Fall 2018
Quarterly Markets Report

By ISO New England's Internal Market Monitor

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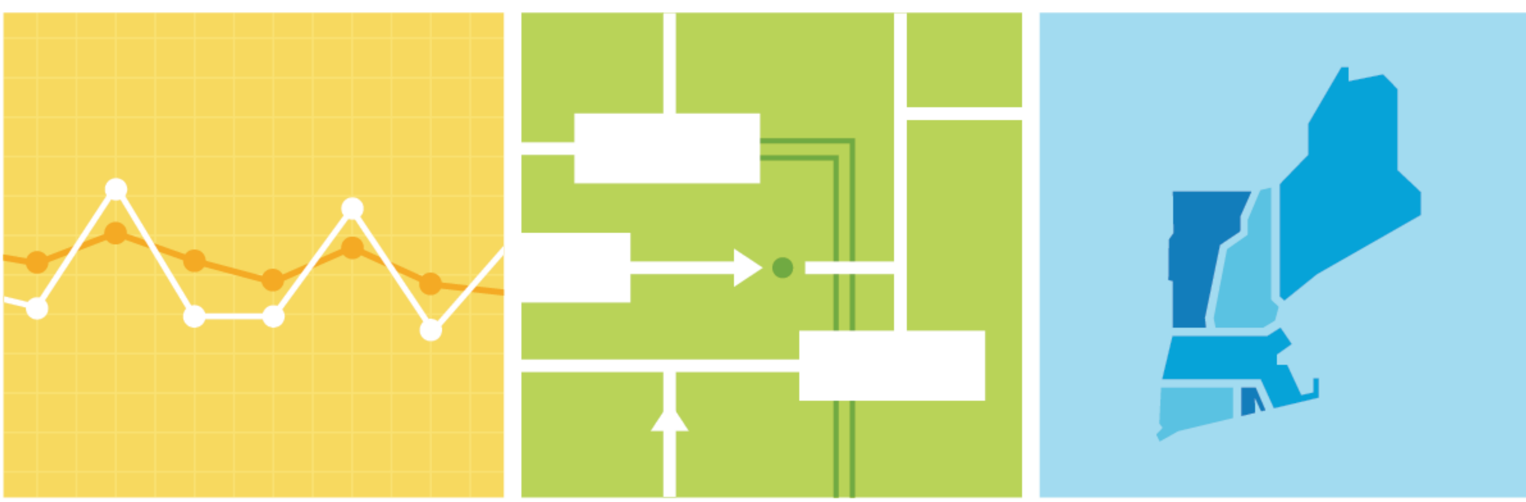

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Preface

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.

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[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.

Contents

Preface iii

Contents iv

Figures v

Tables vi

Section 1 Executive Summary 1

Section 2 Overall Market Conditions 3

2.1 Wholesale Cost of Electricity 4

2.2 Load 5

2.3 Supply 7

2.3.1 Native Generation by Fuel Type 7

2.3.2 Generator Availability 8

2.3.3 Imports and Exports 10

Section 3 Day-Ahead and Real-Time Markets 12

3.1 Energy Prices 12

3.2 Marginal Resources and Transactions 13

3.3 Virtual Transactions 16

3.4 Net Commitment Period Compensation 17

3.5 Real-Time Operating Reserves 20

3.6 Regulation 21

Section 4 Forward Markets 23

4.1 Forward Capacity Market 23

4.2 Financial Transmission Rights 26

Section 5 Unoffered Winter Capacity in the FCM 28

5.1.1 Relevant FCM Obligations 28

5.1.2 Qualified Capacity Determination 29

5.1.3 Analysis of Unoffered Capacity due to Ambient Temperatures 29

5.1.4 Conclusion and Recommendation 31

Figures

Figure 2-1: Wholesale Market Costs and Average Natural Gas Prices by Season 4
Figure 2-2: Percentage Share of Wholesale Cost 5
Figure 2-3: Average Hourly Real-Time Load 6
Figure 2-4: Monthly Average Load and Monthly Total Degree Days 6
Figure 2-5: Seasonal Load Duration Curves 7
Figure 2-6: Share of Native Electricity Generation by Fuel Type 8
Figure 2-7: Average of Total MW Out of Service by Fuel Type 8
Figure 2-8: Fall 2018 vs. Fall 2017 Supply and Demand Curves 9
Figure 2-9: Average Hourly Real-Time Imports, Exports, and Net Interchange 10
Figure 3-1: Simple Average Day-Ahead and Real-Time Hub Prices and Gas Generation Costs 12
Figure 3-2: Simple Average Day-Ahead and Real-Time Prices by Location and Gas Generation Costs 13
Figure 3-3: Real-Time Marginal Units by Fuel Type 14
Figure 3-4: Day-Ahead Marginal Units by Transaction and Fuel Type 15
Figure 3-5: Total Offered and Cleared Virtual Transactions (Average Hourly MW) 16
Figure 3-6: NCPC Payments by Category ($ millions) 18
Figure 3-7: Real-Time Reserve Payments by Product and Zone 20
Figure 3-8: Regulation Payments ($ millions) 21
Figure 4-1: Capacity Payments ($ millions) 25
Figure 4-2: System-wide CC and GT Generator Temperature curve 30
Figure 4-3: Unoffered Capacity and Temperatures from September to November 2018 31

Tables

Table 2-1: High-level Market Statistics 3
Table 3-1: Hours and Level of Non-Zero Reserve Pricing 21
Table 4-1 : Primary and Secondary Forward Capacity Market Prices for the Reporting Period 26

Section 1
Executive Summary

This report covers key market outcomes and the performance of the ISO New England wholesale electricity and related markets for Fall 2018 (September 1, 2018 through November 30, 2018).[3] On Monday, September 3, 2018, the system experienced the first capacity scarcity condition under the ISO's new pay for performance rules. The events of September 3 had notable impacts on Fall 2018 market outcomes.

Wholesale Costs: The total estimated wholesale market cost of electricity was $2.43 billion, an increase of 40% over $1.74 billion in Fall 2017, and an increase of 3% over the previous quarter (Summer 2018).

- Fall 2018 energy costs substantially drove the increase in wholesale market costs.

Energy costs totaled $1.4 billion; a 51% (or $474 million) increase over Fall 2017 costs. Increased energy costs were a result of higher natural gas prices, which increased by 56% relative to Fall 2017 prices. Energy payments totaled $30.7 million on September 3, or about 2% of total energy payments over the season.

- Fall 2018 Forward Capacity Market prices also contributed to the increase in wholesale market costs.

Capacity costs totaled nearly $1 billion, up 28% (by $219 million) over last Fall. Fall 2018 was the second quarter of the the ninth capacity commitment period, which began in June 2018. Compared to the eighth auction, the payment rate for resources increased by 36% in all capacity zones with the exception of SEMA/Rhode Island (from $7.03/kW-month to $9.55/kW-month). As a result of inadequate supply, the payment rate for new and existing resources in SEMA/Rhode Island (20% of total capacity in the ninth auction) was higher than in other zones.

Energy Prices: Day-ahead and real-time energy prices at the Hub averaged $43.21 and $45.35 per megawatt hour (MWh), respectively. The premium in real-time prices was driven by the September 3 shortage event. Excluding September 3 yields an average real-time LMP that was slightly under the day-ahead average, at $42.94/MWh. Both day-ahead and real-time prices were about 50% higher than Fall 2017 prices, on average.

- Day-ahead and real-time energy prices continued to track with natural gas prices.
- Gas prices averaged $4.21/MMBtu in Fall 2018, and increase of 56% compared to $2.70/MMBtu in the prior Fall.
- Gas prices were high in November 2018, averaging $6.32/MMBtu. The impact of high gas prices on LMPs was partially offset by changes in the supply mix relative to November 2017, as higher amounts of imports, coal-fired and hydro generation displaced relatively expensive gas-fired generation.
- Energy market prices did not differ significantly among the load zones.

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

Net Commitment Period Compensation: NCPC payments totaled $11.9 million, a decrease of $2.5 million compared to Fall 2017. NCPC payments represented less than 1.0% of total wholesale energy costs in Fall 2018, down from 1.6% in Fall 2017. The majority of NCPC (80%) was for first contingency protection (also known as "economic" NCPC). The ISO paid out most of the first contingency payments in the real-time market. Nearly a quarter of the real-time first contingency payments ($1.9 million) for Fall 2018 occurred on September 3.

At $1.6 million, local second-contingency protection payments accounted for 13% of total NCPC payments. These payments decreased significantly (by approximately $4 million) relative to Fall 2017, and were primarily paid in the day-ahead market when the ISO committed generators to provide local reliability protection to support planned transmission outages.

Real-time Reserves: Real-time reserve payments totaled $14.1 million. About two-thirds of the reserve payments occurred on September 3. Despite high payments on the day of the shortage event, total real-time reserve payments declined by 16% compared to the Fall 2017 total of $16.8 million. The decrease was driven by lower ten-minute non-spinning and thirty-minute operating reserve payments.

The frequency of non-zero ten-minute spinning reserve pricing in Fall 2018 was greater than in Fall 2017. The average non-zero hourly spinning reserve price increased relative to Fall 2017, from $23.36 to $27.58/MWh.

Regulation**:** Total regulation market payments were $8.9 million, up 21% from $7.4 million in Fall 2017. Regulation payments during the September 3, 2018 shortage event totaled $1.2 million. The increase in regulation payments was driven by higher natural gas and electricity prices in Fall 2018, which affect energy market opportunity costs for generators providing this service.

Forward Capacity Market: During the reporting period, the IMM observed a number of combined-cycle (CC) and gas turbine (GT) resources taking on additional capacity supply obligations (CSOs) and not offering the acquired capacity in the day-ahead and real-time energy markets.

The IMM is concerned that generators may be contracting at, or close to, their maximum capacity (i.e. their winter qualified capacity), as determined by the ISO, even though that capacity is not deliverable in certain months given expected ambient temperatures. We estimate that in October, about 650 megawatts (MW) of CSOs were undeliverable (not offered into the energy market) due to ambient conditions. Combined cycle and gas turbine generators that took on additional capacity obligations for the month accounted over 90% of unoffered capacity.

In the IMM's opinion, resource owners should not increase their CSO positions when there is an expectation that the additional capacity cannot be offered in the energy market. In other words, a resource's winter qualified capacity value should not be the sole determining factor in acquiring additional capacity.

Further, the IMM recommends that the ISO explore changes to the FCM qualification rules that would better align the determination of qualified capacity values with expected ambient temperatures and generator capabilities.

Section 2
Overall Market Conditions

This section provides a summary of key trends and drivers of wholesale electricity market outcomes from Winter 2016 through Fall 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	Fall 2018	Summer 2018	Fall 2018 vs Summer 2018 (% Change)	Fall 2017	Fall 2018 vs Fall 2017 (% Change)
Real-Time Load (GWh)	29,086	34,646	-16%	28,621	2%
Peak Real-Time Load (MW)	24,399	25,944	-6%	20,999	16%
Average Day-Ahead Hub LMP ($/MWh)	$43.22	$33.02	31%	$29.12	48%
Average Real-Time Hub LMP ($/MWh)	$45.37	$33.03	37%	$30.46	49%
Average Natural Gas Price ($/MMBtu)	$4.21	$2.89	46%	$2.70	56%
Average Oil Price ($/MMBtu)	$13.26	$12.74	4%	$9.53	39%

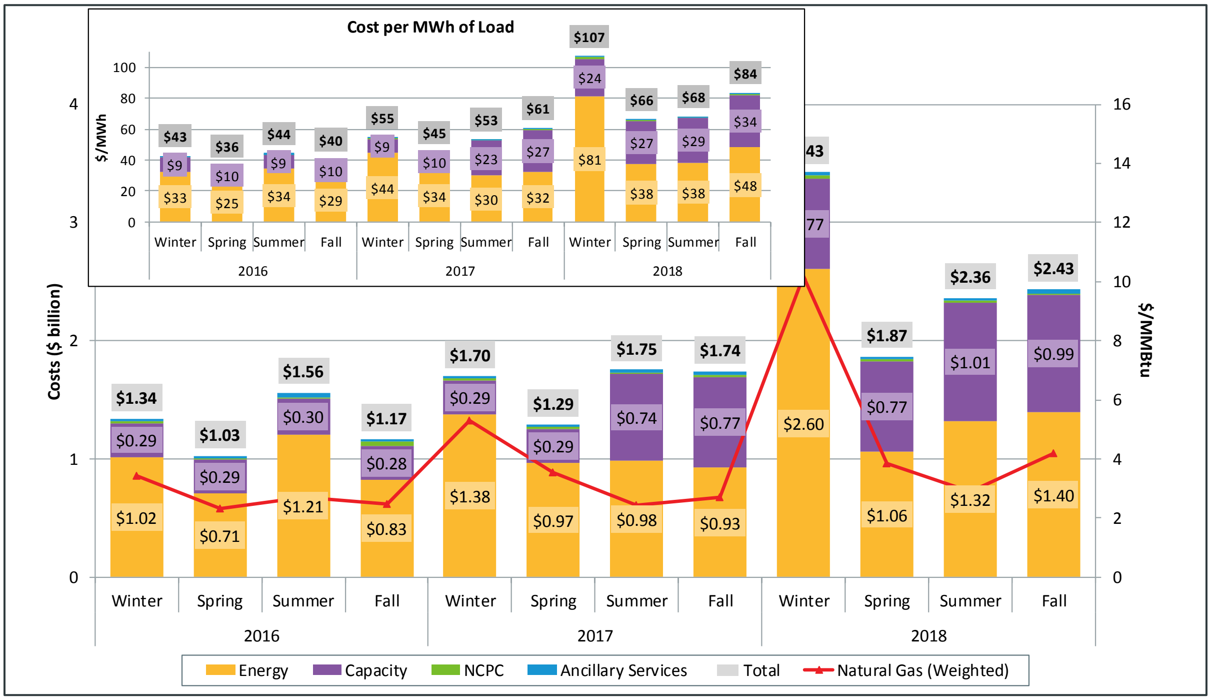
Higher natural gas prices drove the increase in energy costs in Fall 2018 compared to Fall 2017. To summarize the table above:

- Average gas prices in Fall 2018 were $4.21/MMBtu, a 46% increase from Summer 2018, and a 56% increase from Fall 2017. Gas prices increased throughout the country, but New England saw greater price increases due to colder weather and higher pipeline demand. Pipeline demand in New England increased by 22% compared to Summer 2018, and 14% compared to Fall 2017. This was primarily driven by colder temperatures during the second half of November. From November 16-30, 2018, gas prices averaged $8.63/MMBtu, up from $3.46/MMBtu during the same time period in 2017.
- Total real-time load increased by 2% in Fall 2018 (29,806 GWh) compared to Fall 2017 (28,621 GWh). Warmer temperatures in early September and colder temperatures in late November led to higher average loads compared to Fall 2017. The high temperatures on September 3 caused peak load to reach 24,399 MW in Fall 2018; 16% higher than the 20,999 MW peak in Fall 2017. The relationships are discussed further in Section 2.2 below.
- Average day-ahead LMPs in Fall 2018 were $43.22/MWh, 48% higher than in Fall 2017. As discussed above, higher gas prices led to higher LMPs.

2.1 Wholesale Cost of Electricity

The estimated wholesale electricity cost (in billions of dollars) for each season by market, along with average natural gas prices (in $/MMBtu) is shown in Figure 2-1 below. The inset graph shows the wholesale cost per megawatt hour of real-time load served. [4,5]

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



In Fall 2018, the total estimated wholesale cost of electricity was $2.43 billion (or $84/MWh), an increase of 40% compared to $1.74 billion in Fall 2017, and an increase of 3% over the previous quarter (Summer 2018). Natural gas prices continued to be a key driver of energy prices.

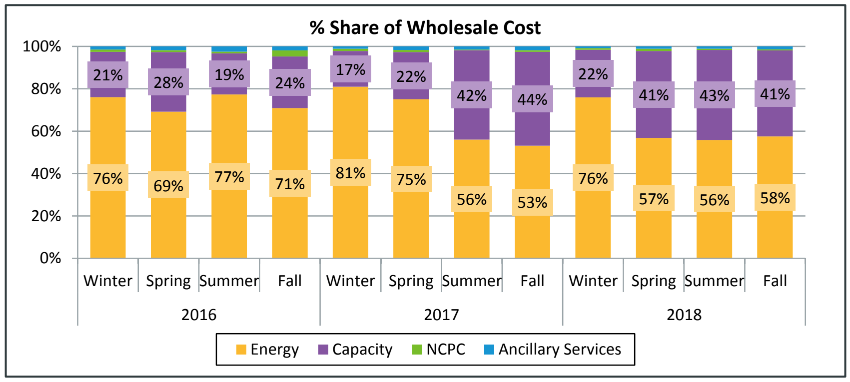
Energy costs were $1.40 billion ($48/MWh) in Fall 2018, 51% higher than Fall 2017 costs, driven by a 56% increase in natural gas prices. The shortage event of September 3 resulted in energy payments of $30.7 million, or about 2% of the total energy costs over the season. Energy costs made up 58% of the total wholesale cost. The share of each wholesale cost component is shown in Figure 2-2.

[4] 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.

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

Capacity costs are driven by clearing prices in the primary capacity auctions, and totaled $988 million ($34/MWh), comprising 41% of total costs. Beginning in Summer 2018, rising capacity market costs contributed to the higher wholesale costs relative to previous quarters. Last year, the capacity payment rate was $7.03/kW-month.[6] This year, the payment rate for new and existing resources increased to $9.55/kW-month in all capacity zones but SEMA/Rhode Island. As a result of inadequate supply, the payment rate in SEMA/Rhode Island was higher than in other zones, at $17.73 and $11.08/kW-month for new and existing resources, respectively. The higher rates caused capacity costs to increase.

Figure 2-2: Percentage Share of Wholesale Cost



At $11.9 million ($0.41/MWh), Fall 2018 Net Commitment Period Compensation (NCPC) costs represented less than 1% of energy costs, a similar share compared to other quarters in the reporting horizon. In dollar terms, NCPC costs were $2.5 million lower than Fall 2017 NCPC costs, and $0.8 million lower than Summer 2018 NCPC costs. Section 3.4 contains further details on NCPC costs.

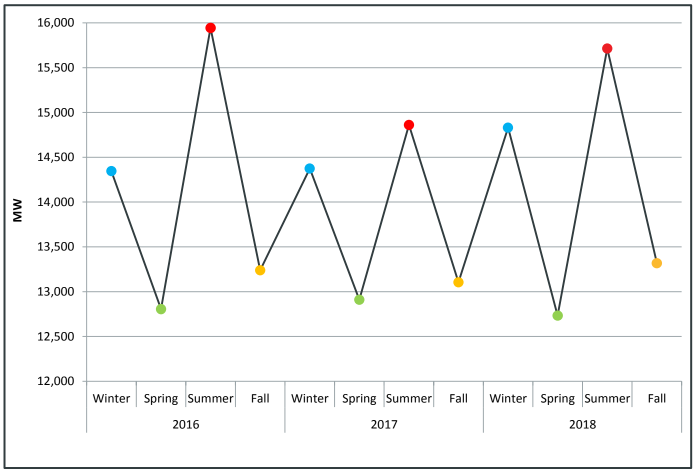
Ancillary services, which include operating reserves and regulation, totaled $33.2 million ($1.14/MWh) in Fall 2018, representing 1% of total wholesale costs. Ancillary service costs increased by 9% compared to Fall 2017, and increased by 31% compared to Summer 2018.

2.2 Load

The return of fall brought cooler temperatures and a decline in average real-time load compared to the hot and humid Summer 2018 season. Average load was higher, however, than the prior two fall seasons due to warmer weather in September (driving cooling load) and colder temperatures in October and November (driving heating load). Average hourly load by season is shown in Figure 2-3 below.

[6] In FCA 8, administrative pricing rules set the capacity payment rate for new and existing resources at $7.03/kW-month.

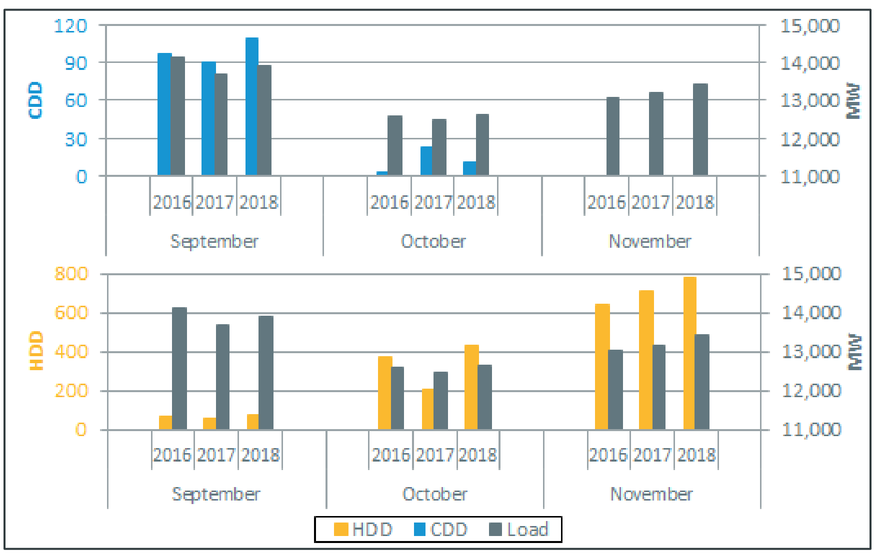
Figure 2-3: Average Hourly Real-Time Load



In Fall 2018, hourly load averaged 13,316 MW, a 15% decrease from Summer 2018. This decline follows the typical seasonal pattern, where load is driven up in the summer by air conditioning demand and then declines in fall as temperatures drop. Comparing Fall 2018 to the two prior fall seasons, shows real-time load averaged 2% above Fall 2017 and 1% higher than average load in Fall 2016.

The monthly breakdown of load over the last three fall seasons is shown in Figure 2-4 below; the top panel compares monthly average load to monthly total cooling degree days (CDD), and the bottom panel shows monthly average load and total heating degree days (HDD).[7]

Figure 2-4: Monthly Average Load and Monthly Total Degree Days

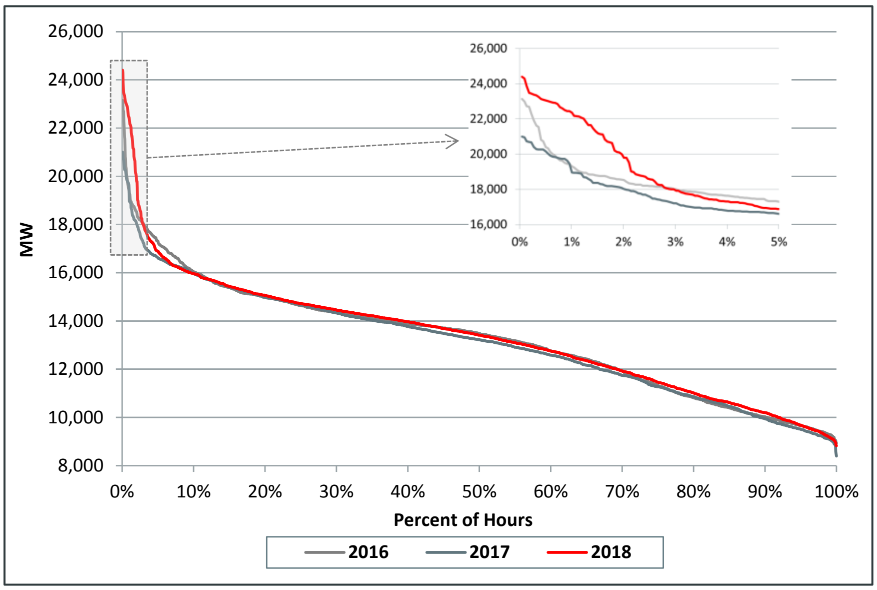


[7] Cooling degree day (CDD) measures how warm an average daily temperature is relative to 65°F and is an indicator of electricity demand for cooling (e.g., air conditioning use). It is calculated as the number of degrees (°F) that each day's average temperature exceeds 65°F. For example, if a day's average temperature is 70°F, the CDD for that day is 5. Similarly, heating degree day (HDD) is an indicator of electricity demand for heating and is calculated as the number degrees in which each day's average temperature was below 65°F. The figure illustrates the sum of all the CDDs or HDDs within a month.

Higher real-time load in September was driven by higher temperatures as indicated by greater monthly total CDDs compared to September 2016 and 2017. Despite September 2018 having higher monthly total CDDs (i.e., warmer temperatures) than September 2016, monthly average load was slightly lower. This can be partly explained by the growth in energy efficiency and behind-the-meter solar generation. In October and November, higher loads were driven by an increase in HDDs as temperatures were cooler relative to the prior years. Note that October had the mildest weather relative to the other months, with lower monthly total CDDs than September and fewer HDDs than November; as a result October saw the lowest average load levels compared to the other months in fall.

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

Figure 2-5: Seasonal Load Duration Curves



During the 5% of hours with the highest load levels, load averaged 19,509 MW, which is 1,549 MW higher than the average for Fall 2017. The increase in peak load was driven by a four-day period of relatively high temperatures (September 3 through 6). The daily high temperature exceeded 85°F on each of these days with September 3 reaching a high above 90°F. Peak load for Fall 2018 occurred on September 6, hitting 24,399 MW in hour ending 16.

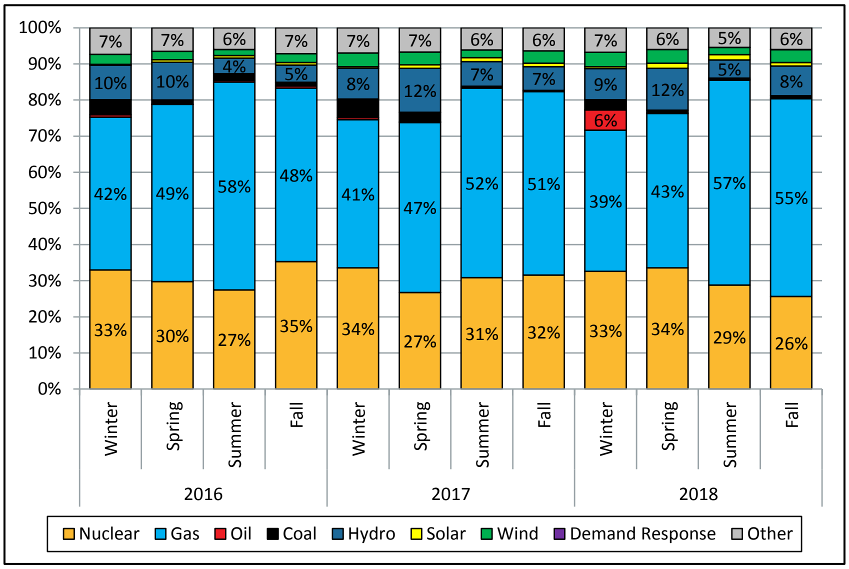
2.3 Supply

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

2.3.1 Native Generation by Fuel Type

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

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

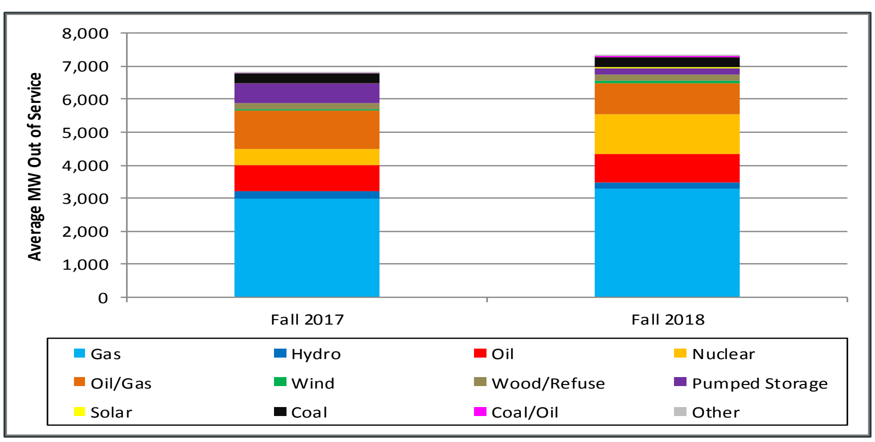


The majority of New England's generation comes from nuclear and gas-fired generation, which together accounted for 80% of total native energy production in Fall 2018. Nuclear production shares fell in Fall 2018 due to refueling outages in October and November. Newly installed natural gas-fired generators contributed to a higher share of natural gas-fired generation in Fall 2018 (55%) compared to Fall 2017 (51%). Hydro and wind generation increased in Fall 2018 (12%) compared to Summer 2018 (7%). This rise was driven by increased precipitation and wind in Fall 2018.

2.3.2 Generator Availability

Along with rising demand and natural gas prices, increased generator outages also contributed to higher average LMPs in Fall 2018 compared to Fall 2017. The average amount of unavailable (out of service) generation[8] by fuel type for Fall 2017 and 2018 is shown in Figure 2-7 below.

Figure 2-7: Average MW Out of Service by Fuel Type

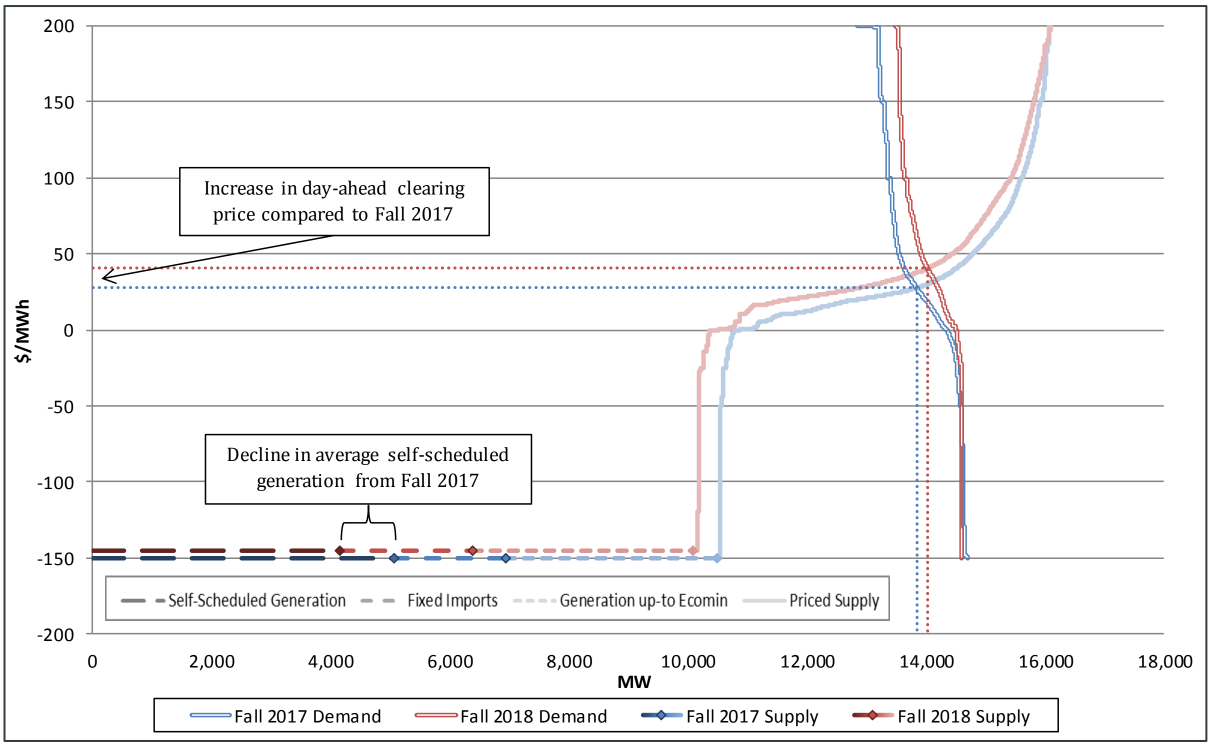


[8] IMM's calculation of capacity out of service includes both planned and unplanned outages. Generation that is offered below the applicable seasonal claimed capability is counted as an unplanned outage.

In Fall 2018, total generator outages averaged about 500 MW greater than Fall 2017 outages. Categorizing generator outages by fuel type helps illustrate whether out of service capacity would have been economic if it had been available. Most notably, there were more nuclear generator outages in Fall 2018 (dark yellow portion of graph). In Fall 2018, nuclear generator outages averaged about 700 MW higher than nuclear outages in Fall 2017, meaning that there was less fixed (price-taking) supply on the system in Fall 2018.

Aggregate day-ahead market supply and demand curves for Fall 2018 and Fall 2017 are presented in Figure 2-8 below. The supply curves are divided into four sections (self-scheduled generation, fixed imports, generation up-to economic minimum [Ecomin], and priced supply).

Figure 2-8: Fall 2018 vs. Fall 2017 Supply and Demand Curves



The increase in outages caused day-ahead self-scheduled generation to decrease relative to Fall 2017 by 916 MW, on average. This decrease in self-scheduled generation effectively shifted the supply curve leftward; all else equal this works to push up LMPs, as it becomes necessary to move farther up the supply curve in order for supply and demand to stay in balance. Two other factors also contributed to higher LMPs. First, natural gas prices increased by 56% from Fall 2017; the impact of this increase was partially offset by higher amounts of imports and coal-fired and hydro generation on the days that saw the highest natural gas prices. Second, as discussed in Section 2.2, demand increased due to a warmer September and colder October and November; this is depcited as the rightward shift in the demand curve relative to Fall 2017 in Figure 2-8.

2.3.3 Imports and Exports

New England was a net importer of power from its neighboring control areas of Canada and New York during Fall 2018.[9] On average, the net flow into New England was about 2,586 MW per hour. In Fall 2018, New England met about 19% of its average real-time load by power imported from New York and Canada. This is slightly higher than the average of the prior 11 seasons (17%). Figure 2-9 shows the average hourly gross import, export and net interchange power volumes by external interface for the last 12 quarters.

Figure 2-9: Average Hourly Real-Time Imports, Exports, and Net Interchange

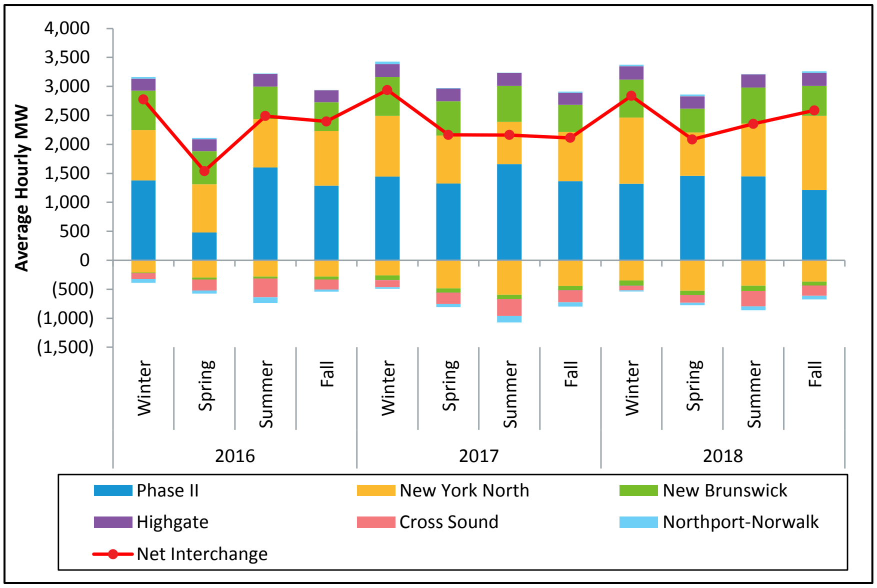


Figure 2-9 illustrates that net interchange and imports generally rise in the summer and winter quarters when New England energy prices and demand tend to be higher. However, the average hourly net interchange value of 2,586 MW was up 10% from Summer 2018, when average hourly net interchange was 2,353 MW per hour. The Fall 2018 net interchange value also reflects a 23% increase from Fall 2017, when average hourly net interchange was 2,100 MW per hour.

One of the primary reasons for the increase in net interchange between Fall 2017 and Fall 2018 is because average net interchange increased by 126% at the New York North interface, from 403 MW per hour in Fall 2017 to 910 MW per hour in Fall 2018. The reasons for this increase are manifold, but a primary factor can be accounted for by considering the spark spread of a natural gas generator that bought its gas in New York and sold its power in New England. The spark spread for generator engaging in such behavior increased by 75% between Fall 2017 and

[9] 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.

Fall 2018 as a result of the percentage change in the price of energy in New England outstripping the percentage change in the price of gas in New York.[10]

The largest percentage of imports into New England in Fall 2018 (39%) came from the New York North interface, where an average of 1,278 MWs were imported. This represents a 41% increase from Summer 2018 (909 MW) and a 51% increase from Fall 2017 (847 MW). Meanwhile, Phase II contributed 37% of the total average hourly imports into New England during Fall 2018. Hourly imports at Phase II in Fall 2018 averaged 1,212 MW, down 16% from Summer 2018 (1,450 MW) and down 11% from Fall 2017 (1,367 MW). This reduction at Phase II is partly explained by outages at this interface in Fall 2018. An unplanned outage at Phase II spanned the majority of September 2018, reducing the import capability of the interface by over half. Subsequent planned outages in October 2018 for major maintenance made the interface completely unavailable for close to a week and significantly limited its import capability for another week.

[10] This calculation used the the day-ahead Transco Zone 6 (NY) price for natural gas, the day-ahead energy price at the New York North Interface (.I.ROSETON 345 1), and an assumed heat rate of 7.8 MMBtu/MWh.

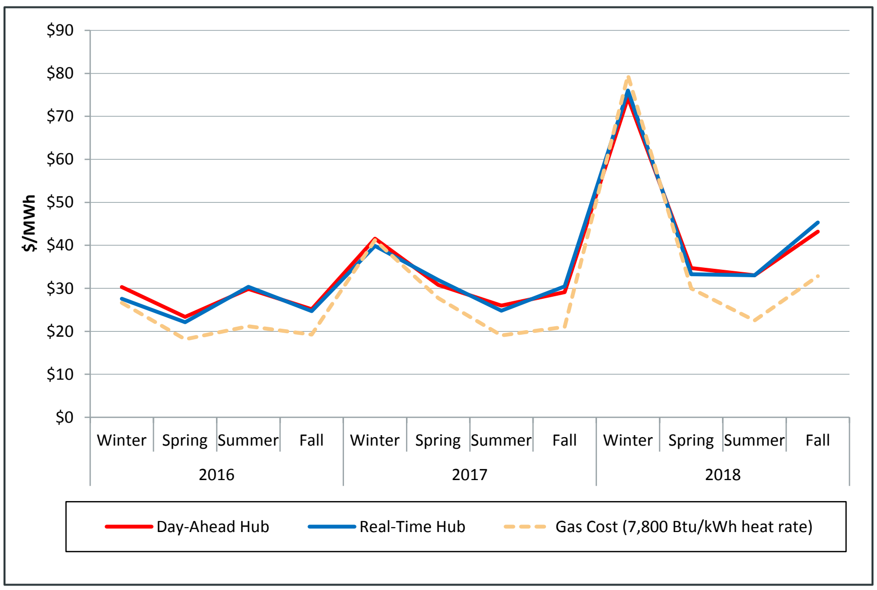
Section 3
Day-Ahead and Real-Time Markets

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

3.1 Energy Prices

The average real-time Hub price for Fall 2018 was $45.35/MWh, which was higher than the average day-ahead price of $43.21/MWh. The premium in the real-time price was driven by the shortage event on September 3; excluding this day yields an average real-time LMP that was slightly under the day-ahead average, at $42.94/MWh. Day-ahead and real-time prices, along with the estimated cost of generating electricity using natural gas, are shown in Figure 3-1 below. The natural gas cost is based on the average natural gas price each season and a generator heat rate of 7,800 Btu/kWh.[11]

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



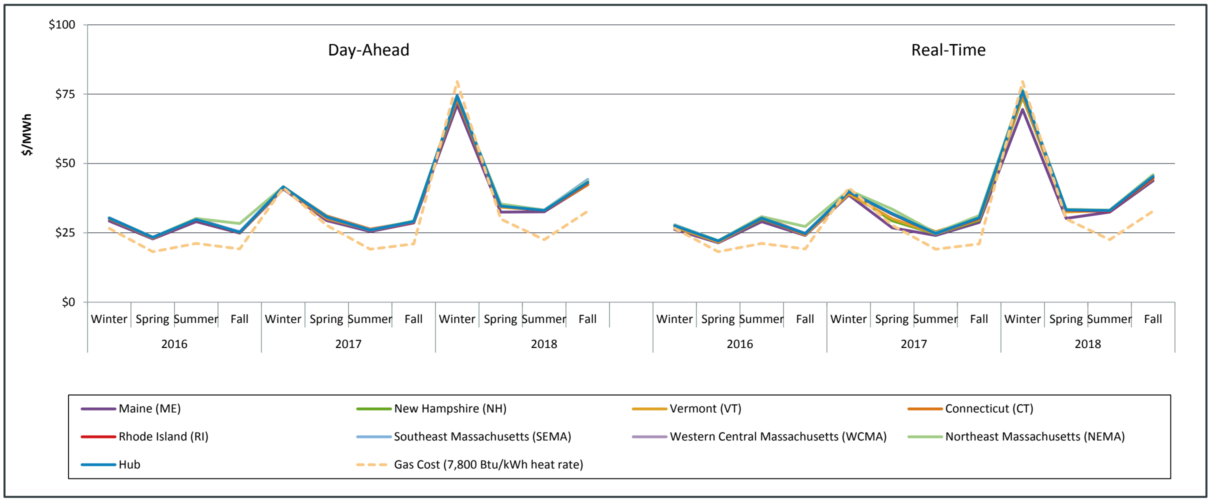
As Figure 3-1 illustrates, the seasonal movements of energy prices (solid lines) are generally consistent with changes in natural gas generation costs (dashed line). The spread between the estimated cost of a typical natural gas-fired generator and electricity prices tends to be highest during the Summer months as less efficient generators, or generators burning more expensive fuels, are required to meet the region's higher demand. Gas costs averaged $33/MWh in Fall 2018. Average electricity prices were higher than average estimated gas costs in Fall 2018, and the spread was greater than in previous fall seasons. In Fall 2018, average day-ahead Hub LMPs were $10/MWh higher than average estimated gas costs, compared to $8/MWh and $6/MWh higher in Fall 2017 and Fall 2016, respectively. Higher loads and an increase in nuclear generator outages in Fall 2018 contributed to the higher spread between LMPs and gas costs.

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

In Fall 2018, average day-ahead and real-time prices were higher than Fall 2017 prices, by about $14 and $15/MWh, respectively. This is consistent with the change in natural gas prices, which increased by 56%. Gas prices were particularly high in November 2018, averaging $6.32/MMBtu. During this month, the impact of high gas prices on LMPs was partially offset by changes in the supply mix relative to November 2017. In November 2018, the system saw increased imports from New York, as well as increases in coal-fired and hydro generation.

The seasonal average day-ahead and real-time energy prices for each of the eight New England load zones 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



Prices did not differ significantly among the load zones in either market.[12] In the day-ahead market, the Maine average price was $0.84/MWh (2%) lower than the Hub. Price separation in Maine was generally consistent with the price separation observed in real-time, with prices $1.60/MWh (4%) lower than Hub prices, on average. Wind generators with lower marginal costs are located in export-constrained areas of northern New England and often set real-time prices in Maine, with a greater frequency in the winter, spring, and fall. Additionally, planned transmission outages further constrained exports and contributed to slightly lower prices in Maine in Fall 2018.

3.2 Marginal Resources and Transactions

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

In this section marginal units by transaction and fuel type are reported on a load-weighted basis. The methodology accounts for the contribution that a marginal resource makes to overall price paid by load. When more than one resource is marginal, the system is typically constrained and marginal resources likely do not contribute equally to meeting load across the

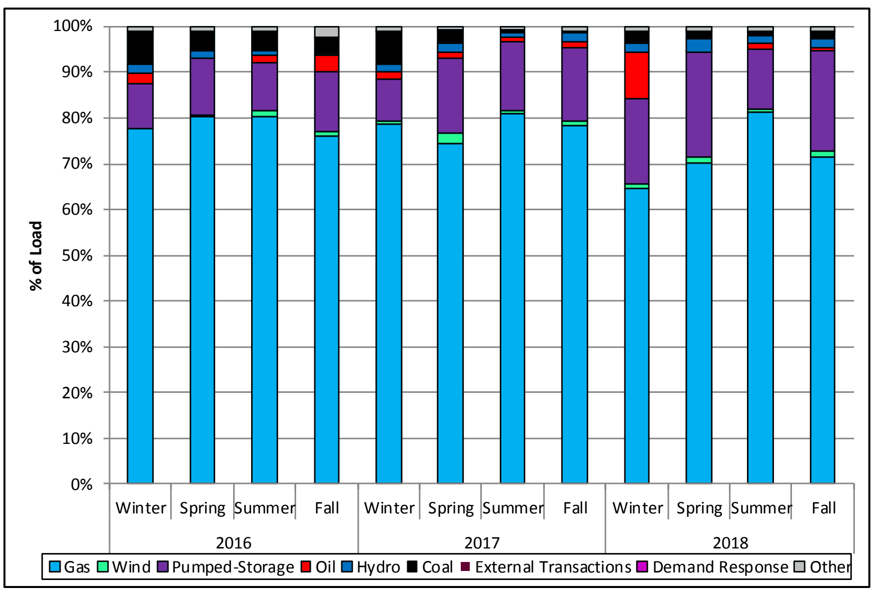
[12] A load zone is an aggregation of pricing nodes within a specific area. There are currently eight load zones in the New England region, which correspond to the reliability regions.

system. For example, resources within an export-constrained area are not able to fully contribute to meeting the load for the wider system. Consequently, the impact of these resources on the system LMP is muted. For this reason, the graphs below now show results for load-weighted marginal resources.

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.[13] Note that with implementation of the price-responsive demand (PRD) project on June 1, 2018, demand response resources are now eligible to be marginal and set price; in Fall 2018, they were rarely marginal in real-time or day-ahead (< 1% of the time).

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



Natural gas-fired generators set price for about 70% of total load in Fall 2018, which is a decrease from Summer 2018 and lower than the prior two fall seasons. This decline was offset by an increase in share of load for which pumped-storage was marginal. Energy from gas-fired generators also accounted for more than half of native generation, and is often the lowest cost fossil fuel type generation. This implies that gas-fired generators will typically operate more often than coal- or oil-fired generators, as generators are committed and dispatched in merit order. Most of the time, more expensive coal- and oil-fired generators are not required to meet system demand. Because gas-fired generators are often the most expensive units operating, they set price frequently.

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

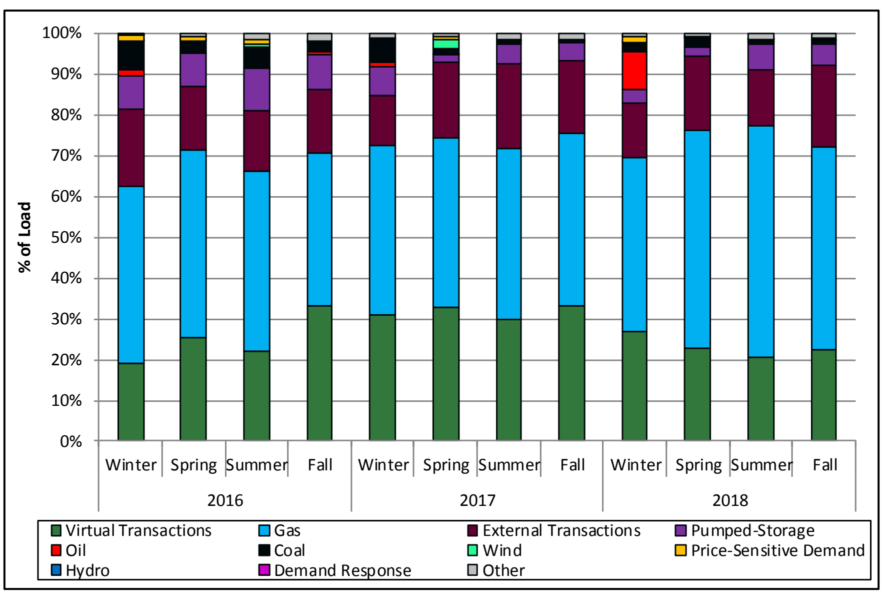
In addition to their relative cost, many gas-fired generators are eligible to set price due to their dispatchable range. By contrast, nuclear generation accounts for about one third of native generation in New England, but does not set price. Nuclear generators in New England are offered at a fixed output,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

Pumped-storage units (generators and demand) set price for about 22% of total load in Fall 2018, which is an increase compared to the prior two fall seasons. This increase was primarily a result of pumped-storage units being marginal more often during October and November relative to the same months in the two prior fall seasons. Pumped-storage units generally offer energy at a price that is close to the margin. They are often called upon when conditions are tight due to their ability to start up quickly and their relatively low commitment costs compared with fossil fuel-fired generators. Because they are online relatively often and priced close to the margin, they can set price frequently.

Wind generators set price for the entire system less than 1% of the time. However, wind generators are frequently marginal in *local export-constrained areas*, where the impact on the average load price is limited. Wind generators located in an export-constrained area can only deliver the next increment of load to a small number of locations located within the export-constrained area. This is because the transmission network that moves energy out of the 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.

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



Gas-fired generators were the most frequent marginal resource type in the day-ahead market; they set price for 50% of total day-ahead load in Fall 2018. This an increase compared to the prior two fall seasons, when gas was marginal for about 40% of day-ahead load. Just as gas-fired generators are the most frequent marginal fuel type in the real-time market, they make up

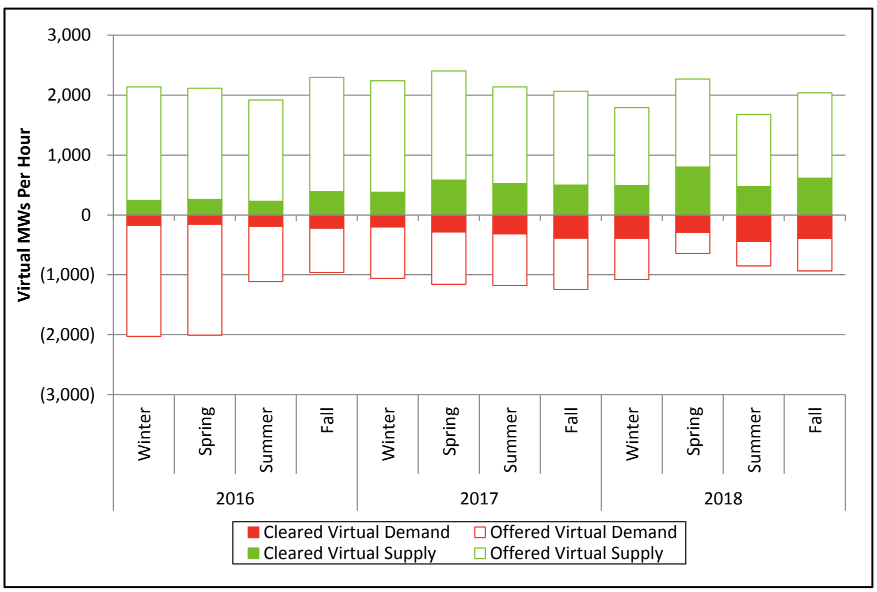
most of marginal *generation* in the day-ahead market as well. Generators as a group comprised about 57% of all marginal entities in the day-ahead market.

Virtual transactions set price for 22% of day-ahead load in Fall 2018 (13% virtual supply, 9% virtual demand). This is a decline compared to Fall 2017 when virtual transactions were marginal for 33% of load (17% virtual supply, 16% virtual demand). Although there was an increase in virtual transactions that cleared compared to Fall 2017, there were fewer virtual transactions that were marginal. Virtual transactions are a day-ahead market product that profit by arbitraging differences between day-ahead and real-time energy prices. When a systematic difference between the day-ahead and real-time markets emerges, virtual transactions are one mechanism through which the day-ahead market can adjust to better reflect real-time conditions. Virtual transactions can offer at any price and many are offered around the margin. Virtual transactions also have a high propensity to be marginal because they do not have operational constraints, which generally limit the ability to be marginal.[14]

3.3 Virtual Transactions

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

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



In Fall 2018, total offered virtual transactions averaged approximately 2,973 MW per hour, which was 18% more than the average amount offered in Summer 2018 (2,527 MW per hour) and 10% less than the average amount offered in Fall 2017 (3,308 MW per hour). In general, the average amount of offered virtual transactions has decreased over the 12-quarter period covered in this report, falling by 29% from Winter 2016 (4,162 MW per hour) to Fall 2018 (2,973 MW per hour). This decline is most pronounced for offered virtual demand, which has

[14] 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.

decreased by 54% relative to the Winter 2016 level (from 2,024 MW per hour in Winter 2016 to 934 MW per hour in Fall 2018). The amount of offered virtual supply has only decreased by 5% over the same period (from 2,137 MW per hour in Winter 2016 to 2,038 MW per hour in Fall 2018).

On average, 1,007 MW per hour of virtual transactions cleared in Fall 2018, which represents an increase of 10% compared to Summer 2018 (916 MW per hour) and an increase of 14% compared to Fall 2017 (887 MW per hour). In general, the average amount of cleared virtual transactions has increased over the 12-quarter period covered in this report, rising by 141% from Winter 2016 (418 MW per hour) to Fall 2018 (1,007 MW per hour). Cleared virtual supply has increased by 153% (from 243 MW per hour to 615 MW per hour) over this 12-quarter period, while cleared virtual demand has increased by 125% (from 174 MW per hour to 391 MW per hour).

Beginning in Summer 2016, the average offer prices of virtual transactions have converged towards actual LMPs, resulting in higher percentages of virtual transactions clearing. In general, the percent of cleared virtual transactions has grown nearly every quarter over the reporting period, rising from 10% in Winter 2016 to 34% in Fall 2018. The growth is likely attributable to a reduction in transaction costs, in the form of reduced NCPC charges, to virtual transactions.[15]

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

This creates an 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

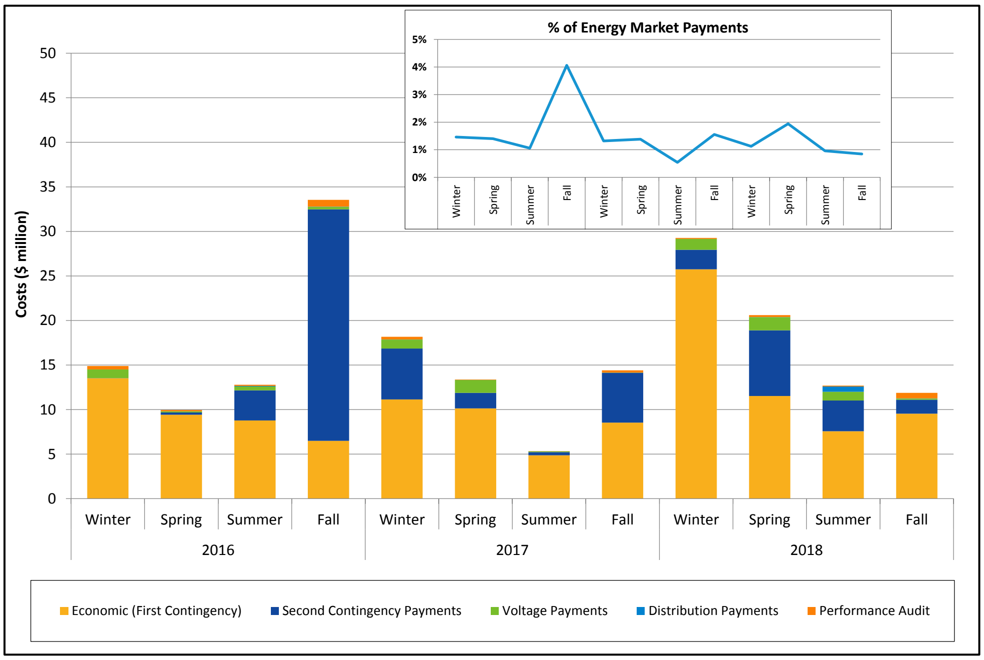
Net Commitment Period Compensation (NCPC), commonly known as uplift, is a make-whole payment provided to resources when energy prices are insufficient to cover production costs. Uplift may be required for resources committed and dispatched economically. It may also be required for resources dispatched out of economic-merit order for reliability purposes. Uplift is made to resources that provide a number of services, including first- and second-contingency

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

protection, voltage support, distribution system protection, and generator performance auditing.[16]

Decreases in LSCPR and voltage NCPC payments in Fall 2018 relative to Summer 2018 more than offset the $2.0 million increase in economic NCPC payments, keeping total Fall 2018 uplift payments in line with payments from the prior quarter. These payments are illustrated by season and category in Figure 3-6 below. The inset graph shows uplift payments as a percentage of total energy payments.

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



Total uplift payments made in Fall 2018 fell by 6% from Summer 2018, down from $12.7 million to $11.9 million. Uplift payments were also down relative to payments in Fall 2017, when payments totaled $14.4 million. As shown in the inset graph in Figure 3-6, Fall 2018 uplift payments fell within a normal range of historic values when expressed as a percentage of total wholesale energy market costs. Fall 2018 uplift payments represent 0.8% of the total wholesale energy market costs, down from 1.0% in Summer 2018 and from 1.6% in Fall 2017.

The vast majority of uplift (80%) incurred during the reporting period was for first contingency protection ($9.5 million). About 80% of the total first contingency payments ($7.6 million) were paid in the real-time market, while the other 20% ($1.9 million) were paid in the day-ahead market. Nearly a quarter of the real-time first contingency NCPC ($1.9 million) incurred during the reporting period was from September 3, when tight system conditions resulted in real-time prices in excess of $2,500/MWh. A large portion of

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

the real-time first contingency NCPC payments made on this day came in the form of NCPC credits that are based on lost opportunities (i.e., dispatch lost opportunity cost NCPC, rapid response pricing opportunity cost NCPC, and posturing NCPC) as these tend to be higher when real-time prices are higher. Additionally, more traditional "make-whole" NCPC payments were made to numerous generators on this day that were committed in the real-time but were unable to recover their effective offer costs despite the high energy prices.[17]

The next largest category of uplift (13%) incurred during the reporting period was for local second-contingency protection (LSCPR). Total LSCPR payments of $1.6 million were down 55% from the Summer 2018 total of $3.5 million and also down from the $5.6 million paid in Fall 2017. During Fall 2017, $4.6 million of LSCPR payments went to generators in NEMA/Boston, many of which were needed to support transmission work being done as part of the Greater Boston Reliability Project, a multi-faceted project to bolster the electrical system in Northeastern Massachusetts. As various transmission upgrades related to the project have been completed over the last year, and new generators within the region have become commercial, the need for reliability commitments within NEMA/Boston has diminished. The vast majority (83%) of LSCPR uplift paid this reporting period was in the day-ahead market as the need for local reliability protection can often be anticipated based on planned transmission outages. Over 40% ($0.7 million) of the LSCPR payments in Fall 2018 went to generators located in Maine that were required to support planned transmission outages, while another 37% ($0.6 million) went to generators in Southeastern Massachusetts. In total, 22 different generators received LSCPR payments in Fall 2018.

Voltage uplift payments in Fall 2018 totaled $135 thousand. This represents an 86% decrease from the $1.0 million paid in Summer 2018, but a significant increase from the $26 thousand paid in Fall 2017. Like LSCPR commitments, generator commitments for voltage support can often be anticipated in the day-ahead market based on planned transmission outages. In Fall 2018, 90% ($122 thousand) of the voltage NCPC was paid in the day-ahead market. This contrasts with Summer 2018, when the vast majority (86%) of voltage uplift payments were made in the real-time market. The primary reason for this unusual deviation in Summer 2018 was because of a large payment to a generator committed in real-time to provide voltage support in NEMA/Boston on June 10. This generator received $0.8 million of voltage uplift on that day.

Distribution uplift payments in Fall 2018 ($16 thousand) were drastically lower than Summer 2018 ($0.6 million), when two oil-fired generators on Martha's Vineyard were frequently required by the local distribution company to prevent overloading a cable bringing power to the island.

Audit (GPA) uplift payments totaled $628 thousand in Fall 2018. Audit uplift payments tend to be higher in the fall when many dual-fuel generators are audited by the ISO to prove their capability using more expensive fuel oil.

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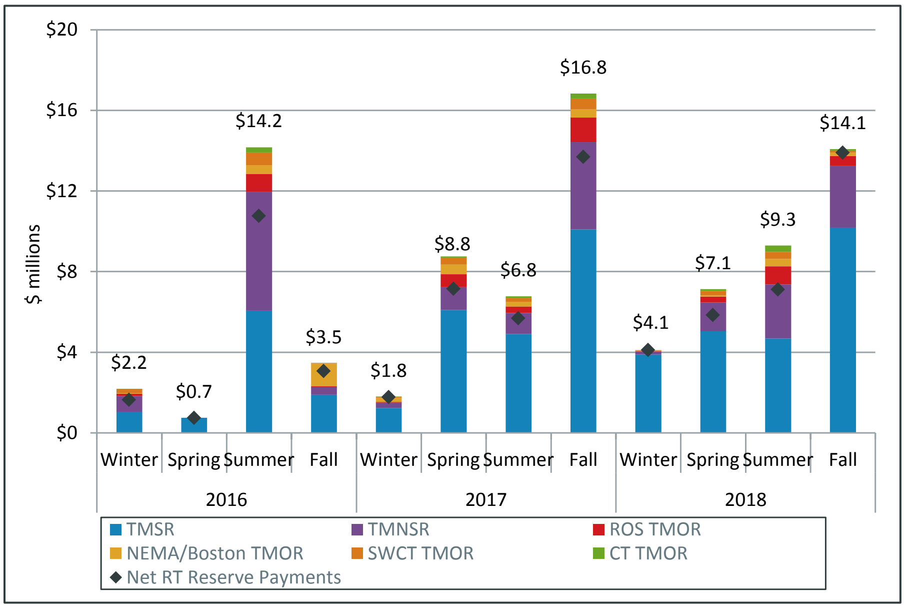
[17] For more information about the NCPC payments that arose on September 3, 2018, see the IMM's Summer 2018 Quarterly Markets Report: https://www.iso-ne.com/static-assets/documents/2018/12/2018-summer-quarterly-markets-report.pdf

3.5 Real-Time Operating Reserves

A key driver of real-time reserve payments in Fall 2018 was the shortage event on September 3. Of the $14.1 million in reserve payments made in Fall 2018, about $9 million (about two-thirds) occurred on that day. Real-time reserve payments by product and by zone are illustrated in Figure 3-7 below. Real-time reserve payments to generators designated to satisfy forward reserve obligations are reduced by a forward reserve obligation charge so that a generator is not paid twice for the same service. Net real-time reserve payments, which were $13.9 million in Fall 2018, are shown as black diamonds in Figure 3-7.

Figure 3-7: Real-Time Reserve Payments by Product and Zone



Despite the relatively high amount of payments made for September 3, real-time reserve payments were down $2.8 million (16%) from Fall 2017. The decline resulted from a decrease in ten-minute non-spinning reserves (TMNSR) payments and thirty-minute operating reserve (TMOR) payments. The relatively large TMNSR and TMOR payments in Fall 2017 resulted from a four-day period of warm weather and scheduled generation outages in late September 2017 that led to low reserve margins and high reserve prices. Consistent with previous seasons, ten-minute spinning reserves (TMSR) payments made up a majority of the total payment ($10.2 million), followed by TMNSR payments ($3.1 million) and TMOR payments ($0.8 million).

The frequency of non-zero reserve pricing by product and zone along with the average price during these intervals for the past three Fall seasons is provided in Table 3-1 below. [18]

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

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

Product	Zone	Fall 2016		Fall 2017		Fall 2018	
		Hours of Non-zero Pricing	*Avg. Price $/MWh*	*Hours of Non-zero Pricing*	*Avg. Price $/MWh*	*Hours of Non-zero Pricing*	*Avg. Price $/MWh*
TMSR	System	100.8	$10.21	373.9	$23.36	436.1	$27.58
TMNSR	System	0.1	$0.98	4.5	$11.67	3.2	$11.68
TMOR	System	1.4	$0.96	28.7	$10.46	6.8	$7.72
	NEMA/Boston	90.8	$28.48	4.6	$11.13	0.3	$7.72
	CT	0.0	$0.96	0.0	$10.46	0.0	$7.72
	SWCT	0.0	$0.96	0.0	$10.46	0.0	$7.72

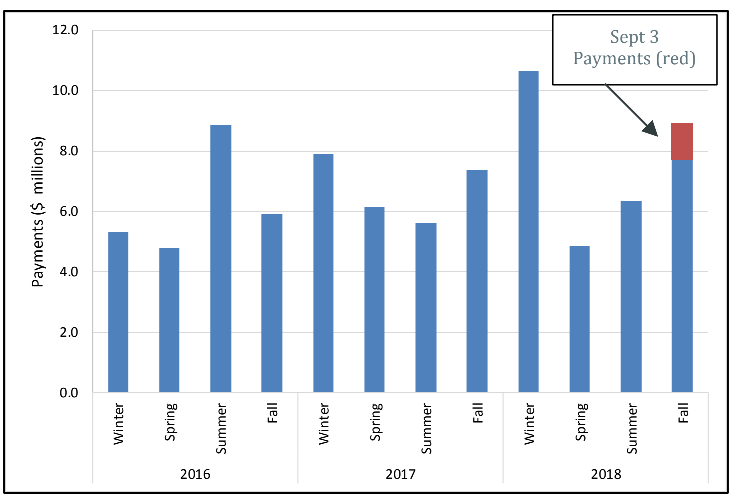
The TMSR clearing price was above zero (i.e., there was non-zero reserve pricing) in 436.1 hours (20% of total hours) during Fall 2018, greater than the hours of non-zero reserve pricing in the two prior fall seasons. In the hours when the TMSR price was above zero, the price averaged $27.58/MWh, an increase from the prior seasons and consistent with the rise in real-time energy prices. More hours of non-zero reserve pricing, combined with a higher average TMSR price, helps explain the increase in TMSR payments compared to the prior fall seasons.

The majority of hours of non-zero TMNSR pricing and TMOR pricing shown in Table 3-1 occurred during the shortage event on September 3. Of the 3.2 hours of non-zero TMNSR pricing shown in Table 3-1, about 2.4 hours were on September 3; similarly, of the 6.8 hours of non-zero TMOR pricing during Fall 2018, 5.3 hours were on that day.

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.[19]

Figure 3-8: Regulation Payments ($ millions)



[19] 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.

Total regulation market payments were $8.9 million during the reporting period, up by about 40% from $6.3 million in Summer 2018, and up by just by over 20% from $7.4 million in Fall 2017. The shortage event in the real-time energy market on September 3 had a significant impact on regulation payments in Fall 2018, resulting in $1.2 million in payments for a single day (shown as the red portion of the bar). The payments on September 3 reflect the very high energy market revenues that regulation resources gave up while providing regulation.

Excluding the September 3 results, the increase in regulation payments for Fall 2018 was more modest compared to Fall 2017, at about 5% ($0.4 million). Fall 2018 payments increased 21.7% ($1.4 million) relative to Summer 2018; this increase reflects much higher natural gas and electricity prices in Fall 2018, which affect energy market opportunity costs for generators providing regulation.

Section 4
Forward Markets

This section covers activity in the Forward Capacity Market (FCM) and in Financial Transmissions Rights (FTRs).

4.1 Forward Capacity Market

The Forward Capacity Market (FCM) is a long-term market designed to procure the resources needed to meet the region's local and system-wide resource adequacy requirements.[20] 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.

The ISO introduced Pay-for-Performance (PFP) rules beginning on June 1, 2018 to incent reliable operation during scarcity conditions.[21] Prior to June 1, 2018, resource owners faced de minimis financial penalties when unable to perform during periods of scarcity. The PFP rules improve the underlying market incentives by replicating performance incentives that exist in a fully functioning and uncapped energy market. Pay-for-performance rules provide a two-settlement construct that links payments to performance during scarcity conditions. Without this linkage, participants lack the incentive to make investments that ensure their resources perform when needed most. Also, absent these incentives, participants that have not made investments to ensure their resources' reliability are more likely to clear in future FCAs because they can offer at lower prices. This can create a structural bias in the FCM to clear less reliable resources, which, over time, erodes system reliability. Paying for actual performance during scarcity conditions incents resource owners to make investments and perform routine maintenance to ensure resource readiness to provide energy or operating reserves during scarcity conditions.

Pay-for-performance works as follows: a resource owner is compensated for that resource's capacity supply obligation (CSO) held in a given month, but is subject to adjustments based on its performance during scarcity conditions. The PFP design replaced the shortage event rules in place through May 31, 2018. PFP is based on a two-settlement market built around the delivery of energy and operating reserves when they are needed most. If a resource fails to perform relative to expectations, it must buy the difference back at a performance payment rate. Under-performers compensate over-performers, with few exceptions.[22] Additionally, energy market only assets (known as PFP-only resources) are compensated for their contribution to load and reserve requirements. Since they hold no CSO, PFP-only resources cannot under-perform and receive compensation for over-performance during scarcity conditions.

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

[21] A scarcity condition occurs for the system or for certain capacity zones in five-minute increments. For more information, see Section III.13.7.2.1 of the tariff.

[22] Energy efficiency resources are provided an exemption during off-peak periods. See III.13.7.2.2 of the tariff for actual capacity provided calculations.

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.[23] Between the initial auction and the commitment period, there are six discrete opportunities to adjust annual 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 CSOs traded in each commitment period.

The Fall 2018 reporting period falls within the capacity commitment period (CCP) that started on June 1, 2018 and will end on May 31, 2019. In the corresponding Forward Capacity Auction (FCA 9), the ISO introduced a sloped zonal demand curve. This means that cleared demand could exceed the Net Installed Capacity Requirement (NICR).[24]

In FCA 9, conditions existed which caused the capacity zones and external interfaces to close at different rounds and prices:

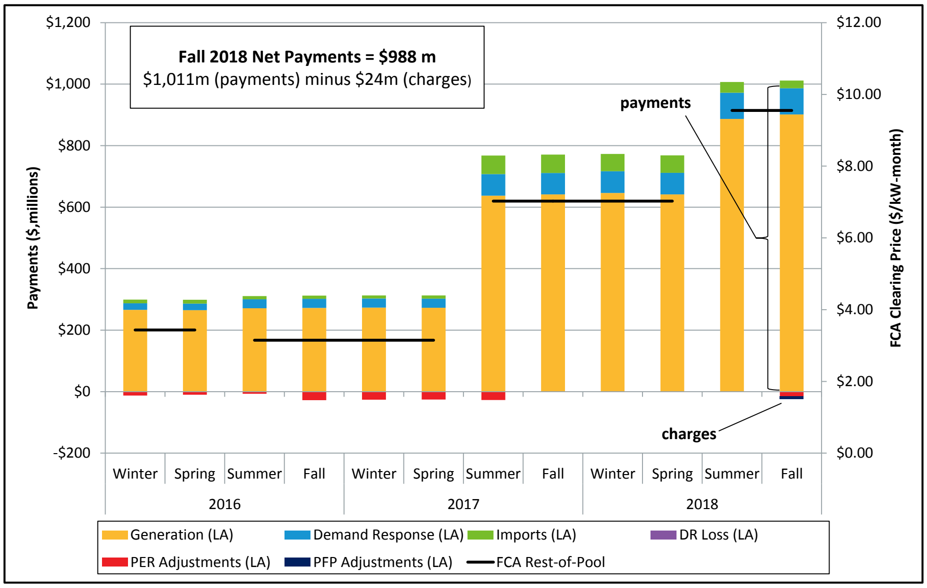
- The auction did not run in the SEMA/Rhode Island capacity zone, as conditions were met to trigger inadequate supply. As a result, the payment rate for existing resources located in SEMA/Rhode Island was set to the Net Cost of New Entry (or net CONE) of $11.08/kW- month, and the payment rate for new resources was set to the FCA 9 starting price ($17.73/kW-month).
- The rest of the system (with the exception of New York AC Ties and New Brunswick Interfaces) closed in round three with a payment rate of $9.55/kW-month.
- New York AC Ties closed in round four with a payment rate of $7.97/kW-month.
- New Brunswick closed in round five with a payment rate of $3.94/kW-month, which concluded the auction.

Total FCM payments, as well as the clearing prices for Winter 2016 through Fall 2018, are shown in Figure 4-1 below. The black lines (corresponding to the right axis, "RA") represent the FCA clearing prices for existing resources in the Rest-of-Pool capacity zone. The orange, blue, and green bars (corresponding to the left axis, "LA") represent payments made to generation, demand response, and import resources, respectively. The red bar represents reductions in payments due to Peak Energy Rent (PER) adjustments. The dark blue bar represents Pay-for-performance adjustments.

[23] 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.

[24] For a detailed IMM review of FCA 9, see the Q1 2015 report: https://www.iso-ne.com/static-assets/documents/2015/06/q1_2015_qmr_for_publication_0609.pdf

Figure 4-1: Capacity Payments ($ millions)



Total net FCM payments increased significantly from the prior fall. In Fall 2018, capacity payments totaled $988 million, which accounts for adjustments to primary auction CSOs.[25] New and existing resource payment rates outside of SEMA/Rhode Island increased 36%, from $7.03/kW-month payments in the last four quarters to $9.55/kW-month in Fall 2018 due to the higher clearing price in FCA 9. Payments to import resources declined, shifting to generation resources. The shift is due to lower prices at the external interfaces, and new generation resources that cleared in FCA 9.

Payments fell compared to Summer 2018 due to reductions resulting from the September 3 event. PER adjustments totaled $14.8 million in Fall 2018. Peak Energy Rent payments related to the September 3 event will cost resources about $7 million a month through June 2019, totaling approximately $56 million.[26]

Pay-for-Performance adjustments totaled $8.8 million, largely due to rules that exempt energy efficiency resources from performance charges. This resulted in an under-collection of performance charges, with capacity resources making up the difference based on a prorated amount of their capacity supply obligation.[27] The under-collection totaled roughly $7.9 million, which is reflected in the $8.8 million in charges during the quarter.

Secondary auctions allow participants the opportunity to buy or sell capacity after the initial auction. A summary of prices and volumes associated with reconfiguration auction and bilateral trading activity during Fall 2018, alongside the results of the relevant primary FCA are detailed in Table 4-1 below.

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[25] 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.

[26] For more information, see Section 5 of our Summer 2018 report. https://www.iso-ne.com/static-assets/documents/2018/12/2018-summer-quarterly-markets-report.pdf

[27] For more information, see Section 5 of our Summer 2018 report. https://www.iso-ne.com/static-assets/documents/2018/12/2018-summer-quarterly-markets-report.pdf

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

FCA # (Commitment Period)	Auction Type	Period	Systemwide Price ($/kW-mo)**	Cleared MW	Capacity Zone/Interface Prices ($/kW-mo) SEMA/RI	New Brunswick	New York AC Ties
FCA 9 (2018-19)	Primary	12-month	9.55	34,695	17.73/11.08*	3.94	7.97
	Monthly Reconfiguration	Nov-18	1.01	556			
	Monthly Bilateral	Nov-18	2.01	664			
	Monthly Reconfiguration	Dec-18	0.96	724			
	Monthly Bilateral	Dec-18	2.14	545			
	Monthly Reconfiguration	Jan-19	1.26	954			
	Monthly Bilateral	Jan-19	2.14	625			

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

***bilateral prices represent volume weighted average prices*

Three monthly reconfiguration auctions took place in Fall 2018. Cleared volume increased from 556 MW in November 2018, to 724 MW in December 2018, and then 954 MW in January 2019. There are two factors contributing to increased trade volumes in the monthly auctions. First, thermal generators tend to offer incremental winter qualified capacity that they cannot offer into the summer periods at low prices. Second, participants submitted more demand bids at higher prices compared to prior auctions. The increase in supply offers, coupled with more demand bids led to increased clearing volumes.

4.2 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.[28] FTRs are sold in annual and monthly auctions, both of which conduct separate auctions for on-peak and off-peak hours. The amount of FTRs awarded in each auction is based on a market feasibility test that ensures that the transmission system can support the awarded set of FTRs during the period. FTRs awarded in one of the two annual auctions have a term of one year. The remaining feasible FTRs are made available in monthly auctions, each having a term of one month. FTR auction revenue is distributed to Auction Revenue Rights (ARRs) holders, who are primarily congestion-paying Load Serving Entities (LSEs) and transmission customers.

All FTR holders are compensated on a monthly basis through the congestion revenue fund, which is the collection of congestion costs in the day-ahead and real-time energy market for that month. Because congestion costs are based on actual system conditions, the congestion

[28] 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 withdrawn from the New England grid) and the point of receipt (where power is injected onto 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.

revenue fund can be larger or smaller than the positive target allocations to FTR holders.[29] If the congestion revenue fund for a month is less than the total positive FTR target allocation for that month, the payments to FTR holders are prorated. If there is excess revenue in the congestion revenue fund at the end of the year, any monthly deficiency is made up to the extent possible.

The monthly auctions for September 2018, October 2018, and November 2018 resulted in a combined total of 84,800 MW of FTR transactions. The total auction revenue for these three months was $2.83 million, which represents a 4% decrease compared to Summer 2018 ($2.97 million) and an 11% increase compared to Fall 2017 ($2.55 million). The increase in auction revenue relative to the prior fall period can be a function of many factors, including: (i) higher levels of anticipated congestion on the system and (ii) an increase in auction participant's willingness to pay for FTRs. Twenty-eight bidders participated in the September 2018 auction, while 29 bidders participated in both the October 2018 and November 2018 auctions. The level of participation was consistent with recent auctions.

FTRs in September 2018, October 2018, and November 2018 were fully funded, meaning that enough congestion revenue and revenue from negative target allocations was collected to pay the positive target allocations in those months. In fact, there was a surplus in each of these months: $1.93 million in September 2018, $0.81 million in October 2018, and $2.11 million in November 2018. Surpluses like these are carried over until the end of the year, when they are used to pay any unpaid monthly positive target allocations, like those in June 2018. Any remaining excess at the end of the year is then allocated to those entities that paid the congestion costs.

The submission window for round one of the long-term 2019 FTR auction was open from October 23 to October 25, while round two was open from November 27 to November 29. In each of these auctions 25% of the capability of the New England transmission system was auctioned off. FTRs awarded as part of these long-term auctions have a term of one year. In round one of the long-term 2019 FTR auction, 17,419 MWs of FTRs were purchased across the on-peak and off-peak auctions at a cost of $8.37 million. In round two of the long-term 2019 FTR auction, 19,540 MWs of FTRs were purchased across the on-peak and off-peak auctions at a cost of $10.43 million. Meanwhile, 463 MWs of FTRs were sold in round two by participants who had purchased FTRs in round one. Sales of FTRs in round two amounted to $0.10 million. Twenty-six bidders participated in round one, while 29 participated in round two.

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

Section 5
Unoffered Winter Capacity in the FCM

During the reporting period, the IMM observed a number of combined-cycle (CC) and gas turbine (GT) resources taking on additional capacity supply obligations (CSOs) and not offering the acquired capacity in the day-ahead and real-time energy markets.[30] The unoffered capacity was particularly pronounced in October, as the FCM transitioned from the summer period (June through September) to the winter period (October through May). As the FCM transitions to winter, resources receive higher qualified capacity values.

The IMM is concerned that generators may be contracting at, or close to, their maximum capacity (i.e. their winter qualified capacity), as determined by the ISO, even though that capacity is not deliverable in certain months given expected ambient temperatures. We estimate that in October, about 650 megawatts (MW) of CSOs were undeliverable (not offered into the energy market) due to ambient conditions. The value of the unoffered capacity in the primary Forward Capacity Auction (FCA) was almost $10 million.[31]

The IMM believes that generators should not take on additional CSOs that they do not expect to be capable of delivering in the energy market. Further, the IMM recommends that the ISO explore changes to the FCM qualification rules that would better align the determination of qualified capacity values with expected ambient temperatures.

5.1.1 Relevant FCM Obligations

Capacity resources have both physical and financial obligations. First, the FCM is designed to obtain capacity based on the system's reliability needs and therefore relies on the delivery of physical capacity.[32] The Tariff requires that capacity resources offer their physically available CSO amount into the day-ahead and real-time energy markets.[33] In the context of the observed behavior discussed in this section, resources appear to be offering capacity consistent with this requirement. However, their physically available capacity (i.e. the economic maximum component of supply offers) falls short of their CSO position due to ambient temperatures.

Second, the pay-for-performance (PFP) construct provides financial incentives to resources to deliver on their CSO during capacity scarcity conditions. Deviations between actual delivered capacity (energy plus reserves) and CSO positions are settled at the current spot performance rate of $2,000/MWh. Resources may be incented to increase their CSO positions, even to levels above what can be delivered, if the additional income exceeds the expected cost of holding the additional obligation. It appears that the risk of incurring the PFP performance rate of

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[30] Combined cycle (CC) and gas turbine (GT) generators are the focus of this section as their maximum capacities are heavily impacted by ambient air conditions.

[31] Resources acquired the additional obligations during October and November at a lower price in the monthly regonfiguration auctions compared to the FCA clearing price.

[32] The system planning criteria known as installed capacity requirement is based on the probability of disconnecting load no more than once in ten years due to a resource deficiency (also referred to as Loss of Load Expectation or "LOLE").

[33] Section III.13.6.1.1.1. of the tariff states that "a Generating Capacity Resource having a Capacity Supply Obligation shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market at a MW amount equal to or greater than its Capacity Supply Obligation whenever the resource is physically available".

$2,000/MWh for undelivered capacity is not discouraging these generators from taking on CSOs that are undeliverable.

5.1.2 Qualified Capacity Determination

The ISO determines a generator's summer and winter qualified capacity (QC) values based on performance audits. The summer QC is based on an ambient temperature of 90°F and establishes the maximum CSO a resource can obtain in the primary auction (the FCA). The summer QC also sets the maximum CSO a generator can obtain during summer months (June, July, August and September) in monthly auctions/bilaterals. The winter QC is based on an ambient temperature of 20°F and establishes the maximum CSO a resource can obtain during winter months (October to May).

There can be a high amount of variation between the summer and winter QC values. There is also a high degree of variation in monthly ambient temperatures which, as described below, impacts the actual maximum output of CC and GT generators from month to month. While the qualification rules are based on two broad time horizons (summer and winter), resources can shape their capacity positions to better align with their expected capability at a monthly level through bilateral transactions and in monthly reconfiguration auctions.

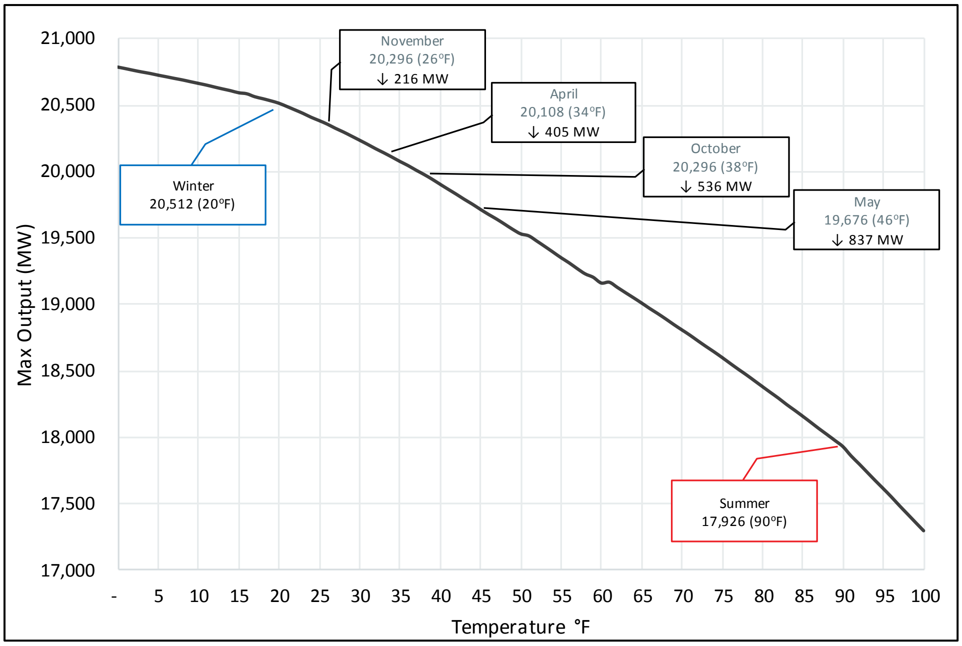
5.1.3 Analysis of Unoffered Capacity due to Ambient Temperatures

In this section, we first assess the extent of differences between QC values and the maximum output levels of a fleet of 152 CCs and GTs, based on output curves in the ISO's NX-12 forms. Then we analyze the issue as it applied to Fall 2018, by measuring the amount of undeliverable CSO megawatts in the energy market.

The relationship between temperature and total output capability is shown in Figure 5-1 below. The output levels corresponding to the fifth percentile of temperatures during October, November, April, and May (from 2005-2018) are also shown.[34] These are the winter months when the highest differences are expected between the output levels at 20°F (the basis of the winter QC) and actual maximum output.

[34] The fifth percentile of temperatures are shown to provide a conservative indication of deliverable capacity over the course of a month. For context, temperatures are above 90°F less than 1% of the time during the summer. During winter, temperatures are below 20°F less than 7% of the time.

Figure 5-1: System-wide CC and GT Generator Temperature curve

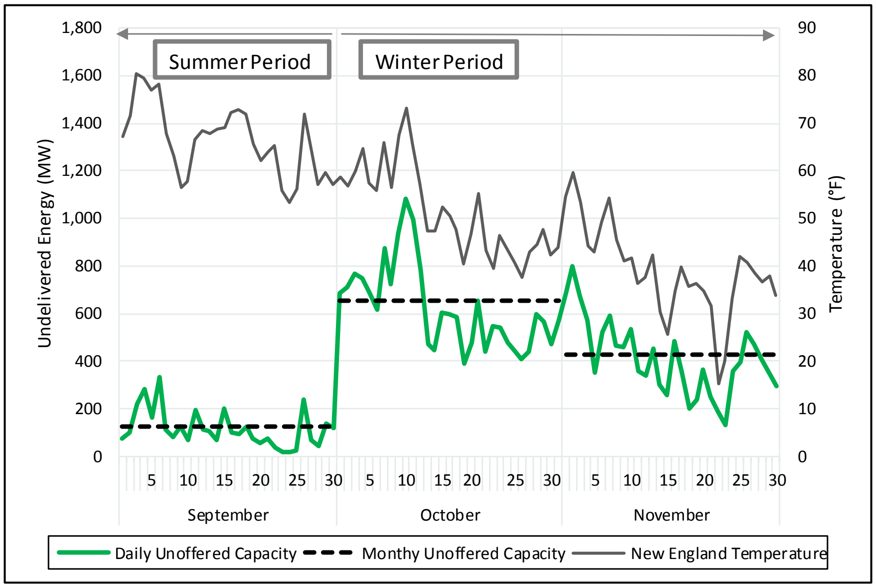


The coolest five percent of temperatures in October, November, April, and May are between 8°F and 26°F warmer than the 20°F value used to set winter QC. This translates to system-wide megawatt difference of between 216 MW (November) and 837 MW (May). Therefore, if CC and GT resources contracted at the winter QC value, their actual output could fall short by about 837 MW.

Next, we assessed the extent of unoffered capacity during winter months due to ambient conditions. Offered capacity for all available CCs ad GTs was compared to each generators' available CSO position.[35] The difference between the offered capacity and CSO position (the unoffered capacity) is driven by reductions due to ambient air temperatures. The unoffered capacity is shown in Figure 5-2 below (green and dashed black lines) along with the New England temperatures (gray line). The dashed black lines show monthly average undelivered energy.

[35] In other words, the energy offers and CSO positions were adjusted to exclude generator capacity on full or partial outage.

Figure 5-2: Unoffered Capacity and Temperatures from September to November 2018



Unoffered capacity increases significantly in October when the winter period starts. As one would expect, unoffered capacity tends to decline as temperatures drop, however the level is still significant throughout October and November. On average, unoffered capacity for CCs and GTs totaled about 650 MW in October and 430 MW in November, a fourfold and twofold increase on September (160 MW), respectively.

Unoffered capacity increased during the winter period when CC and GT resources took on additional capacity through monthly auctions, monthly bilaterals, and composite offers. These resources were unable to offer their full CSO into the energy market due to warmer temperatures compared to the 20°F winter QC value. CCs and GTs that took on additional capacity in October and November accounted over 90% of unoffered capacity (about 600 MW and 400 MW, respectively).[36]

5.1.4 Conclusion and Recommendation

It is the IMM's position that resource owners should not increase their CSO positions when there is an expectation that the additional capacity cannot be offered in the energy market. In other words, a resource's winter qualified capacity value should not be the sole determining factor in acquiring additional capacity.

The IMM recommends that the ISO review its existing qualification rules to address the disconnect between the determination of qualified capacity for two broad time horizons (summer and winter), the ability of the generators to transact on a monthly basis, and the fluctuations in output capability based on ambient conditions. A possible solution would be for the ISO to develop more granular (e.g. monthly) ambient temperature-adjusted qualified

[36] Thermal resources took on an additional 1,069 MW in October when their QC increased. Resources that took on additional capacity accounted for 63% (10,714 MW) of total thermal resource capacity (17,611 MW), but accounted for 93% (603 MW) of total undelivered energy (653 MW).

capacity values, based on forecasted temperatures and the existing output/temperature curves that the ISO currently has for each generator.