the LSCPR payments made in Winter 2018 were paid out on one day during the Cold Snap to one unit in NEMA/Boston. In general, fewer reliability commitments were made by the ISO in Winter 2018 compared to Winter 2017. This is partly due to an increase in transmission import capability into NEMA/Boston.

Voltage NCPC payments in the quarter totaled $1.2 million. This was a modest increase compared to $1.0 million last winter, but a significant increase from last quarter, when an unusually low amount of voltage NCPC payments were made ($26,000). The vast majority (93%) of voltage NCPC paid out this reporting period was in the day-ahead market as the need for voltage support can often be anticipated based on planned transmission outages and forecasted generation-load imbalances. Close to $1 million of the voltage NCPC paid this quarter occurred between December 23 and December 28, when two generators were committed to mitigate high voltages in NEMA as a result of overlapping transmission outages.

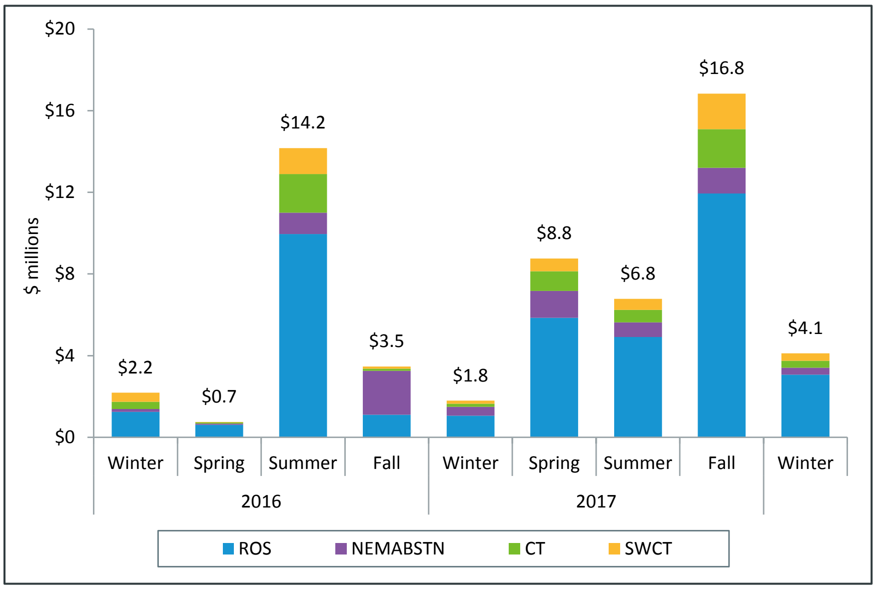
Generator performance audit (GPA) NCPC payments totaled $107,000 in Winter 2018. This reflects a 65% decrease from the total paid last winter ($308,000) and a 58% decrease from the $257,000 paid in Fall 2017. Distribution NCPC payments were very small in Winter 2017, amounting to under two thousand dollars.

[13] It is important to note that, while the majority of posturing NCPC credits in Winter 2017 went to oil-fired units, pumped-storage hydro units also received a significant share of these NCPC credits.

3.5 Real-Time Operating Reserves

Total real-time reserve payments, by reserve zone, from Winter 2016 through Winter 2018 are illustrated in Figure 3-7 below. Note that these figures are intended to show the value of real-time reserves and therefore are the gross real-time credits for providing reserve products at the respective real-time clearing price. The netting of real-time payments for a participant's forward reserve market (FRM) obligations is not accounted for in the chart totals. During Winter 2018, there were no reductions to real-time reserve payments for forward reserve obligations as non-zero, non-spinning reserve prices occurred only during off-peak (non-FRM) hours.

Figure 3-7: Real-Time Reserve Payments by Zone ($ million)



As shown in Figure 3-7, total real-time reserve payments were higher in Winter 2018 than in the preceding winter periods. The distribution of payments among the reserve zones reflects that the majority of reserve pricing occurred for system requirements over this quarter.

The frequency of non-zero reserve pricing by zone along with the average price during these intervals over the past three winter periods are shown in Table 3-1 below.[14]

[14] Non-zero reserve pricing means that there was 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.

Table 3-1: Hours and Level of Non-Zero Reserve Pricing[15]

Product	Zone	Winter 2016		Winter 2017		Winter 2018	
		Avg. Price $/MWh	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*
TMSR	System	$17.94	105.2	$11.46	166.2	$17.47	315.2
TMNSR	System	$6.10	0.0	$1.13	0.0	$0.49	0.0
TMOR	System	$6.10	6.3	$1.13	1.5	$0.49	1.3
	NEMA/Boston	$6.10	0.0	$6.39	13.6	$0.49	0.0
	CT	$6.10	0.0	$1.13	0.0	$0.49	0.0
	SWCT	$6.10	0.0	$1.13	0.0	$0.49	0.0

As shown in Table 3-1, there were 315 hours of system ten-minute spinning reserve (TMSR) pricing during Winter 2018. During these hours, there were 39 hours of reserve deficiency, whereby reserve prices were capped at the corresponding reserve constraint penalty factor (RCPF) of $50/MWh.[16] During Winter 2018 the average price for TMSR was $17.47/MWh, which was an increase of about 50% relative to Winter 2017 but comparable to Winter 2016.

In Winter 2018, system thirty-minute operating reserve (TMOR) pricing occurred for 1 hour, and the replacement TMOR RCPF was triggered for a total of 10 minutes. A decrease in pricing of local TMOR in NEMA/Boston during Winter 2018 compared to Winter 2017 is due to transmission work that occurred in Winter 2017 that caused local reserve constraints to bind more frequently in that local reserve zone.

While the frequency and magnitude of reserve pricing is a function of many different factors that influence system conditions, the implementation of Fast-Start Pricing in March 2017 has increased reserve pricing. As intended, Fast-Start Pricing more accurately reflects the cost of operating higher cost fast-start generation and, on average, has increased the price of energy.[17] Because the price of energy has increased, so too has the opportunity cost of holding back generators to provide reserves rather than energy thus resulting in higher and more frequent reserve pricing.

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 3-8 below.[18]

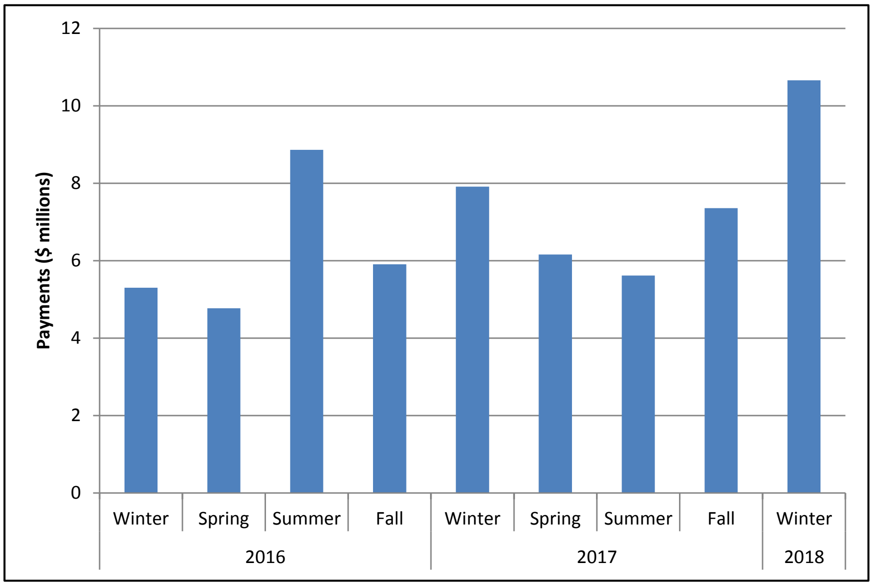
[15] The NEMA/Boston, CT and SWCT load zones have positive average TMOR prices but 0 hours of pricing. This is because the TMOR price for the zones is equal to the System TMOR price even when reserve zone pricing is not in effect.

[16] 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.

[17] See section 5.5 of the Summer 2017 Quarterly Markets report for detail on fast-start pricing: https://www.iso-ne.com/static-assets/documents/2017/12/2017-summer-quarterly-markets-report.pdf

[18] 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.

Figure 3-8: Regulation Payments ($ millions)



Total regulation market payments were $10.7 million during the reporting period, up 45% from $7.4 million in Fall 2017, and up 35% from $7.9 million in Winter 2017. Regulation payments increased relative to the earlier periods predominately as a result of higher regulation capacity prices and uplift (regulation make-whole) payments in December and January. The increased capacity prices resulted primarily from the reflection of energy market opportunity costs in regulation capacity clearing prices, during periods of unusually cold weather that resulted in both high fuel prices and energy market LMPs. Regulation uplift payments also increased as a result of regulation capacity prices being insufficient in some hours to fully compensate regulation resources for actual energy market opportunity costs.

Section 4
Market Performance during the December/January Cold Snap

The system experienced abnormal conditions from December 26, 2017 through January 9, 2018 as a result of cold weather, constrained natural gas and oil systems and the switch in economic merit-order between gas- and oil-fired generation. High natural gas prices and unplanned generator outages led to high energy prices, with day-ahead and real-time LMPs averaging $165/MWh and $179/MWh, respectively.

This section of the report discusses market outcomes and performance during this period, referred to as the "Cold Snap".

4.1 System Conditions

For most of this period, daily low temperatures ranged from -4°F to 15°F. The period from December 26 through January 7 was the coldest twelve-day stretch observed in New England since 1980. In Boston, the Cold Snap marked the longest period of temperatures below 20°F since 1918. In addition to the extreme cold, a blizzard known as "the bomb cyclone" brought snow and ice into the region on January 4 and 5, causing severe coastal flooding.

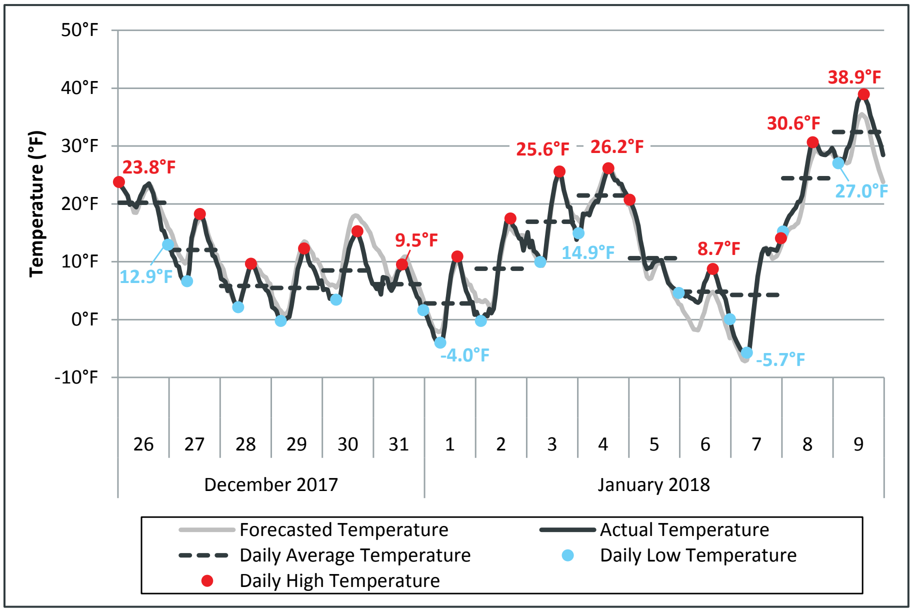
The ISO issued a Cold Weather Watch on several days, and implemented an M/LCC 2 (Abnormal Conditions Alert)[19] event from January 3 through January 9. The cold temperatures increased demand for natural gas, and drove gas prices up to a four-year high of $61/MMBtu. Consequently, oil- and coal-fired generation was economic relative to gas-fired generation for several days. Several generators went out of service due to mechanical issues or transmission line trips during severe weather.

Hourly New England forecasted and actual temperatures from December 26 through January 9 are shown in Figure 4-1.[20] Forecast temperatures are shown by a light gray line, and actual temperatures are represented by a solid black line. Red dots signify actual daily highs, blue dots show daily lows, and average daily temperatures are shown by horizontal dotted lines.

[19] When notified of an M/LCC 2 Abnormal Condition Alert, applicable power system operations, maintenance, construction and test personnel and each applicable Market Participant are expected to take precautions so that routine maintenance, construction or test activities associated with any generating station, Dispatchable Asset Related Demand (DARD), Real-Time Demand Response, Real-Time Emergency Generation, transmission line, substation, dispatch computer, and communications equipment do not further jeopardize the reliability of the power system.

[20] The New England temperature is a weighted average of eight New England cities: Windsor CT, Boston MA, Bridgeport CT, Worcester MA, Providence RI, Concord NH, Burlington VT, and Portland ME.

Figure 4-1: Hourly New England Temperatures during Cold Snap

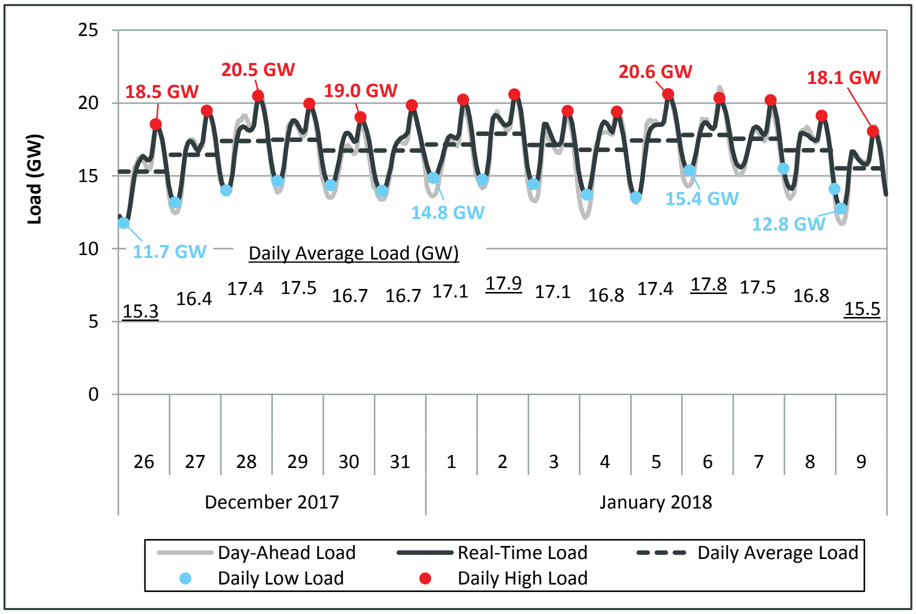


The high temperature on December 26 was about 24°F. Seven days of temperatures that did not exceed 20°F followed, from December 27 through January 2. In that time span the lowest daily high temperature was 9.5°F on December 31 and the lowest hourly temperature was -4°F on the morning of January 1. Compared with surrounding days, January 3 and 4 were relatively warm, but remained below freezing, with high temperatures around 26°F. Three more days of sub-15°F daily average temperatures followed, completing the coldest 12-day stretch (December 26 – January 7) in New England since 1980.

Load Levels

Load levels during the Cold Snap were generally high. The highest hourly load observed in the previous two winter seasons (2016 and 2017) was about 19,650 MW. During the Cold Snap, peak load exceeded this value on eight separate days. Average hourly load is shown below in Figure 4-2. Similar to Figure 4-1 above, day-ahead load is shown as a light gray line and actual load is shown as a solid black line. Daily high actual loads are shown as red dots and daily low actual loads are shown as blue dots. Average daily loads are shown as horizontal dotted black lines. Additionally, average daily load values are shown below the load values in black text.

Figure 4-2: Hourly New England Load during Cold Snap

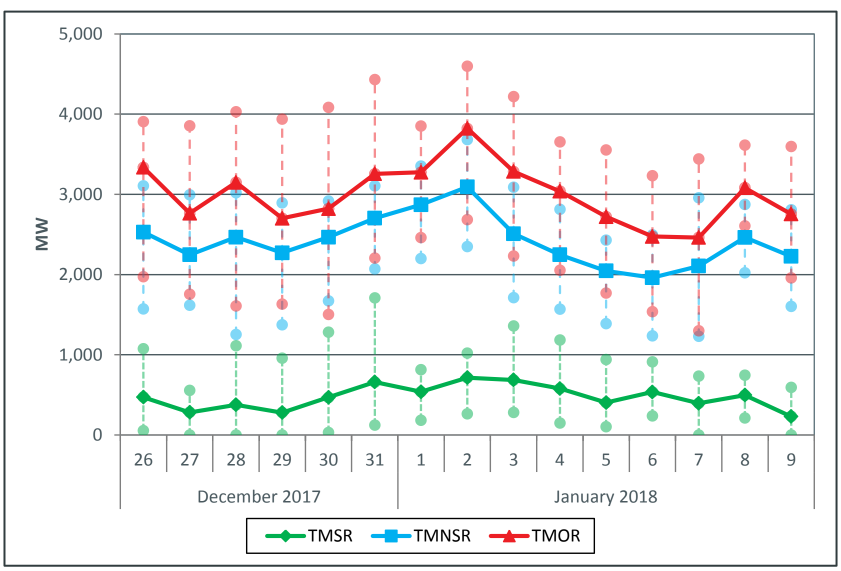


On December 26, peak load was about 18,500 MW, the lowest peak load until January 9 (18,100 MW). The average real-time load from December 27 through January 8 was 17,200 MW, 2,670 MW (18%) above the season average from the past three winter seasons. The highest load during the period was 20,600 MW on January 5, when the temperature dropped rapidly from a high of 21°F in the first hour of the day to a low of 4.6° in the last hour of the day. It was the highest winter peak load observed since January 2014.

Operating Reserve Margins

The average hourly reserve margin (i.e., available reserves above the reserve requirement) as well as the 90th (top circle) and 10th (bottom circle) percentiles are shown in Figure 4-3 below.

Figure 4-3: System Operating Reserve Margins



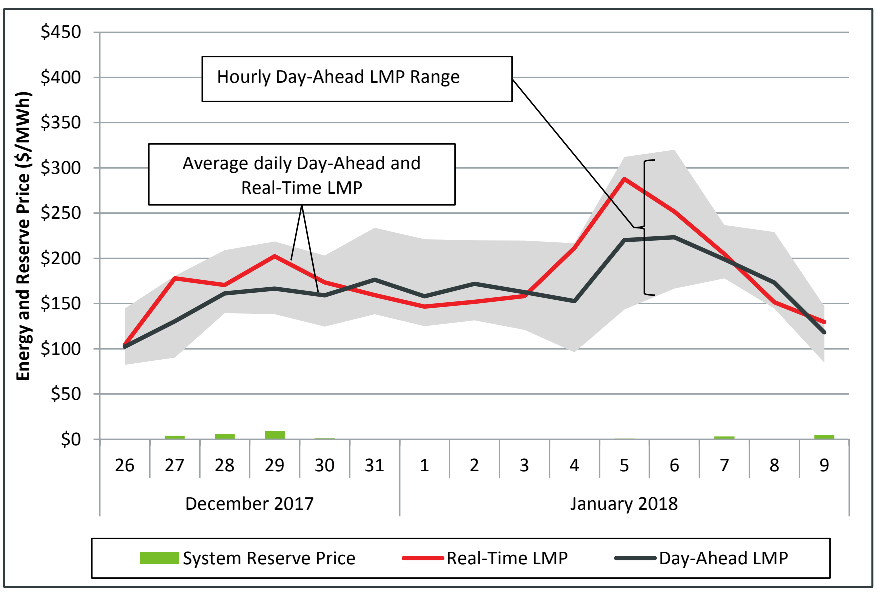
As seen, the system had ample reserves to satisfy the system-level TMNSR and TMOR requirements and on average had about 2,400 MW and 3,000 MW, respectively, of available reserves in excess of the requirement. The average hourly margin for the system TMSR requirement was about 500 MW and is inherently lower given the requirement is lower. On seven days, the TMSR reserve margin was equal to or below the TMSR requirement resulting in TMSR pricing. In total, there was about 340 five-minute intervals, or 28 hours, with TMSR pricing up to the TMSR RCPF of $50/MWh. This can be seen on the graph when the 10th percentile for the TMSR margin is at or near 0 MW meaning that 10% of observations were equal to or below that level.

4.2 Market Prices

Prices during the Cold Snap were high, reflecting high load levels and fuel prices. Average daily day-ahead prices during the 15-day period were between $103 and $220/MWh. Over the past three winters, the nine highest-priced days in the day-ahead market and the ten highest-priced days in the real-time market were observed during the Cold Snap.

Day-ahead and real-time Hub energy prices, as well as system reserve prices, are shown below in Figure 4-4 below. Day-ahead prices are shown with a solid black line. The range of day-ahead prices is also shown by the gray area. The red line shows real-time Hub LMPs. The green bar at the bottom shows the system reserve price. Average reserve prices during the Cold Snap were very low and comprised entirely of spinning reserve (TMSR) pricing.

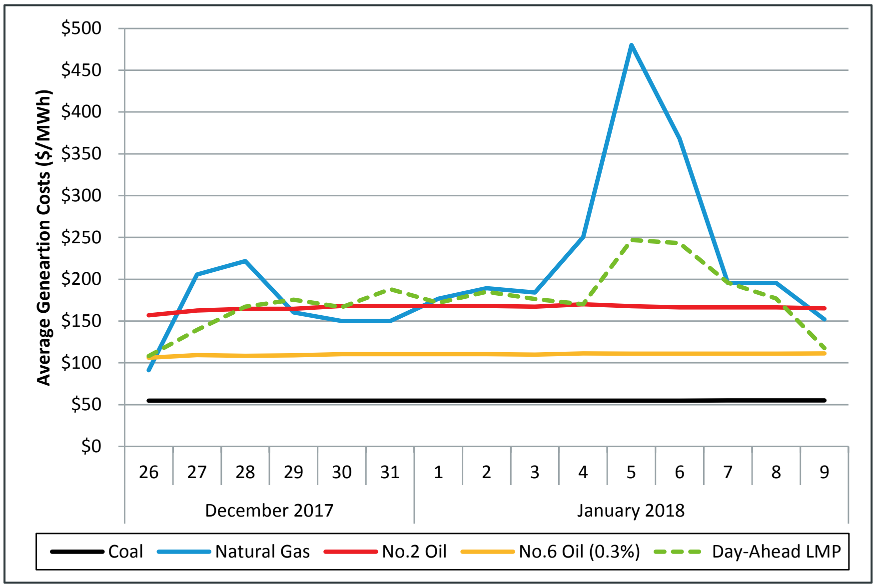
Figure 4-4: Day-Ahead and Real-Time Energy and Reserve Prices



The highest prices during the Cold Snap were observed on January 5 and 6 as temperatures averaged about 8°F. Peak loads on these days exceeded 20,000 MW. Additionally, January 5 and 6 experienced the highest natural gas prices of the Cold Snap, at over $60 and about $47/MMBtu, respectively. Real-time prices were significantly higher than day-ahead prices on January 4 and 5 as a large nuclear unit was forced out of service in real-time.

Natural gas prices exceeded oil and coal prices during the Cold Snap due to tight pipeline conditions. This, in turn, impacted generation costs. Daily average day-ahead LMPs, alongside the generation costs of various fuel types assuming standard heat rates, are illustrated in Figure 4-5 below. The green line represents day-ahead electricity prices, while other colors represent different fuel generation costs.

Figure 4-5: Daily Fuel Prices During Cold Snap



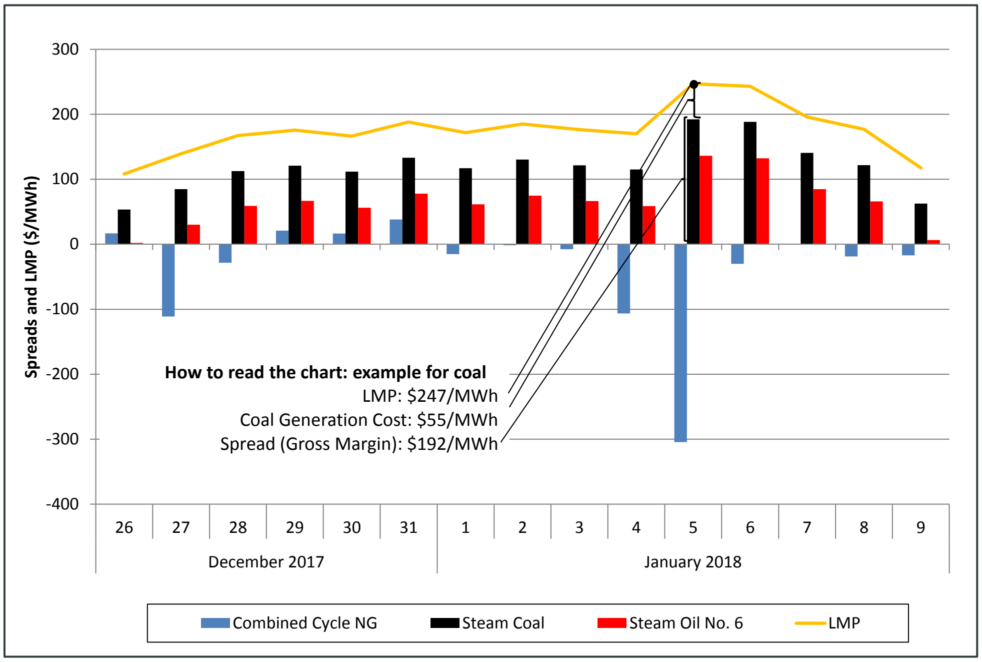
Generation costs for natural gas-fired generators averaged $211/MWh during the Cold Snap. That is 166% higher than the average Winter 2018 generation cost of $80/MWh. On average, natural gas generation costs were 285%, 92%, and 27% higher than coal, No 6. oil, and No 2.oil, respectively. Elevated natural gas prices impacted the merit order of natural gas-fired generation. This, in turn, caused many dual-fuel generators to switch from natural gas to their alternate fuel source. More information on the supply fuel mix and fuel spreads are presented in the following section.

4.3 Market Economics by Fuel

Fuel spreads represent the short-run potential net revenue available to generators using particular fuel types; the fuel spread is measured as the LMP less the variable fuel-based production cost of generating 1 MW of electricity.[21] Fuel spreads provide a rough indication of the fuel types that were in-merit to provide supply on a particular day, and the financial gain from providing supply. The on-peak fuel spreads (hours ending 8 to 23), along with the day-ahead LMP are provided in Figure 4-6 below. The difference between the LMP line and the bars represents the estimated cost of each fuel. For example, on January 5, with an LMP of $247/MWh and an estimated coal generation cost of $55/MWh, the spread is $192/MWh. In the case of natural gas, on the same day the estimated generation costs was $551/MWh, resulting in a *negative* spread of $304/MWh.

[21] For example, during an hour with a $100/MWh electricity LMP, a combined cycle generator with an average heat rate of 7.800 MMBtus/MWh and a fuel cost of $10/MMBtu, would have net revenue of $22/MWh ($100 - $78). The spread estimates ignore other short-run variable costs such as emissions and variable operations and maintenance.

Figure 4-6: Daily On-Peak Spreads During Cold Snap in the Day-Ahead Energy Market



In the day-ahead market, spreads were significantly positive for coal-fired generation throughout the period, averaging $120/MWh for on-peak periods.[22] This is not surprising, since coal was the least-cost fuel (of the three) throughout the Cold Snap period (averaging $5.50/MMBtu), and LMPs at the Hub averaged $175/MWh for the period. Oil-fired generators (using No. 6 fuel oil as a benchmark) also experienced significantly positive spreads in the day-ahead market, with spreads averaging $65/MWh and rising as high as $136/MWh on January 5. Overall, natural gas-fired generators experienced small positive spreads to significantly negative spreads during on-peak periods. Those positive day-ahead market spreads were limited to only five days during period, and averaged $19/MWh on those days. The spreads were significantly negative for natural gas-fired generators on three days, when average spreads were less than a -$100/MWh. Spreads in the real-time energy market exhibited similar results and are not presented.[23]

Fuel Mix

As noted in the preceding section, natural gas became significantly more expensive during the Cold Snap (reaching a high of $62/MMBtu on January 5), resulting in a reduction of supply contribution from natural gas-fired generators compared to generators of other fuel types.[24] Overall, the fuel mix of generators providing supply throughout the period reflected the change in relative fuel prices. This is depicted in Figure 4-7 below, which illustrates the average percentage contribution

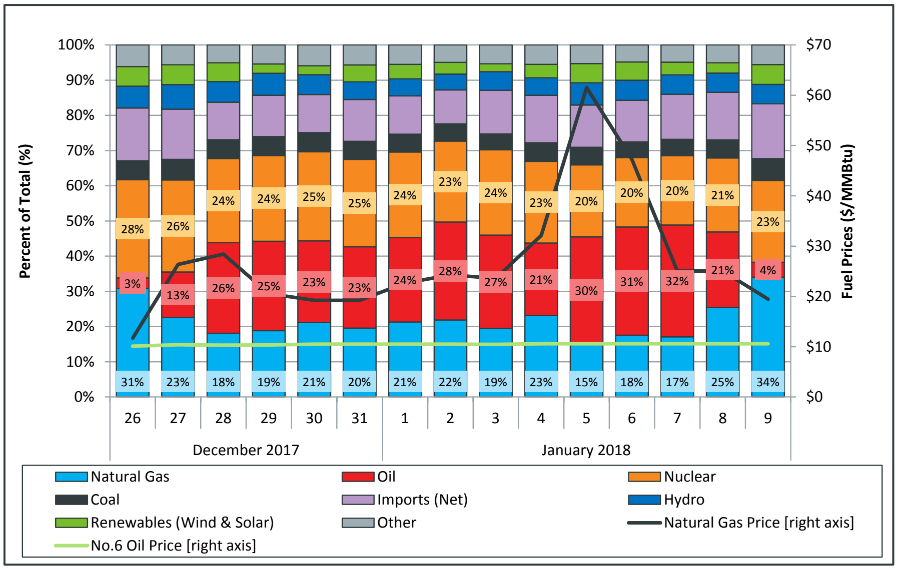
[22] The assumed heat rates for converting fuel prices to fuel cost for generating 1 MW were: 7.800 MMBtu/MWh for natural gas, 10.000 MMBtu/MWh for coal, and 10.500 MMBtu/MWh for fuel oil no. 6. It is expected that other types of fuel oil generators, on average, likely had higher heat rates and would have experienced smaller gains from operating during the Cold Snap.

[23] Many large generators participate in the day-ahead energy market and financially hedge their electric market positions when scheduled in that market. In terms of net revenue expectations from operation, the real-time market operation results become less important for these financially-hedged generators.

[24] The $62/MMBtu natural gas price represents an average price for the electric day (HE 1- HE24) and not the gas day.

of each fuel type for each day of the Cold Snap (corresponding to the left axis) compared to the natural gas and fuel oil no. 6 prices (right axis).

Figure 4-7: Daily Fuel Mix During Cold Snap



At the start of the Cold Snap on December 26, natural gas-fired generators supplied, on average, 4,500 MW per hour or 31% of the total supply, compared to lower shares for coal (5%), oil (3%) nuclear (28%), imports (15%), and wind, solar and all other supply (18%). As natural gas prices rose, natural gas-fired generators provided a declining share of supply, with its supply reduced to 2,500 MW per hour, on average, (15% of total supply) by January 5, the peak of natural gas prices.

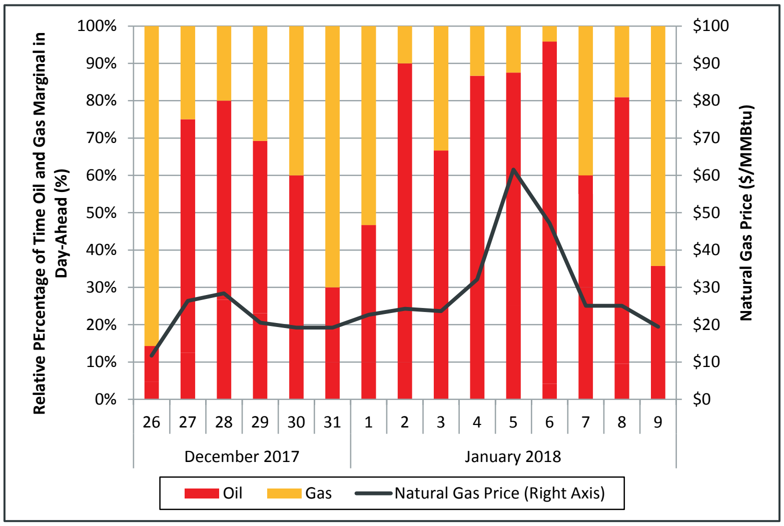
Oil-fired generators, which typically have higher dispatch costs than natural gas-fired generators, became in-merit more frequently during the Cold Snap, displacing the supply from some natural gas-fired generators. While oil-based generators provided just 435 MW of supply per hour on average on December 26, output from oil-fired generators rose to about 5,000 MW per hour on average, or 30% of total supply, from January 5 through 7. In addition to displacing natural gas-fired generation, oil-fired generation also offset a 650 MW per hour average reduction in nuclear generation resulting from an outage on January 4.

The supply from most other fuel types remained relatively steady during the Cold Snap. With coal prices significantly below natural prices throughout the period, coal's share of total supply did not notably change, while renewable generation and net imports, which are less reflective of merit-order dispatch, also maintained a relatively constant share of supply.

Marginal Resources: Natural Gas versus Oil

As natural gas prices increased, oil-fired generators set price more frequently than gas units in both the day-ahead and real-time markets. The relative percentage of time gas and oil units set price in the day-ahead market is shown below. Only gas and oil units are shown here to highlight the displacement of gas as the most frequently marginal fossil fuel type at the system level. Only day-ahead is shown due to the similarity of the trend in day-ahead and real-time.

Figure 4-8: Comparison of Frequency of Gas and Oil Setting Day-Ahead Price

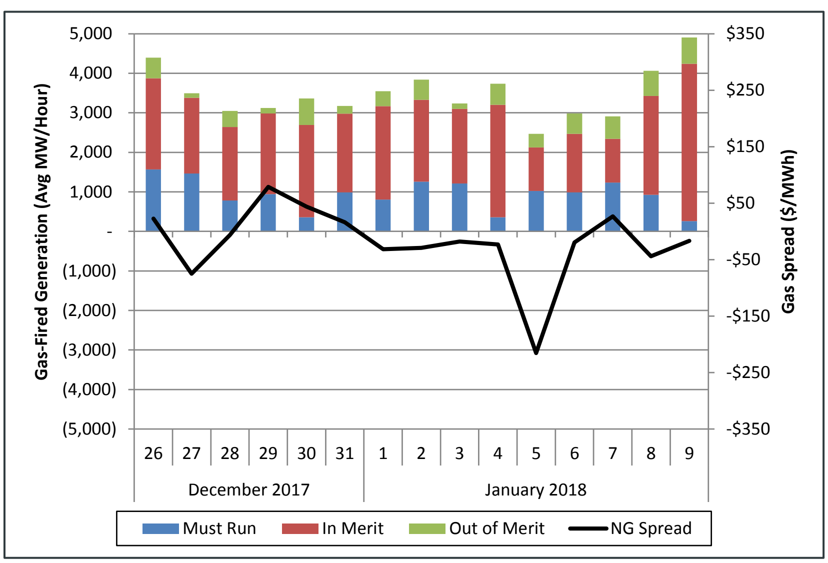


During the Cold Snap, oil-fired generators were marginal more frequently than gas-fired generators in 11 out of 15 days. The frequency of marginal oil generation was generally correlated with the natural gas price – i.e. as the natural gas price increased oil-fired generators economically displaced gas-fired generators in merit order and subsequently set price more frequently.

Operation of Gas-fired Generators Despite Negative Spreads

Gas-fired generators operated on a number of days during the Cold Snap period when natural gas spreads were significantly negative (See Figure 4-6 above) . This section utilizes generator offer and output data along with the LMP to describe the operation of gas-fired generators during periods with negative spark spreads. A gas-fired generator could have operated during this period for one of three reasons: self-commitment/self-scheduling to a generator's economic minimum, in-merit commitment/dispatch by the ISO, or out-of-merit commitment/dispatch by the ISO. The real-time generation graph below summarizes gas-fired generator output by these three categories.

Figure 4-9: Real-Time Gas-Fired Generation by Commitment/Dispatch Type



During the Cold Snap period, total real-time output from gas-fired generators tended to fluctuate between 3,000 and 4,000 MW per hour on average, except for the beginning and ending of the Cold Snap period and January 5 (the day with the highest natural gas prices). For the three categories of generation types, self-committed gas generation (labeled as "must run") in real-time accounts for 27% on average of gas-fired generation. Compared to the day-ahead market (not shown above), this represents a significant increase, where the share of gas generation from self-commitment was 15%. The increase in self-committed generation in real-time may reflect participants burning the gas they purchased in advance to fulfill their day-ahead energy market commitments.

In-merit generation represents the majority (61%) of the scheduled gas-fired generation in the real-time market during the Cold Snap. In-merit generation represents inframarginal dispatch by the ISO, where offer prices were below market LMPs. In-merit generation scheduled by the ISO is guaranteed recovery of as-offered costs; however, in many cases during the Cold Snap, these in-merit offers were effectively below the cost of generation given observable natural gas index values. In merit, gas-fired generation may occur for at least four reasons during negative gas spread periods: 1) Participants chose to reflect a forward contract price for gas in their offers (rather than the spot market price), 2) Participants were able to obtain gas at spot prices less than the index price used to calculate the gas spread, 3) Participants used a gas price forecast that was too low when preparing their electricity market offers, or 4) Participants had firm gas arrangements that required delivery of gas and chose not to sell the gas to other buyers (potentially because of electricity market obligations).[25]

Finally, a small portion of gas-fired generation (12%) was scheduled out-of-merit (OOM): that is, when generators' offer prices exceeded LMPs. The small amount of OOM generation in the real-time market occurred predominately for generators that were ramping to economic minimum levels, were operating at economic minimum levels, or were providing regulation service. These situations accounted for approximately 80% of gas-fired OOM generation.

Impact of Postured Resources on the Market Supply Curve

Posturing allows the ISO to constrain down generators from their optimal economic schedule to maintain system reliability. The ISO utilized this feature on several occasions during the Cold Snap due to concerns surrounding the rapid depletion of oil inventory at a number of oil generation facilities. The output of the postured oil-fired generators, that was otherwise economic, was replaced by relatively more expensive generation, thereby increasing overall productions costs for a given operating day. However, posturing of resources and preservation of oil stocks potentially avoids higher production costs and shortage conditions from occurring during future operating days.

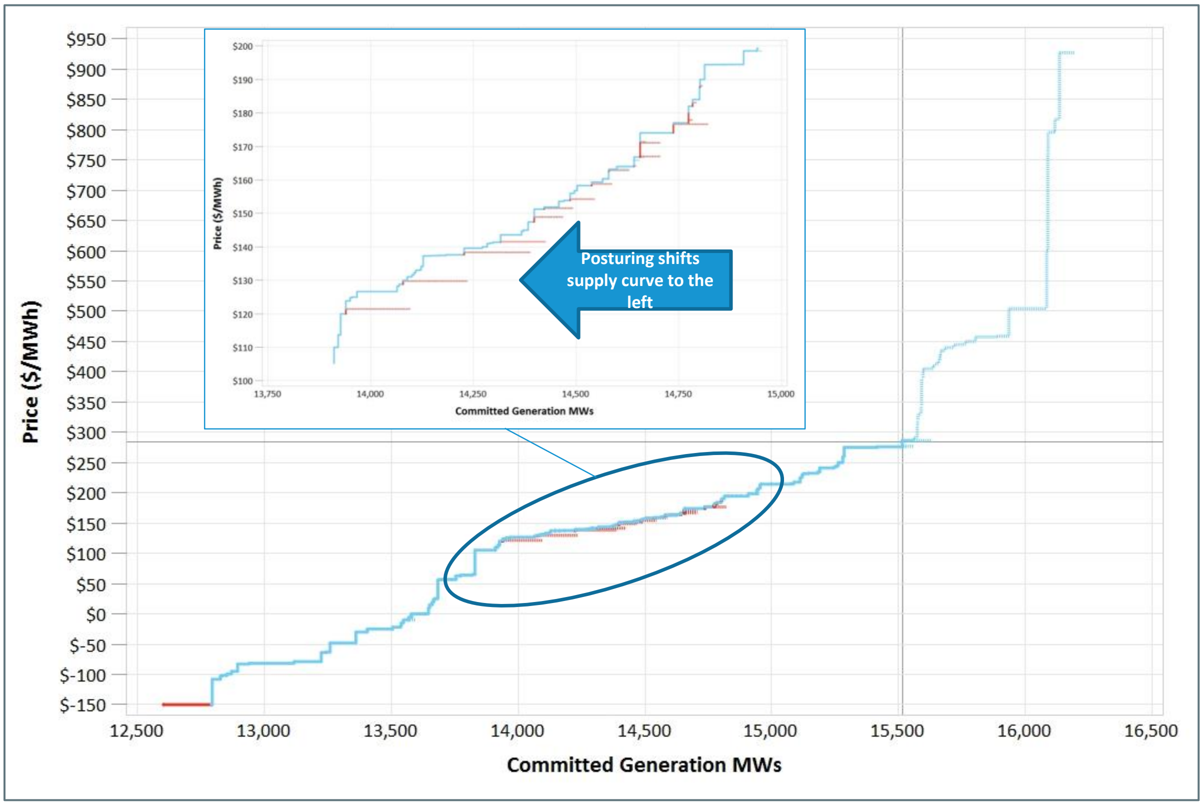
This section illustrates the impact of posturing on real-time energy market price formation. Four oil-fired generators were postured on January 5, the day with the highest gas prices and real-time LMPs of the Cold Snap. The supply curve at 3:00 pm on January 5 is shown in Figure 4-10 below.

The supply curve shown in Figure 4-10 is composed of actual real-time offers from online generators. The blue line represents offers from generators that were not postured. The red lines extending horizontally from the supply curve between $100 and $200 on the y-axis show supply

[25] The gas price used to calculate the gas spreads is a volume-weighted average of transactions across multiple gas indexes for the New England region. The gas spreads are for on-peak hours only (hours ending 8-23 daily).

offers submitted by postured oil-fired generators within their dispatchable range.[26] This energy would have been available for dispatch if the generators were not postured. The postured generators were online, operating at their economic minimum levels. The solid red line at the base of the supply curve (-150/MWh) is fixed energy that was produced by the postured generators. It represents the energy that the postured generators had to produce due to their economic minimum constraints. This energy is must-take, but is shown at the ISO's offer floor for simplicity. The x-axis is shown beginning at just over 12,500 MW. The supply curve between 0 MW and the starting value displayed in the figure (the red line at -$150/MWh) is composed of fixed generation that was not postured. The generation is must-take due to operational constraints, such as economic minimum or ramp-down limitations. The inset graph shows a close-up of the circled portion of the curve.

Figure 4-10: Supply Curve at 3PM on January 5, 2018



The impact of posturing on the supply curve is illustrated in Figure 4-10. If the dispatchable capacity from postured oil-fired generators (the red horizontal portions) was included in the supply curve, more economic generation would have been available to meet load. Allowing these generators to produce would have shifted the supply curve to the right, resulting in supply intersecting demand at a lower price. The actual LMP during this interval was $280/MWh. If the full capacity of the postured generators had been made available and the same generation had been online, the estimated price is much lower, at $164/MWh. This estimation has limitations. The supply curve shown here includes all generators that were actually online during the interval. If the posturing had not occurred, some of these online generators may not have been committed and

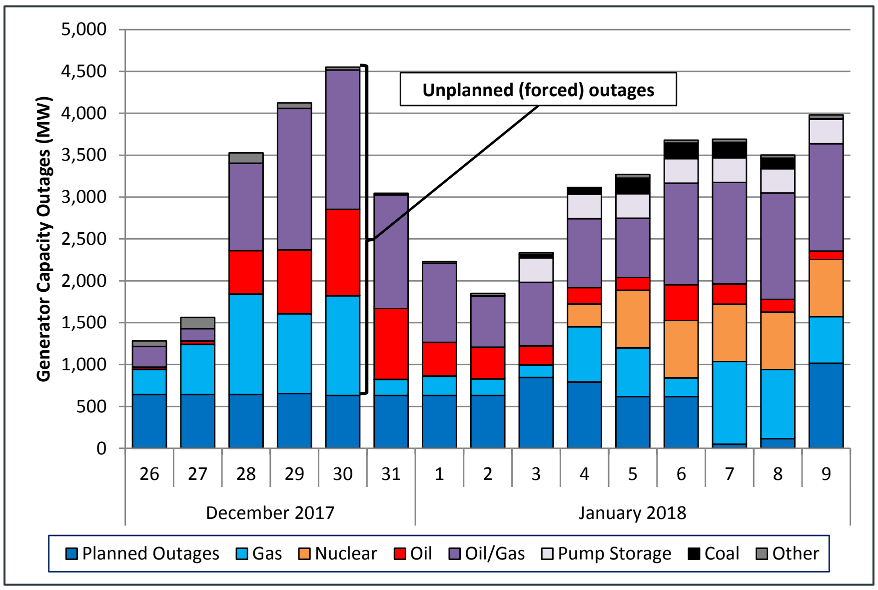
[26] The dispatchable range of the postured generators was assumed to be from economic minimum to economic maximum. Upward ramp rates were not considered to show what their output may have been if, earlier in the day, these units had not been postured.

there would have been less fixed supply (the supply from 0 MW to just over 12,500 MW that is must-take). The reduction in fixed supply would offset some of the reduction in the LMP. Though this estimation most likely overstates the effect of posturing on LMPs, it illustrates the direction of the pricing impact and the relative position of the postured units in the merit order.

4.4 Resource Availability

The Cold Snap affected physical availability for a number of generators. As discussed in the preceding section, some oil-fired generators were postured to preserve oil consumption. Additionally, some generators tripped during the winter storm on January 4. The average daily capacity (MW) of out-of-service generation by fuel type is shown in Figure 4-11 below. The blue portion of each bar (bottom) shows generation capacity that was out of service due to planned outages, while the remaining colored portions show the generation capacity that was out of service due to forced (unplanned) outages by fuel type.

Figure 4-11: Average Generation Out of Service by Fuel Type

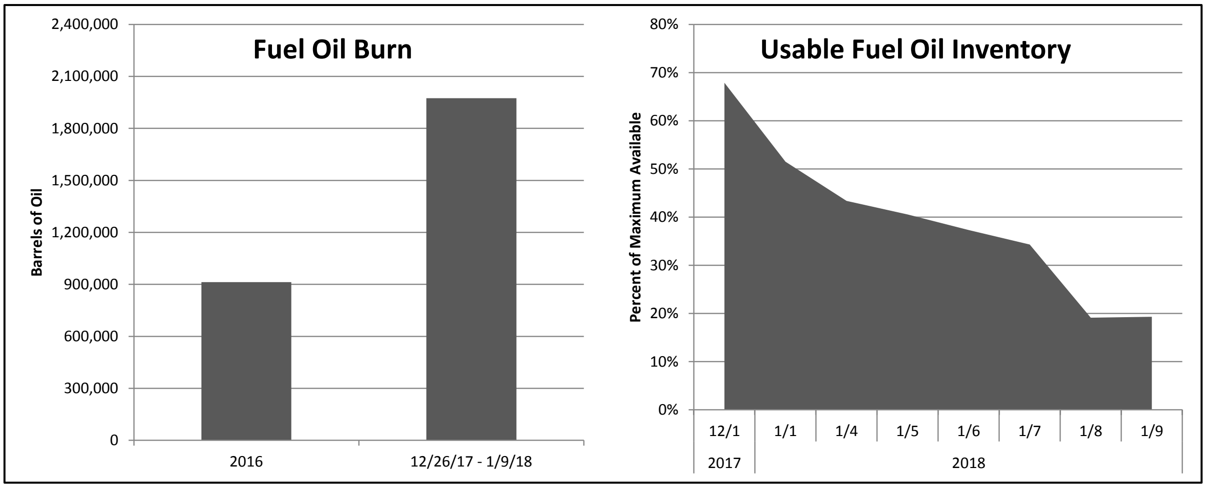


The volume of generator unavailability began increasing on December 28 as multiple gas-, oil-, and dual fuel-fired generators were forced out of service due to mechanical issues. Outages declined to about 2,000 MW in the beginning of January and increased again on January 4, the day of the "bomb cyclone", when a nuclear unit was forced out of service due to a transmission line trip that was related to weather conditions. Additionally, multiple gas- and dual fuel-fired generators were forced out of service due to mechanical issues arising from operating in harsh weather conditions (e.g., anti-icing activity, frozen coolant lines, etc.). During the Cold Snap, most generator outages appeared to be the result of mechanical issues, as opposed to fuel inventory or delivery issues.

Oil Availability

New England fuel oil burn for all of 2016 compared to the Cold Snap (left graph) as well as the percent of maximum usable fuel oil inventory available (right graph) is illustrated in Figure 4-12 below.

Figure 4-12: Fuel Oil Burned and Usable Fuel Oil Inventory



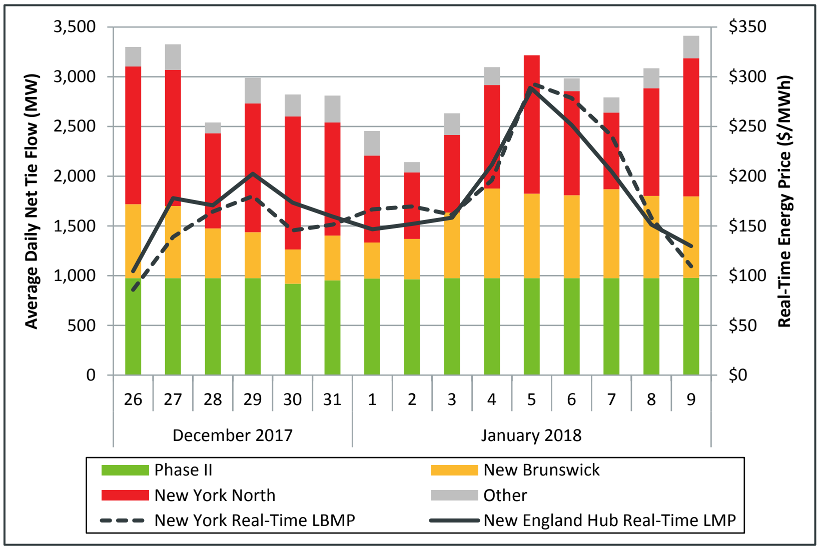
During the Cold Snap, oil-fired generators burned 2 million barrels of fuel oil which was about twice as much as the oil burned for the entire year of 2016. At the beginning of December 2017, it is estimated that the oil-based generation fleet in New England had about 70% of maximum available fuel oil (i.e., aggregate oil tank capacity). By the end of the Cold Snap, oil-fired generators had depleted stocks to about 20%, with many large generators only having enough oil left to operate for a few more days.[27] Oil-fired generators had difficulty replenishing oil stocks as cold temperatures and ice prevented barges from delivering oil to major ports reducing available oil supply to the New England region. Further, hazardous driving conditions prohibited or delayed oil trucks from delivering oil.

External Transactions

New England was a net importer of power throughout the Cold Snap. Net imports by interface are shown in Figure 4-13 below. The "Other" category includes Highgate, which connects New England to Quebec, and the Cross Sound Cable and Northport interfaces, which connect New England to New York.

[27] Based on survey results and is the best approximation of usable oil, discounting for unit outages, reductions, or emissions.

Figure 4-13: Net Imports by Interface



Imports over Phase II were consistent during the Cold Snap, about 1,000 MW per hour. Most of the fluctuation in imports from Canada occurred at the New Brunswick interface. At New Brunswick, New England was a net importer of about 650 MW per hour on average. The quantity of imports was generally correlated with the New England price; when New England prices were higher, more imports flowed over the New Brunswick interface. Most imports from New York were over the New York North interface. New York North imports fluctuated, mostly following the New England and New York price difference. On days when the average New England price was higher than the average New York price, an average of 1,240 MW per hour of imports flowed over the New York North interface. On days when New England prices were lower, 950 MW of imports flowed over New York North, on average.

4.5 Market Settlements

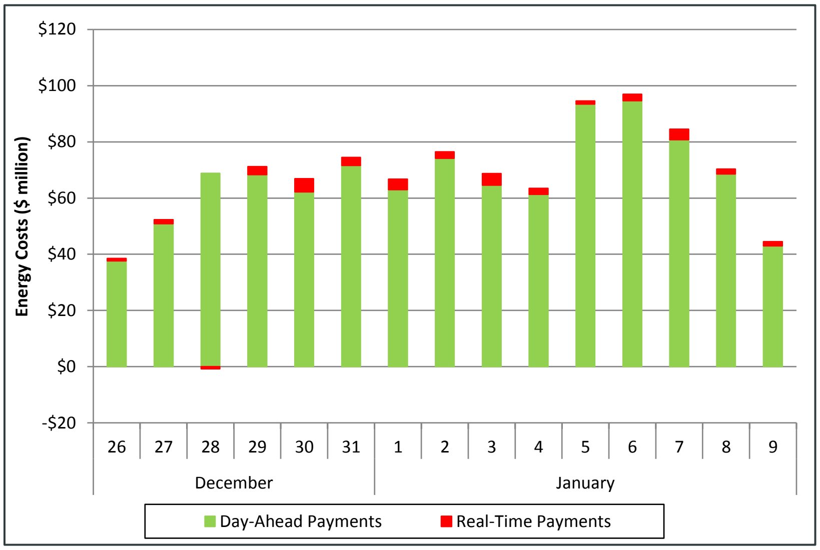
Higher fuel prices, demand and energy prices during the Cold Snap drove the significant increase in year-over-year wholesale energy costs in Winter 2018. This section presents market settlement metrics during the Cold Snap in relation to the following areas:

- Value of day-ahead and real-time energy market
- Cleared day-ahead generation and real-time deviations
- NCPC payments

Value of Day-Ahead and Real-Time Energy Markets

During the 15-day Cold Snap, energy market costs totaled $1.04 billion. This represents 40% of total energy costs over the entire 90-day Winter 2018 season. The majority of these costs (97%) were incurred in the day-ahead market. Figure 4-14 below shows the day-ahead and real-time energy costs by day over the period.

Figure 4-14: Value of Day-ahead and Real-time Energy Markets During Cold Snap



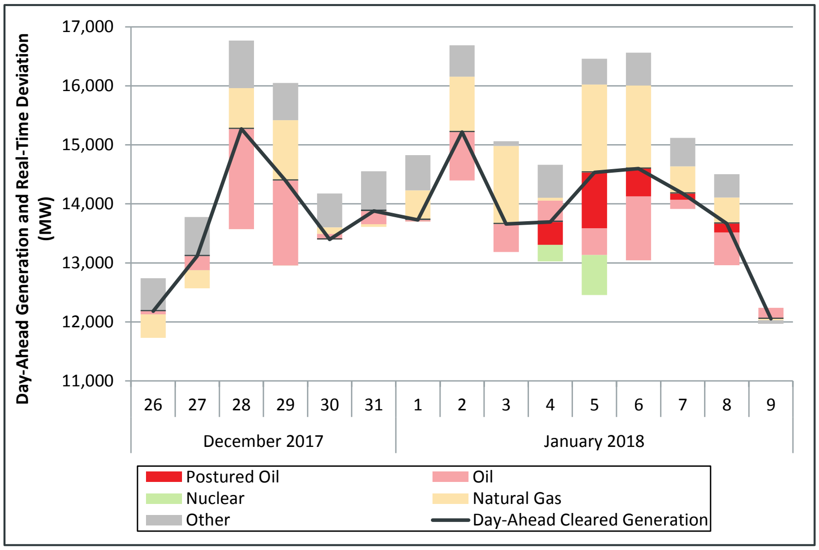
The highest energy costs occurred on January 5 and 6 when the system experienced the highest natural gas prices of the period, between $47 and $62/MMBtu.

Cleared Day-Ahead Generation and Real-Time Deviations

Generator deviations by fuel type are shown in Figure 4-15 below. The average hourly day-ahead cleared generation is shown by the black line and also by the horizontal black lines on the stacked bars. Average hourly deviations from the day-ahead schedule, by fuel type, are shown by the colored bars. If the bar is below the horizontal black line, it shows that generators of that fuel type delivered less in real-time than they cleared in the day-ahead market. If the bar appears above the black line, it shows that generators of that fuel type delivered more energy than they cleared in the day-ahead market.

Positive and negative generator deviations are netted against each other for the following figure. For example, if a yellow bar is shown above the black line, then the total real-time output of gas-fired generators was higher than their day-ahead schedules, although some gas-fired generators may have delivered less. The *Other* category is comprised of coal, hydro, renewables, and virtual supply. The unfaded red section of the bar chart captures the deviations resulting from the ISO's decision to posture oil generators.

Figure 4-15: Generator Deviations by Fuel Type during the Cold Snap

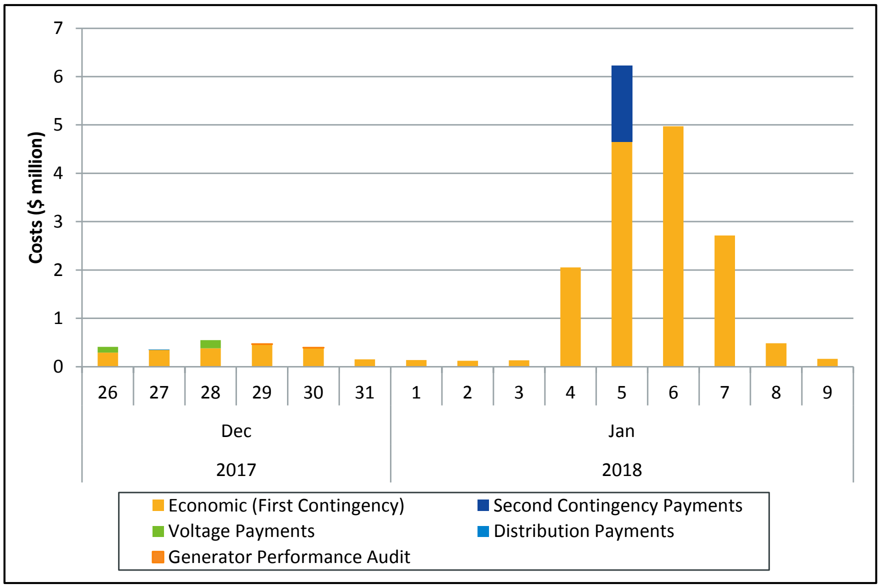


The figure highlights the role that gas-fired generation played during the Cold Snap when oil and nuclear generators were unable to generate the MW in real-time that they had cleared day-ahead. On December 28 and 29 numerous unplanned oil-fired generator outages occurred, resulting in an average reduction in oil generation of over 1,500 MW in real-time, compared with the day-ahead cleared volume. In real-time, natural gas-fired generators delivered almost 900 MW of additional generation to offset the loss of the oil-fired generation. Additionally, wind generators delivered an average of over 500 MW and hydro contributed almost 300 MW of additional real-time generation per hour. At 2:30 PM on January 4, a large nuclear generator that had cleared almost 700 MW per hour in the day-ahead market, and had already cleared in the day-ahead market for all 24 hours on January 5, was forced out of service. In addition, several oil-fired generators were postured beginning on January 4. Between January 4 and January 8, 15 different oil-fired generators were postured for a combined reduction of over 400 MW per hour during these five days. Gas-fired generators provided 770 MW of additional real-time generation per hour on these days to offset the reductions. As discussion in Section 4.3 above, the gas-generation was dispatched on economic merit.

Net Commitment Period Compensation

Nearly two-thirds of the total NCPC payments made in Winter 2018 occurred during the Cold Snap. NCPC payments totaled $19.3 million during this period, of which, nearly 90% were for first contingency needs. NCPC payments by category are shown for each day of the Cold Snap in Figure 4-16 below.

Figure 4-16: NCPC Payments by Category during Cold Snap ($ millions)



In particular, NCPC payments spiked during a four-day period from January 4 to January 7. Total NCPC payments during this four-day period amounted to $15.96 million, or about 55% of total Winter 2018 NCPC payments. One of the primary reasons for this increase in NCPC payments was because of the number of resources that were postured for reliability over this four-day period and the high opportunity cost associated with this ISO-initiated action. In total, 12 different generators received posturing NCPC credits that amounted to $6.8 million over this four-day period. In fact, two generators received over $2 million of posturing NCPC credits over this period, with one receiving close to $4 million. Additionally, there was a large real-time NCPC credit ($1.6 million) received by a generator in NEMA/Boston on January 5, 2018, for providing local second-contingency protection.

Section 5
Forward Markets

This section of the report covers activity in the forward capacity market (FCM) and in financial transmissions rights (FTRs). The next section (Section 6) provides a detailed review of the twelfth forward capacity auction (FCA 12), which was run in February 2018.

5.1 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 current capacity commitment period (CCP) started on June 1, 2017 and ends 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 existing clearing prices for Winter 2016 through Winter 2018 are shown in Figure 5-1 below. The black lines (corresponding to the right axis, "RA") represent the

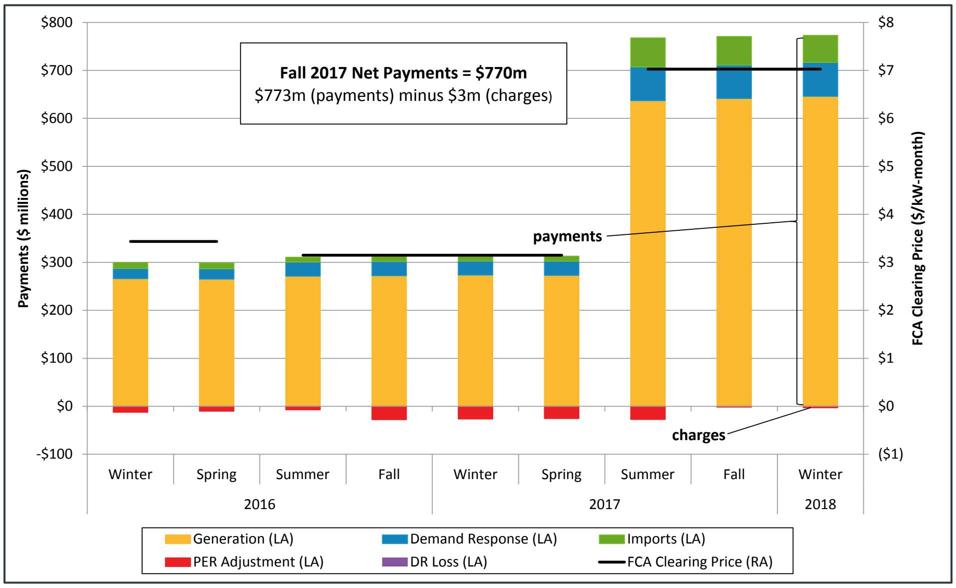
[28] In the capacity market, resource categories include generation, demand response and imports.

[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

FCA clearing prices for existing resources in the Rest-of-Pool capacity zone. The orange, blue, and green bars (corresponding to the left axis, "LA") represent payments made to generation, demand response, and import resources, respectively.

Figure 5-1: Capacity Payments ($ millions)



In Winter 2018, capacity payments totaled $770 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 5-1 below provides a summary of prices and volumes associated with reconfiguration auction and bilateral trading activity that occurred during Winter 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 5-1: Primary and Secondary Forward Capacity Market Prices for the Reporting Period

					Capacity Zone/Interface Prices			
FCA # (Commitment Period)	Auction Type	Period	Systemwide Price ($/kW-mo)**	Cleared MW	NEMA/Bos	SEMA/RI	New Brunswick	New York AC Ties
FCA 8 (2017-18)	Primary	12-month	15/7.03*	33,712	15/15*			
	Monthly Reconfiguration	Feb-18	0.50	1,005	1.55			
	Monthly Bilateral	Feb-18	2.58	514				
	Monthly Reconfiguration	Mar-18	0.40	697	5.00			
	Monthly Bilateral	Mar-18	2.65	441				
	Monthly Reconfiguration	Apr-18	0.55	902	5.00			
	Monthly Bilateral	Apr-18	3.33	159				
FCA 9 (2018-19)	Primary	12-month	9.55	34,695		17.73/11.08*	3.94	7.97
	Annual Bilateral (3)	12-month	4.89	424				

**price paid to new resources/price paid to existing resources*

***bilateral prices represent volume weighted average prices*

****cleared supply/cleared demand*

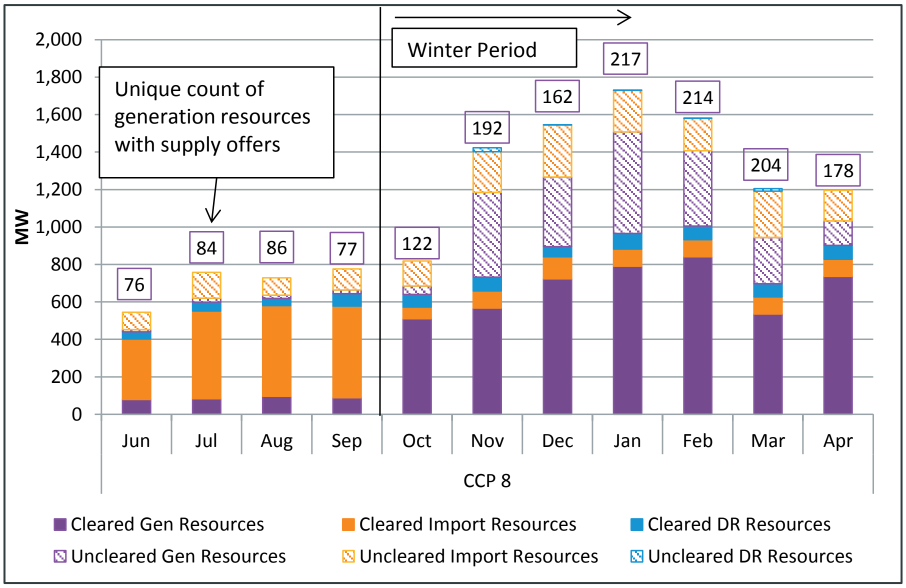
Over the course of Winter 2018, generation resources increased their CSOs through monthly reconfiguration auctions. Generators may choose to gain additional CSO MWs due to increased generating capability during the winter period when ambient temperatures are colder.[32,33] This leads to increased participation and lower prices in the monthly auctions.

Supply offers, segmented by resource type, for CCP 8 are shown in Figure 5-2 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] 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.

[33] The gain in capacity is simply the difference between their winter and summer qualified capacity.

Figure 5-2: Monthly Reconfiguration Auction Supply Offers During CCP 8



The figure highlights increased cleared generation capacity in the winter period. Generator resources take advantage of their increased winter capability discussed in the paragraph above. An average of 184 generation resources participated during the winter period. This is more than double the average of 81 during the summer period. The average volume weighted Rest-of-Pool price in summer months was $4.54/kW-month. The average price declined to $1.15/kW-month during the winter period.

5.2 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.[34] 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 the annual auction have a term of one year and after the annual auction occurs, the remaining feasible FTRs are made available in monthly auctions, each having a term of one month.

FTR auction revenue is distributed to Auction Revenue Rights (ARRs) holders which primarily consist of 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 for that month. Because congestion costs are based on actual system conditions, the congestion revenue fund can be larger or smaller than target allocations to FTR holders that are derived in FTR auctions. For example, if less congestion materializes on the transmission system than modeled in the feasibility test used in an FTR auction, there would be less congestion revenue available to FTR holders.

[34] 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.

Three monthly FTR Auctions were conducted during the Winter 2018 reporting period for a combined total of 94,500 MW of FTR transactions. The total auction dollar amount distributed to ARR holders was $3.3 million, which was a 49% increase compared to Winter 2017. The increase in distribution to ARR holders can be a function of many factors including but not limited to: (i) higher levels of anticipated congestion on the system thus more FTR MWs available and (ii) an increase in auction participant's willingness to pay for FTRs. Thirty-two bidders in December, 30 bidders in January and 35 bidders in February participated in the monthly auctions for the quarter. The level of participation was consistent with recent auctions. For Winter 2018 the congestion revenue fund was 100% funded, meaning that enough congestion revenue was collected to pay the target allocations to FTR holders.

Section 6
The Twelfth Forward Capacity Auction (FCA 12)

This section presents a review of the twelfth Forward Capacity Auction (FCA 12), which was held in February 2018 and covers the capacity commitment period (CCP) beginning June 1, 2021 through May 31, 2022. The rest of this section provides an overview of the inputs and high level outcomes of the auction. It subsequently covers auction outcomes, in terms of prices, cleared capacity and an assessment of market competitiveness.

FCA 12 incorporated the Marginal Reliability Impact (MRI) methodology in the calculation of the sloped system and zonal demand curves. The MRI methodology estimates how an incremental change in capacity impacts system reliability at various capacity levels. The sloped demand curves for constrained capacity zones allow more capacity to clear in the export-constrained zones (or less in the case of an import-constrained zone) at lower prices (or higher for import-constrained zones) compared to the system clearing price.[35] The full MRI system-wide curve was not implemented for FCA 12. Instead, a transitional approach was taken, with the demand curve reflecting a hybrid of the previous linear demand curve and the new convex-shaped MRI curve.[36]

As discussed further below, nearly 40,000 MW of capacity qualified to participate in the auction. The descending clock auction went into the fourth round and cleared 34,828 MW at a price of $4.63/kW-month. There was an excess of capacity willing to import over the New Brunswick and Phase I/II HQ interfaces, which resulted in lower export-constrained prices of $3.16/kW-month and $3.70/kW-month, respectively. The projected payments for FCA 12 are $2.1 billion, absent secondary market trading and performance payments. The IMM concluded that the auction outcomes were the result of a competitive auction.

6.1 Resource Qualification

The amount of qualified capacity from new and existing resources compared to the capacity requirement indicates the potential level of participation and competition in the auction. When developing the target capacity to be procured, the ISO calculates a Net Installed Capacity Requirement (NICR). NICR is the amount of capacity (in megawatts, MW) needed to meet the region's reliability requirements (after accounting for tie benefits with Hydro-Quebec). Due to transmission limitations there are also Local Sourcing Requirements (LSR) for import-constrained areas and Maximum Capacity Limits (MCL) for export-constrained areas. If the amount of qualified capacity is below NICR, then the system may be unable to meet resource adequacy planning criteria. Depending on the degree to which the system is short and there is inadequate competition, the clearing price can reach the starting price.[37] Figure 6-1 below shows the qualified capacity that participated in the auction compared to NICR (blue bar on the left). The total qualified capacity in

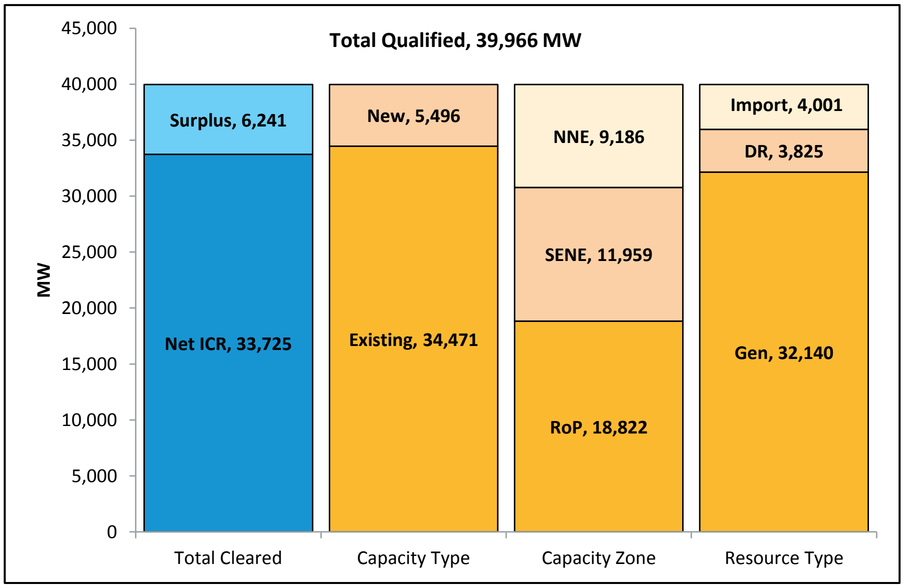
[35] The capacity zones were Southeastern New England (SENE), Northern New England (NNE), and Rest-of-Pool (RoP). The SENE import-constrained capacity zone includes the NEMA/Boston, Southeastern Massachusetts, and Rhode Island load zones. The NNE export-constrained zone comprises the Maine, New Hampshire, and Vermont load zones.

[36] The transition period began with FCA 11 and can last for up to three FCAs, unless certain conditions relating to Net Installed Capacity Requirement (NICR) growth are met, pursuant to Section III.13.2.2.1 of the Tariff.

[37] The starting price is equal to 1.6 times the net cost of new entry (Net CONE). Net CONE is the netted value equals the estimated CONE net of revenues from energy, reserve, and other markets.

FCA 12 was roughly 40,000 MW. The three orange bars to the right show the breakdown of the total qualified capacity amount across three dimensions: capacity type, capacity zone and resource type.

Figure 6-1: Breakdown of the Qualified Capacity in FCA 12



The blue bar shows that there was a surplus of qualified capacity of about 6,240 MW, or almost 19%, above NICR; NICR has been declining over the past several FCAs. Increased energy efficiency and improved solar PV forecasts impacted NICR significantly. An adjustment to the solar PV forecast methodology alone caused an estimated 335 MW decline in Net ICR compared to last year.[38]

The first orange bar (capacity type) shows that the qualified capacity from existing resources exceeded the Net ICR, by about 750 MW.[39] In FCA 11, the ISO introduced priced retirement de-list bids, which count as existing capacity headed into the auction. In FCA 11, only 30 MW of retirement capacity entered the auction with a qualified bid. In FCA 12, that number increased to 520 MW; this includes the retirement of Bridgeport Harbor 3, a 383-MW oil-fired resource in Connecticut.

The second orange bar represents qualified capacity by capacity zone. There was sufficient qualified capacity in Southeastern New England (SENE) compared to the LSR. Qualified capacity was about 11,960 MW, roughly 1,940 MW over the local requirement. The Northern New England (NNE) capacity zone had roughly 9,190 MW of qualified capacity, which was slightly over (by about 400 MW) the MCL. If all new and existing resources in NNE stayed in the auction to $4.63/kW-month, then the price may have separated. As discussed in the next section, this was not the case.

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38 The methodology changes from the reliability hours methodology to the hourly profile methodology. For more information on the differences, please refer to https://www.iso-ne.com/static-assets/documents/2017/11/icr_2017_fca_12.pdf

39 "New Capacity" also includes capacity from resources that qualify as new, but have participated in prior auctions, such import resources.

6.2 Auction Outcomes

In addition to the amount of qualified capacity eligible to participate in the auction, there are several other factors that contribute to the auction outcome. These factors include the auction parameters provided by the ISO as well as participant behavior, which are summarized in this section.

Two important demand-side parameters declined in FCA 12: NICR and Net Cost of New Entry (Net CONE). NICR (MW) and Net CONE ($/kW-month) are used as the scaling point for the MRI curve. The MRI curve is scaled to show prices that load is willing to pay at various levels of capacity, which in turn provides various levels of system reliability. The FCA 12 NICR declined by 350 MW compared to FCA 11, which marked the fifth consecutive year of decline. The decrease in FCA 12 was primarily due to improved solar forecasts used by the ISO to calculate NICR.[40] In addition, Net CONE changed to reflect updated reference technologies.[41] The reference technology for FCAs 12 - 14 reflects costs of a combustion turbine ($8.04/kW-month), which was selected as the most economically efficient resource tested by the ISO. In FCAs 9 –11, the ISO chose a combined cycle turbine ($11.08/kW-month).[42] The combination of declining Net ICR and Net CONE values moved the scaling point inward, which in turn lowered demand in FCA 12.

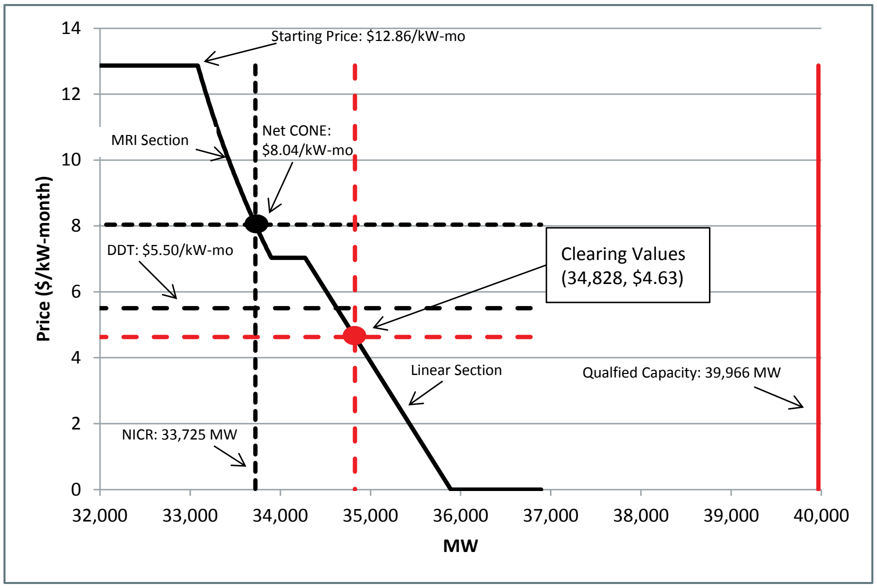
Figure 6-2 below illustrates the system-wide transitional demand curve (black solid line), which is the combination of the simple linear demand curve (labeled as the Linear Section) and convex MRI curve (labeled as the MRI Section). The first sloped section of the demand curve, which begins at the starting price and ends at the horizontal section, is based on the MRI methodology. The horizontal section of the curve begins at the FCA 10 clearing price of $7.03/kW-month and is 375 MW long. The demand curve then becomes linearly sloped down to $0/kW-month. On the supply side, the qualified and cleared capacities are shown (solid and dashed red lines, respectively). The clearing price of $4.63/kW-month is shown at the intersection of the cleared MW (dotted red line) and the demand curve.

[40] The methodology changes from the reliability hours methodology to the hourly profile methodology**.** For more information on the differences, please refer to https://www.iso-ne.com/static-assets/documents/2017/11/icr_2017_fca_12.pdf

[41] The market rule requires the ISO to recalculate Net CONE with updated data at least every three years. See Market Rule 1, Sections III.13.2.4 and III.A.21.1.2(a).

[42] For more information on reference technology selection, see Section IV.E of the following FERC filing: https://www.iso-ne.com/static-assets/documents/2017/01/cone_and_ortp_updates.pdf. The cited Net CONE value applied in FCA 9; the Net CONE value for combined cycle turbines fluctuated slightly for the subsequent auctions.

Figure 6-2: System-wide FCA 12 Demand Curve, Prices, and Quantities



The auction closed in the fourth round for the Rest-of-Pool, SENE and NNE zones. As qualified capacity exited in the first three rounds, the solid red line moved towards the dotted red line. The fourth round opening price was the dynamic de-list bid threshold (DDBT) price, meaning existing resources could submit bids to exit (de-list) the market during the fourth round. When prices fall below this threshold, existing resources (that do not have a static or permanent de-list bid in the auction) can actively submit prices in the auction. It also serves as an important threshold for market power mitigation, whereby an existing resource that submits bids above this level is subject to a cost review by the IMM and potential market power mitigation.

During the fourth round the ISO performed reliability reviews for the submitted dynamic de-list bids, totaling 2,772 MW. Two dynamic de-list bids, Mystic 7 and Mystic 8, were rejected for local reliability reasons in the NEMA/Boston load zone, which is located in the SENE capacity zone. Both of these resources had sufficiently high de-list bid prices that they would not have received a CSO. Therefore, their combined 1,278 MW was administratively held in the auction at prices of $5 and $5.499/kW-month.[43] After accounting for the two rejected bids, a total of 1,430 MW from 30 resources were able to dynamically de-list. Over 1,200 MW of the dynamic de-lists were from natural gas-fired resources. Three dynamic de-list bids set the clearing price when supply fell short of demand. The marginal resources' de-list bids were then rationed to allow for demand to exactly equal supply. The auction cleared 34,828 MW at a price of $4.631/kW-month. As shown in Figure 6-2, supply met demand and price was set along the linear sloped portion of the transitional demand curve.

Retaining the Mystic 7 and Mystic 8 resources out-of-market had an impact on the auction clearing price. Once the decision to retain these resources was made, their combined 1,278 MW of capacity was represented as price-taking capacity (bid price of $0/kW-month) in the pricing run of the auction. This administrative action makes the capacity from the two retained resources infra-

[43] See Attachment B of the FCA 12 FERC Filing: https://www.iso-ne.com/static-assets/documents/2018/02/fca_12_results_filing.pdf

marginal (where it was extra-marginal before) and, as a result, lowers the supply curve in the neighborhood of the clearing price. This results in the auction clearing at a lower price.

While on the surface it appears that retaining the two Mystic resources resulted in a lower auction clearing price, it would not be appropriate to price all capacity procured in the SENE zone (or system wide) using the bid prices from the retained resources. These two resources were retained for reliability and provide a service that cannot be supplied by all other resources in the SENE zone (or system wide).

Had the ISO modeled the local reliability need in the auction as a nested sub-zone within SENE, meeting the local reliability requirement in-market in the nested sub-zone would have lowered the SENE (and possibly system-wide) price similar to what was observed in FCA 12.[44] The quantity procured to meet the local reliability requirement in the nested sub-zone within SENE would have cleared at a higher price in that sub-zone (based on the de-list bid prices of the two Mystic resources held for reliability). However, the quantity procured in-market from the two Mystic resources in the nested sub-zone would have reduced the demand for other capacity in the SENE zone, which therefore also would have resulted in a lower SENE price (compared to the case where the Mystic resources were not held for reliability). In short, an in-market solution to the reliability need may very well have resulted in a price reduction in SENE and the rest of the system similar to the reduction resulting from the out-of-market solution used in FCA 12.

The New Brunswick and Phase I/II interfaces had excess supply at the end of round four and needed an additional round to clear. The auction continued into the fifth round and cleared at a price of $3.16/kW-month for New Brunswick and $3.70/kW-month for Phase I/II. The lower clearing prices were deemed to be competitive. The prices reflect reasonable expectations of competing opportunities in the New York ISO's spot capacity market.[45]

The IMM found the results of FCA 12 to be competitive. At the start of the fourth round, bids were priced below the dynamic de-list bid threshold. Within this dynamic range, existing resources have the opportunity to remove capacity at a price that is not reviewed by the IMM. Entering the fourth round, sufficient surplus remained so that no single market participant could have effectively exercised market power at the system or zonal levels. Therefore, resource owners were incentivized to offer at competitive prices and the outcome of the auction was competitive.[46]

Further, before the auction occurs, the IMM applies mitigation rules for existing and new resources. While several of the existing resources were offered into the market by pivotal suppliers, none of the pivotal suppliers had active static de-list bids or offers from new import capacity resources (that are treated similarly to existing resources). Because there were no static de-list bids or offers from new import capacity resources from pivotal suppliers, the IMM did not have to apply market power mitigation to the existing resources belonging to pivotal suppliers.[47] As with existing

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[44] We are not suggesting that the ISO would have or should have modeled the reliability need as a nested sub-zone in SENE, but are using a market-based counter-factual to highlight price impacts. The FCM procures capacity to meet resource adequacy needs and is not currently configured to address other products.

[45] See Attachment D of the FCA 12 FERC Filing: https://www.iso-ne.com/static-assets/documents/2018/02/fca_12_results_filing.pdf

[46] See Attachment D of the FCA 12 FERC filing for more information: https://www.iso-ne.com/static-assets/documents/2018/02/fca_12_results_filing.pdf

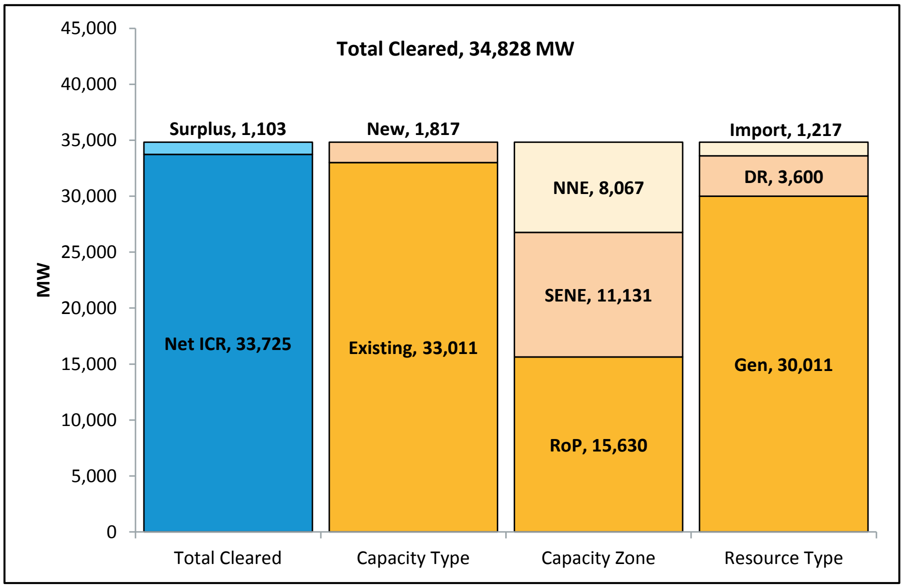
[47] See Attachment D page 4 for more information: https://www.iso-ne.com/static-assets/documents/2016/02/er16-___-000_2-29-16_fca_10_results_filing.pdf

resources, new capacity resources undergo a mitigation review if the proposed new resource offer floor price is below the relevant competitive benchmark (i.e. the offer review trigger price).

6.3 Cleared Resources

The amount of cleared capacity in FCA 12 exceeded system-wide and capacity zone requirements. The amount of cleared capacity is shown in Figure 6-3 below across several dimensions: capacity type, capacity zone, and resource type. Each of the bars in the figure are equal to the total amount of cleared capacity.

Figure 6-3: Breakdown of the Cleared Capacity in FCA 12



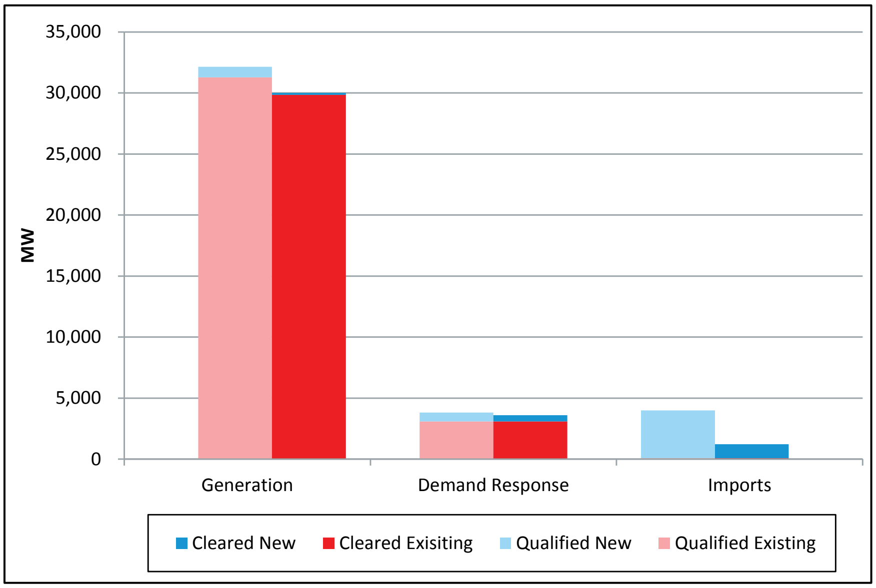
The blue bar shows that cleared capacity exceeded NICR by over 1,100 MW. This was down from the 1,800 MW surplus in FCA 11 despite a lower NICR value. The primary reason for the lower surplus was the cleared dynamic de-lists discussed in Section 6.2.

Moving to the right, the first orange bar (capacity type) shows that new resource capacity accounted for 1,800 MW of total cleared capacity. A little over 500 MW came from demand response resources, while less than 200 MW came from generation resources. The other 1,100 MW were from import resources that qualified as new resources for the FCA. A majority of those import resources are treated as *new* for qualification purposes, but are in fact backed by *existing* tie line capacity that has participated in previous auctions.

By capacity zone (second orange bar), the cleared amount in NNE was roughly 720 MW short of the MCL, and therefore the zonal export constraint was not binding. Neither was the SENE import-constraint; cleared capacity located within the SENE zone was roughly 1,100 MW over the LSR.

Qualified and cleared capacity by resource type (generation, demand response and imports) are illustrated in Figure 6-4 below. The light red and light blue columns represent *qualified* existing and new capacity, while the dark red and dark blue columns represent *cleared* existing and new capacity.

Figure 6-4: Qualified and Cleared Capacity by Resource Type in FCA 12



The difference between qualified existing (light red) and cleared existing (red) generation resources is roughly 1,450 MW. As mentioned above, natural gas-fired resources accounted for 1,200 MW of those dynamic de-lists. As for new generation, 850 MW qualified and 170 MW cleared. The additions came from 80 MW of incremental capacity from two pumped-storage resources, a 58 MW simple cycle gas turbine in SENE, and 21 MW from 52 solar resources across New England.

The highest ratio of qualified to cleared new capacity was among demand response resources. New demand response resources qualified 730 MW of capacity, and cleared 510 MW. This was split between 140 MW of active demand response resources and 370 MW of passive demand response resources.[48] The entry of passive demand response is less likely to be directly driven by capacity market prices, but rather by state public policy goals.

[48] Passive resources include energy efficiency and load reducing distributing generation projects that provide long term peak capacity reduction. Active demand response resources are dispatchable resources that provide reliability during demand response events.