Summer 2024
Quarterly Markets Report

By ISO New England's Internal Market Monitor

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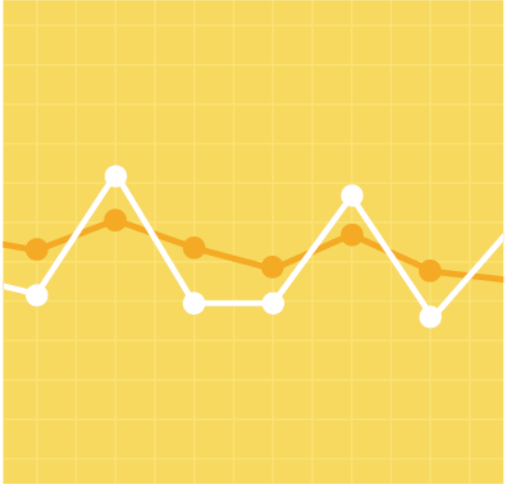

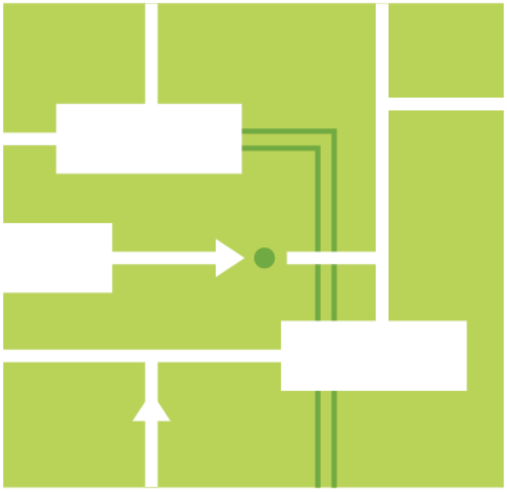

Document Revision History		
Date	**Version**	**Remarks**
11/25/2024	Original	Initial Posting
12/18/2024	Revision 1	1) Correction to calculation of total PfP payments for the June 18 and August 1 scarcity events. Total PfP payments for June 18 were $13.9 million not $10.1 million as originally stated. Total PfP payments for August 1 were $48.8 million not $36.9 million as originally stated. 2) Correction to footnote 44, which previously stated that a local reserve constraint bound for two intervals. The footnote now states that no local reserve constraints bound.

Preface/Disclaimer

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 Summer 2024 (June 1, 2024 through August 31, 2024).

Wholesale Costs: The total estimated wholesale market cost of electricity was $1.94 billion, up 21% from $1.61 billion in Summer 2023. The increase was driven by higher energy and capacity costs.

Energy costs totaled $1.56 billion; up 26% (by $0.32 billion) from Summer 2023 costs. Increased energy costs were a result of higher loads (up 5%) and CO_2 emissions costs, which offset the effect of lower natural gas prices (down 21%) on LMPs.

Capacity costs totaled $337 million, up 31% (by $80 million) from last summer. Beginning in Summer 2024, higher capacity clearing prices from the fifteenth Forward Capacity Auction (FCA 15) led to higher wholesale costs relative to the previous FCA. During Summer 2023, the capacity payment rate for all new and existing resources was $2.00/kW-month. This year, the payment rate for new and existing resources increased to $2.61/kW-month due to a higher Net Installed Capacity Requirement (up by 780 MW) and a decrease in surplus capacity due to the retirement of the Mystic combined cycle generators.

Energy Prices: Day-ahead and real-time energy prices at the Hub averaged $39.03 and $37.45 per megawatt hour (MWh), respectively. These were 9-14% higher than Summer 2023 prices on average.

- LMPs typically move in the same direction as natural gas prices. However, in Summer 2024, two factors combined to send LMPs rising while gas prices declined: 1) higher loads and increased utilization of gas generation in its upper dispatch ranges put upward pressure on LMPs; and 2) the average cost of RGGI CO_2 allowances increased by 80% from Summer 2023.
- Gas prices averaged $1.80/MMBtu in Summer 2024, 21% lower than the Summer 2023 price of $2.30/MMBtu. This decrease continued the trend of lower gas prices since early 2023.
- Real-time load was 5% higher in Summer 2024 than the prior summer, driving tighter system conditions.
- Energy market prices did not differ significantly among load zones, reflecting low levels of transmission congestion on the system.

System Events: Capacity scarcity conditions (CSC) occurred on June 18, 2024 and August 1, 2024.

On Tuesday, June 18, 2024, the ISO experienced 30 minutes of capacity scarcity conditions when an unplanned generator outage resulted in a loss of 560 MW during the evening peak. It was a hot day with average temperatures peaking at 89°F during HE 18 and other generator trips occurred throughout the day. Operators made supplemental generator commitments and evaluated the impact of changing the Total30 reserve bias. The capacity scarcity conditions were relatively short-lived, lasting for six five-minute pricing intervals between 17:50 – 18:15. The event transferred $13.9 million in pay-for-performance (PfP) payments from under-performing capacity resources to supply assets and external transactions that outperformed obligations.

On August 1, the ISO experienced 110 minutes of capacity scarcity conditions. Like the June event, low reserve margins were also driven by hot weather, high loads, and unplanned generator outages. A gas generator tripped at 16:44, resulting in a loss of 330 MW just before the evening peak. Loads peaked at 23,758 during HE 18. Operators made supplemental generator commitments leading up to the evening peak due to capacity concerns. The capacity scarcity conditions saw a longer duration than in previous events, lasting for 22 five-minute pricing intervals in the intervals beginning 16:55-17:00 and 17:45-19:20. PfP charges totaled $48.8 million. The increase in payments compared to the June 18 event was due to the longer duration of capacity scarcity conditions on August 1 and a higher balancing ratio.

Net Commitment Period Compensation (NCPC): NCPC payments totaled $13.3 million, up 96% compared to $6.8 million in Summer 2023. Additionally, NCPC increased to 0.9% of total energy payments, up from 0.6% during the previous summer. The year-over-year increase was due to an increase in economic first contingency payments to fast-start resources.

First contingency payments totaled $12.0 million and comprised the majority of NCPC. Local second contingency payments ($0.2 million) primarily occurred in the day-ahead market to generators located in Southeast Massachusetts due to import transmission constraints. Distribution payments ($1.1 million) increased 47% from Summer 2023 following higher loads. These payments are common in summer months when loads are high.

Real-time Reserves: Gross real-time reserve payments totaled $23.9 million, a significant increase from Summer 2023 payments of $3.7 million due to the capacity scarcity conditions that occurred this season. Though gross payments were high, there were $11.1 million in forward reserve obligation charges, resulting in net real-time reserve payments of $12.8 million for the season.

Summer 2024 is noteworthy for the high frequency of non-zero pricing for non-spinning reserves. TMNSR and TMOR were priced above $0/MWh in about 50 and 30 hours respectively this summer, roughly 10 times more than in the prior summer. Non-spinning reserve pricing generally resulted from high loads and tight system conditions, with high utilization of the natural gas fleet depleting the amount of reserves those generators were able to provide. Though non-spinning reserve prices were very high during capacity scarcity conditions, they were relatively low during the other hours of non-zero pricing, resulting in lower average TMNSR and TMOR prices over this period compared to prior periods.

The average TMSR clearing price increased significantly from the prior summer season, while the frequency of non-zero TMSR pricing was similar. This outcome reflects that fact that the TMSR product contributes to satisfying all of the ISO's reserve requirements. Consequently, when the non-spinning reserve constraints bind, the value that TMSR provides by helping to satisfy these constraints is reflected in the TMSR clearing price.

Regulation: Regulation market payments totaled $6.1 million, down just 4% from $6.4 million in Summer 2023. The slight decrease in payments resulted primarily from lower regulation capacity prices (down 6%). Capacity prices decreased due to a decline in regulation offer prices, as alternative technology regulation resources continue to make up a larger share of the regulation mix. Regulation service prices also decreased (down 28%) from Summer 2023.

Financial Transmission Rights (FTRs): The congestion revenue fund (CRF) balance was negative in Summer 2024 (-$1.0 million), marking the first season that this has occurred during the reporting period. This outflow from the CRF was the result of significant negative real-time congestion revenue over the period (-$1.2 million). Two periods with notable negative real-time congestion were during hours ending 19-20 on June 18 (-$0.5 million) and hours ending 4-5 on August 4 (-$0.2 million). During both of these periods, the New York North interface was constrained.

Though FTRs were underfunded in all three summer months, excess congestion revenue collected during the year is allocated to unpaid positive target allocations at the end of the year. At the end of August 2024, the congestion revenue fund had a surplus of $1.6 million for the year.

Energy Market Competitiveness: The residual supply index for the real-time energy market in Summer 2024 was 104, indicating that the ISO could meet the region's load and reserve requirement without energy and reserves from the largest supplier, on average. There was at least one pivotal supplier present in the real-time market for 34% of five-minute pricing intervals in Summer 2024, the same as the Summer 2023 value. Though Summer 2024 saw higher loads and fewer net imports than Summer 2023, there was an increase in energy and reserves from native generation, leading to similar reserve margins.

Mitigation continued to occur very infrequently. During Summer 2024, mitigation asset hours represented just 0.04% of total-asset hours. Real-time manual dispatch energy (MDE) mitigation occurred the most frequently in Summer 2024 with 106 asset hours of mitigation. The conduct test threshold for MDE mitigation is relatively tight, only allowing offers from resources being manually dispatched by the ISO to be 10% higher than reference levels.

Summer 2024 Forward Reserve Market Auction**:** In August 2024, ISO New England held the forward reserve auction for the Winter 2024-2025 delivery period (October 1, 2024 to February 28, 2025). System-wide supply offers in the Winter 2024-2025 auction exceeded the requirements for both TMNSR and TMOR. The clearing price for both TMNSR and TMOR in the Winter 2024-25 auction was $1,999/MW-month. The TMNSR price was lower than in the previous Winter auction due to a 342 MW increase in TMNSR supply offers, with much of it offered at lower prices than in the prior winter.

The Residual Supply Index (RSI) for the system-level TMNSR and TMOR products in Winter 2024-2025 were 106 and 102, respectively. These values were above the structurally competitive level of 100, and increased from the structurally uncompetitive values observed for the previous winter auction. The increase in TMNSR offers in the Winter 2024-2025 auction had the effect of increasing the RSI for both reserve requirements.

Do-Not-Exceed Dispatch Rules for Solar Generation

Beginning December 5, 2023, front-of-the-meter (FtM) solar generators in New England became subject to Do-Not-Exceed (DNE) dispatch rules, aligning them with wind and hydro resources in using price-based curtailment when transmission constraints occur. This update allows all intermittent resources to compete on price when limited by transmission, improving on previous methods that did not consider pricing. The gradual rollout, delayed by technical challenges, continues, with 66% of FtM solar generators now following DNE dispatch.

Under DNE, FtM solar generators in the Forward Capacity Market (FCM) with a Capacity Supply Obligation (CSO) must offer their capacity into the Day-Ahead Market (DAM). This change has led to a significant increase in day-ahead offers from FtM solar participants that are now offering close to their expected real-time output, rising from near 0 MW pre-DNE to 126 MW in Summer 2024.

As DAM-cleared solar volumes rise, virtual supply at solar nodes has dropped by 69% compared to Summer 2023. DNE dispatch and the must-offer requirement have enhanced solar participation in the DAM while reducing virtual supply's role at these locations.

Section 2
Special Section: Solar DNE Must-Offer Compliance

Front-of-the-meter (FtM) solar generators are those able to receive dispatch instructions from the ISO and participate in wholesale energy markets.[3] Beginning 12/5/2023, FtM solar generators in New England started to be subject to Do-Not-Exceed (DNE) dispatch rules. These rules are analogous to those already in effect for wind and intermittent hydro generators, and allow for efficient, price-based curtailment of these intermittent resources when their output must be reduced due to binding transmission constraints. This change represents an improvement over prior operational practices, which would have involved the pro-rata curtailment of these resources if necessary to respect transmission constraints without consideration of price. In addition, with the DNE dispatch implementation for FtM solar, all intermittent resources (i.e., solar, wind, and hydro) will compete on price when limited by transmission. Previously, solar generators would have had curtailment priority over other intermittent resources. This change levels the playing field for these intermittent resources.

The rollout of DNE dispatch to solar generators has been staggered as a result of technical challenges at individual generators, resulting in individual generators implementing DNE at different times. The rollout of DNE dispatch to solar resources continues to the present day; while most solar generators have implemented DNE dispatch, some have not.

Solar generators that have adopted DNE dispatch and that are part of a resource in the Forward Capacity Market (FCM) fall purview to Tariff section III.13.6.1.3.1,[4] which applies a 'must-offer' requirement to intermittent resources. This provision requires that these resources offer their expected capability into the Day-Ahead and Real-Time energy markets, conditional on having a Capacity Supply Obligation (CSO).

Table 2-1 provides an overview of the FtM solar generation currently participating in the ISO's markets.

Table 2-1: FtM Solar participation

Concept	Value	% Total
Count of FtM PV Generators	58	-
Total Summer Max Net Output (MW)	807	-
Subset: PV currently on DNE Dispatch (MW)	699	87%
Subset: PV associated with FCM Resource (MW)	564	70%
Subset: PV on DNE *and* associated with FCM Resource (MW)	531	66%

[3] Solar generators that are < 5 MW in size may elect to participate in the ISO's real-time energy market as settlement-only generators. Such generators do not receive dispatch instructions from the ISO and are not considered in the analysis in this section.

[4] See Tariff section III.13.6.1.3.1

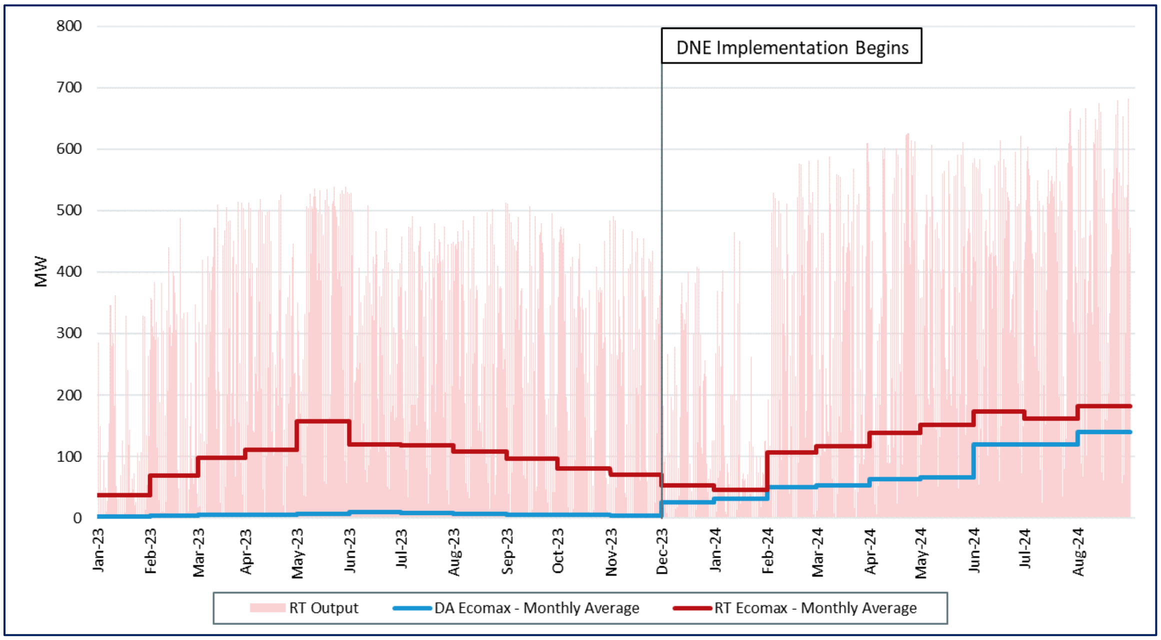
Currently, approximately 66% of the FtM solar capability on the ISO-NE system may have the requirement to offer into the Day-Ahead Market (DAM) applied (conditional on having a CSO in the delivery month).

This section examines the effect of solar DNE dispatch and the associated must-offer requirement on the day-ahead and real-time energy markets.

Solar Energy Supply Offered into the DAM has increased

Figure 2-1 shows the average monthly offered Ecomax of all FtM solar generators in the Day-ahead and Real-time energy markets, as well as the real-time output of those generators.[5]

Figure 2-1: Average Day-ahead and Real-time FtM Solar Offers



The figure above illustrates that solar generator participation in the DAM has increased significantly with DNE dispatch. Prior to DNE, average day-ahead solar offer quantity was close to 0 MW. Since DNE, the average day-ahead solar offer quantity has increased. During Summer 2024, monthly day-ahead Ecomax offer values were 74% of the monthly real-time Ecomax offer values (on average).[6] The average summer (June, July, and August) day-ahead offer quantity from solar resources post-DNE is 126 MW, relative to only 8 MW for the same period prior to DNE.

[5] The monthly average Ecomax values shown here, and in subsequent figures, include *all* hours in each month, including overnight hours when solar resources offer Ecomax = 0. This is why the hourly real-time output frequently exceeds the monthly average real-time Ecomax.

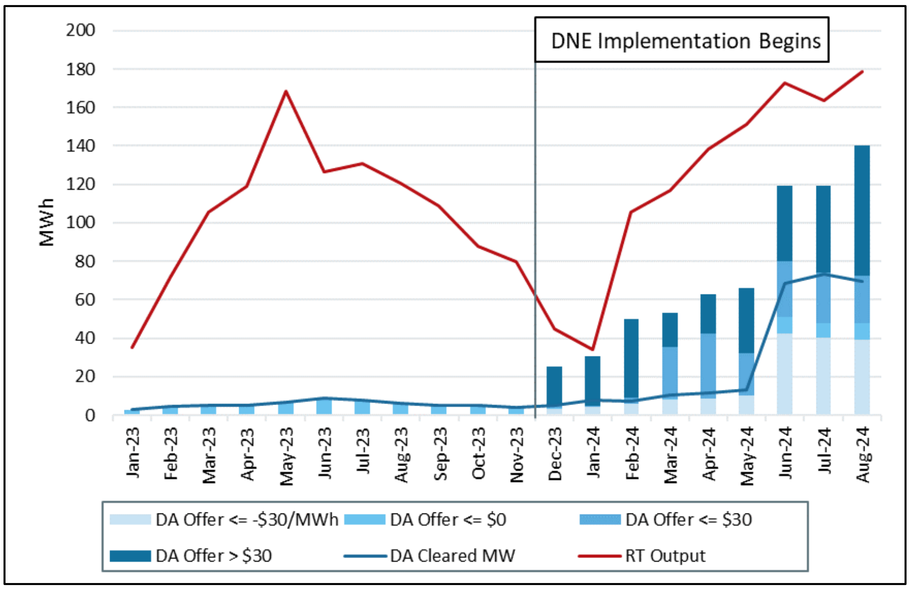
[6] Recall that 66% of the FtM solar fleet is subject to the must offer requirement at present, so this increase in day-ahead offered quantities indicates that affected resources are indeed offering their expected capability into the DAM.

The conclusion here is that DNE dispatch rules have significantly increased the amount of supply offered into the DAM from these low marginal cost resources that are expected to produce in real-time, and participants subject to the day-ahead must-offer requirement are offering close to their expected real-time output.

Solar Energy Supply Clearing in the DAM has increased

Figure 2-2 below provides further detail on how FtM solar resources are clearing in the DAM.[7]

Figure 2-2: Day-ahead Offer Quantities and Prices



While solar resources increased day-ahead offer quantities following DNE implementation, cleared day-ahead quantities have increased at a slower rate. Between December 2023 and February 2024, day-ahead cleared quantities were similar in magnitude to those of the prior winter, and most capability was offered at a price greater than $30/MWh and did not clear. Between March 2024 and May 2024, solar generators increased the quantity of capability offered in the $0/MWh - $30/MWh range, and the quantities that they cleared in the DAM continued to increase slowly. In Summer 2024, we observed a significant increase in solar generators offering and clearing in the DAM, with cleared quantities offered, on average, in the $0 - $30/MWh range. On average, solar generators cleared 41% of actual real-time output in the DAM during this period. This trend of offering day-ahead energy quantities at competitive prices suggests that solar generators are becoming more comfortable with DAM participation and have an increasing willingness to clear in the DAM to capture day-ahead premiums[8], particularly in months with higher levels of solar insolation.

These data also reflect the volumetric risk that solar resources consider when taking on a day-ahead energy award. Solar energy can generally be thought of as having a marginal cost of $0/MWh and may have negative marginal costs if receiving out-of-market subsidies. However, taking a day-ahead position adds additional risk associated with potential inability to cover that position in real

[7] The values in this figure represent hourly averages for all hours in each month.

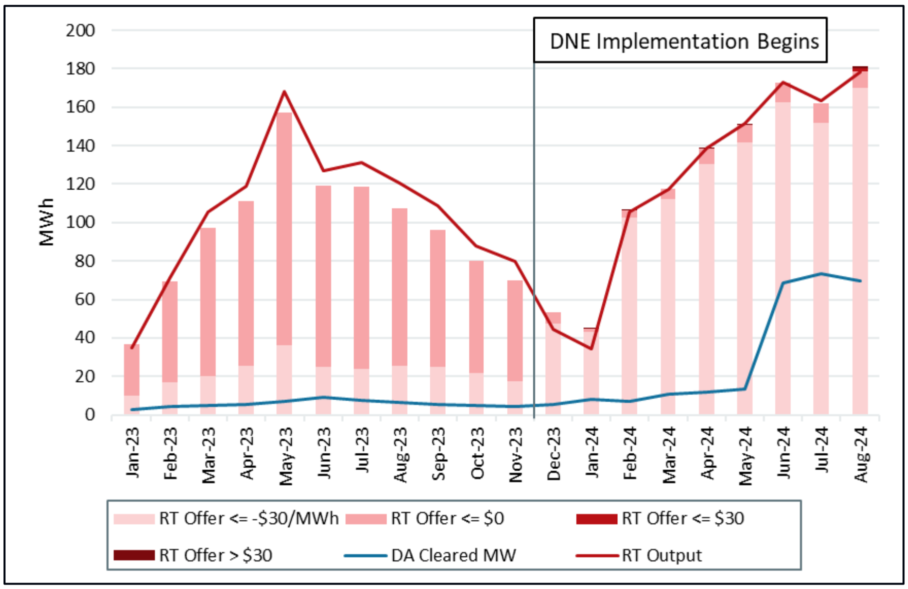
[8] See Section 4.1 for discussion on energy prices.

time if the solar insolation is less than expected. As a result, we see the solar generators clearing day-ahead energy quantities at prices greater than $0/MWh.

Real-time Offers Reflect Expected Real-Time Output

Figure 2-3 provides additional information on FtM solar generator behavior in the real-time energy market.

Figure 2-3: Real-time Offer Quantities and Prices



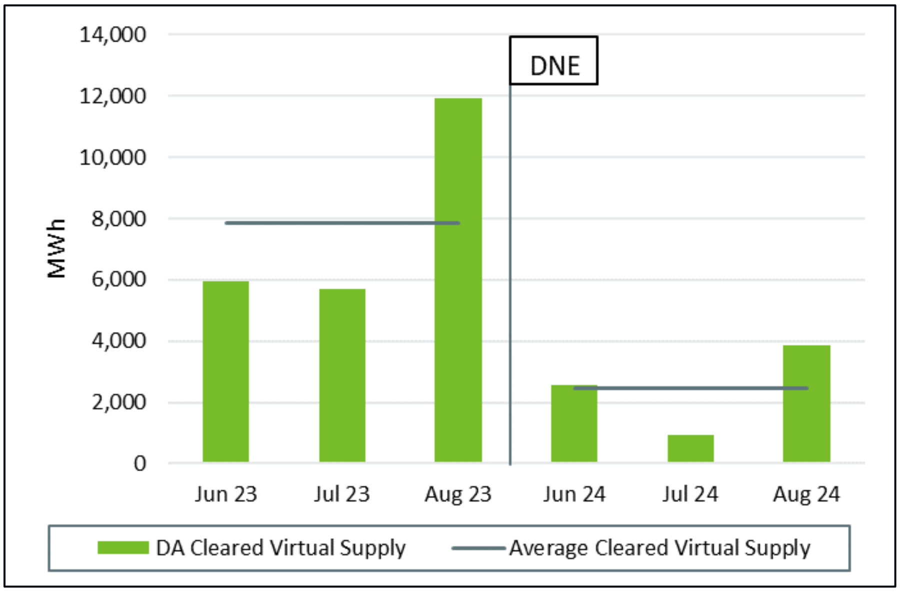
Real-time solar energy supply is generally price-taking, with the vast majority of supply offered at $0/MWh or less. A notable shift in real-time offer prices has occurred as a result of DNE implementation. Prior to DNE, the majority of solar energy was offered in the range of -$30/MWh to $0/MWh. Following DNE, the majority of solar energy is offered at lower prices, in the range from -$150/MWh to -$30/MWh. This trend reflects the fact that, post-DNE, these generators must compete based on price. In addition, we observe that the real-time offered Ecomax of solar resources is closely aligned with delivered output.

When solar or other renewable resources are curtailed as a result of transmission constraints, the system receives less low-cost energy from these resources than it would absent the transmission constraint. Curtailment of FtM PV in real-time due to binding transmission constraints remains a rare occurrence. Since the implementation of DNE, such curtailment has occurred for six solar generators, and with different frequencies and time durations. The least affected of these generators was curtailed for only 15 minutes, while the most affected was curtailed for 16 hours. In aggregate, only 312 MWh of solar generation has been curtailed because of binding transmission constraints since DNE implementation.

Virtual Supply at Solar Nodes has decreased

Figure 2-4 highlights clearing outcomes for virtual supply (incremental offers, INCs) at solar nodes during summer periods. We focus on the summer periods because the cleared day-ahead energy from solar generators increased significantly beginning in June 2024. This additional day-ahead energy supply is expected to drive changes to cleared virtual supply.

Figure 2-4: Virtual Supply Clearing at Solar Nodes



As day-ahead cleared energy from solar generators has increased, we have observed a significant decrease in virtual supply clearing at nodes where solar generators are located. Cleared virtual supply quantities at these nodes decreased by ~5,400 MWh (69% decrease) in Summer 2024 relative to Summer 2023.

In summary, DNE dispatch rules and the associated must-offer requirement have had the effect of increasing the offered and cleared supply of FtM solar resources in the DAM. As these resources increased their cleared quantities in the DAM, the clearing of virtual supply has declined.

Section 3
Overall Market Conditions

This section provides a summary of key trends and drivers of wholesale electricity market outcomes. Selected key statistics for load levels, day-ahead and real-time energy market prices, and fuel prices are shown in Table 3-1 below.

Table 3-1: High-Level Market Statistics

Market Statistics	Summer 2024	Spring 2024	Summer 2024 vs Spring 2024 (% Change)	Summer 2023	Summer 2024 vs Summer 2023 (% Change)
Real-Time Load (GWh)	33,299	26,206	27%	31,804	5%
Peak Real-Time Load (MW)	24,833	17,354	43%	23,006	8%
Average Day-Ahead Hub LMP ($/MWh)	$39.03	$25.66	52%	$34.27	14%
Average Real-Time Hub LMP ($/MWh)	$37.45	$24.64	52%	$34.33	9%
Average Natural Gas Price ($/MMBtu)	$1.80	$1.60	13%	$2.30	-21%
Average No. 6 Oil Price ($/MMBtu)	$14.54	$15.74	-8%	$14.91	-3%
Average RGGI allowance price ($/tn CO_2)	$24.40	$19.31	26%	$13.50	81%

Key observations from the table above:

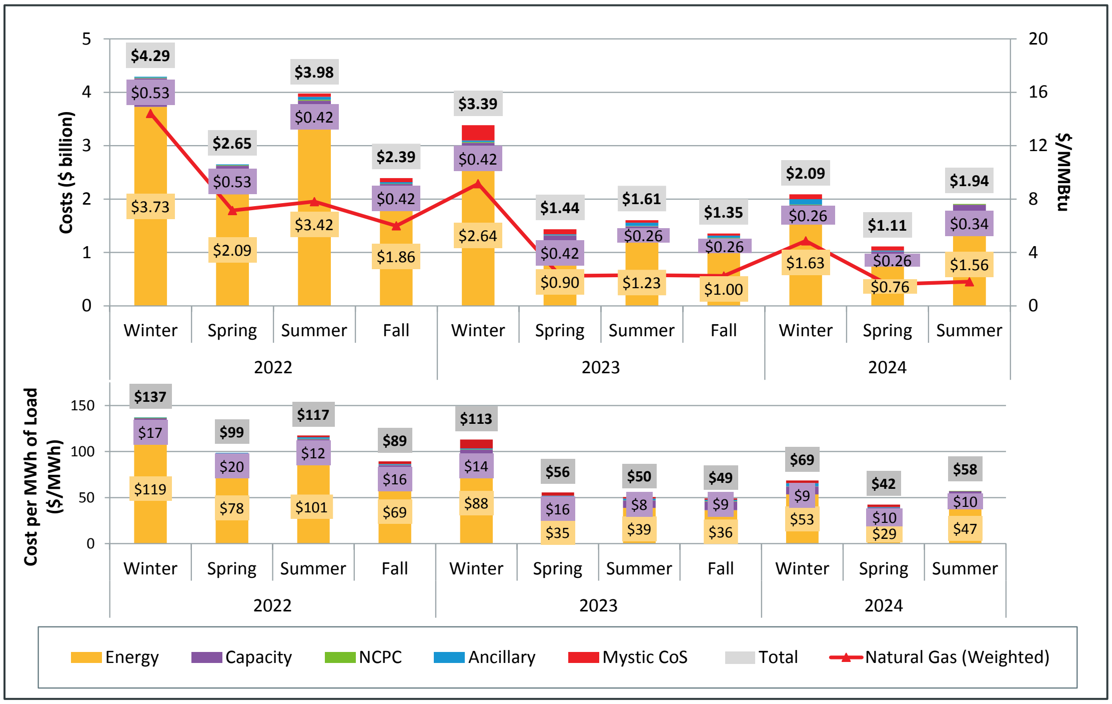
- Real-time load was 5% higher in Summer 2024 than the prior summer season, driving tighter system conditions observed during this period.
- Day-ahead LMPs averaged $37.45/MWh, a $1.58/MWh premium over the real-time LMP. These day-ahead prices were 14% higher than the prior summer season and primarily reflective of the higher load level and utilization of gas resources in the upper, and more expensive, portions of their dispatchable ranges.
- While natural gas prices were 21% lower, on average, in Summer 2024, average LMPs were higher than the prior summer. Typically, LMPs and natural gas prices trend in the same direction, but this summer, the drop in the average natural gas price was more than offset by an increase in the average RGGI CO_2 allowance price. These averaged $24.40 per short ton of CO_2, an 81% increase over Summer 2023 prices. The net impact of falling natural gas costs and rising RGGI CO_2 costs was a cost increase of approximately $1/MWh for gas-fired generators when compared with Summer 2023.[9]

[9] The IMM assumes a standard efficiency of 7.8 MMBtu/MWh to represent New England gas-fired generation.

3.1 Wholesale Cost of Electricity

The estimated wholesale cost of electricity (in billions of dollars), categorized by cost component, is shown by season in the upper panel of Figure 3-1 below. The upper panel also shows the average price of natural gas price (in $/MMBtu) as energy market payments in New England tend to be correlated with the price of natural gas in the region.[10] The bottom panel in Figure 3-1 depicts the wholesale cost per megawatt hour of real-time load.

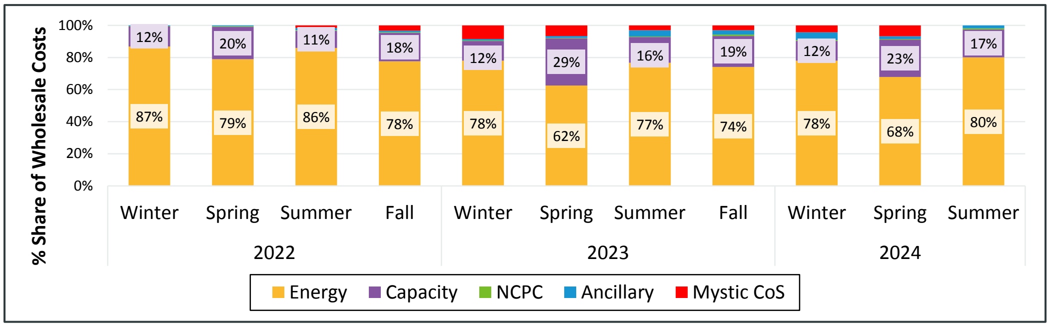
Figure 3-1: Wholesale Market Costs and Average Natural Gas Prices by Season



In Summer 2024, the total estimated wholesale cost of electricity was $1.94 billion (or $58/MWh of load), a 21% increase compared to $1.61 billion in Summer 2023 and a 75% increase compared to $1.11 billion in Spring 2024. The increase from Summer 2023 resulted from higher energy and capacity costs. The share of each wholesale cost component since Winter 2021 is shown in Figure 3-2 below.

[10] 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, Maritimes and Northeast, 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 10 on D+2.

Figure 3-2: Percentage Share of Wholesale Costs



Energy costs comprised 80% of wholesale costs and totaled $1.56 billion ($47/MWh) in Summer 2024, 26% higher than Summer 2023 costs. Though average natural gas prices decreased (down 21%), energy costs moved in the opposite direction due to increased CO_2 emissions costs and heat wave periods that resulted in high loads and LMPs. About a third of all energy costs occurred on just 11 days that saw high temperatures.

Capacity costs are determined by the clearing price in the primary forward capacity auction (FCA). In Summer 2024, the FCA 15 clearing price resulted in capacity payments of $337 million ($10/MWh), representing 17% of total costs. The current capacity commitment period (CCP15, June 2024 – May 2025) cleared at $2.61/kw-month. This was 30% higher than the primary auction clearing price of $2.00/kW-month for the prior capacity commitment period. Section 6.1 discusses recent trends in the Forward Capacity Market in more detail.

Beginning in Summer 2022, the Mystic 8 and 9 generators began receiving supplemental payments per their cost-of-service agreement (Mystic CoS) with the ISO. These payments ended after Spring 2024 because Mystic 8 and 9 ceased physical operation in May 2024.

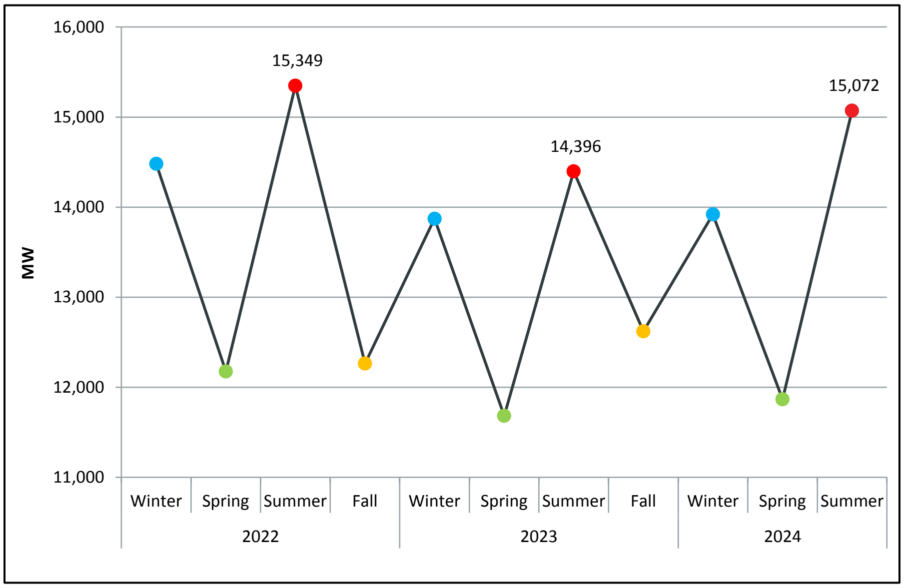
At $13.3 million ($0.40/MWh), Summer 2024 Net Commitment Period Compensation (NCPC) costs represented 0.9% of total energy costs, a higher share compared to most quarters in the reporting period. Summer 2024 NCPC costs were $6.5 million higher than in Summer 2023 due to an increase in economic first contingency payments to fast-start resources.

Ancillary service costs, which include payments for operating reserves and regulation, totaled $36.8 million ($1.10/MWh) in Summer 2024, representing 2% of total wholesale costs. Ancillary service costs decreased by 40% compared to Summer 2023 costs, as lower forward reserve payments offset the increase in real-time reserve payments.

3.2 Load

New England average loads typically peak in summer due to air conditioning demand. Average hourly load by season is illustrated in Figure 3-3 below.

Figure 3-3: Average Hourly Load by Quarter



Summer 2024 loads averaged 15,072 MW, up 5% from Summer 2023. As discussed below, higher loads followed hotter weather conditions. Increased cooling demand was partially offset by increased behind-the-meter (BTM) solar generation. BTM solar reduced loads by an estimated 914 MW on average, up 28% from Summer 2023 (712 MW). Estimated installed BTM capacity grew to 4,700 MW, up 18% from the prior year. The increase in BTM generation is also attributable to sunnier average conditions in Summer 2024 relative to 2023.

Load and Temperature

The stacked graph in Figure 3-4 below compares average monthly load (left axis) to the monthly average Temperature-Humidity Index (right axis).[11]

Figure 3-4: Monthly Average Load and Monthly Temperature-Humidity Index

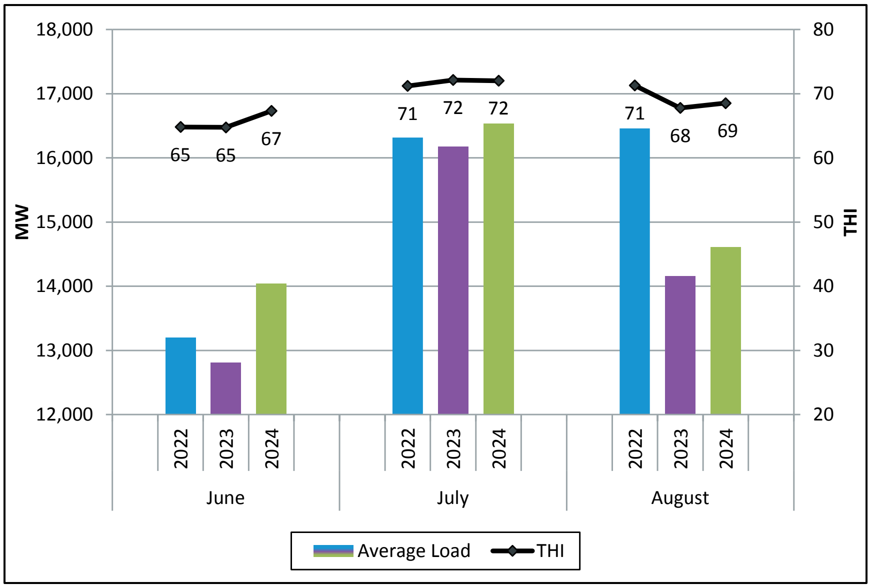


Figure 3-4 shows that average load increased in all three months compared to the prior year. Average load increased by 10% from June 2023 to June 2024, driven by significant increases in temperatures as reflected in a higher temperature-humidity index. Hot weather led to 82 cooling degree days in June, up from 43 in June 2023.[12] July and August loads increased 2% and 3% from the prior year, respectively.

[11] The Temperature-Humidity Index combines temperature and dew point (humidity) into one metric that is a useful indicator of electricity demand in summer months when the impact of humidity on load is highest. The THI is calculated as 0.5 x [Dry-Bulb Temperature (°F)] + 0.3 x [Dew Point (°F)] + 15.

[12] Cooling degree days (CDD) measure how warm an average daily temperature or temperature-humidity index is relative to 65°F, and is an indicator of electricity demand for air conditioning. It is calculated as the number of degrees (°F) that the average of a day's high and low temperatures are above 65°F. For example, if a day's high temperature is 80°F and low temperature is 60°F, the average of the high and low temperatures is 70°F, and the CDD for that day is 5. These CDDs are based on THI and are reported in the *Net Energy and Peak Load* Report, available at https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/net-ener-peak-load.

Peak Load and Load Duration Curves

New England's system load over the past three summer seasons is shown as load duration curves in Figure 3-5 below, with the inset graph showing the 5% of hours with the highest loads.[13]

Figure 3-5: Summer Load Duration Curves

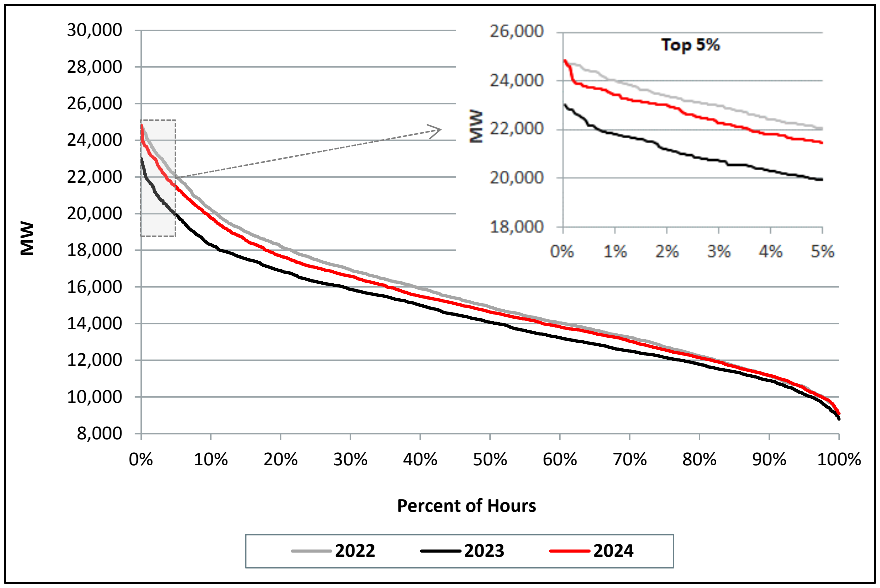


Figure 3-5 shows that loads in Summer 2024 exceeded loads in Summer 2023 and were generally slightly lower than Summer 2022 loads. Annual peak load occurred on July 16 when temperatures reached 91^{0}F and load reached 24,816 MW.[14] Peak load exceeded both 2023 peak load (24,043 MW) and 2022 peak load (24,780 MW).[15]

[13] A load duration curve depicts the relationship between load levels and the frequency in which loads occur at that level or higher.

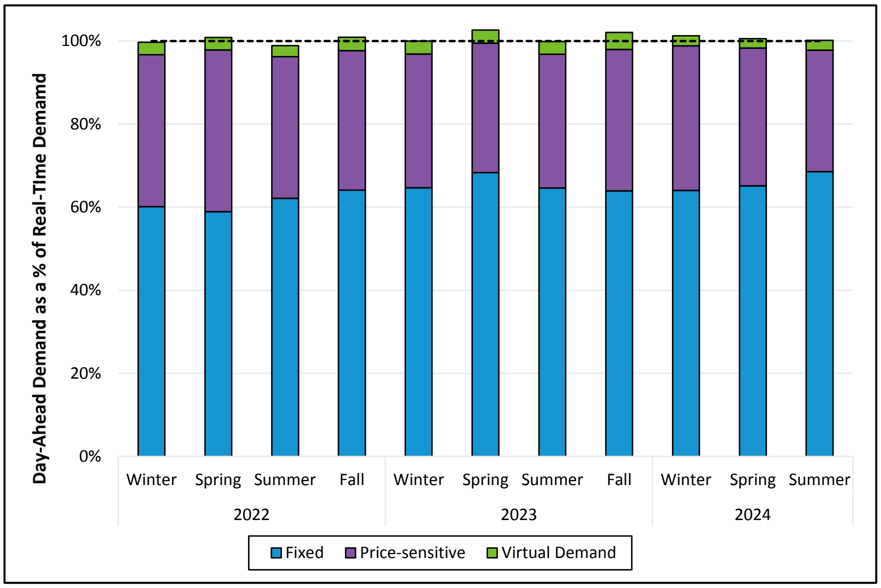
[14] Reported temperatures represent the 23-city weighted average for New England used in the load forecasting process. On July 16, temperatures reached 94^{0}F in Boston, driving high loads. For more information on temperature and load forecasting procedures, see ISO demand forecast procedures, available at https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/sysop/out_sched/sop_outsch_0040_0010.pdf.

[15] Annual peak load in 2023 occurred in September during heat wave conditions that extended into early fall. Therefore, 2023 annual peak load is not captured in this visualization of summer loads.

Load Clearing in the Day-Ahead Market

The amount of demand that clears in the day-ahead market is important because, along with the ISO's Reserve Adequacy Analysis, it influences generator commitment decisions for the operating day.[16] The day-ahead cleared demand as a percentage of real-time demand is shown Figure 3-6 below.

Figure 3-6: Day-Ahead Cleared Demand as Percent of Real-Time Demand, by Quarter



In Summer 2024, participants cleared an average of 100% of their real-time demand in the day-ahead market, similar to Summer 2023. Fixed-demand bids made up a larger share of total cleared demand relative to last year (69% vs. 65%). Priced-demand bids fell to 29% of cleared demand, down from 32% in Summer 2023. Most priced-demand bids are priced well above expected day-ahead LMPs. Such bids are effectively similar to fixed demand, and therefore the reduction in priced bids in Summer 2024 did not cause significant market impacts. Virtual demand fell to 2% of cleared demand from 3% in 2023.

[16] The Reserve Adequacy Analysis (RAA) is conducted after the day-ahead market is finalized and is designed to ensure sufficient capacity is available to meet ISO-NE real-time demand, reserve requirements, and regulation requirements. The objective is to minimize the cost of bringing additional capacity into the real-time market.

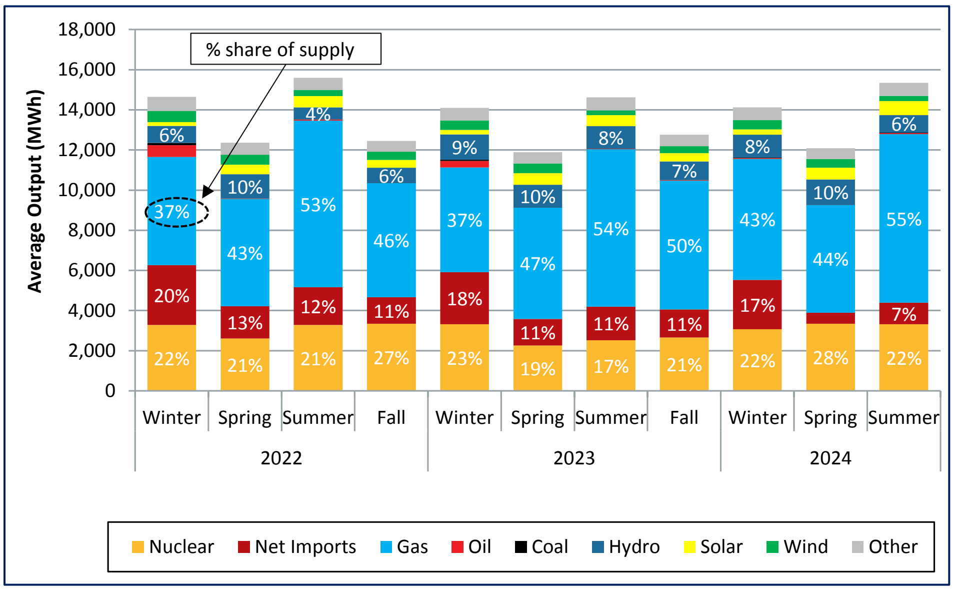
3.3 Supply

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

3.3.1 Generation by Fuel Type

The breakdown of actual energy production by fuel type provides useful context for the drivers of market outcomes. The shares of energy production by generator fuel type for Winter 2022 through Summer 2024 are illustrated in Figure 3-7 below. Each bar's height represents the average electricity generation from that fuel type, while the percentages represent the share of generation from that fuel type.[17]

Figure 3-7: Share of Electricity Generation by Fuel Type



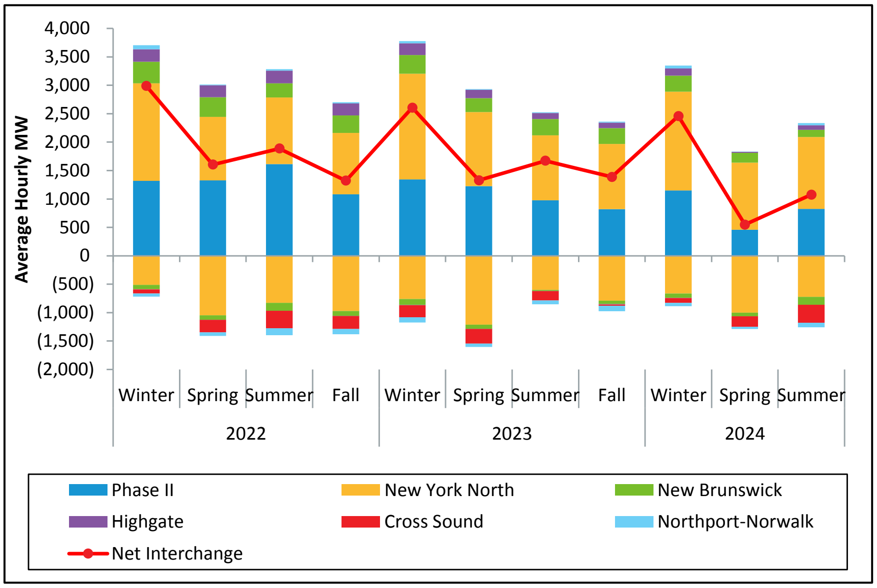
Average output in Summer 2024 (15,341 MWh) was 5% higher than in Summer 2023. In keeping with past seasons, natural gas and nuclear generation provided the majority of energy supply (76%) during Summer 2024. Net imports, which reached a historic low in Spring 2024 as a result of low Canadian reservoir levels, increased moderately in Summer 2024 and accounted for 7% of energy supply on average. Solar output, while still a small share of overall supply, increased by 25% relative to Summer 2023, reflecting the increase in installed solar capability in the region.

[17] Electricity generation equals native generation plus net imports. The "Other" category includes energy storage, landfill gas, methane, refuse, steam, wood, and demand response. The "Hydro" category includes traditional hydro generation as well as pumped storage hydro generation.

3.3.2 Imports and Exports

New England continued to be a net importer of power from its neighboring control areas of Canada and New York in Summer 2024.[18] The average hourly import, export and net interchange power volumes by external interface for the last 11 seasons are shown Figure 3-8 below.

Figure 3-8: Average Hourly Real-Time Imports, Exports, and Net Interchange



On average, the net flow of energy into New England was 1,076 MW per hour from the neighboring control areas in Canada and New York. Total net interchange represented 7% of load (NEL), down from 12% in Summer 2023.

Canadian Interfaces

Net interchange from the three Canadian interfaces accounted for 83% of total net interchange during Summer 2024, which was in line with the levels from the prior summer (81%). However, average net interchange at the Canadian interfaces fell from 1,350 MW to 890 MW per hour mostly due to reduced net interchange over the New Brunswick interface.

In Summer 2024, New England exported an average of 14 MW per hour to New Brunswick. Historically, New England has been a net importer of energy from New Brunswick, with net imports averaging 209 MW per hour over the prior 10 seasons. Beginning in Spring 2024, a nuclear generator in New Brunswick started an extended outage that continued through the entire

[18] 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.

summer.[19] This outage limited the generation capacity within New Brunswick and resulted in increased exports out of New England over the New Brunswick interface.

At the Phase II and Highgate interfaces, which connect New England to Québec, average quarterly net interchange fell from Summer 2023 levels by 16% (or 152 MW) and 22% (or 22 MW), respectively. In Québec, normally abundant water resources and hydro generation provide excess electricity supply, which can be sold to neighboring control areas. However, drier weather over the last year reduced the excess energy available in Québec and limited exports into New England.[20]

New York Interfaces

At the New York interfaces, New England typically imports energy over the New York North interface and exports energy over the two interfaces with Long Island, Cross Sound Cable and Northport-Norwalk. Collectively, New England was a net importer from New York, averaging 186 MW of net imports per hour, down from 322 MW in Summer 2023. Most of the year-over-year differences were the result of the Cross Sound Cable interface returning to its maximum export capability this summer.

During the summer, New England exports energy over the Cross Sound Cable to Long Island, an area that is often import-constrained compared to the rest of the New York control area. In Summer 2024, New England exported an average of 315 MW, up from 166 MW in Summer 2023. Beginning in August 2023, transmission work forced the Cross Sound Cable to go out of service, limiting the total exports last summer. No major transmission outages occurred this summer and exports were more in line with levels during Summer 2022 (308 MW per hour). At the New York North and Northport-Norwalk interfaces, average net interchange was similar to the prior Summer. During Summer 2024, New England *imported* an average of 544 MW per hour at New York North and *exported* an average of 44 MW at Northport-Norwalk. Both interfaces saw seasonal averages within 10 MW of the prior summer.

[19] For more information on the outage of the New Brunswick nuclear generator, see *Update to extended outage schedule at Point Lepreau Nuclear Generating Station* (Aug 15, 2024), available at: https://www.nbpower.com/en/about-us/news-media-centre/news/2024/update-to-extended-outage-schedule-at-point-lepreau-nuclear-generating-station/

[20] For more information on Québec's reduction in exports, see Hydro-Québec's *Quarterly Bulletin, Second Quarter 2024*, available at https://www.hydroquebec.com/data/documents-donnees/pdf/quarterly-bulletin-2024-2.pdf

3.4 Market Performance on June 18, 2024

This section examines the performance of the New England electricity markets during the June 18, 2024 capacity scarcity conditions (CSC).

3.4.1 Event Overview

On Tuesday, June 18, 2024, the ISO experienced 30 minutes of capacity scarcity conditions[21] primarily due to a generator trip during the evening peak which resulted in a loss of 560 MW. Other generator trips also occurred throughout the day, resulting in a 745 MW reduction in generation during hour-ending (HE) 19 compared to the day-ahead schedule. Additionally, it was a hot day with average temperatures peaking at 89°F during HE 18. Loads peaked at 22,446 MW during HE 19. The ISO initiated emergency procedures in response to the tight conditions. Operators made supplemental generator commitments and evaluated the impact of changing the Total30 reserve bias. An M/LCC2 Abnormal Conditions Alert[22] was in effect from 17:30 on June 18 until 22:00 on June 20. The ISO implemented OP-4[23] Actions 1 and 2 from 17:40-22:00 on June 18. The capacity scarcity conditions were relatively short, lasting for six five-minute pricing intervals between 17:50 – 18:15.

3.4.2 Drivers of Tight System Conditions

Weather and Load

Average temperatures reached 89ºF on June 18. Load peaked at 22,446 MW with minimal load forecast error before or during the shortage event. Relatively high loads led to conditions where generator trips had significant impacts on operating reserve margins.

Unplanned Generator Outages

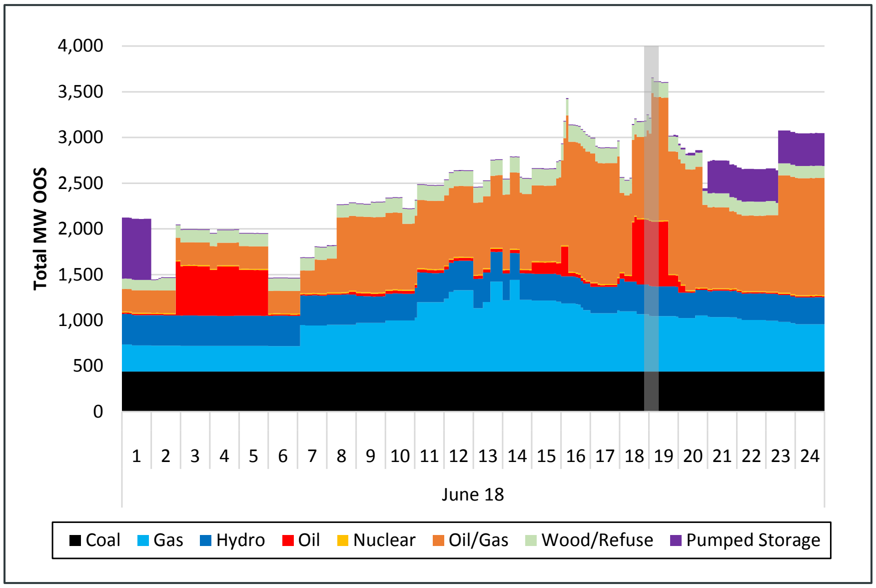
Unplanned generator outages were the primary driver of the June 18 shortage event. Figure 3-9 illustrates actual real-time out-of-service generation capacity broken out by generator type. The capacity shortage condition is indicated by the gray area.

[21] For more information on the ISO's rules surrounding capacity scarcity conditions, see *Market Rule 1, Section III.13.7.2.1*, available at https://www.iso-ne.com/static-assets/documents/2014/12/mr1_sec_1_12.pdf

[22] For more information on abnormal conditions procedures, see the ISO's *Master/Local Control Center Procedure No. 2*, available at https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/mast_satllte/mlcc2.pdf

[23] For more information on ISO actions during capacity deficiencies, see *ISO New England Operating Procedure No. 4 – Action During A Capacity Deficiency*, available at https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op4/op4_rto_final.pdf

Figure 3-9: Planned and Unplanned Outages by Generator Type, June 18[24]



Total outage MW peaked during the capacity scarcity conditions. Three generators that had cleared in the day-ahead market tripped throughout the day and remained unavailable or reduced during the evening peak when the shortage event occurred, leading to a loss of 745 MW. Then, a 560 MW oil-fired generator that had been manually committed due to capacity concerns that afternoon tripped offline at 17:22, triggering the event. The outages that occurred on June 18 were caused by typical mechanical issues that generators experience throughout the year. While generator equipment can become more stressed during hot weather, the mechanical issues were not explicitly related to heat. However, older generators that don't typically run are often committed on days with high loads, which can lead to an increased risk of trips. Generator outages generally have more of an impact on price in the summer when available supply is already tight due to high loads. In these instances, a trip can lead to a steep movement up the supply curve that results in higher prices than would be observed during a milder time of year.

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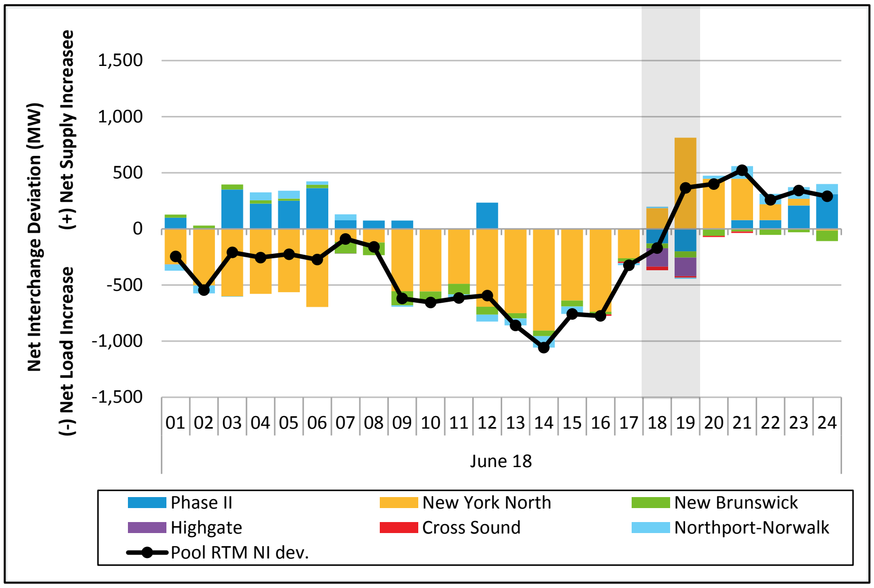
24 This figure combines outage data from the Control Room Operations Window (CROW) system with real-time operational data. If a generator has a physical reduction logged in CROW, or if its real-time operational capability is less than its seasonal claimed capability, that generation is considered out of service (accounting for overlaps). Accounting for real-time operational data is necessary because not all outages are required to be logged in CROW

Net Imports

During the capacity scarcity conditions, net imports performed close to, or above day-ahead cleared schedules. Deviations between day-ahead cleared and real-time scheduled net imports at the six interfaces are shown below in Figure 3-10 below.

Figure 3-10: Day-Ahead vs. Real-Time Net Interchange Deviations, June 18

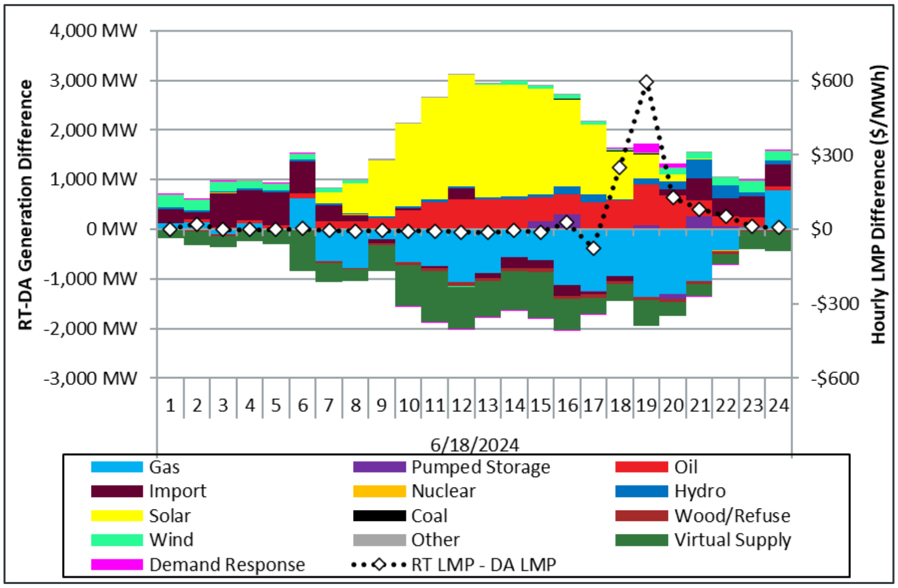


During the start of the scarcity conditions in HE 18, the real-time net interchange was below the day-ahead levels (171 MW lower) due to negative deviations at the Phase II (130 MW lower) and Highgate (165 MW lower) interfaces. As average hourly real-time prices increased by HE 19, the system-level deviations were positive (366 MW higher) as net interchange at New York North increased to 812 MW above day-ahead cleared levels. Following the event, real-time flows remained at least 259 MW higher than day-ahead cleared volumes the rest of the operating day.

Supply Mix Changes

The differences in generation obligations and average LMPs at the Hub between the day-ahead and real-time markets are shown in Figure 3-11 below.

Figure 3-11: Differences between Hourly Real-Time and Day-Ahead Generation Obligations and LMPs, June 18



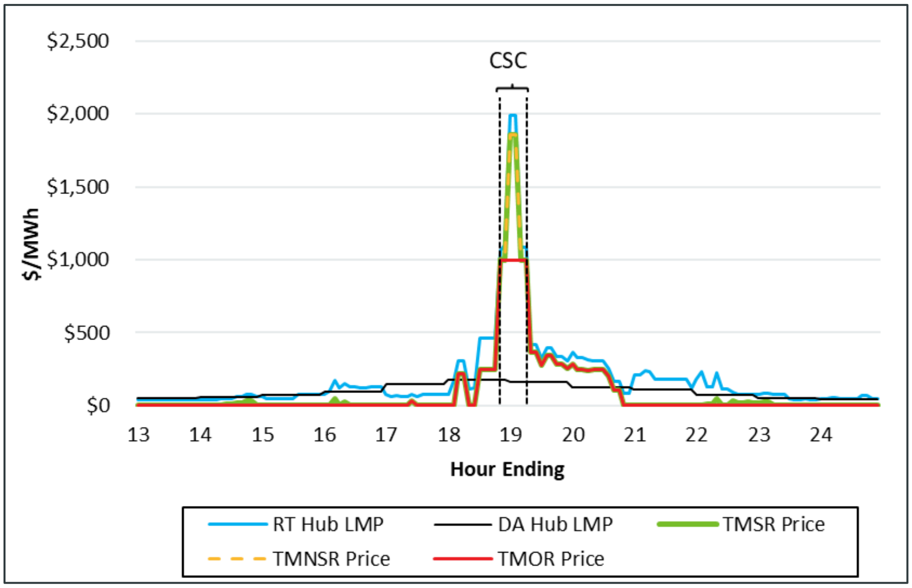
Additional real-time output from oil-fired generators is evident throughout this operating day. For the majority of the day (through HE 18), these deviations are attributable to a single, large oil-fired resource that self-scheduled during the morning and afternoon, and was then issued a supplemental commitment by the control room to keep the unit online. This resource tripped offline at the end of HE 18, resulting in the need to dispatch many offline fast-start resources for energy. The oil deviations evident for the remainder of the day (from HE 19 onward) are attributable to these resources. During HE 19, these oil-fired generators produced 815 MWh. Another notable form of energy supply during HE 19 is demand response, which was dispatched in response to the capacity scarcity conditions. During this hour, demand response resources provided 206 MWh of energy supply, 64% of their dispatched quantity of 321 MW.

3.4.3 Energy Prices, Reserve Prices, and Uplift

Energy and Reserve Prices

Energy and reserve prices from June 18 are shown in Figure 3-12 below.

Figure 3-12: Five-Minute Energy and Reserve Prices, System Level, June 18



A deficiency of total thirty-minute reserves in pricing intervals 17:50 – 18:15 resulted in high prices during this thirty-minute timeframe, reflective of the $1,000/MWh Minimum Total Reserve Penalty Factor. The penalty factor set the TMOR clearing price at $1,000/MWh during this timeframe. In addition, the ten-minute reserve requirement was binding for a portion of this period, resulting in three pricing intervals in which TMSR and TMNSR prices exceeded the TMOR price. The highest price for TMSR and TMNSR was $1,860.71/MWh, which occurred during two five-minute pricing intervals. Because energy price calculations reflect the opportunity cost of providing energy over reserves, these reserve prices are reflected in the real-time LMP. The highest real-time Hub LMP observed during this period was $1,993.23/MWh.

Uplift

Real-time uplift totaled $0.5 million on June 18. Leading up to the event, operators manually committed and dispatched a large oil-fired generator with a long lead time for capacity, leading to "dispatch-out-of-merit" uplift payments. The majority of uplift was "commitment-out-of-merit" payments after the event while many generators stayed online throughout or after their minimum run time for reliability as prices fell. While "commitment-out-of-merit" payments were the largest category of uplift during the event, individual generators received relatively small payments, indicating that generators recovered most of their commitment costs during the event and that total uplift was driven by relatively small payments to multiple generators.

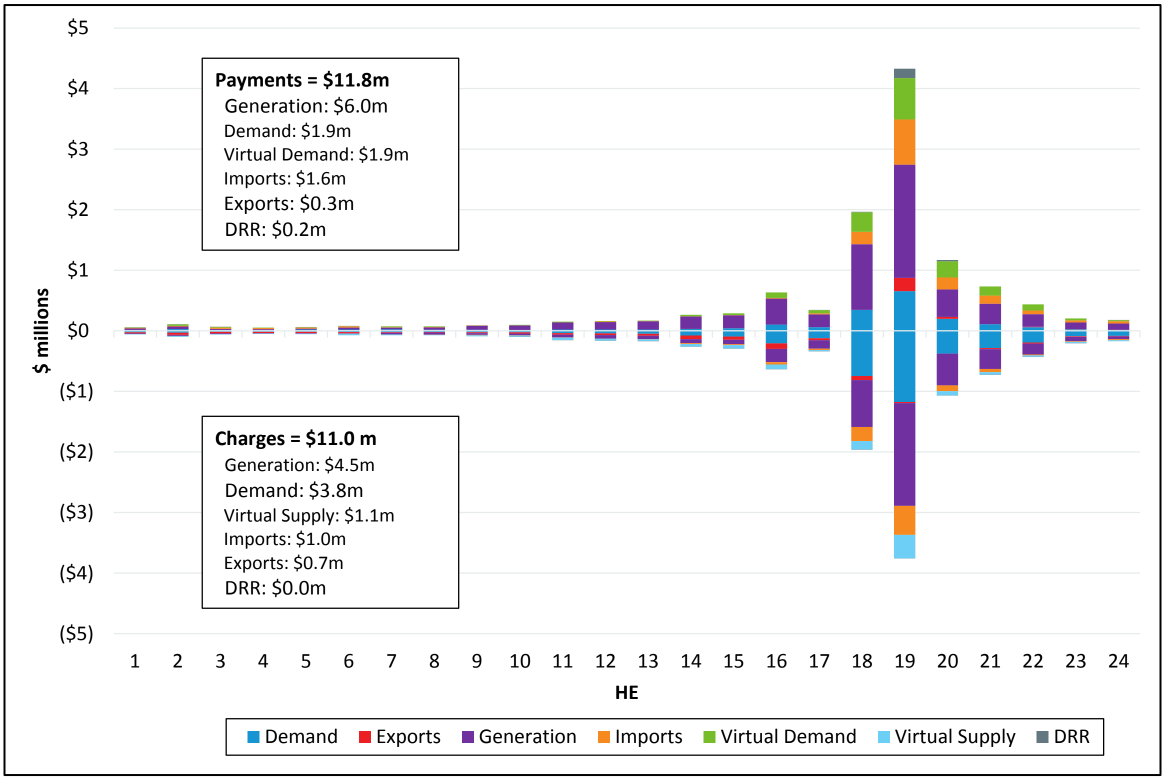
3.4.4 Two-Settlement System Outcomes

This subsection provides insight into under- and over-performers relative to forward positions on June 18, 2024. Coverage includes both the energy and the capacity markets.

Energy Charges and Payments

Total energy charges to load on June 18 amounted to an estimated $30.9 million. Of this, $30.6 million (99%) in charges were made in the day-ahead market, while net real-time charges accounted for the remaining $0.3 million (1%).[25] Gross payments for real-time deviations totaled $11.8 million, while gross charges totaled $11.0 million.[26] Real-time energy charges and payments by hour are shown in Figure 3-13 below.

Figure 3-13: Real-Time Deviation Energy Charges and Payments, June 18



Generation incurred the largest gross real-time charges ($4.5 million) on June 18.[27] In aggregate, under-performing generators produced up to 2,300 MW per hour less in real time compared to

[25] Most costs are incurred in the day-ahead market, where most generation and load clear. Deviations against day-ahead positions are settled in the real-time market.

[26] These totals are the gross payments and charges that resulted from participant deviations from day-ahead obligations by activity type (load, generation, etc.) and location. By contrast, the $0.4 million represents net real-time charges that resulted from real-time load obligation deviations.

[27] Gross real-time charges to generation are calculated in three steps. First, each participant's negative generation deviation at each location (their day-ahead generation in excess of their real-time generation) is calculated. Second, that negative generation deviation is multiplied by the LMP at the same location to get the dollar amount charged to the participant. Third, the charges are summed across all participants and locations to arrive at gross real-time charges to generation. Similar steps are performed to compute the other charges and payments by activity type (load, exports, etc.).

their day-ahead awards. Given that numerous units with day-ahead awards experienced unplanned outages on June 18, these real-time charges to generators are to be expected. There were also significant charges to demand ($3.8 million) as some load-serving entities bought more energy in real time than they had purchased in the day-ahead market. Notable charges also went to virtual supply ($1.1 million) and imports ($1.0 million). On the payments side, the majority of payments went to generators ($6.0 million) that produced more energy in real time than they had cleared in the day-ahead market. Significant payments were also made to virtual demand ($1.9 million) and imports ($1.6 million).

Forward Capacity Market (FCM) Pay-for-Performance

During capacity scarcity conditions, every FCM-participating resource, energy market asset, and external transaction is subject to Pay-for-Performance (PfP) credits or charges based on energy market performance. The performance of FCM-participating resources is assessed relative to their CSO adjusted by the system-wide balancing ratio.[28] PfP payments or charges are settled at the Capacity Performance Payment Rate. The payment rate increased to $5,455/MWh for the June 2024-May 2025 Capacity Commitment Period, up from $3,500/MWh for June 2021-May 2024.

PfP settlement reduces a resource's base capacity revenue for under-performing resources, and increases revenue for over-performing resources. The transfer is among supply resources, meaning that load is not exposed to PfP risk. A resource's financial obligation is based on its CSO cleared in the Forward Capacity Auction, which can be adjusted in secondary auctions prior to the delivery month. Resource's financial risks are limited by monthly and annual stop-loss limits.[29] Figure 3-14 below shows PfP outcomes by resource type for both CSO and non-CSO resources for the June 18, 2024 event.[30]

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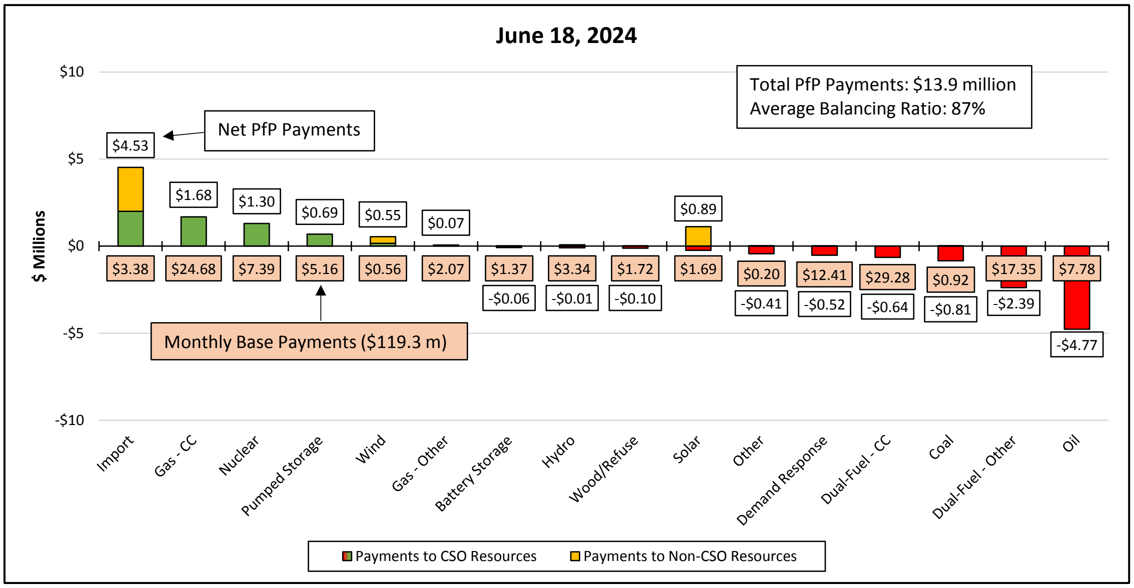
[28] For more information on the balancing ratio, see ISO's *Section III Market Rule 1 Standard Market Design*, section III.13.7.2.3, available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf .

[29] For more information about stop-loss limits, see ISO's *Section III Market Rule 1 Standard Market Design,* section III.13.7.3, available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf.

[30] In this figure, "Dual-fuel" refers to dual-fuel (gas/oil) resources and "CC" refers to combined-cycle resources. Total PfP Payments ($13.9 m) are calculated as the sum of PfP payments to each resource in the final monthly settlement. This is equivalent to the total amount of PfP charges to underperforming resources. Net PfP payments by fuel type are calculated as the net sum of PfP payments to resources of each fuel type. The sum of net PfP payments across fuel types is therefore not equal to the calculated total PfP payments.

Figure 3-14: Capacity Market Settlements by Fuel Type, June 2024



Imports, both with and without CSOs, were the best-performing resource type during the event. Imports with CSOs earned $2.0 million in PfP credits, while additional uncontracted imports earned an additional $2.5 million. Combined-cycle gas, nuclear, and pumped-storage generators outperformed obligations, earning $3.7 million in total. Non-combined-cycle dual-fuel generators and oil-fired generators were the worst performers during the event, with combined losses of $7.2 million. Poor oil performance was driven by unit trips leading into the event and the relative inflexibility of older oil-fired units. These losses were less than their base capacity payments for the month, and no resources neared stop-loss limits during the event.

PfP transfers totaled $13.9 million on June 18, 2024. For perspective, capacity base payments, including CSO payments from both primary and secondary auctions, totaled $119.3 million for the month. The system balancing ratio during the event averaged 87%, indicating that resources with CSO were obligated to provide at least 87% of their capacity to avoid PfP charges.

3.4.5 Operator Actions

System operators use manual actions to ensure reliability during tight conditions. Below, Table 3-2 lists available operator actions, and indicates whether each was used on June 18. We then give additional detail on each action that was used, in chronological order.

Table 3-2: Operator Interventions on June 18

Action	Occurred on 6/18
Cuts To External Transactions	No
Posturing	No
Manual Dispatch	Yes
Manual Fast-Start Commitments	No
Supplemental Commitments	Yes
Fast-Start Reliability Flag	No
Reserve Bias Changes	Evaluated

Supplemental commitments: At 15:09, operators issued a supplemental commitment for a 560 MW oil-fired generator due to capacity concerns. The generator tripped at 17:22, triggering the shortage event.

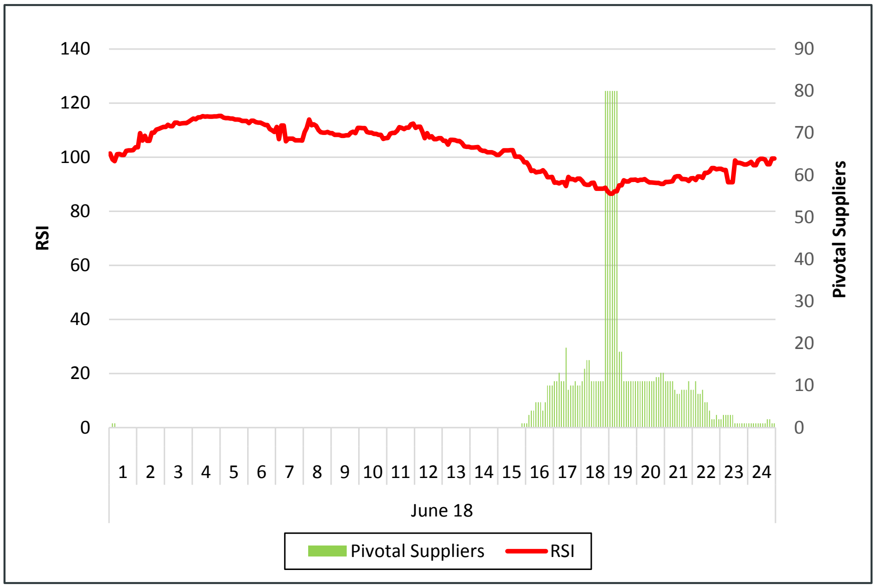
Reserve bias changes: Operators use reserve bias changes to increase the system operating reserve requirement with the intention of procuring additional reserves in the subsequent market dispatch solution. From 15:31 to 16:18, operators evaluated the impact of changing the Total30 reserve bias from 100 to several different values ranging from 110 to 150. Operators determined that the bias changes would not achieve the desired results, so they continued with additional manual actions.

Manual dispatch: Around 16:30, the operators manually dispatched five on-line generators to increase available reserves. Operators can increase total available reserves by dispatching up slower-ramping generators, allowing faster-ramping generators to be dispatched down to provide reserves. Between 16:45 and 18:25, operators dispatched these five generators up to a combined 97 MW above their market software dispatch points.

3.4.6 Market Power Assessment and Mitigation

With tight system conditions on June 18, we observed numerous participants ("pivotal suppliers") with potential market power. A participant is considered pivotal if load and the reserve requirement cannot be satisfied without their supply. Figure 3-15 depicts the real-time residual supply index (RSI) and number of pivotal suppliers for each five-minute pricing interval on June 18.

Figure 3-15: Residual Supply Index, June 18



On June 18, the RSI reached its lowest value of 86.5 during the two intervals beginning 18:00 and 18:05, indicating that the system could only meet about 87% of load and the reserve requirement without the largest supplier. During the shortage event intervals, all participants with supply available are considered pivotal.

The system event did not result in noteworthy energy market supply offer mitigation. With the exception of pivotal suppliers, the event also did not result in significant indicators of potential market power. Table 3-3 indicates the incidence of market power flags and mitigations.

Table 3-3: Market Power Flags and Mitigation, June 18

Type	DA Reliability	RT Reliability	MDE	DA CAE	Pivotal Suppliers
Market Power Flag - Asset Hours	0	0	17	6	1,401
Mitigations - Asset Hours	0	0	2	0	0

During the event, there were minimal manual dispatches by the ISO, resulting in two asset hours of manual dispatch energy mitigation. These were the only mitigations that occurred on June 18.

As would be expected given the tight system conditions on June 18, there were a significant number of generators associated with pivotal suppliers. During periods with negative reserve margins, all generators with available supply are considered pivotal. Three hundred and twenty-one generators were flagged as being associated with pivotal suppliers throughout the day, resulting in 1,148 asset hours of pivotal supply dispatch). None of these generators were mitigated. The applicable mitigation for pivotal suppliers (general threshold mitigation) has relatively tolerant thresholds and none of the associated generators exceeded the conduct test and market impact test needed to trigger mitigation for pivotal suppliers.

3.5 Market Performance on August 1, 2024

This section of the report looks specifically at how the New England electricity markets performed during the capacity scarcity conditions (CSC) that occurred on August 1, 2024.

3.5.1 Event Overview

The ISO also experienced capacity scarcity conditions on Thursday, August 1. Similar to the June 18 event, low reserve margins on August 1 were also driven by hot weather, high loads, and unplanned generator outages. A gas-fired generator tripped at 16:44, resulting in a loss of 330 MW just before the evening peak. Loads peaked at 23,758 during HE 18. Operators made supplemental generator commitments leading up to the evening peak due to capacity concerns. An M/LCC2 Abnormal Conditions Alert was in effect from 16:45 to 22:00, and the ISO implemented OP-4 Actions 1 and 2 from 16:45 to 21:45. The capacity scarcity conditions saw a longer duration than in previous events and spanned two separate time periods, lasting for 22 five-minute pricing intervals in the intervals beginning 16:55-17:00 and 17:45-19:20.

3.5.2 Drivers of Tight System Conditions

Weather and Load

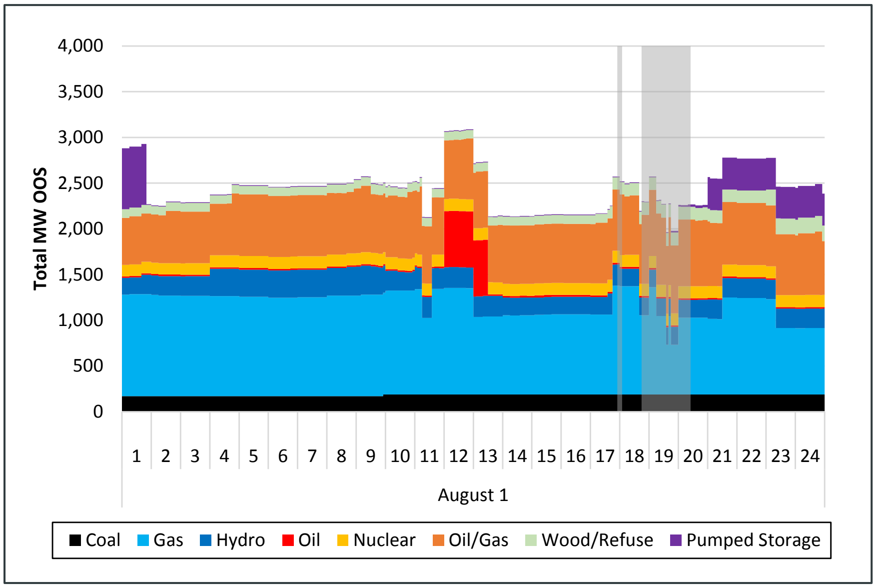
Loads peaked at 23,758 MW on August 1 as temperatures reached 90°F. Peak load during the event was lower than the annual peak load from July (24,816 MW). Load was roughly 300 MW above forecast during the reserve shortage period.[31] Similar to the June 18 event, high loads contributed to tight conditions but the primary cause of the scarcity event was unplanned generator outages.

Unplanned Generator Outages

Unplanned generator outages were also a primary driver of the August 1 shortage event. Figure 3-16 illustrates out-of-service generation capacity broken out by generator type. The capacity shortage condition is indicated by the gray area.

[31] The ISO publishes multiple load forecasts throughout the operating day. Loads reached 300 MW above the forecast published at approximately 9:30 on the prior day, which was the final load forecast published before the close of the day-ahead market. For more information, see the three-day system demand forecast, available at https://www.iso-ne.com/markets-operations/system-forecast-status/three-day-system-demand-forecast.

Figure 3-16: Planned and Unplanned Outages By Generator Type, August 1



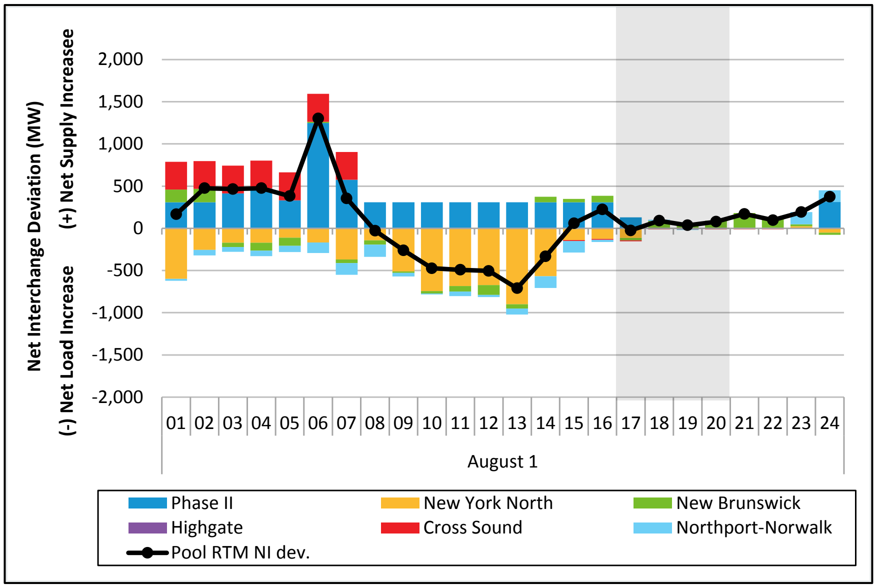
Total outage MW ranged between 2,000 and 2,500 MW during the capacity scarcity conditions. Four generators that had cleared in the day-ahead market experienced unplanned outages or reductions due to mechanical problems throughout the day, resulting in a loss of about 380 MW. Then, a gas-fired generator tripped at 16:44 due to a feed water pump issue. This 330 MW loss triggered the capacity scarcity conditions that began at 16:55. As with the June 18 event, the mechanical issues that caused generator trips were not explicitly related to the heat.

Net Imports

Throughout the middle of the operating day, real-time net interchange into New England was lower compared to the day-ahead market. However, flows at New York North responded as New England prices increased compared to New York and New England imported an average of nearly 3,000 MW between HE 18 and HE 20. Deviations between day-ahead cleared and real-time scheduled net imports at the six interfaces are show below in Figure 3-17 below.[32]

[32] The Highgate interface was out of service on August 1, 2024.

Figure 3-17: Day-Ahead vs. Real-Time Net Interchange Deviations, August 1

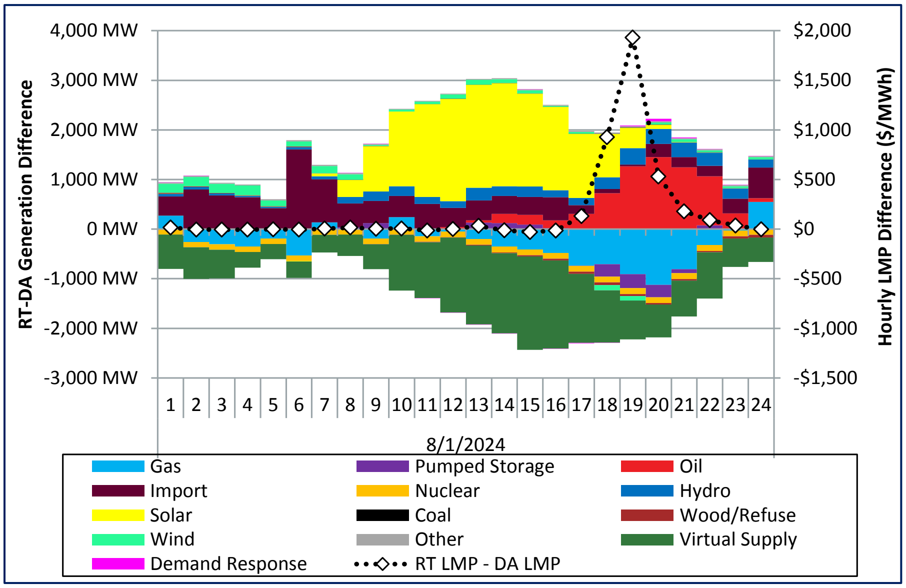


During the start of the scarcity conditions in HE 17, net imports were 25 MW below what cleared in the day-ahead market as real-time flows at New York North remained slightly below day-ahead levels. New York experienced high prices during this period, averaging $550/MWh between 16:30 and 17:55. However, net imports at New York North were up to 1,400 MW by HE 18, the maximum import Total Transfer Capability (TTC) of the interface. Through the rest of the system event and operating day, net interchange remained slightly above day-ahead cleared volumes. Scheduling additional imports to ease tight conditions was not feasible as most interfaces were already restricted by, or approaching the real-time import TTCs.

Supply Mix Changes

The differences in generation obligations and average LMPs at the Hub between the day-ahead and real-time markets are shown in Figure 3-18 below.

Figure 3-18: Differences between Hourly Real-Time and Day-Ahead Generation Obligations and LMPs, August 1



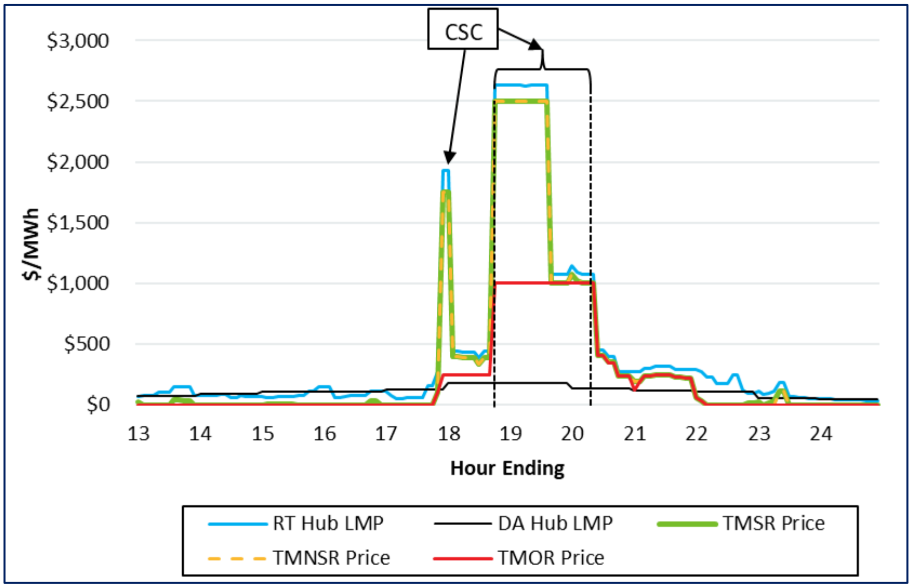
Oil-fired generators were called upon to provide additional output during the evening hours of this operating day. The ISO supplementally committed several oil-fired generators as conditions tightened, and additional fast-start oil-fired generators were dispatched in merit order as a result of the capacity scarcity conditions. Total output from oil-fired generation peaked at 1,450 MWh during HE 20 on this day. Unplanned outages and reductions on three natural-gas fired generators resulted in negative deviations of 536 MWh during the highest priced hour. Additionally, some pumped-storage hydro and natural gas-fired generation was dispatched down from their day-ahead schedules in order to provide operating reserves in real-time; this resulted in negative deviations for these generators.

3.5.3 Energy Prices, Reserve Prices, and Uplift

Energy and Reserve Prices

Energy and reserve prices from August 1 are shown in Figure 3-19 below.

Figure 3-19: Five-Minute Energy and Reserve Prices, System Level, August 1



There were two distinct periods of operating reserve deficiency on this day. First, a deficiency of total ten-minute reserves in pricing intervals 16:55 – 17:00 resulted in TMSR and TMNSR prices of $1,750/MWh during this ten minute period, reflective of the $1,500/MWh Ten Minute Reserve Requirement Penalty Factor. Later, during pricing intervals 17:45 – 19:20, deficiencies of both total ten-minute and total thirty-minute reserves resulted in high prices during this 100 minute (1.67 hour) time period. The reserve constraint penalty factors for both of these reserve constraints ($1,500/MWh and $1,000/MWh respectively) affected prices during this time period. TMSR and TMNSR prices reached $2,500/MWh for 55 minutes, while TMOR clearing prices were $1,000/MWh for this entire 100 minute period. As always, the opportunity cost of providing reserves rather than energy was reflected in real-time LMP calculations. The highest observed real-time Hub LMP during this period was $2,634.05/MWh.

Uplift

Real-time uplift totaled $0.6 million on August 1. Similar to June 18, manual dispatches for capacity drove dispatch out of merit payments prior to the event. Payments during the event were driven by dispatch opportunity costs rather than unrecovered commitment costs. Following the event, generators that remained online received significant commitment out of merit payments. Operators manually committed many fast-start demand response resources during the event, which provided energy during scarcity conditions but remained online and received uplift following the event.

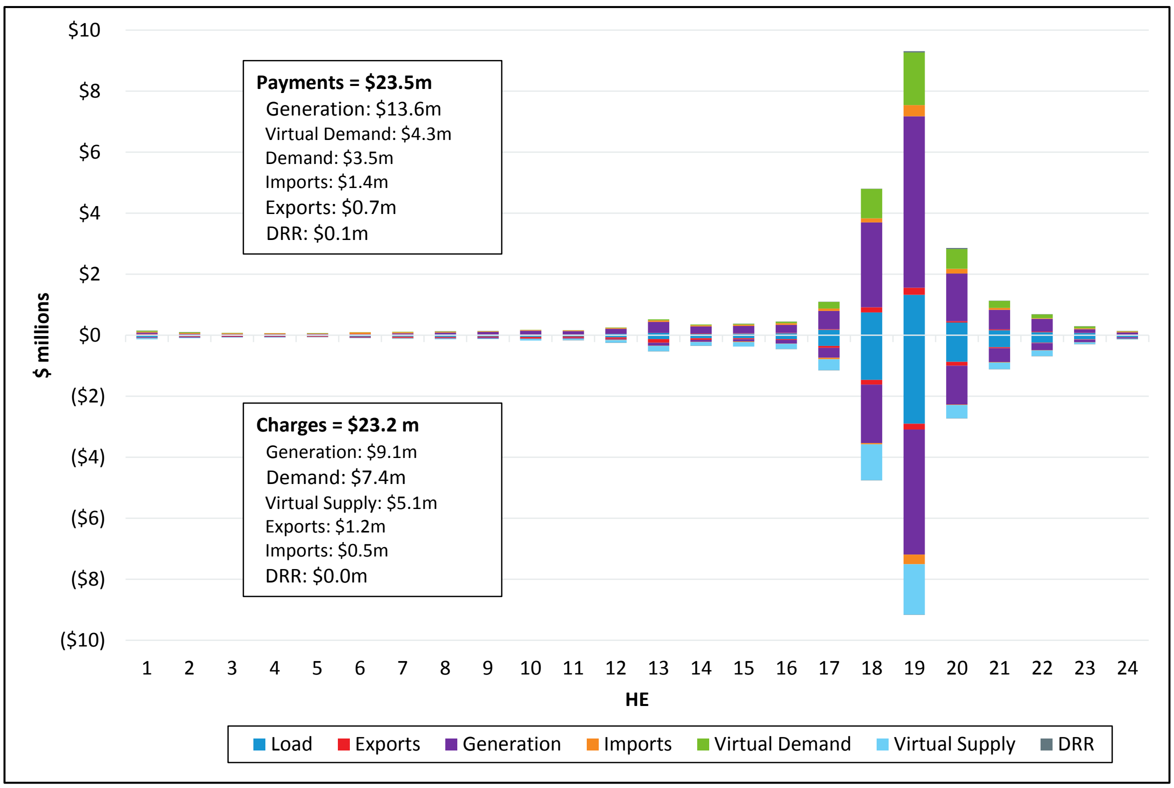
3.5.4 Two-Settlement System Outcomes

This subsection provides insight into under- and over-performers relative to forward positions on August 1, 2024. Coverage includes both the energy and the capacity markets.

Energy Charges and Payments

Total energy charges to load on August 1 amounted to an estimated $38.7 million. Nearly all of these charges were made in the day-ahead market, with net real-time charges accounting for less than $0.1 million. Gross payments for real-time deviations totaled $23.5 million, while gross charges totaled $23.2 million.[33] Real-time energy charges and payments by hour are shown in Figure 3-20 below.

Figure 3-20: Real-Time Deviation Energy Charges and Payments, August 1



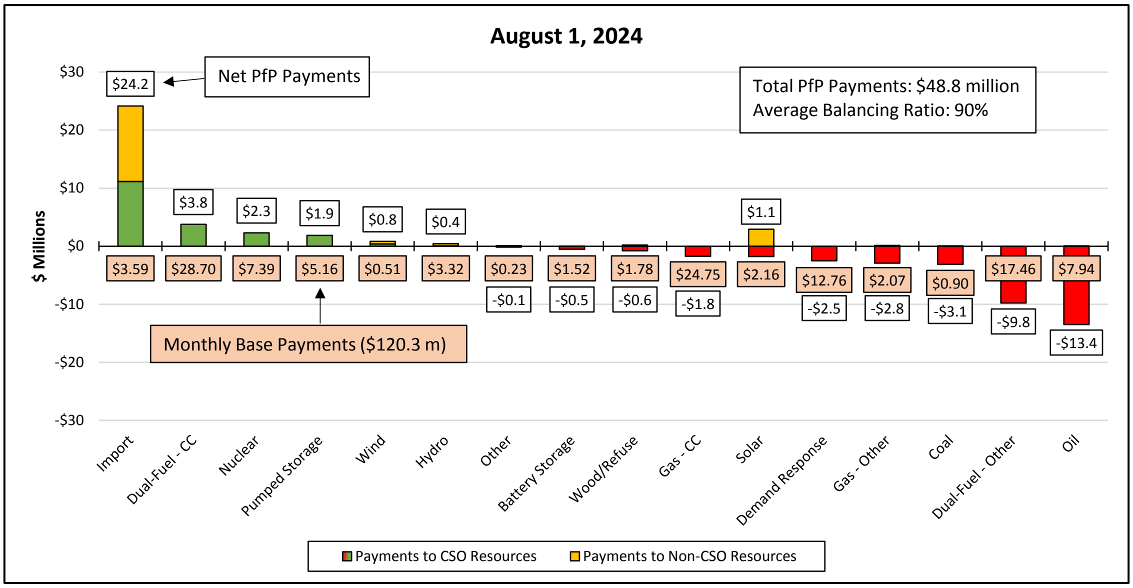
Generation incurred the largest gross real-time charges ($9.1 million) on August 1. In aggregate, under-performing generators produced up to 2,000 MW per hour less in real time compared to their day-ahead awards. There were also significant charges to demand ($7.4 million) as some load-serving entities bought more energy in real time than they had purchased in the day-ahead market. Notable charges also went to virtual supply ($5.1 million). On the payments side, the majority of payments went to generators ($13.6 million) that produced more energy in real time than they had cleared in the day-ahead market. Significant payments were also made to virtual demand ($4.3 million) and physical demand ($3.5 million).

[33] These totals are the gross payments and charges that resulted from participant deviations from day-ahead obligations by activity type (load, generation, etc.) and location.

Forward Capacity Market (FCM) Pay-for-Performance

Figure 3-21 below shows PfP outcomes by resource type for both CSO and non-CSO resources for the August 1, 2024 event.[34]

Figure 3-21: Capacity Market Settlements by Fuel Type (August 2024)



Similar to the June event, imports provided relatively flexible energy during shortage conditions on August 1. Imports with CSOs earned $11.2 million in PfP credits, and uncontracted imports earned $13.0 million. Nuclear and pumped-storage generators again outperformed obligations on average. Oil-fired generators similarly accrued the largest PfP charges, with losses at $13.4 million. Notably, these losses exceeded base payments to oil-fired generators, indicating that oil-fired resources lost money in total during August. Oil-fired resources reached 35% of monthly stop-loss limits on average, and no individual resources reached stop-loss limits during the event.[35] While resources came closer to stop-loss limits on August 1 relative to prior events, the limits remain relatively far from observed PfP losses.

PfP charges totaled $48.8 million on August 1. The increase in PfP payments compared to the June 18 event was driven by the longer duration of capacity scarcity conditions on August 1 and a higher balancing ratio. The system balancing ratio during this event averaged 90%, indicating that resources were obligated to provide at least 90% of their capacity to avoid PfP charges. Capacity base payments, including CSO payments from both primary and secondary auctions, totaled $120.3 million for the month.

[34] In this figure, "Dual-fuel" refers to dual-fuel (gas/oil) resources and "CC" refers to combined-cycle resources.

[35] Penalties to under-performing resources in PfP events are subject to monthly and annual stop-loss limits. Stop loss limits are a function of resource CSO and FCA starting prices. For more information on stop-loss limits, see ISO's *Section III Market Rule 1 Standard Market Design,* section III.13.7.3, available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf.

3.5.5 Operator Actions

Below, Table 3-4 lists available operator actions, and indicates whether each was used on August 1. We then give additional detail on each action that was used.

Table 3-4: Operator Interventions on August 1

Action	Occurred on 8/1
Cuts To External Transactions	No
Posturing	No
Manual Dispatch	No
Manual Fast-Start Commitments	Yes
Supplemental Commitments	Yes
Fast Start Reliability Flag	No
Reserve Bias Changes	No

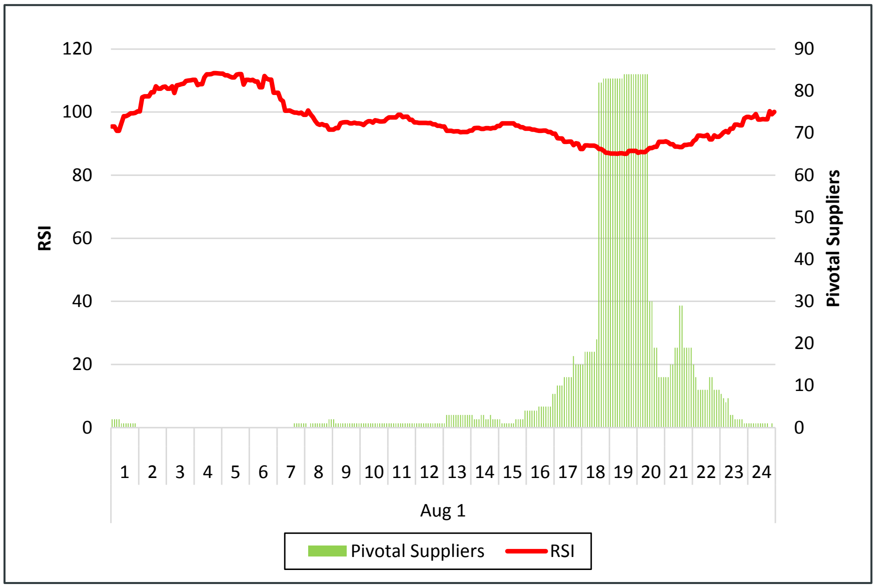
Manual fast-start commitments: From 17:46-18:44, system operators manually committed 56 off-line fast-start DRRs and 13 off-line fast-start generators to access additional capacity. The manual DRR commitments provided an additional 40 MW of energy, while the manual generator commitments provided an additional 400 MW of energy.

Supplemental commitments: From 17:20-17:55, operators issued supplemental commitments for eight generators due to capacity concerns. These generators produced about 95 MW combined after coming on-line.

3.5.6 Market Power Assessment and Mitigation

Given the tight system conditions on August 1, we observed numerous participants with potential market power. Figure 3-22 depicts the real-time residual supply index (RSI) and number of pivotal suppliers for each five-minute pricing interval on August 1.

Figure 3-22: Residual Supply Index, August 1



On August 1, the RSI reached its lowest value of 86.8 from 18:30-18:35, indicating that the system could only meet about 87% of load and the reserve requirement without the largest supplier. The August 1 event saw more five-minute intervals with 80 or more pivotal suppliers than the June 18 event because reserve margins were below zero for a longer period on August 1. When the reserve margin is at or below zero, all available suppliers are pivotal.

The system event did not result in noteworthy energy market supply offer mitigation. With the exception of pivotal suppliers, the event also did not result in significant indicators of potential market power.

Table 3-5 indicates the incidence of market power flags and mitigations on August 1.

Table 3-5: Market Power Flags and Mitigation, August 1

Type	DA Reliability	RT Reliability	MDE	DA CAE	Pivotal Suppliers
Market Power Flag - Asset Hours	0	17	21	0	2,057
Mitigations - Asset Hours	0	0	1	0	0

During the event, there were minimal reliability commitments and manual dispatches by the ISO. The reliability commitments were for two "special constraint resources" (SCR) providing support for a local distribution network. These SCR commitments occur frequently during the summer and were not necessarily a result of the system event. Twenty-one asset hours of manual generator dispatch (MDE) occurred on the day of the event, with one generator having its energy market supply offer mitigated for one hour.

Similar to the June 18 event, there were many generators associated with pivotal suppliers. During periods with negative reserve margins, all available generators are pivotal. Three hundred and twenty-nine generators were flagged as being associated with pivotal suppliers throughout the day, resulting in 1,617 asset hours of pivotal supply dispatch. This was a higher number of pivotal supplier asset hours than on June 18 because the August 1 shortage was longer in duration. None of these generators were mitigated. The applicable mitigation for pivotal suppliers (general threshold mitigation) has relatively tolerant thresholds and none of the associated generators exceeded the conduct test and market impact test needed to trigger mitigation for pivotal suppliers.

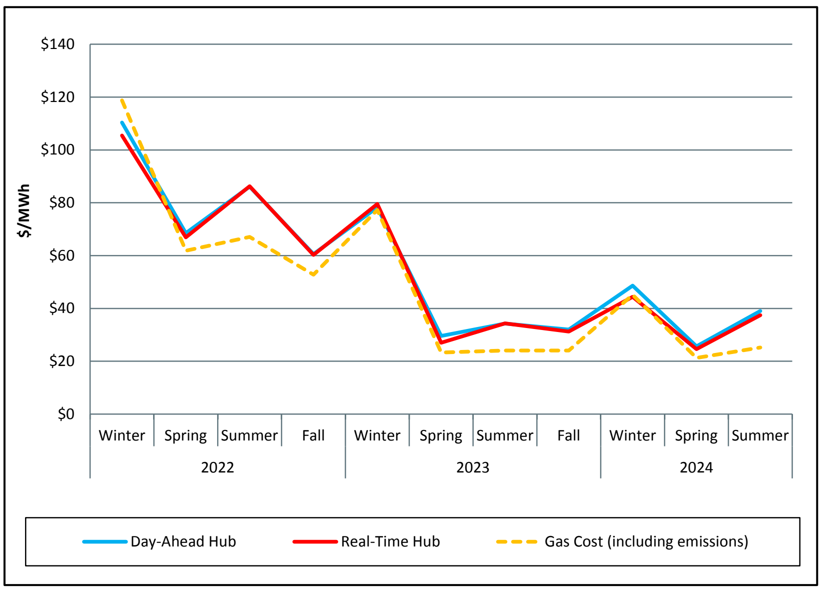
Section 4
Day-Ahead and Real-Time Markets

This section covers trends in, and drivers of, market outcomes for energy, operating reserves, and regulation products.

4.1 Energy Prices

In New England, seasonal movements of energy prices are generally consistent with changes in natural gas generation costs. These trends can be seen in Figure 4-1 which shows the average day-ahead and real-time energy prices, along with the estimated cost of generating electricity using natural gas in New England.[36]

Figure 4-1: Simple Average Day-Ahead and Real-Time Hub Prices and Gas Generation Costs



The average real-time and day-ahead Hub prices for Summer 2024 were $37.45 and $39.03/MWh, respectively. Gas costs averaged $25.21/MWh in Summer 2024. Though quarterly average real-time prices were slightly lower than day-ahead prices, there were certain days where real-time prices were substantially higher due to shortage events and tight system conditions. The elevated real-time prices that occurred during the capacity scarcity conditions on June 18 and August 1 are discussed in Sections 3.4 and 3.5.

Average energy prices in Summer 2024 were higher than Summer 2023 prices by about $5 and $3/MWh (up 60%) in the day-ahead and real-time markets, respectively. These small increases occurred despite lower natural gas prices in Summer 2024, which were down 21% from Summer 2023 prices. LMPs typically move in the same direction as natural gas prices. However, in Summer 2024 two factors, in particular, combined to send LMPs rising while gas prices declined: 1) higher loads and increased utilization of gas generation in its upper dispatch ranges put upward pressure

[36] The natural gas cost is based on the average natural gas price each season and a generator heat rate of 7,800 Btu/kWh, which is the estimated average heat rate of a combined cycle gas turbine in New England.

on LMPs; and 2) the average cost of RGGI CO_2 allowances increased by 80% from Summer 2023. The increase in RGGI prices (~$5/MWh) more than offset the drop in natural gas prices (~$3.85/MWh).

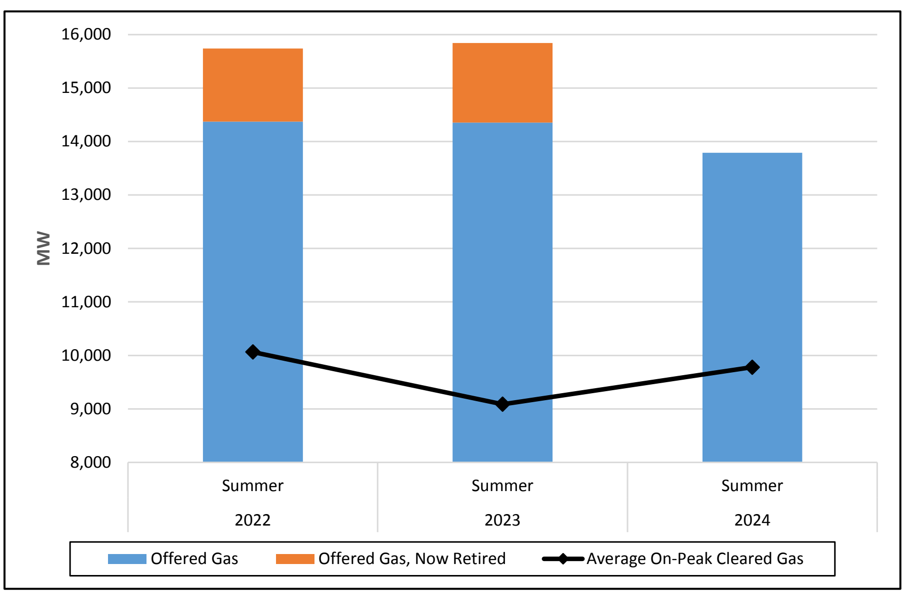
The spread between the average day-ahead electricity price and average estimated gas and CO_2 emissions cost was $14/MWh in Summer 2024, higher than the $10/MWh spread in Summer 2023. The higher spreads in Summer 2024 were driven by the utilization of gas resources in the upper portions of their dispatchable ranges, which are more expensive. This occurred more frequently in Summer 2024 due to the higher loads and tighter conditions compared to the previous summer. The increased frequency of expensive gas generation setting price led to greater spreads for more efficient gas generators, which were often inframarginal.

Gas Generation Offers, Clearing, and Impact on Pricing Outcomes

Gas generators are frequently marginal in the day-ahead market, and LMPs typically reflect the operating costs of gas-fired generation on the lower segments of the supply curve. In high-load conditions, gas-fired generators are often cleared in the upper segments of their supply curves, leading to high LMPs as these relatively expensive upper-block ranges or other resource types set price. Such conditions occurred more frequently in Summer 2024 than in prior years due to decreases in available gas generation. This led to high LMPs and significant spreads between energy prices and gas costs in a few peak hours of the season.

The amount of total gas generation available on the supply curve decreased in Summer 2024 as a result of generator retirements and outages. Figure 4-2 below shows the average hourly offered and cleared gas generation in the day-ahead market in Summer 2024 relative to prior years. Offered gas is separated by capacity that was active in prior years but retired in Summer 2024.

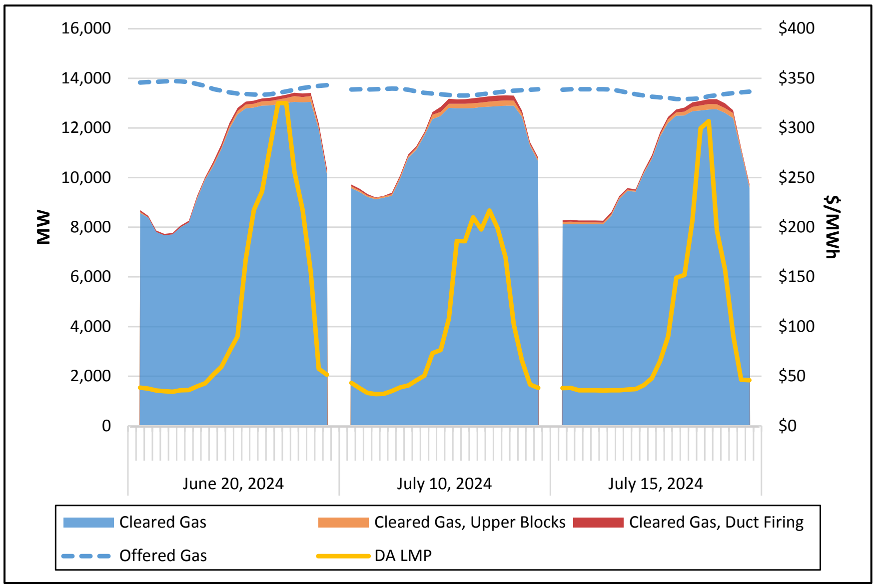
Figure 4-2: Day-Ahead Offered and Cleared Gas Generation



Average hourly offered gas generation fell to 13,800 MW, down from over 15,700 MW in the prior two summers. The decline in offered gas generation is attributable to generator retirements and extended outages. In peak hours, 9,800 MW of gas generation cleared the day-ahead market on average, up from Summer 2023 and comparable to Summer 2022 (10,000 MW).

While gas generation cleared below total physical availability on average in Summer 2024, there were multiple hours when gas generation cleared near total capacity, leading to relatively high prices in the day-ahead market. Figure 4-3 below shows hourly offered and cleared gas generation alongside day-ahead LMPs on select peak days in Summer 2024. Offered gas is calculated as the cumulative Ecomax of all available gas generators in the day-ahead market. The figure disaggregates cleared gas generation into normal operating segments and upper block or duct-firing segments.[37]

Figure 4-3: Day-Ahead Gas Clearing on Peak Days



Gas generation cleared at almost full offered capacity during peak hours on June 20, July 10, and July 15. Gas-fired generators cleared at high total utilization rates more frequently than in prior years following the reduction in offered capacity, with 98 hours when gas-fired generators cleared more than 95% of offered capacity in Summer 2024, up from 0 hours in Summer 2023 and 51 hours in Summer 2022. Gas cleared at essentially full capacity (99% or more) in the day-ahead market in eight hours, up from only one hour in 2022. Gas-fired generators with upper block or duct firing capabilities were utilized in peak hours, with over 350 MW of upper block or duct firing output during peak hours on all three days.

[37] Upper block and duct firing ranges represent relatively expensive gas generation. Upper block generation is produced by relatively inefficient power blocks in a gas generator's upper output ranges. Duct firing involves burning fuel to heat exhaust gases and increase electricity output. Upper block and duct firing generation are estimated using generator reference level data. More information on upper block generation is available in the EIA's article *Power blocks in natural gas-fired combined-cycle plants are getting bigger*, (February 12, 2019), at https://www.eia.gov/todayinenergy/detail.php?id=38312. More information on duct firing is available in the EIA's article *Most combined-cycle power plants have duct burners that add energy to the turbine exhaust* (June 15, 2022), available at https://www.eia.gov/todayinenergy/detail.php?id=52778.

Since gas generation typically makes up the flat portion of the supply curve when gas is inexpensive, high gas-fired generator utilization rates are associated with pricing outcomes on the steep portion of the supply curve. In such conditions, gas-fired generators operate in relatively inefficient upper output ranges and other generation sources, imports, and virtual supply frequently set price. Day-ahead LMPs exceeded $200/MWh on each of the three peak days. Spark spreads exceeded $215/MWh on June 20, $170/MWh on July 10, and $270/MWh on July 15 during peak hours as nearly all relatively efficient gas generation cleared the market.[38] These hours significantly contributed to the observed gap between LMPs and estimated gas generation costs in Summer 2024.

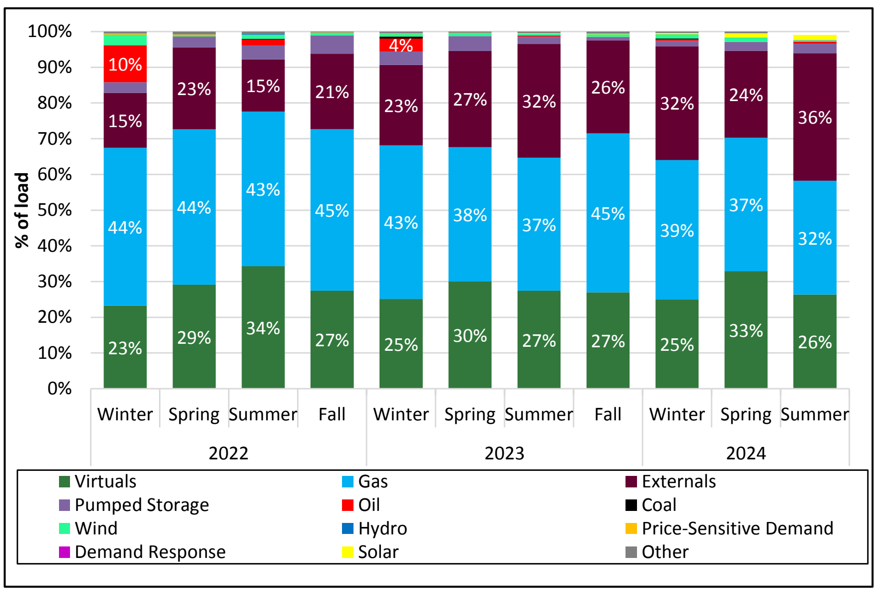
4.2 Marginal Resources and Transactions

This section reports marginal units by transaction and fuel type on a load-weighted basis. When more than one resource is marginal, the system is typically constrained and marginal resources likely do not contribute equally to setting price for load across the system. The methodology employed in this section accounts for these differences, weighting the contribution of each marginal resource based on the amount of load in each constrained area.

Day-Ahead Energy Market

The percentage of load for which each transaction type set price in the day-ahead market since Winter 2022 is illustrated in Figure 4-4 below.

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



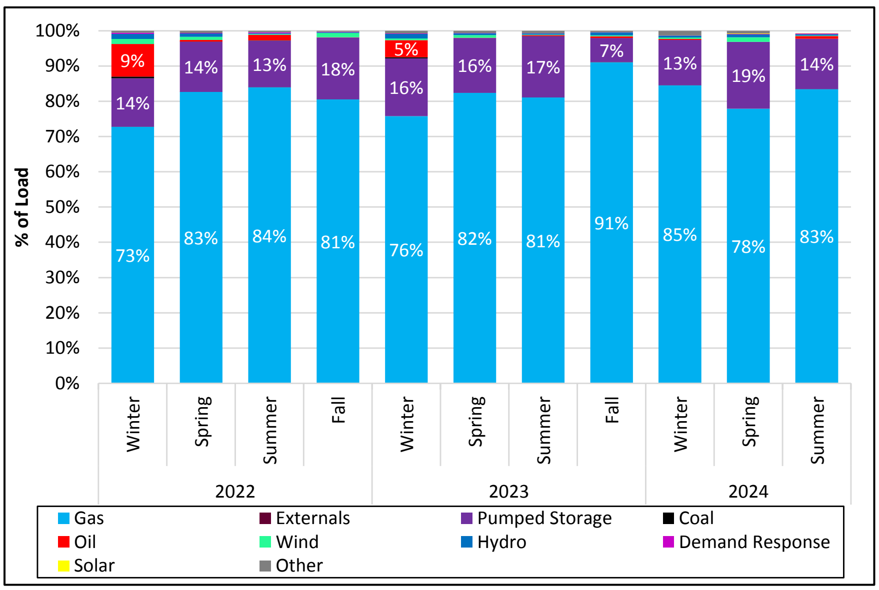
[38] Spark spreads are calculated as the difference between day-ahead LMPs and gas generation costs, including emissions prices. Gas prices in $/MMBtu and emissions prices in $/short ton are converted to $/MWh through standard generating efficiency and emissions rate assumptions. The IMM assumes a standard efficiency of 7.8 MMBtu/MWh to represent New England gas-fired generation.

External transactions were the most common marginal resource type in the day-ahead market, setting price for 36% of total day-ahead load in Summer 2024. This percentage is the highest share that externals have accounted for in the reporting period and was largely the result of one participant that reduced their level of fixed imports in favor of priced imports. Gas-fired generators and virtual transactions were next, setting price for 32% and 26% of load, respectively. Other resource types were collectively marginal for around 6% of load.[39] Of note from this group, solar accounted for slightly more than 1%. Beginning in December 2023, solar resources with a Capacity Supply Obligation ("CSO") were required to begin participating in the day-ahead market as a part of the Do Not Exceed Dispatch ("DNE") project.[40] Section 2 of this report assesses the impact of this new market rule.

Real-Time Energy Market

The percentage of load for which each fuel type set price in the real-time market since Winter 2022 is shown in Figure 4-5 below.

Figure 4-5: Real-Time Marginal Units by Fuel Type



Natural gas-fired generators set price for highest percentage of load in the real-time market in Summer 2024 (83%). Pumped-storage facilities (generation and demand) set price for 14% of load in Summer 2024. Both of these levels were comparable to the prior two summer seasons. All other resource types accounted for around 2% of load, with solar generation representing a little over 0.1%.

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

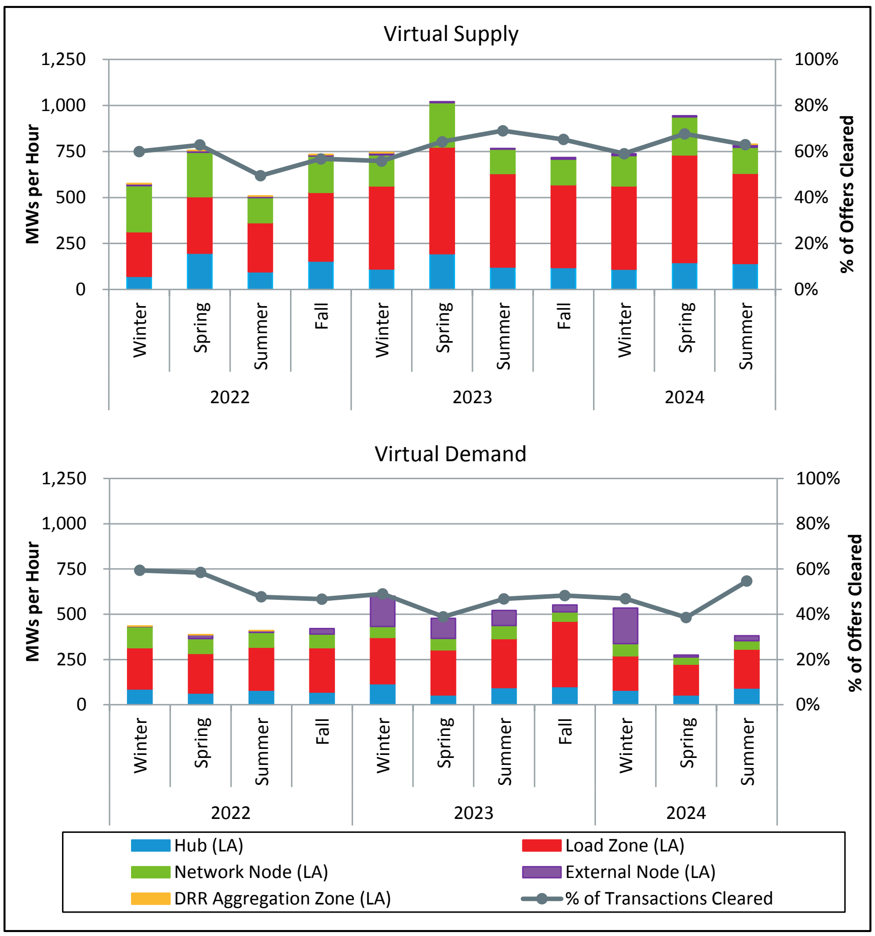
[40] For more information about the incorporation of solar generation into the DNE rules, see the ISO's filing to FERC Revisions to ISO New England Transmission, Markets and Services Tariff to Incorporate Solar Resources into DNE Dispatch Rules, Docket No. ER23- -000 (November 30, 2022), available at https://www.iso-ne.com/static-assets/documents/2022/11/extend_dne_to_solar_resources.pdf.

4.3 Virtual Transactions

In the day-ahead energy market, participants submit virtual demand bids and virtual supply offers to profit from differences between day-ahead and real-time LMPs. Generally, profitable virtual transactions improve price convergence and help the day-ahead dispatch model better reflect real-time conditions.

The average volume of cleared virtual supply (top graph) and virtual demand (bottom graph) are shown on the left axis in Figure 4-6 below. Cleared transactions are categorized based on the location type where they cleared: Hub, load zone, network node, external node, and Demand Response Resource (DRR) aggregation zone. The line graph (right axis) shows cleared transactions as a percentage of submitted transactions, both for virtual supply and virtual demand.

Figure 4-6: Cleared Virtual Transactions by Location Type



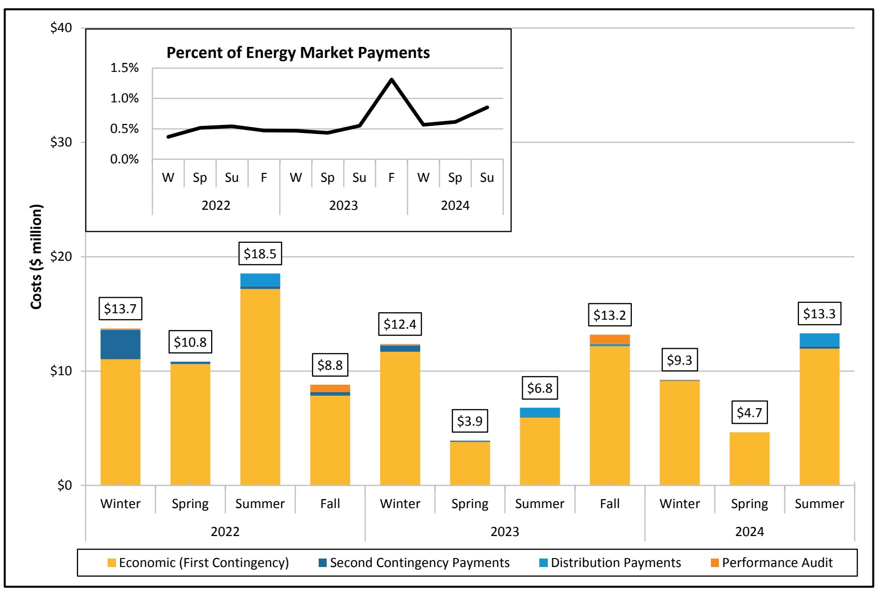
Total cleared virtual supply averaged 789 MW per hour in Summer 2024, up 3% from Summer 2023 (767 MW per hour). Two notable factors behind the levels of cleared virtual supply are: 1) the growing amount of solar settlement-only generation (SOG) and 2) the day-ahead bidding behavior of wind and solar generation. By the end of Summer 2024, the installed capacity of solar SOGs was over 2,250 MW. Since SOGs cannot participate in the day-ahead market, participants often clear virtual supply on days when solar generation is expected to be high and impactful on real-time prices. Participants also frequently use virtual supply to try to capture differences between day-ahead and real-time prices in export-constrained areas, particularly areas with wind and solar generation. Beginning in December 2023, the Do-Not-Exceed (DNE) Dispatch Project expanded to include utility-scale (> 5 MW installed capacity) solar generation (see Section 2 for more detail). Typically, these generators offer high-priced energy in the day-ahead market, but produce energy at low, or even negative, prices in the real-time market.[41]

Cleared virtual demand averaged 381 MW per hour in Summer 2024, down 27% from Summer 2023 (522 MW per hour). In Summer 2024, participants cleared an average of 27 MW per hour at external nodes, which was down from 83 MW per hour in Summer 2023. Most of the decrease occurred at the Highgate interface, which connects New England to the Hydro-Québec control area. At Highgate, average cleared virtual demand dropped from 51 MW per hour in Summer 2023 to 18 MW per hour in Summer 2024.

4.4 Net Commitment Period Compensation

Net Commitment Period Compensation (NCPC) credits are make-whole payments to generators, external transactions, or virtual participants that incur uncompensated costs when following ISO dispatch instructions. NCPC categories include first- and second-contingency protection, voltage support, distribution system protection, and generator performance auditing.[42] Figure 4-7 below shows total NCPC by category and quarter for 2022-2024. The inset graph shows quarterly NCPC payments as a percent of total energy market payments.

Figure 4-7: NCPC by Category



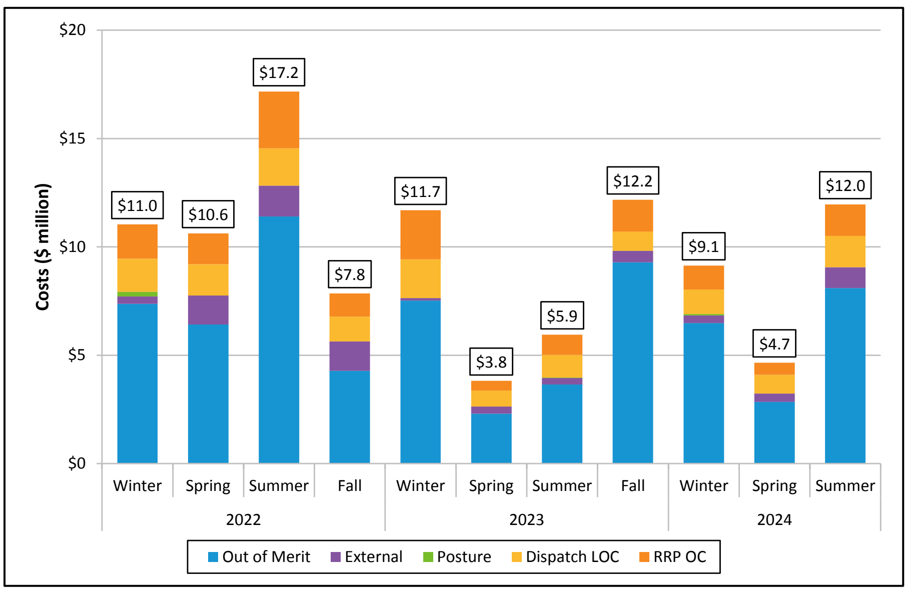
[41] In Summer 2024, wind generation averaged 155 MW per hour in the day-ahead market, while real-time wind generation averaged 262 MW hour.

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

NCPC payments totaled $13.3 million in Summer 2024, up from $6.8 million in Summer 2023. Uplift increased to 0.9% of energy market payments from 0.6% in both Summer 2023 and Spring 2024. The increase was mostly driven by economic first contingency payments, which totaled $12.0 million. As discussed below, real-time fast-start commitments continued to drive the majority of economic uplift. While the majority of NCPC was paid to generators committed for system load and reserve requirements, local second contingency payments totaled $0.2 million and distribution protection payments reached $1.1 million. Local second contingency payments primarily occurred in the day-ahead market to generators located in Southeast Massachusetts due to import transmission constraints. Distribution payments are common in summer months when loads are high, and increased 47% from Summer 2023 following higher loads.

Economic NCPC can be further categorized by reason, including out of merit payments for generator operating costs that are not fully covered through energy market revenue, external payments, posturing, and dispatch or rapid response opportunity cost payments. The following Figure 4-8 displays economic NCPC payments by reason.

Figure 4-8: Economic NCPC by Reason



Out of merit payments continued to make up the largest share of economic NCPC at $8.1 million, or 68% of economic uplift. Commitment out of merit payments were clustered in groups of hot days when conditions were tight. On such days, fast-start commitments are commonly used to maintain system reliability. While fast-start pricing mechanics reduce total uplift payments, real-time fast-start commitments can receive uplift if the unit is not in merit throughout its run time. Oil-fired generators and dual fuel-fired generators received the largest shares of out of merit payments.

Economic payments to external or virtual transactions totaled $1.0 million, up from $0.3 million last summer. Day-ahead external and virtual payments are typically transfers between market participants to fund congestion-relieving transactions. Such day-ahead payments totaled $0.2 million in Summer 2024. Real-time external uplift is primarily driven by price forecast error when scheduling external transactions. Real-time external uplift totaled $0.7 million during the summer.

Dispatch and rapid response pricing opportunity cost payments comprised the remainder of economic NCPC at $2.9 million. Opportunity cost payments accounted for 24% of economic NCPC, down from 33% in Summer 2023.

4.5 Real-Time Operating Reserves

This section provides details about real-time operating reserve pricing and payments. ISO-NE procures three types of real-time reserve products: (1) ten-minute spinning reserve (TMSR), (2) ten-minute non-spinning reserve (TMNSR), and (3) thirty-minute operating reserve (TMOR). Real-time reserve prices have non-zero values when the ISO must re-dispatch resources to satisfy a reserve requirement.[43] Resources providing reserves during these periods receive real-time reserve payments.

Real-time Reserve Pricing

The frequency of system-level non-zero reserve pricing for each product, along with the average price during these intervals, for the past three summer seasons is provided in Table 4-1 below.[44]

Table 4-1: Hours and Level of Non-Zero Reserve Pricing

Product	Summer 2024		Summer 2023		Summer 2022	
	Avg. Price $/MWh	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*
TMSR	$48.57	215.5	$13.30	177.8	$19.98	343.1
TMNSR	$180.67	51.3	$270.38	5.4	$204.82	20.4
TMOR	$212.35	31.1	$275.29	3.5	$231.08	14.9

Summer 2024 is noteworthy for the high frequency of non-zero pricing for the TMNSR and TMOR reserve products relative to past seasons. TMNSR was priced above $0/MWh in over 50 hours this summer, while TMOR was priced above $0/MWh in over 30 hours; this level of reserve pricing is roughly 10 times greater than that observed in the prior summer period. These periods of reserve pricing generally resulted from high loads and tight system conditions, with high utilization of the natural gas fleet depleting the amount of reserves those units were able to provide. The higher occurrence of non-zero pricing resulted in lower *average* non-zero TMNSR and TMOR prices over this period compared to prior periods, despite the occurrence of Capacity Scarcity Conditions (CSCs) on two days during this timeframe. Of course, during those CSCs, reserve prices were very high and reflected underlying Reserve Constraint Penalty Factors (RCPFs). The TMOR clearing price was $1,000/MWh for 2.2 hours, while the TMNSR clearing price was $2,500/MWh for 0.9 hours.

The average TMSR clearing price increased significantly from the prior summer season, while the frequency of non-zero TMSR pricing held relatively steady. This pricing outcome reflects that fact that the TMSR product is able to contribute to satisfying all of the ISO's reserve requirements

[43] Real-time operating reserve requirements are utilized to maintain system reliability. There are several real-time operating reserve requirements: (1) the ten-minute reserve requirement; (2) the ten-minute spinning reserve requirement; (3) the minimum total reserve requirement; (4) the total reserve requirement; and (5) the zonal reserve requirements. For more information about these requirements, see *Section III Market Rule 1: Standard Market Design*, Section III.2.7A, available at https://www.iso-ne.com/static-assets/documents/2014/12/mr1_sec_1_12.pdf.

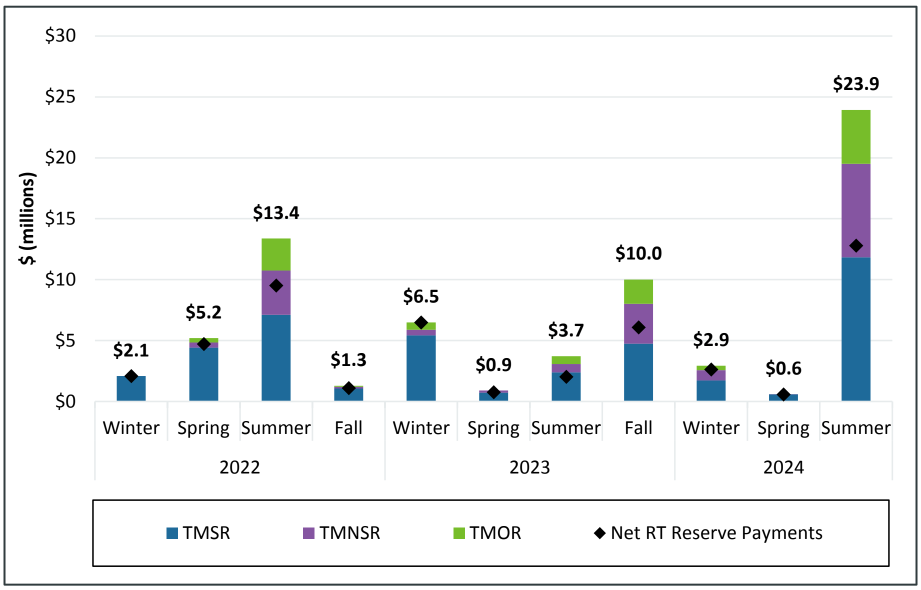
[44] The zonal thirty-minute reserve requirements did not bind in any of these summer seasons. As a result, real-time reserve prices in reserve zones were equal to those at the system level.

(including requirements for total 10-minute and total 30-minute reserves). Consequently, when these less restrictive reserve constraints bind, the value that TMSR provides by helping to satisfy these constraints is reflected in the TMSR clearing price. As noted in the paragraph above, these less restrictive reserve constraints bound much more often in Summer 2024, resulting in higher TMSR prices.

Real-time Reserve Payments

Real-time reserve payments by product and by zone are illustrated in Figure 4-9 below. The height of the bars indicate gross reserve payments, while the black diamonds show net payments (i.e., payments after reductions have been made to forward reserve resources providing real-time reserves).[45]

Figure 4-9: Real-Time Reserve Payments by Product and Zone



Gross reserve payments in Summer 2024 were $23.9M and exceeded all prior seasons, as a direct result of the long-duration capacity scarcity conditions that occurred during this season. These gross payments were reduced to net payments of $12.8M as a result of $11.1M in forward reserve obligation charges. This 47% reduction indicates that many resources had sold their reserve capability in the Forward Reserve Market, and thus did not receive the higher real-time TMNSR and TMOR prices that were prevalent during this season.

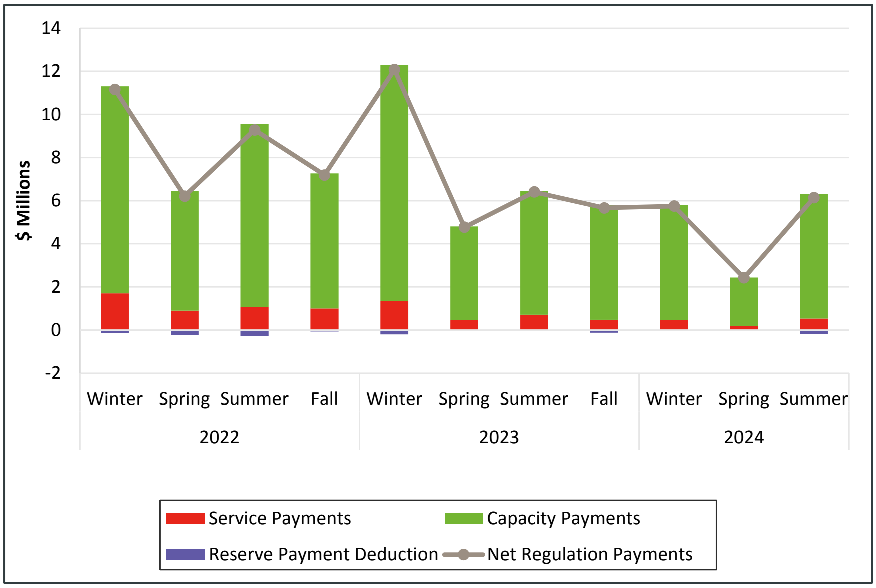
4.6 Regulation

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

[45] The forward reserve market is a forward market that procures operating reserve capability in advance of the actual delivery period. Real-time reserve payments to resources designated to satisfy forward reserve obligations are reduced by a forward reserve obligation charge so that a resource is not paid twice for the same service. For more information about forward reserve obligation charges, see the ISO's *Section III Market Rule 1 Standard Market Design,* Section III.10.4, available at https://www.iso-ne.com/static-assets/documents/2014/12/mr1_sec_1_12.pdf .

available capacity to match supply and demand (and to regulate frequency) over short time intervals. Quarterly regulation payments are shown in Figure 4-10 below.

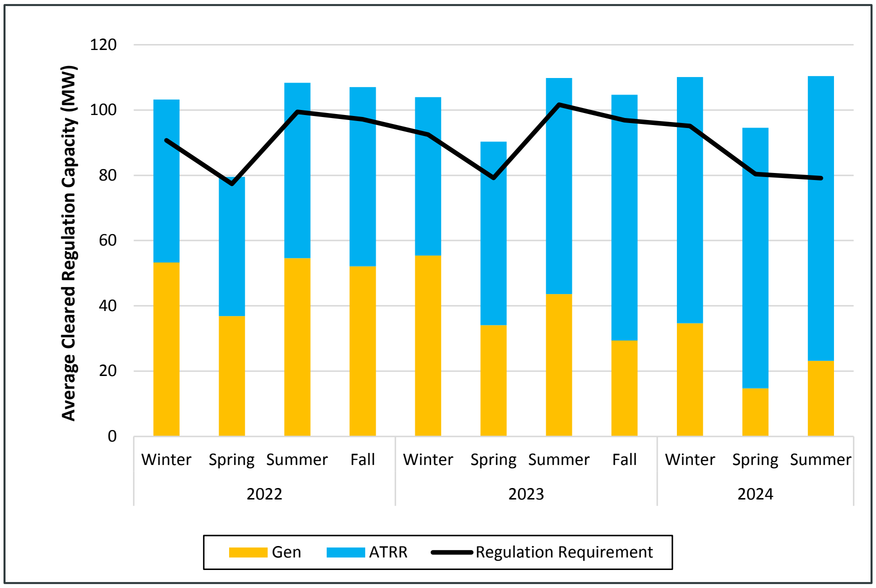
Figure 4-10: Regulation Payments



Total regulation market payments were $6.1 million during Summer 2024, down just 4% from $6.4 million in Summer 2023. The slight decrease in payments resulted primarily from lower capacity prices (down 6%). Capacity prices decreased due to a decline in regulation offer prices, as alternative technology regulation resources continue to make up a larger share of the regulation mix. Regulation service prices also decreased (down 28%) from Summer 2023.

Two different types of resources can provide regulation: traditional generators and alternative technology regulation resources (ATRRs). Almost all ATRRs in the New England market are battery resources that can opt to participate solely as regulation resources, or may choose to provide a broader combination of energy market services: consumption (battery charging), generation (battery discharging), and regulation. The regulation resource mix is shown in Figure 4-11 below.

Figure 4-11: Average Cleared Regulation MW by Resource Type



The resource mix of cleared regulation capacity has changed over the reporting period. In Winter 2022, ATRRs (blue bars) cleared an average of 50 MW of regulation capacity, making up 48% of total cleared regulation. In Summer 2024, ATRRs provided 87 MW or 79% of regulation. This change follows continuing increases in the installed capacity of battery resources in the region. Regulation capacity available from ATRRs increased to 221 MW on average in Summer 2024, up from 195 MW in Summer 2023. The change in resource mix also suggests that battery resources are lower-cost regulation resources, as ATRRs have increasingly displaced traditional generators in merit order for regulation market commitment.

Section 5
Energy Market Competitiveness

One of ISO New England's three critical goals is to administer competitive wholesale energy markets. Competitive markets help ensure that consumers pay fair prices and incentivize generators to make short- and long-run investments that preserve system reliability. Section 5.1 evaluates energy market competitiveness at the quarterly level. First, this section presents two metrics on system-wide structural market power. Next, the section provides statistics on system and local market power flagged by the automated mitigation system. We also discuss the amount of actual mitigation applied for instances where supply offers were replaced by the IMM's reference levels.

5.1 Pivotal Supplier and Residual Supply Indices

This analysis examines opportunities for participants to exercise market power in the real-time energy market using two metrics: 1) the pivotal supplier test (PST) and 2) the residual supply index (RSI). Both of these metrics identify instances when the largest supplier has market power.[46] The RSI represents the amount of demand that the system can satisfy without the largest supplier's available energy and reserves. If the value is less than 100, the largest supplier would be needed to meet demand, and could exercise market power if permitted. Further, if the RSI is less than 100, there is one or more pivotal suppliers.

Pivotal suppliers are identified at the five-minute level by comparing the real-time supply margin[47] to the sum of each participant's total supply that is available within 30 minutes.[48] When a participant's available supply exceeds the supply margin, they are pivotal.

The average RSI and the percentage of five-minute intervals with pivotal suppliers are presented in Table 5-1 below.

[46] Many resources in New England are owned by companies that are subsidiaries of larger firms. Consequently, tests for market power are conducted at the parent company level.

[47] The real-time supply margin measures the amount of available supply on the system after load and the reserve requirement are satisfied. It accounts for ramp constraints and is equal to the Total30 reserve margin: Gen_{Energy} + $Gen_{Reserves}$ + [*Net Interchange*] -*Demand* - [$Reserve\ Requirement$]

[48] This is different from the pivotal supplier test performed by the mitigation software, which does not consider ramp constraints when calculating available supply for each participant. Additionally, the mitigation software determines pivotal suppliers at the hourly level.

Table 5-1: Residual Supply Index and Intervals with Pivotal Suppliers (Real-Time)

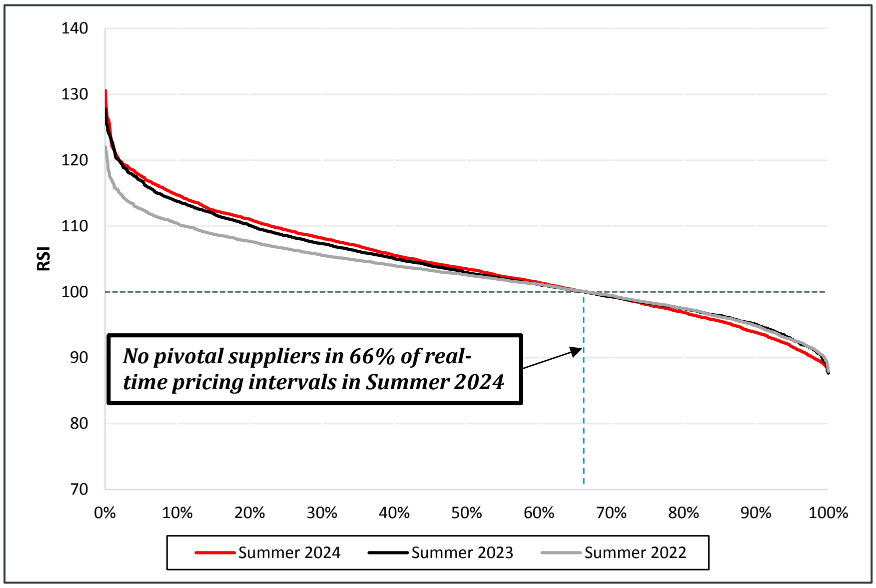
Quarter	RSI	% of Intervals With At Least 1 Pivotal Supplier
Winter 2022	106.5	12%
Spring 2022	106.7	19%
Summer 2022	102.6	34%
Fall 2022	104.0	28%
Winter 2023	105.2	20%
Spring 2023	107.7	22%
Summer 2023	103.8	34%
Fall 2023	98.9	60%
Winter 2024	101.7	45%
Spring 2024	105.5	29%
Summer 2024	104.0	34%

The RSI was above 100 in most quarters of the reporting period, indicating that, on average, the ISO could satisfy load and reserve requirements without the largest supplier. The Fall 2023 RSI was below 100 due to lower reserve margins that resulted from several long-term pumped-storage generator outages. Pumped-storage units typically provide large volumes of reserves, as they can come online at their full capacity quickly.

There was at least one pivotal supplier in 34% of real-time pricing intervals in Summer 2024, which was the same value as the previous two summers. While there were more hours of tight system conditions in Summer 2024, the average system reserve margin in Summer 2024 was 2,975 MW, similar to that of the previous two summers. Though Summer 2024 saw higher loads and fewer net imports than Summer 2023, there was an increase in energy and reserves from native generation, leading to similar reserve margins.

Duration curves that rank the average hourly RSI over each summer quarter in descending order are illustrated in Figure 5-1 below. The figure shows the percent of hours when the RSI was above or below 100 for each quarter. An RSI below 100 indicates the presence of at least one pivotal supplier.

Figure 5-1: System-Wide Residual Supply Index Duration Curves



In Summer 2024, the RSI was lower than that of Summer 2023 across 30% of the ranked observations (see right hand side of graph). The lowest Summer 2024 RSI value was 87.1, and occurred during the evening peak hour (HE 19) of August 1, when capacity scarcity conditions were in effect.

5.2 Energy Market Supply Offer Mitigation

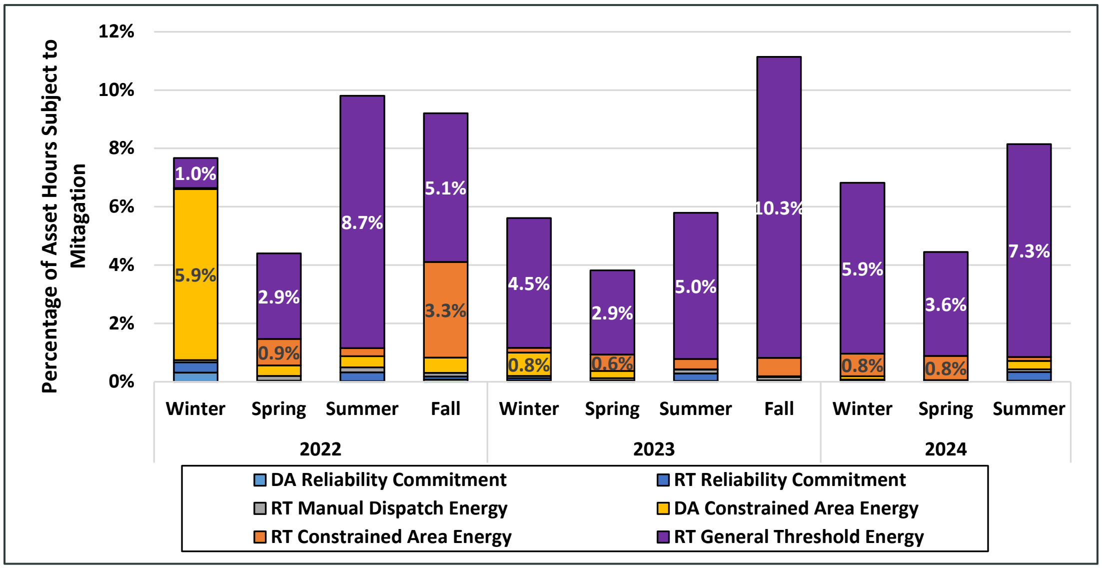
The IMM reviews energy market supply offers for generators in both the day-ahead and real-time energy markets. This review minimizes opportunities for participants to exercise market power. As in earlier periods, the mitigation of energy market supply offers occurred infrequently in Summer 2024.

Energy Market Mitigation Frequency

A structural test failure serves as the first indicator of potential market power in our energy markets. The percentage of commitment asset hours with a structural test failure from Winter 2022 to Summer 2024 is shown below in Figure 5-2.[49]

[49] A structural test failure depends on the type of mitigation analyzed. For the definitions of the structural test applied in general threshold and constrained area mitigation, see *Section III Market Rule 1 Appendix A Market Monitoring, Reporting and Market Power Mitigation*, Section III.A.5.2, available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf. For the conditions to pursue manual dispatch energy and reliability commitment mitigation see the same aforementioned source, Sections III.A.5.5.3 and III.A.5.5.6.1, respectively.

Figure 5-2: Energy Market Mitigation Structural Test Failures

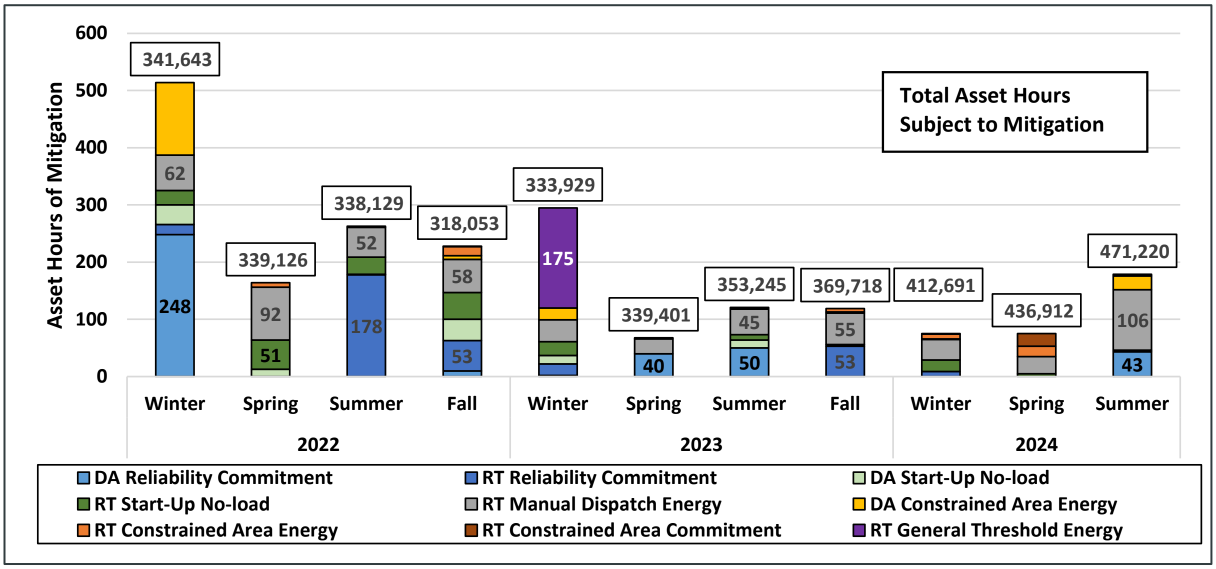


In Summer 2024, the total asset hours subject to mitigation reached about 471,000 asset hours, in which 38,410 asset hours (8.2%) failed structural tests.[50] The frequency of structural test failures was similar to the two previous summers. The structural test for general threshold energy mitigation fails the most often and is triggered when a committed generator is owned by a pivotal supplier. Overall, asset hours of structural test failures represent a very small fraction of potential asset hours subject to mitigation and, consequently, lead to an even smaller fraction of asset hours mitigated.

Asset hours of mitigation by type are shown in Figure 5-3 along with the total amount of asset hours subject to mitigation (white boxes).

[50] The asset hours subject to mitigation are estimated as a committed generator with an economic dispatchable range at or above its economic minimum (eco min). Each such on-line generator during a clock hour represents one asset hour of generation potentially subject to energy market mitigation.

Figure 5-3: Energy Market Mitigation Asset Hours



There were 179 mitigation asset hours in Summer 2024, which was slightly higher than that of Summer 2023 but lower than in Summer 2022. Real-time manual dispatch energy (MDE) mitigation occurred the most frequently in Summer 2024 with 106 asset hours of mitigation. The conduct test threshold for MDE mitigation is relatively tight, only allowing offers of resources being manually dispatched by the ISO to be 10% higher than reference levels.[51]

Reliability commitment mitigation: Reliability commitments primarily occur to satisfy local reliability needs, and are generally due to routine transmission line outages, outages facilitating upgrade projects, or localized distribution system support.[52] There were 46 asset hours of reliability commitment mitigations in Summer 2024, most of which occurred in the day-ahead market for commitments in the Southeast and Northeastern Massachusetts load zones.

Start-up and no-load (SUNL) commitment mitigation: This mitigation type addresses grossly over-stated commitment costs (relative to reference values), which could otherwise result in very high uplift.[53] SUNL mitigations occur very infrequently and may reflect a participant's failure to update energy market supply offers as fuel prices fluctuate – particularly natural gas. There was no SUNL commitment mitigation in Summer 2024.

Constrained area (CAE/CACM) mitigation: The frequency of transmission-constrained area mitigation follows the incidence of transmission congestion and import-constrained areas within

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[51] More information on Energy Market Mitigation types and thresholds can be found in *An Overview of New England's Wholesale Electricity Markets: A Market Primer (June 5, 2023)*, Section 11.2.1, available at https://www.iso-ne.com/static-assets/documents/2023/06/imm-markets-primer.pdf.

[52] This mitigation category applies to most types of "out-of-merit" commitments, including local first contingency, local second contingency, voltage, distribution, dual-fuel resource auditing, and any manual commitment needed for a reason other than meeting system load and operating reserve constraints. For more on applicability, see *Section III Market Rule 1 Appendix A Market Monitoring, Reporting and Market Power Mitigation*, Section III.A.5.5.6.1, available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf.

[53] The conduct test for this mitigation type compares a participant's offers for no-load, start-up and incremental energy cost up to economic minimum to the IMM's reference values for those same parameters. It uses a very high conduct test threshold (200% applied to the start-up, no-load, and offer segment financial parameters).

New England. In Summer 2024, structural test failures totaled 2,001 asset hours spread across several load zones. With relatively tolerant conduct and market impact test thresholds, the frequency of constrained area mitigation is low relative to the frequency of structural test failures. Over the entire reporting period, mitigation has occurred for only 185 asset hours in the day-ahead energy market and only 86 asset hours in the real-time energy market. In Summer 2024, there were 27 asset hours of constrained area mitigation, most of which occurred in the day-ahead market on June 19 when planned line outages caused a binding constraint on the North-East New England Import Interface.

General threshold energy (GTE) mitigation: Despite having the highest frequency of structural test failures, general threshold energy mitigation occurs the least frequently of all mitigation types. Across the reporting period, an average of roughly 19,425 asset hours of pivotal supplier energy were subject to mitigation each quarter; mitigation has occurred for only 175 asset hours, all in Winter 2023. As expected, structural test failures tend to occur for lead market participants with the largest portfolios of generators, with six participants accounting for 76% of the structural test failures over the reporting period.

Manual dispatch energy (MDE) mitigation: The ISO will utilize manual dispatch points for flexible resources to address short-term issues on the transmission grid. As a result, gas- or dual fuel-fired generators receive manual dispatches most often, accounting for 87% of the 445 asset hours of manual dispatch in Summer 2024. Due to a relatively tight conduct test, manual dispatch energy mitigation occurs more often than any other mitigation type, totaling 106 asset hours in Summer 2024.

Section 6
Forward Markets

This section covers activity in the Forward Capacity Market (FCM), in Financial Transmission Rights (FTRs), and in the Summer 2024 Forward Reserve Auction.

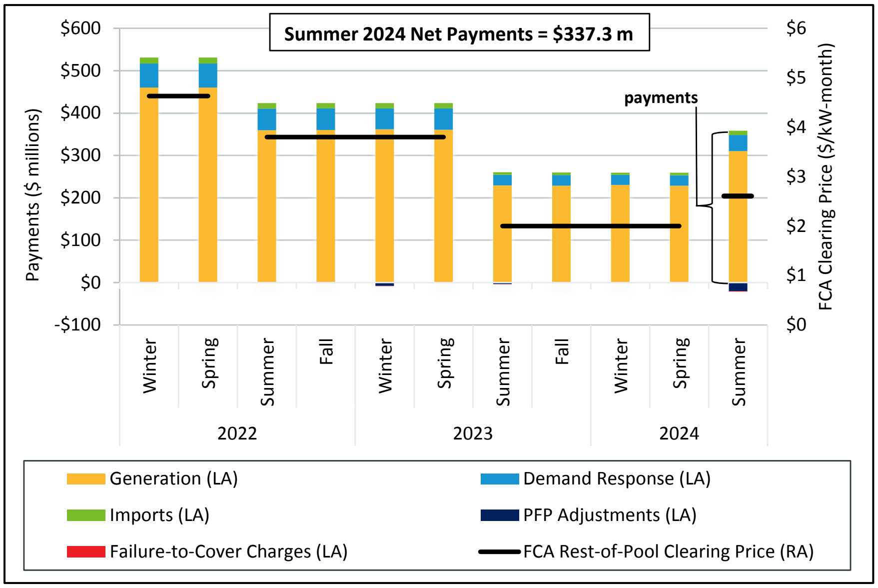
6.1 Forward Capacity Market

The Capacity Commitment Period (CCP) associated with Summer 2024 started on June 1, 2024, and will end on May 31, 2025. The corresponding Forward Capacity Auction (FCA 15) cleared at $2.61/kW-month, 30% higher than FCA 14. The auction cleared with 34,621 MW of Capacity Supply Obligation (CSO), surpassing the net installed capacity requirement (Net ICR) of 33,270 MW. Price separation between zones occurred in FCA 15, with a lower price ($2.48/kW-month) in the export-constrained Northern New England (NNE) and nested Maine capacity zones and a higher price ($3.98/kW-month) in the import-constrained Southeast New England (SENE) capacity zone. Battery storage resources comprised the largest share of new cleared capacity. The cost-of-service agreement that retained Mystic 8 and 9 during FCA 13-FCA 14 ended and the generators retired effective June 1, 2024. The results of FCA 15 led to a projected total annual cost of $1.32 billion in capacity payments, 39% higher than capacity payments incurred in FCA 14.[54]

Total FCM payments, as well as the clearing prices for Winter 2022 through Summer 2024, are shown in Figure 6-1 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, light blue, and green bars (corresponding to the left axis, "LA") represent payments made to generation, demand response, and import resources, respectively. The dark blue bar represents Pay-for-Performance (PfP) adjustments, while the red bar represents Failure-to-Cover charges.

[54] For more information on FCA 15, see our *Winter 2021 Quarterly Markets Report* (April 28, 2021), available at https://www.iso-ne.com/static-assets/documents/2021/04/2021-winter-quarterly-markets-report.pdf.

Figure 6-1: Capacity Market Payments



Summer 2024 capacity payments reached $337.3 million, up 31% from Summer 2023 payments. The increase in capacity payments is attributable to the higher clearing prices in effect for CCP 15. Capacity resources were charged $20.4 million in PfP transfers for under-performance during capacity scarcity conditions on June 18 and August 1, funding PfP payments to non-capacity imports and assets.[55] Additionally, resources that did not demonstrate a capability to produce energy up to their capacity supply obligation incurred $1.0 million in failure-to-cover charges.

Secondary auctions allow participants the opportunity to acquire or shed capacity after the primary auction. A summary of prices and volumes associated with the reconfiguration auction and bilateral trading activity during Summer 2024 alongside the results of the relevant primary FCA are detailed in Table 6-1 below.

[55] See 3.4.4 for a discussion of the June 18, 2024 PfP event, and 3.5.4 for a discussion of the August 1, 2024 PfP event.

Table 6-1: Primary and Secondary Market Outcomes

					Capacity Zone/Interface Prices ($/kW-mo)			
FCA # (Commitment Period)	Auction Type	Period	Systemwide Price ($/kW-mo)*	Cleared MW**	Maine	New Brunswick	Northern New England	Southeastern New England
FCA 15 (2024-2025)	Primary	12-month	2.61	34,621	2.48	2.48	2.48	3.98
	Monthly Reconfiguration	Aug-24	2.48	470				10.00
	Monthly Bilateral	Aug-24	3.90	92				
	Monthly Reconfiguration	Sep-24	4.00	450				12.50
	Monthly Bilateral	Sep-24	3.90	93				
	Monthly Reconfiguration	Oct-24	3.98	735				
	Monthly Bilateral	Oct-24	1.26	1				
FCA 16 (2025 - 2026)	Primary	12-month	2.59	32,810	2.53	2.53	2.53	2.64
	Annual Reconfiguration (2)	12-month	2.64	187, -479				
FCA 17 (2026 - 2027)	Primary	12-month	2.59	31,370		2.55		
	Annual Reconfiguration (1)	12-month	2.43	246, -40				

**bilateral prices represent volume weighted average prices*

***represents cleared supply/demand*

Monthly reconfiguration auctions for August, September, and October 2024 occurred in Summer 2024. Reconfiguration auction prices represent the prices at which resources trade CSO amongst themselves in each auction. The August 2024 reconfiguration auction cleared at a price slightly below the FCA 15 clearing price, while the September and October reconfiguration auctions cleared above. Significant price separation occurred in the import-constrained SENE capacity zone in the August and September auctions, following similar price separation in prior reconfiguration auctions for CCP 15. High prices were driven by large price-taking demand bids to shed CSO in each auction.

The second annual reconfiguration auction for CCP 16 cleared at $2.64/kw-month, up 2% from the FCA clearing price. More demand bids cleared the auction than new supply, resulting in a decrease in total CSO. The Net Installed Capacity Requirement (Net ICR) in the second Annual Reconfiguration Auction (ARA) was 30,775 MW, down from 31,645 MW in FCA 16 and up slightly from 30,585 MW in the first ARA. While capacity exited the auction, prices remained relatively low with sufficient margin over net ICR. There was no significant price separation in the ARA.

The first annual reconfiguration auction for CCP 17 cleared at $2.43/kw-month, marking a 6% decrease from the FCA clearing price. More supply cleared the auction than demand, adding total CSO as the Net ICR rose to 30,395 MW, up by 90 MW from the primary auction. The additional supply in the auction offset the marginal increase in Net ICR, leading to lower capacity prices.

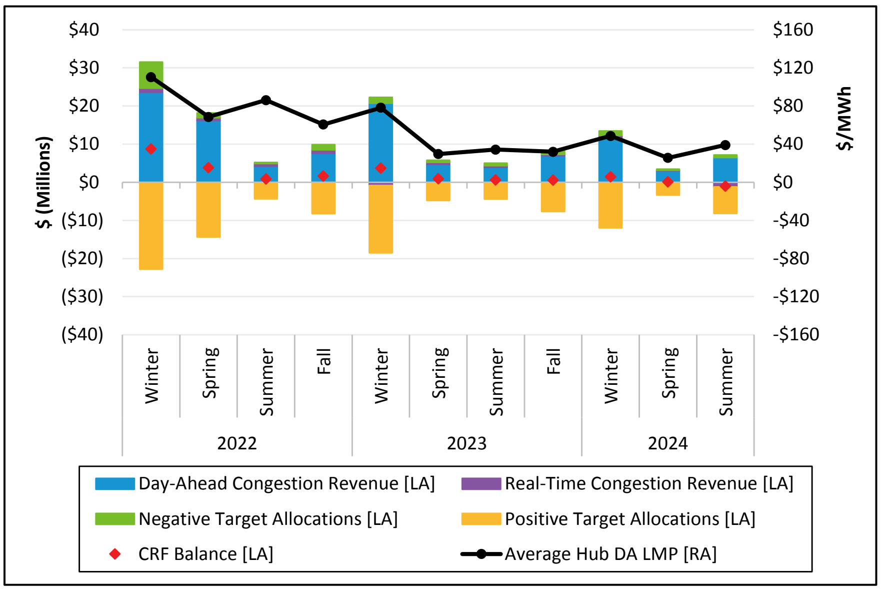
6.2 Financial Transmission Rights

This section of the report discusses Financial Transmission Rights (FTRs), which are financial instruments that settle based on the transmission congestion that occurs in the day-ahead energy market. The credits associated with holding an FTR are referred to as positive target allocations, and the revenue used to pay them comes from three sources:

1) the holders of FTRs with negative target allocations;
2) the revenue associated with transmission congestion in the day-ahead market;
3) the revenue associated with transmission congestion in the real-time market.

Figure 6-2 below shows, by quarter, the amount of congestion revenue from the day-ahead and real-time energy markets, the amount of positive and negative target allocations, and the congestion revenue fund (CRF) balance.[56,57] This figure also depicts the quarterly average day-ahead Hub LMP.[58]

Figure 6-2: Congestion Revenue, Target Allocations, and Day-Ahead LMP by Quarter



The CRF balance was negative in Summer 2024 (-$1.0 million), marking the first time that this has occurred during the reporting period. This outflow from the CRF was the result of significant negative real-time congestion revenue over the period (-$1.2 million) as the day-ahead elements, specifically the day-ahead congestion revenue ($6.4 million) and negative target allocations (-$0.7 million), would have been sufficient to cover the positive target allocations ($7.0 million). Two

[56] The CRF balances depicted are simply the sum of the month-end balances for the three months that comprise the quarter. The month-end balances are calculated as $\sum(DA\ Congestion\ Revenue + RT\ Congestion\ Revenue + |Negative\ Target\ Allocations|) - Positive\ Target\ Allocations$ and do not include any adjustments (e.g., surplus interest, FTR capping).

[57] Figure 6-2 depicts positive target allocations as negative values, as these allocations represent outflows from the CRF. Meanwhile, negative target allocations are depicted as positive values, as these allocations represent inflows to the CRF.

[58] The average annual day-ahead Hub LMP is measured on the right axis ("RA"), while all the other values are measured on the left axis ("LA").

periods with notable negative real-time congestion were during HE 19-20 on June 18 (-$0.5 million) and HE 4-5 on August 4 (-$0.2 million). During both of these periods, the New York North interface was constrained. The first period coincided with the June 18 PfP event, when additional energy was imported from New York in the real-time market in response to the tight system conditions. During the second period, the level of imports from New York had to be reduced in the real-time market to help maintain system reliability.

FTRs were underfunded in all three summer months.[59,60] In June 2024 only 76.9% of positive target allocations were funded, while July 2024 saw 92.0% funding, and August 2024 saw 84.3% funding. However, any excess congestion revenue collected during the year is allocated to unpaid positive target allocations at the end of the year, to the extent possible. At the end of August 2024, the congestion revenue fund had a surplus of $1.6 million for the year.

6.3 Forward Reserve Market

During August 2024, the ISO held the forward reserve auction for the Winter 2024-25 delivery period. The Winter 2024-25 auction is the last Forward Reserve Market (FRM) auction that the ISO will conduct as the market will sunset with the implementation of the Day-Ahead Ancillary Services Initiative ("DASI") in March 2025.[61] Consequently, the associated delivery period with this auction only spans from October 1, 2024 to February 28, 2025. In this section, we review the results of the Winter 2024-25 auction.

6.3.1 Auction Reserve Requirements and Offered Supply

Offered supply was adequate to satisfy the reserve requirements for the Winter 2024-25 auction. This can be seen in Figure 6-3 below, which shows the ISO New England control area and local reserve zones requirements as well as the total quantity of supply offers in the auction available to satisfy these reserve needs.[62, 63,64]

[59] FTRs are said to be underfunded when sufficient revenue has not been collected from the energy market and from FTR holders with negative target allocations to pay FTR holders with positive target allocations all the revenue to which they are entitled.

[60] For more information about the monthly FTR settlement, see the *2024 FTR Monthly Summary*, available at https://www.iso-ne.com/static-assets/documents/100008/2024-monthly-summary.pdf.

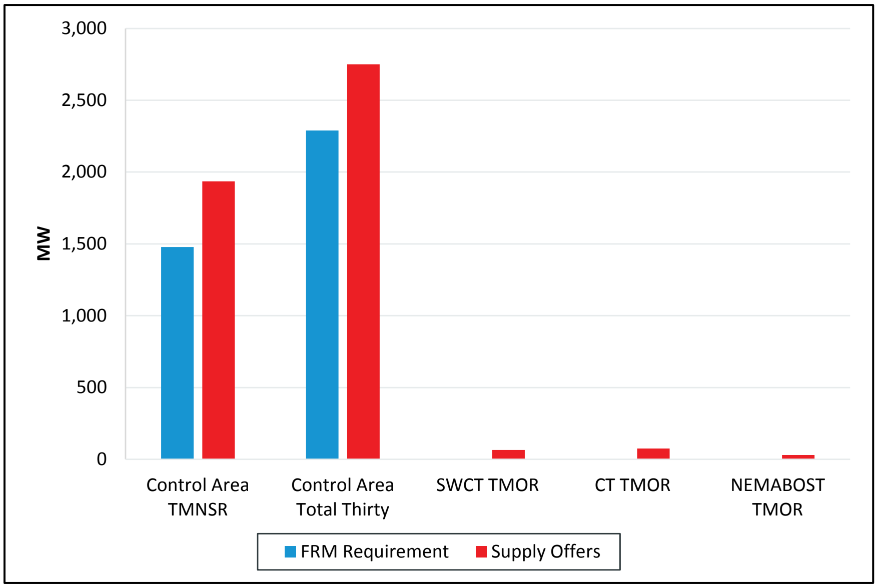
[61] More information about DASI can be found on the ISO's *Day-Ahead Ancillary Services Initiative (DASI)* page, available at https://www.iso-ne.com/participate/support/participant-readiness-outlook/day-ahead-ancillary-services-initiative.

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

[63] The total thirty-minute requirement referred to here is the sum of the ten-minute non-spinning reserve ("TMNSR") and thirty-minute operating reserve ("TMOR") requirements for the control area. This is indicated in the ISO New England Memorandum to Market Participants *Assumptions and Other Information for the Winter 2024-25 Forward Reserve Auction*, (July 22, 2024), available at https://www.iso-ne.com/static-assets/documents/100013/forward_reserve_auction_assumptions_winter_2024_2025.pdf.

[64] Because TMOR supply offers within local reserve zones also provide TMOR to the system, the control area TMOR offers shown in the figure include the local reserve zone supply offers. Hence, the control area TMOR offers represent the total offers throughout the system. A similar adjustment has been made to the Connecticut TMOR supply offers; the SWCT zone is nested within the Connecticut zone, and SWCT offers can contribute to the Connecticut TMOR supply. Given this, SWCT TMOR supply offers are also included in the CT TMOR total. Finally, because TMNSR supply can contribute to TMOR supply, all TMOR totals in the graph include TMNSR in addition to TMOR supply.

Figure 6-3: Forward Reserve Requirements and Supply Offer Quantities



The Winter 2024-25 auction had sufficient offered supply to meet both TMNSR and total thirty-minute reserve requirements for the control area. The ISO bases these requirements on possible system contingencies.[65] The TMNSR requirement was based on the expected single contingency of the Hydro-Québec Phase II Interconnection ("Phase II"). This requirement was 1,478 MW for the Winter 2024-25 auction. Total offered supply that could meet the TMNSR requirement amounted to approximately 1,936 MW. The TMOR requirement was based on the expected single contingency of Millstone. This requirement was 811 MW for the Winter 2024-25 auction. Consequently, the total thirty-minute requirement was 2,289 MW (1,478 MW + 811 MW). The total offered supply that could meet the total thirty-minute requirement amounted to approximately 2,751 MW.

All local reserve zones, which only have a TMOR requirement, were found to have no reserve need.[66]

6.3.2 Auction Results

The clearing price for TMNSR in the Winter 2024-25 auction was lower than the clearing price for the prior winter auction, while the clearing price for TMOR was higher. This can be seen in Figure 6-4 below, which shows forward reserve clearing prices for the TMNSR and TMOR products for the previous six auctions.

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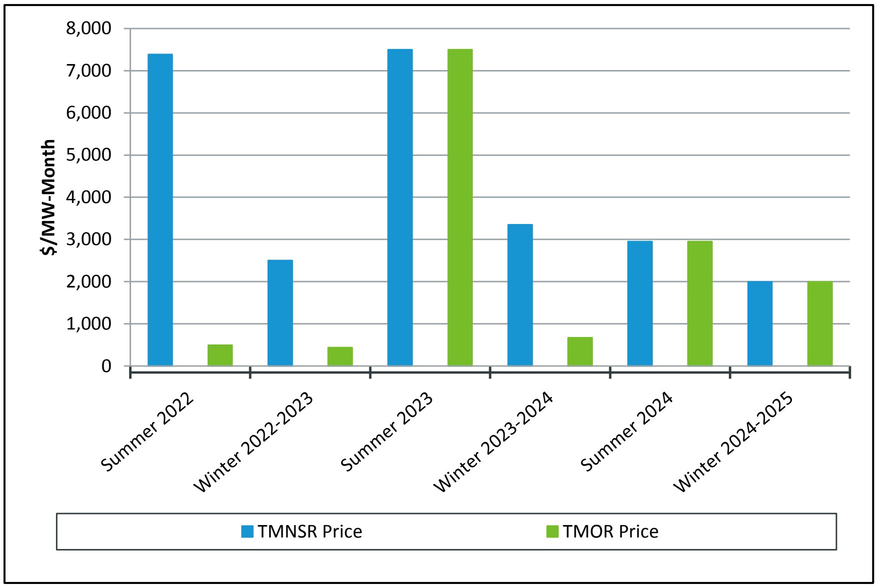
[65] The final requirement may reflect ISO adjustments, such as biasing the requirement, increasing a requirement to reflect historical resource non-performance, and adjusting the TMOR requirement to reflect the replacement reserve requirement. For more information about system forward reserve requirements, see *Section III Market Rule 1 Standard Market Design*, Section III.9.2.1, available at https://www.iso-ne.com/static-assets/documents/2014/12/mr1_sec_1_12.pdf.

[66] For a more detailed indication of the determination of local reserve requirements, see the *ISO New England Manual for Forward Reserve and Real-Time Reserve Manual M-36*, Sections 2.2.3 – 2.2.5, (Effective Date: December 3, 2019), available at https://www.iso-ne.com/static-assets/documents/2020/02/manual_36_forward_reserve_and_realtime_reserve_rev23_20191203.pdf.

Figure 6-4: FRM Clearing Prices for TMNSR and TMOR



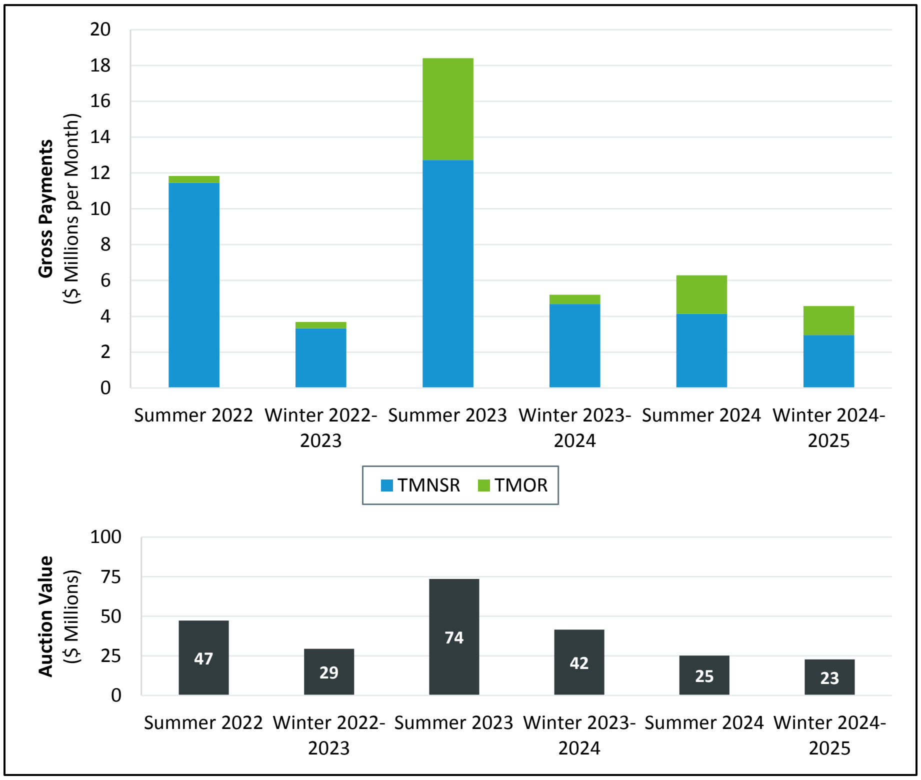
The clearing price for both TMNSR and TMOR in the Winter 2024-25 auction was $1,999/MW-month. The two products will often have the same clearing price when there are abundant low-cost TMNSR offers, as was the case in this auction.[67] Specifically, the Winter 2024-25 auction saw a 342 MW increase in TMNSR supply offers relative to the Winter 2023-24 auction (2,409 MW), with much of it offered more competitively than the prior winter.

The decline in the TMNSR clearing price in the Winter 2024-25 auction should lead to modestly lower gross monthly payments to participants relative to the Winter 2023-24 auction. Figure 6-5 indicates the gross monthly payments (i.e., excluding penalties) available to participants with TMNSR and TMOR FRM obligations for the six most recent FRM delivery periods. The figure also depicts the auction value associated with each auction.[68]

[67] When this happens, the auction is able to meet both control area reserve requirements (i.e., the TMNSR requirement, which can only be met by TMNSR offers, and the total thirty-minute requirement, which can be met by TMNSR and TMOR offers) without having to limit the amount of TMOR offers that would otherwise clear.

[68] The auction value here represents the gross monthly payments multiplied by the number of months in delivery period.

Figure 6-5: Gross Monthly FRM Payments and Auction Value



While gross monthly payments for the Winter 2024-25 auction are estimated to be slightly lower than the prior winter auction, the total auction value is expected to be the lowest of the last six auctions. This is largely the result of the delivery period being shortened from its usual eight months in the winter (October through May) to only five months (October through February) given that DASI is set to go live on March 1, 2025.

6.3.3 Auction Competitiveness

The Winter 2024-25 auction was structurally competitive for both the TMNSR and total thirty-minute requirements as measured by the Residual Supply Index ("RSI"), which is a common measure of supply-side structural competitiveness.[69]

Table 6-2 summarizes the RSI values for each requirement in recent auctions. It utilizes a heat map to indicate auctions that were structurally uncompetitive (i.e., red shading for RSI < 100, indicating the existence of one or more pivotal suppliers).

[69] The RSI values indicate the supply that is available to meet the specific reserve requirement when the supply of the largest supplier is not available. The RSI is stated as a percent of the requirement: for example in Summer 2023, supply – after excluding the largest supplier – could meet only 81% of the TMNSR requirement. When the RSI is less than 100, it suggests that the largest supplier, and potentially other suppliers with strategic information, may be able to exercise market power in the auction. Note also that RSI values for the local reserve zones are not presented since these auctions have not had a local reserve requirement.

Table 6-2: RSI for the TMNSR and Total Thirty-Minute Requirements

Procurement Period	Offer RSI TMNSR	Offer RSI Total Thirty
Summer 2022	78	90
Winter 2022-2023	109	112
Summer 2023	81	86
Winter 2023-2024	82	89
Summer 2024	107	103
Winter 2024-25	106	102

After RSI values of 82 and 89 for the TMNSR and total thirty requirement in Winter 2023-24, respectively, the RSI values increased to 106 and 102 in Winter 2024-25. As mentioned earlier, the Winter 2024-25 auction saw a modest increase in TMNSR offers (342 MW), and this had the effect of increasing the RSI for both reserve requirements. Meanwhile, the reserve requirements were very similar between the two auctions.