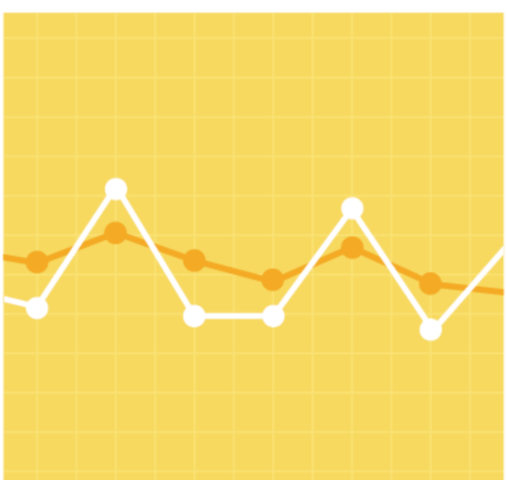
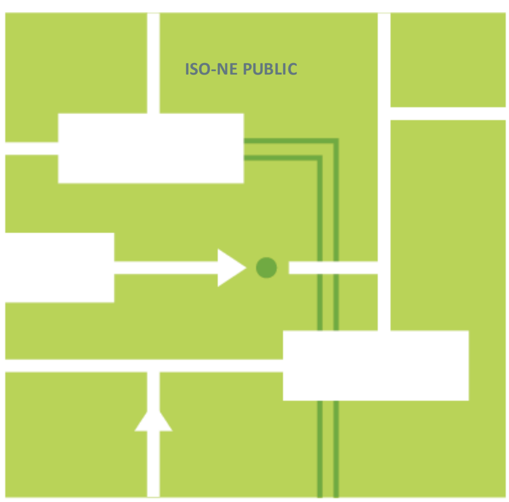
Summer 2025
Quarterly Markets Report

By ISO New England's Internal Market Monitor

NOVEMBER 12, 2025





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 2025 (June 1, 2025 through August 31, 2025).

Wholesale Costs: In Summer 2025, higher natural gas prices (up 83% from Summer 2024) were the main driver of higher market costs compared to Summer 2024. The total estimated wholesale market cost of electricity was $2.61 billion, up 33% from $1.96 billion in Summer 2024. Total energy market costs comprised 86% of wholesale costs and totaled $2.25 billion, a 45% increase from Summer 2024.

Energy market costs include any costs associated with the Forecast Energy Requirement (FER), which was introduced as part of the Day-Ahead Ancillary Services (DA A/S) market (launched March 1, 2025). These costs totaled $122 million in Summer 2025 and were paid to physical generation and imports.

Capacity costs totaled $216 million, representing 10% of total wholesale market costs. The current capacity commitment period (CCP 16, June 2025 – May 2026) cleared at $2.59/kw-month, which was nearly the same as the prior year ($2.61/kw-month in CCP 15, June 2024 – May 2025). Despite the comparable clearing price, total costs were $121 million (35%) lower in Summer 2025 than in Summer 2024, due to less cleared capacity and lower prices in the Southeastern New England region.

Energy Prices: Day-ahead and real-time energy prices at the Hub averaged $53.31 and $49.65/MWh, respectively. These were 33-37% higher than Summer 2024 prices on average.

- Average natural gas prices increased by 83%, which was the primary driver of higher energy prices. The impact of higher gas prices was partially offset by falling RGGI CO_2 allowance prices, which averaged $21.65 per short ton of CO_2, an 11% decrease from Summer 2024 prices.
- The FER price paid through the DA A/S market to day-ahead cleared generation that meets the forecast energy requirement averaged $3.07/MWh. Adding the FER price to the day-ahead LMP resulted in day-ahead prices that were $6.73/MWh higher than the real-time LMP, on average.
- Real-time load was 2% lower in Summer 2025 than the prior summer season due to increased behind-the-meter solar generation and cooler weather.

System Events: On Tuesday, June 24, 2025, ISO New England experienced capacity scarcity conditions which lasted for three hours, from 17:35 through 20:35. At the beginning of the operating day, operators expected low supply margins (106 MW) due to the high temperature (forecasted high of 96°F) and load forecasts (25,800 MW at peak). Actual temperatures and loads were slightly above forecasts, and real-time load peaked at 26,551 MW - the highest recorded load since July 19, 2013. In addition, multiple generator outages and output reductions led to a deficiency in 30-minute operating reserves. Operators took several actions to ease system conditions, including cutting export transactions to New York and manual dispatching or committing generation and demand response resources.

Total Pay for Performance (PfP) credits were $114.3 million, exceeding both the PfP settlements from all prior events and the June 2025 base payments to capacity resources. Most resource types received net PfP charges due to a combination of resource underperformance and the high balancing ratio, which averaged 103% during the scarcity event. Since the balancing ratio was above 100%, resources that did not perform above their CSO were subject to PfP penalties[3]. PfP charges totaled $123.5 million; however, the ISO's implementation of stop-loss provisions meant that $26.4 million were reallocated from resources that hit stop-loss limits to resources that did not reach limits.

Net Commitment Period Compensation (NCPC): NCPC payments totaled $11.4 million in Summer 2025, down from $13.3 million in Summer 2024. The majority of NCPC ($7.1 million) was economic uplift to generators committed out-of-merit to meet load and reserve requirements. Special constraint commitment payments for distribution networks are common in summer months, and such payments totaled $0.6 million. Local second contingency payments were minimal in Summer 2025.

Day-Ahead Ancillary Services[4]: Total net ancillary services and FER payments increased substantially between Spring 2025 ($88 million) and Summer 2025 ($180 million), in-line with the increase in total energy and ancillary services costs observed between the two periods. While the FER credit paid to physical suppliers of day-ahead energy ($122 million) once again represented the largest share of DA A/S-related settlements in Summer 2025 (68%), it was a smaller share than in Spring 2025 (85%). The average FER price rose slightly between Spring 2025 ($2.66/MWh) and Summer 2025 ($3.07/MWh), while the average hourly volume of cleared EIR awards decreased from 143 MWh to 91 MWh.

The percentage of all asset-product-hours that were mitigated fell from 2.4% in Spring 2025 to 1.1% in Summer 2025. The count of distinct assets that were mitigated has leveled off since March (when 136 assets were mitigated) and has ranged between 36-55 over the last five months. It is likely that a growing familiarity with the market design, as well as the approval of participant-submitted offer models, are reducing the incidence of mitigation in this market.

Over the period from March 1, 2025, to August 31, 2025, the actual closeout was $0/MWh in ~73% of hours. However, there were instances when actual closeouts significantly exceeded expected closeouts. The most notable example of this was on June 24 (the day of the shortage event), when the total realized closeout charges for the day significantly exceeded the expected closeout charges.

The IMM performed market simulations to better understand the incremental impact of DA A/S design on market outcomes relative to the day-ahead market design that was in place prior to March 1, 2025. Based on these simulations, we estimate that the DA A/S market has resulted in an increase of $258 million (7.6%) in total energy market costs, with around half of these costs occurring on only 10 days between June 22, 2025, and August 31, 2025.

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[3] A balancing ratio over 100% implies that available CSO was not sufficient to fully cover load and reserve requirements during the event. June 24 was the first time the balancing ratio exceeded 100% since the PfP settlement design implementation.

[4] On March 1, 2025, ISO New England launched a new suite of day-ahead ancillary services (DA A/S) designed to procure operating reserves and ensure sufficient supply to meet the ISO's load forecast through market mechanisms. The new products include day-ahead ten-minute spinning reserve (DA TMSR), day-ahead ten-minute non-spinning reserve (DA TMNSR), day-ahead thirty-minute reserves (DA TMOR), and Energy Imbalance Reserve (EIR).

Real-time Reserves: Payments in Summer 2025 totaled $19.8 million, lower than Summer 2024 ($24.0 million). This reduction was driven by lower TMNSR and TMOR payments. Half of the real-time reserve payments in Summer 2025 occurred on June 24, during the capacity scarcity condition event. The surrounding days, June 23 and June 25, accounted for an additional 25% of the total real-time reserve payments over the summer.

Regulation: Total regulation market payments were $4.7 million during Summer 2025, down 24% from $6.1 million in Summer 2024. The decrease in payments resulted primarily from lower capacity prices (down 27%). 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 34%) from Summer 2024.

Energy Market Competitiveness: The residual supply index for the real-time energy market in Summer 2025 was 104.4, 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 31% of five-minute pricing intervals in Summer 2025, just slightly lower than the Summer 2024 and 2023 values (34% in both periods). Although net imports decreased, 2025 saw lower loads than prior summers which contributed to a modestly higher reserve margin.

Of the nearly 28,000 eligible asset hours that failed structural tests, there were only 151 asset hours of mitigation in Summer 2025 (0.54% of asset hour mitigated). Real-time manual dispatch energy (MDE) mitigation represented about half of that mitigation in Summer 2025 with 75 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.

Financial Transmission Rights (FTRs): Positive target allocations totaled $9.6 million in Summer 2025, down 57% from Spring 2025. The decline in congestion revenue and target allocations relative to Spring 2025 is partly attributable to the completion of some transmission work in preparation of the New England Clean Energy Connect (NECEC) line. The CRF was fully funded for each month of Summer 2025 and has been fully funded each month year-to-date.

Section 2
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 2-1 below.

Table 2-1: High-Level Market Statistics

Market Statistics	Summer 2025	Spring 2025	Summer 2025 vs Spring 2025 (% Change)	Summer 2024	Summer 2025 vs Summer 2024 (% Change)
Real-Time Load (GWh)	32,471	25,971	25%	33,297	-2%
Peak Real-Time Load (MW)	26,551	17,346	53%	24,871	7%
Average Day-Ahead Hub LMP ($/MWh)	$53.31	$41.19	29%	$39.03	37%
Average Forecast Energy Requirement Price ($/MWh)	$3.07	$2.66	15%	-	-
Average Real-Time Hub LMP ($/MWh)	$49.65	$39.25	26%	$37.45	33%
Average Natural Gas Price ($/MMBtu)	$3.29	$3.40	-3%	$1.80	83%
Average No. 6 Oil Price ($/MMBtu)	$15.18	$13.77	10%	$14.54	4%
Average RGGI allowance price ($/tn CO_2)	$21.65	$20.49	6%	$24.44	-11%

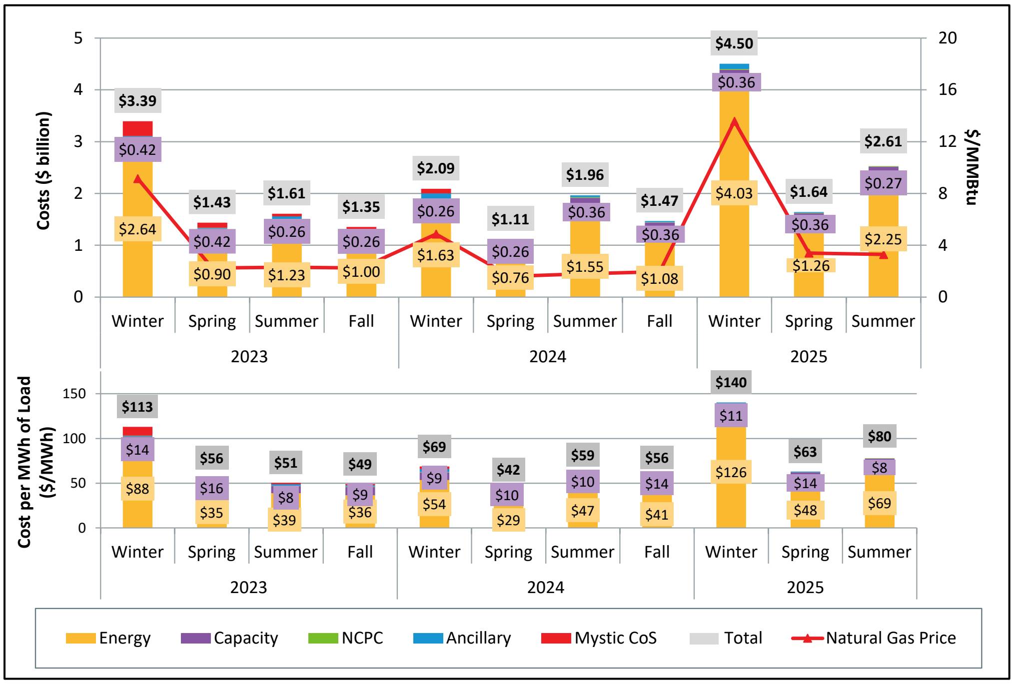
Key observations from the table above:

- Real-time load was 2% lower in Summer 2025 than the prior summer season due to increased behind-the-meter solar generation and cooler weather.
- Day-ahead LMPs averaged $53.31/MWh, while the forecast energy requirement price averaged $3.07/MWh. This price is paid to day-ahead cleared generation that meets the forecasted energy requirement. Together, these prices led to a $6.73/MWh premium over the real-time LMP, on average. Days with warm weather and high loads tended to have much higher day-ahead prices compared to real-time prices. This was due to high volumes of cleared virtual demand in the day-ahead market, and the co-optimization of energy and reserves in the Day-Ahead Ancillary Services (DA/AS) market.
- Average natural gas prices increased by 83%, which was the primary driver of higher energy prices. The impact of higher gas prices was partially offset by falling RGGI CO_2 allowance prices, which averaged $21.65 per short ton of CO_2, an 11% decrease from Summer 2024 prices.

2.1 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 2-1 below. The upper panel also shows the average 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.[5] The bottom panel in Figure 2-1 depicts the wholesale cost per megawatt hour of real-time load.

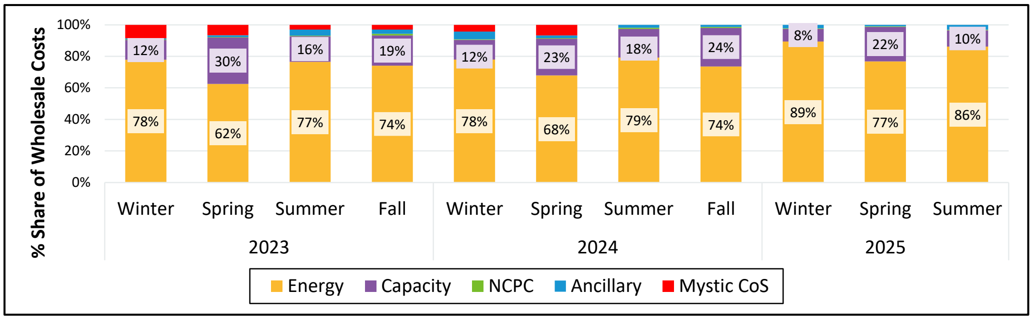
Figure 2-1: Wholesale Market Costs and Average Natural Gas Prices by Season



In Summer 2025, the total estimated wholesale cost of electricity was $2.61 billion (or $80/MWh of load), a 33% increase compared to $1.96 billion in Summer 2024, and a 59% increase compared to $1.64 billion in Spring 2025. The increase from Summer 2024 resulted from higher energy costs. The share of each wholesale cost component since Winter 2023 is shown in Figure 2-2 below.

[5] Unless otherwise stated, the natural gas prices shown in this report are based on the weighted average of the Intercontinental Exchange next-day index values for the following trading hubs: Algonquin Citygates, Algonquin Non-G, Portland, 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 2-2: Percentage Share of Wholesale Costs[6]



Energy costs comprised 86% of wholesale costs and totaled $2.25 billion ($69/MWh) in Summer 2025, 45% higher than Summer 2024 costs. Higher natural gas prices (up 83%) led to the increase in total energy market costs. The energy costs include any costs associated with the Forecast Energy Requirement (FER), which was introduced as part of the Day-Ahead Ancillary Services (DA A/S) market. These costs totaled $122 million in Summer 2025 and were paid to physical generation and imports.

Capacity costs are determined by the clearing price in the primary Forward Capacity Auction (FCA). In Summer 2025, the FCA 16 clearing price resulted in capacity payments of $266 million ($8/MWh), representing 10% of total costs. The current capacity commitment period (CCP 16, June 2025 – May 2026) cleared at $2.59/kw-month, which was the same as the prior year (CCP 15, June 2024 – May 2025). Despite the comparable clearing price, costs were higher in Summer 2024 due to greater cleared capacity and higher prices in the Southeastern New England region. Section 5.1 discusses recent trends in the Forward Capacity Market in more detail.

At $11 million ($0.34/MWh), Summer 2025 Net Commitment Period Compensation (NCPC) costs represented 0.5% of total energy costs, which was in line with costs in prior quarters. Summer 2025 NCPC costs were almost $2 million lower than in Summer 2024 with most NCPC types falling compared to the prior year.

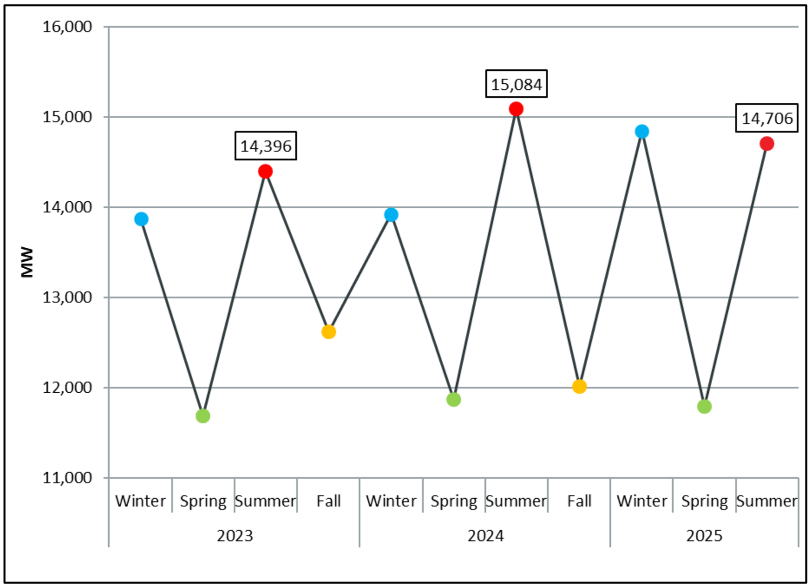
Ancillary service costs, which include payments for day-ahead reserves, real-time reserves and regulation, totaled $82 million ($2.52/MWh) in Summer 2025 representing 3% of total wholesale costs. Ancillary service costs increased by 122% compared to Summer 2024 costs, as DA A/S costs this summer exceeded forward reserve payments during the prior summer. Ancillary costs associated with the DA A/S market totaled $57 million this summer.

[6] 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.

2.2 Load

New England average loads typically peak in summer due to air conditioning demand. Average hourly load by season is illustrated in Figure 2-3 below.

Figure 2-3: Average Hourly Load by Quarter

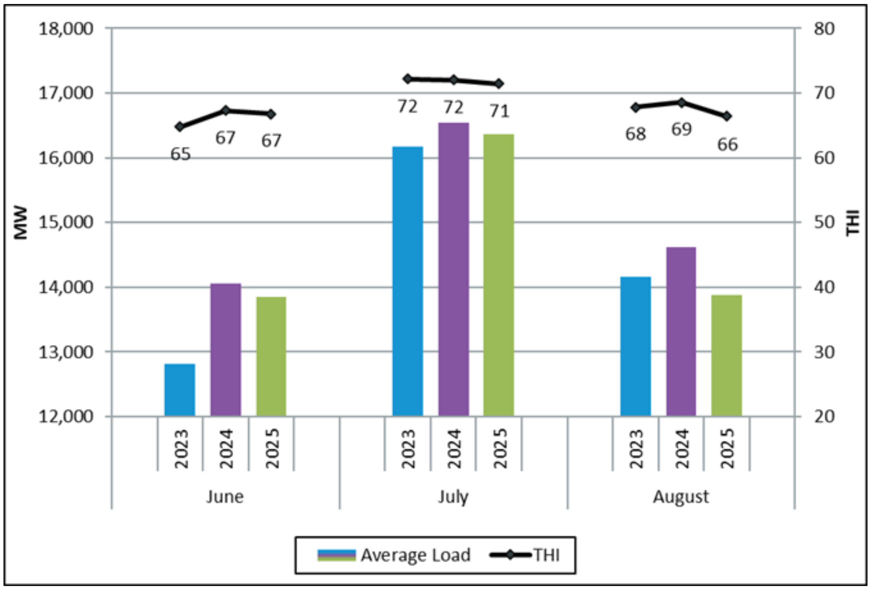


Summer 2025 loads averaged 14,706 MW, down 2.5% from Summer 2024. While weather conditions and economic drivers also shape the average hourly load, the increase in Behind-the-Meter (BTM) solar generation was a significant factor contributing to the lower average load observed in Summer 2025. BTM solar reduced loads by an average of 1,103 MW—21% more than the 912 MW reduction in Summer 2024, and the estimated installed BTM capacity increased in summer to 5,477 MW, up 16% from the previous year.

Load and Temperature

The stacked graph in Figure 2-4 below compares average monthly load (left axis) to the monthly average Temperature-Humidity Index (right axis).[7]

Figure 2-4: Monthly Average Load and Monthly Temperature-Humidity Index



Average load decreased across all three months in Summer 2025 compared to Summer 2024; down 1% in June and July, and 5% in August. While these averages suggest a milder summer overall, they do not fully capture the variability in actual load during Summer 2025. High temperatures were concentrated in fewer days, with periods of intense heat and humidity surpassing the previous summer. Although June 2025 recorded 79 Cooling Degree Days (CDD)[8], slightly down from 81 in June 2024, short but intense periods of extreme heat and humidity led to spikes in cooling demand, offsetting what would have otherwise been a larger load reduction in comparison with Summer 2024.

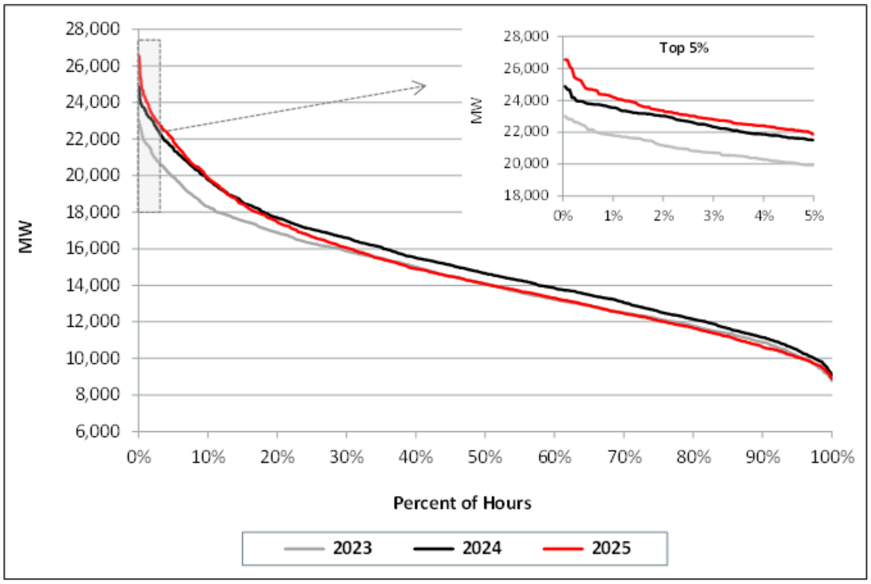
[7] The Temperature-Humidity Index combines temperature and dew point (humidity) into one metric that is a useful indicator of electricity demand in summer months when the impact of humidity on load is highest. The THI is calculated as 0.5 x [Dry-Bulb Temperature (°F)] + 0.3 x [Dew Point (°F)] + 15.

[8] 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 2-5 below, with the inset graph showing the 5% of hours with the highest loads.[9]

Figure 2-5: Summer Load Duration Curves



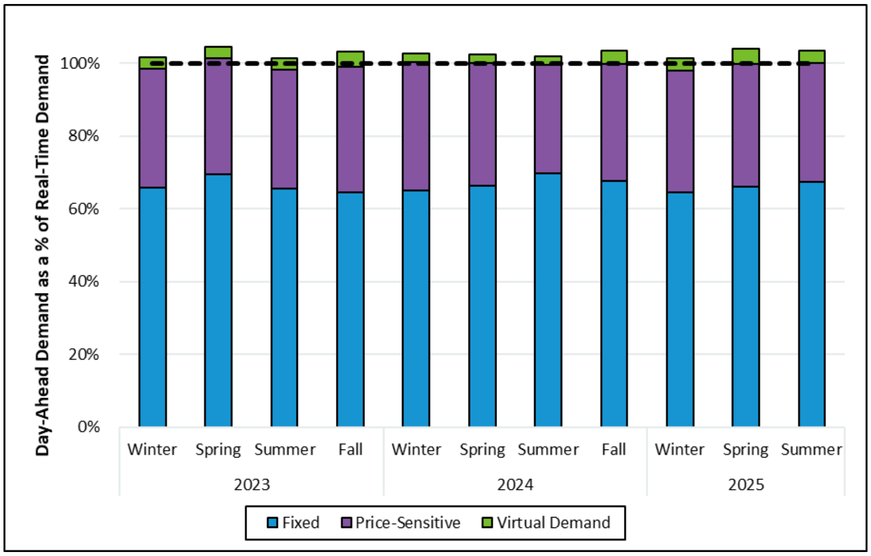
The 2025 load duration curve shifted upward for the 5% of hours with the highest loads when compared with the 2024 curve. The annual peak load occurred on June 24, when temperatures reached 97°F and system load rose to 26,551 MW. This peak exceeded the maximum 2024 load of 24,871 MW and was the highest registered peak since July 2013, highlighting the influence of short, intense periods of extreme heat on system demand. The load duration curve captures not only the magnitude of the annual peak but also the persistence of elevated load levels; therefore, while average loads in 2025 were lower than the prior year, the occurrence of higher-than-expected peaks underscores the importance of monitoring weather-driven volatility.

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

Load Clearing in the Day-Ahead Market

The average amount of load that participants cleared in the day-ahead market as a share of actual real-time load since Winter 2023 is shown in Figure 2-6 below.

Figure 2-6: Day-Ahead Cleared Demand as Percent of Real-Time Demand, by Quarter



In Summer 2025, participants cleared an average of 103% of real-time demand in the day-ahead market, a level similar to Summer 2024. Price-sensitive demand accounted for 33% of cleared demand, up from 30% in Summer 2024. Fixed demand bids declined by 3% relative to the prior year but continued to represent the largest share of total cleared demand at 67%. Finally, virtual demand increased to 3% of cleared demand, compared with 2% in 2024.

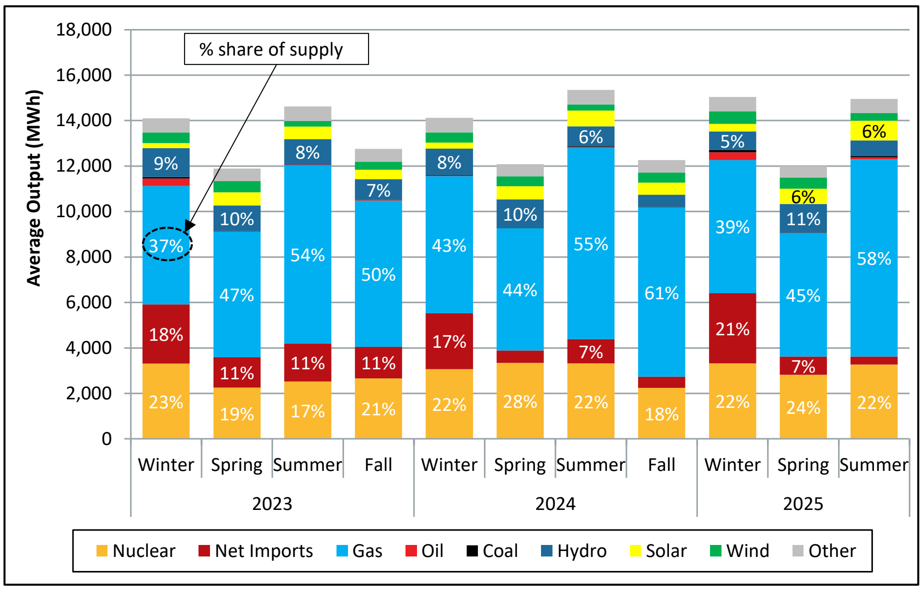
2.3 Supply

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

2.3.1 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 2023 through Summer 2025 are illustrated in Figure 2-7 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.[10]

Figure 2-7: Share of Electricity Generation by Fuel Type



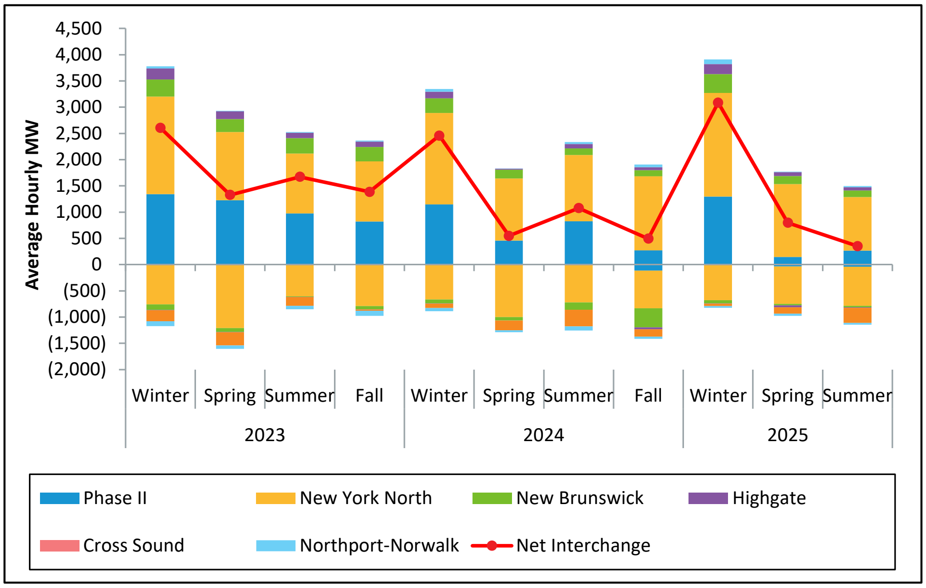
Similar to past seasons, natural gas and nuclear generation provided most of the energy supply (80%) during Summer 2025. New England imported less than 400 MW per hour during the summer, making up 2% of energy supply on average. Last summer, New England imported over 1,000 MW per hour. Drought conditions in the northeast contributed to lower imports, as well as lower hydro output from New England generators (down 21% compared to last summer). Increases in solar and gas generation offset lower hydro and net imports. Solar output increased to 6% of supply, 25% higher than in Summer 2024. Gas generation increased by almost 300 MW compared with last summer, to 58% of the overall supply mix, driven by increased output from single-fuel combined cycle units (not shown).

[10] 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.

2.3.2 Imports and Exports

In Summer 2025, New England continued to be a net importer of power from Canada, but was a net exporter to New York.[11] The average hourly import, export and net interchange power volumes by external interface for the last 11 seasons are shown Figure 2-8 below.

Figure 2-8: Average Hourly Real-Time Imports, Exports, and Net Interchange



On average, the net flow of energy into New England was 353 MW per hour from the neighboring control areas in Canada and New York combined. Total net interchange represented only 2% of load (NEL), down from 7% in Summer 2024.

Canadian Interfaces

Net imports over the three Canadian interfaces were greater than net exports over the three New York interfaces in Summer 2025. However, average net interchange at the Canadian interfaces continued to fall, decreasing from 890 MW to 374 MW largely due to fewer imports over the Phase II interface.

At the Phase II interface, which connects New England to Quebec, average quarterly net interchange fell from Summer 2024 levels by 72% (or 596 MW). In Quebec, normally abundant water resources and hydro generation have historically provided excess electricity supply, which can be sold to neighboring control areas. However, drier weather over the past few years has reduced the excess energy available in Quebec and limited exports from Canada into New England.[12] Despite this declining trend, imports at Phase II remained high in Summer 2025 when loads and energy prices

[11] 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.

[12] For more information see Hydro-Québec's *Quarterly Bulletin, Second Quarter 2025*, available at https://www.hydroquebec.com/data/documents-donnees/pdf/quarterly-bulletin-2025-2.pdf.

increased on hot days. During hours when loads were greater than 20,000 MW, Phase II net interchange averaged nearly 1,500 MW.

In Summer 2025, New England imported an average of 96 MW per hour from New Brunswick, up from 14 MW of net exports in Summer 2024. While imports increased, net interchange at New Brunswick remained below historical averages as a nuclear generator in New Brunswick was out-of-service for half of the summer.[13]

New York Interfaces

At the New York interfaces, New England typically imports energy over the New York North interface and exports energy over the Cross Sound Cable and Northport-Norwalk interfaces which connect to Long Island. Collectively, New England was a net exporter to New York, averaging 21 MW of net exports per hour, down from 186 MW of net imports in Summer 2024. Most of the year-over-year differences were the result of decreased net imports at the New York North interface.

At the New York North interface, net imports fell from 544 MW in Summer 2024 to 274 MW in Summer 2025. The decrease in net interchange was in line with the price differences at the New York North interface. On the New York side of the interface, average day-ahead prices were $4/MWh higher than in New England after being relatively equal in Summer 2024. When prices are higher in New York, participants may be willing to import into New England at a loss and collect additional revenues through Power Purchase Agreements or by selling Renewable Energy Certificates. At the Cross Sound Cable and Northport-Norwalk interfaces, average net interchange was similar to the prior summer. During Summer 2025, New England exported an average of 286 MW per hour at Cross Sound Cable and exported an average of 8 MW at Northport-Norwalk. Each interface saw net exports decrease by about 30 MW from the prior summer.

[13] For more information on the nuclear generator outage, see https://www.nbpower.com/en/about-us/news-media-centre/news/2025/planned-maintenance-outage-to-begin-at-point-lepreau-nuclear-generating-station/

2.4 Market Performance on June 24, 2025

This section examines the performance of the New England electricity markets during the June 24, 2025 Capacity Scarcity Conditions (CSC).[14]

2.4.1 Event Overview

On Tuesday, June 24, 2025, the ISO experienced capacity scarcity conditions which lasted from 17:35 through 20:35, or 37 five-minute intervals.[15] At the beginning of the operating day, operators expected low supply margins (106 MW) due to the high temperature (forecasted high of 96°F) and load forecasts (25,800 MW at peak). Actual temperatures and loads were slightly above forecasts, further stressing system conditions. Real-time load peaked at 26,024 MW, which was the highest recorded load since July 19, 2013. All major New England natural gas pipelines declared Operational Flow Orders (OFOs) on June 24 due to high expected demand, requiring gas generators to balance their real-time gas consumption with day-ahead schedules and limiting operating flexibility. During the evening ramp, a gas-fired generator tripped, and thermal generators were derated, or limited, due to ambient temperatures, leading to a 30-minute operating reserve deficiency. During the capacity scarcity event, two more large gas-fired generators reduced their maximum output or tripped offline due to mechanical issues, which contributed to the length of the event. Operators took several actions to ease system conditions, including cutting export transactions to New York and manual dispatching or committing generation and demand response resources.

Total Pay for Performance (PfP) credits totaled $114.3 million, exceeding both the PfP settlements from all prior events and the June 2025 base payments to capacity resources. Most resource types received net PfP charges due to a combination of resource underperformance and the high balancing ratio, which averaged 103%. The fact that the balancing ratio exceeded 100% implied that capacity resources alone were not sufficient to meet load and reserve requirements during the event. Since the balancing ratio was above 100%, resources that did not perform above their CSO were subject to PfP penalties. The increased PfP rate, higher balancing ratio and length of the event all contributed to stop-loss provisions being implemented. $26.4 million in charges were not collected from under-performing resources due to stop-loss limits.

2.4.2 Drivers of Tight System Conditions

Weather and Load

On June 23, ISO-NE declared M/LCC-2, Abnormal Conditions Alert, due to forecasted hot weather, high dew points, and limited capacity margins for June 24. Figure 2-9 illustrates actual and forecasted load from June 23 to June 25, as well as the forecast contributions from Settlement-only Generators (SOG) and BTM solar resources.

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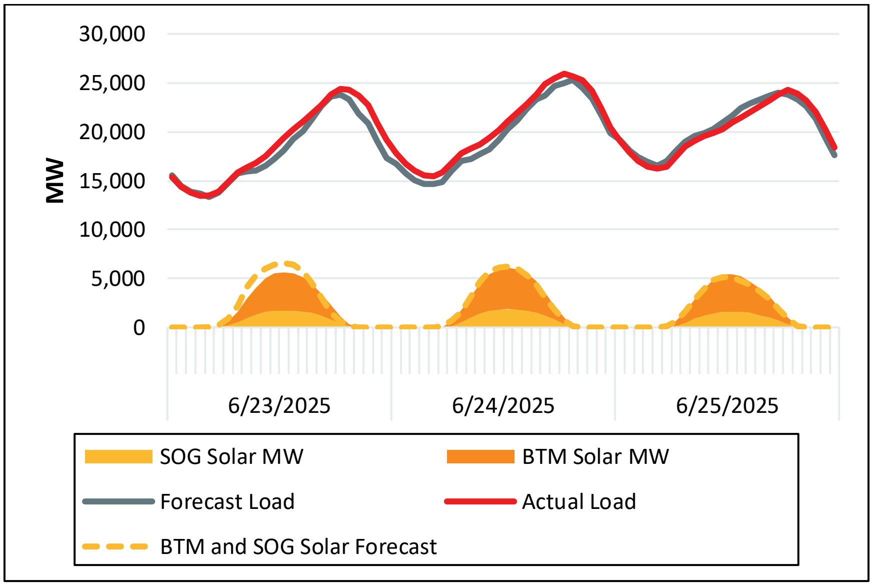
[14] For more information on a Capacity Scarcity Condition see Section III.13.7.2.1 Market Rule 1 located at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf

[15] 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.

Figure 2-9: Forecast and Actual Load with Solar Output, June 23-25



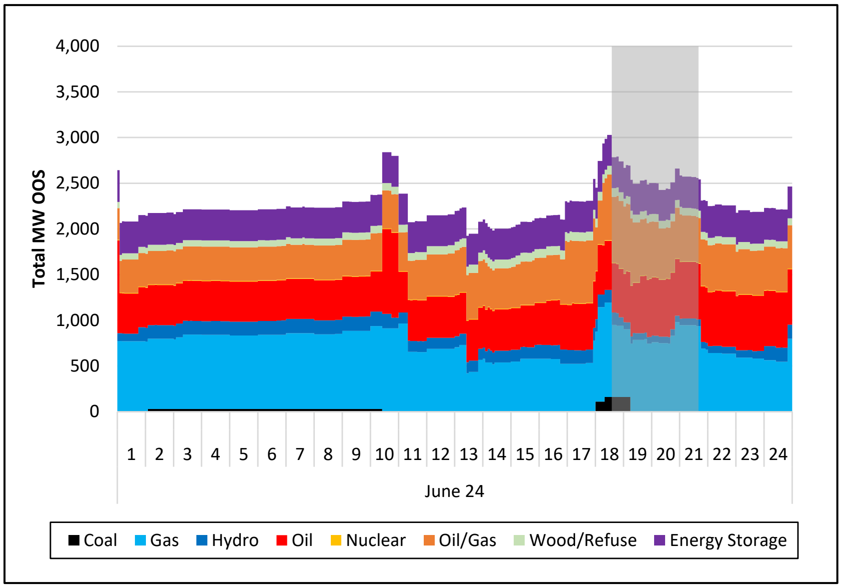
The M/LCC2 alert was in effect from 21:00 on June 23 through 21:00 on June 25. ISO's June 24 Morning Report projected a peak load of 25,800 MW in HE 19. Actual load exceeded that forecast, reaching 26,551 MW[16] in HE 19—the highest system load observed since July 19, 2013. On June 24, actual weather conditions were slightly hotter and more humid than forecasted during the peak. The 23-city weighed average temperature reached 97°F in HE 17, about 1°F above forecast, while dew points averaged 1.1°F higher than expected. These warmer and more humid conditions contributed to the system load peaking above forecast levels.

Unplanned Generator Outages

Unplanned generator outages and reductions contributed to the June 24 shortage event. Figure 2-9 illustrates actual real-time out-of-service generation capacity broken out by generator fuel type. The capacity shortage condition is indicated by the gray area.

[16] Load as seen from the control room. This measurement is used to compare actual loads to the day-ahead forecast.

Figure 2-9: Planned and Unplanned Outages by Generator Fuel Type, June 24[17]



Generator outages and reductions contributed to the capacity scarcity conditions, while further trips during the event prolonged the event duration compared to prior events. Throughout the operating day, thermal generators reduced maximum capability due to the hot temperatures in New England. These ambient temperature derates were generally small for single generators but were impactful across the entire fleet of generators.

Several large real-time generator outages contributed to the capacity scarcity conditions. In total, about 3,000 MW of generation was unavailable at 17:35, the start of the event.

- At 16:00, a dual-fuel generator experienced fuel issues which led to the generator reducing their maximum output by about 200 MW until 19:20.
- At 17:02, a gas-fired generator tripped resulting in the unit producing 177 MW less than their day-ahead cleared volume in HE 18.
- At 18:00, a large natural gas-fired generator moved to a 1x1 configuration; this unit reduced its maximum output by about 290 MW.
- At 19:41, a natural gas-fired generator initially reduced its maximum output by over 100 MW before completely tripping offline just seven minutes later. This resulted in a total loss of over 200 MW.

The outages that occurred on June 24 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, most units performed below their maximum capability due to ambient temperature derates. Generator outages and reductions have more of an impact on price and reliability in the summer when available supply is

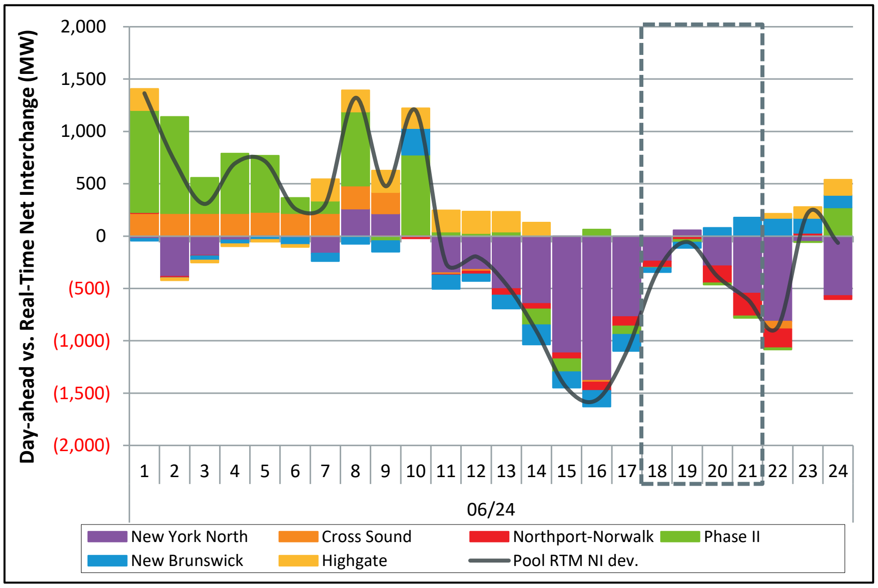
[17] This figure combines outage data from the Control Room Operations Window (CROW) system with real-time operational data. If a generator has a physical reduction logged in CROW, or if its real-time operational capability is less than its seasonal claimed capability, that generation is considered out of service (accounting for overlaps). Accounting for real-time operational data is necessary because not all outages are required to be logged in CROW. Intermittent fuel types (i.e., wind and solar) are not included in this image as these fuel types have large deviations from seasonal claimed capability based on their expected output.

already tight due to high loads. In these instances, a trip can lead to steep movement up the supply curve that results in higher prices and lower reserve margins than would be observed during a milder time of year.

Net Imports

During the capacity scarcity conditions, net imports performed below day-ahead cleared values until operators cut real-time export transactions. Deviations between day-ahead cleared and real-time scheduled net imports at the six interfaces are shown below in Figure 2-10 below.

Figure 2-10: Day-Ahead vs. Real-Time Net Interchange Deviations, June 24



Hot weather across the Eastern Interconnection impacted net interchange between control areas. On June 24, PJM, NYISO and IESO (Canada) all declared an Energy Emergency Alert Level 1.[18] During the start of the scarcity conditions in HE 18, real-time net interchange was below cleared day-ahead levels (344 MW lower) due to negative deviations at the New York North interface. ISO-NE operators managed flows with New York by cutting real-time export transactions. This action moved real-time interchange to day-ahead values, and deviations were small in HE 19, with New England imports exceeding 50 MW more than cleared day-ahead values over the NYN interface. Additionally, New England was a net exporter to Long Island throughout the event.[19] The IMM has recommended that export transactions be charged the PfP rate, which could provide additional incentives for participants to adjust or re-offer export transactions during tight system conditions.[20]

[18] See the *June 24, 2025 OP-4 Event and Capacity Scarcity Condition* presentation at the August 7, 2025 NEPOOL Participants Committee meeting, available at https://www.iso-ne.com/static-assets/documents/100027/june-24-2025-coo-op-4-and-csc-summary-08072025.pdf

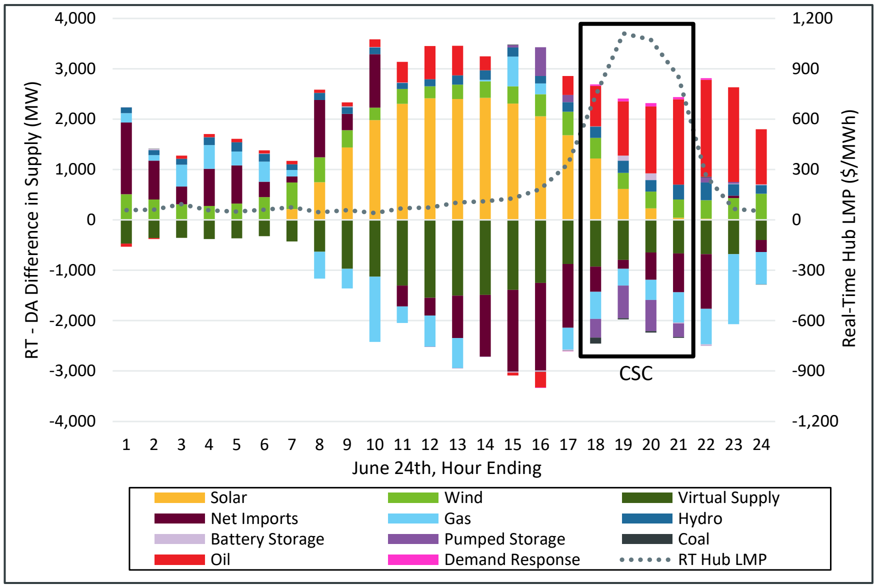
[19] ISO-NE exported 330 MW in each hour over the Cross Sound Cable to New York. At Northport-Norwalk, New England was a net importer during HE 18 and HE 19, but was a net exporter in HE 20 and HE 21.

[20] See our *2024 Annual Markets Report* (May 23, 2025), Section 6.2.1, available at https://www.iso-ne.com/markets-operations/market-monitoring-mitigation/internal-monitor .

Supply Mix Changes

The differences between hourly day-ahead and real-time generation obligations by fuel type are shown alongside the real-time Hub LMP for June 24 in Figure 2-11 below.

Figure 2-11: Differences between Hourly Real-Time and Day-Ahead Generation Obligations and LMPs, June 24



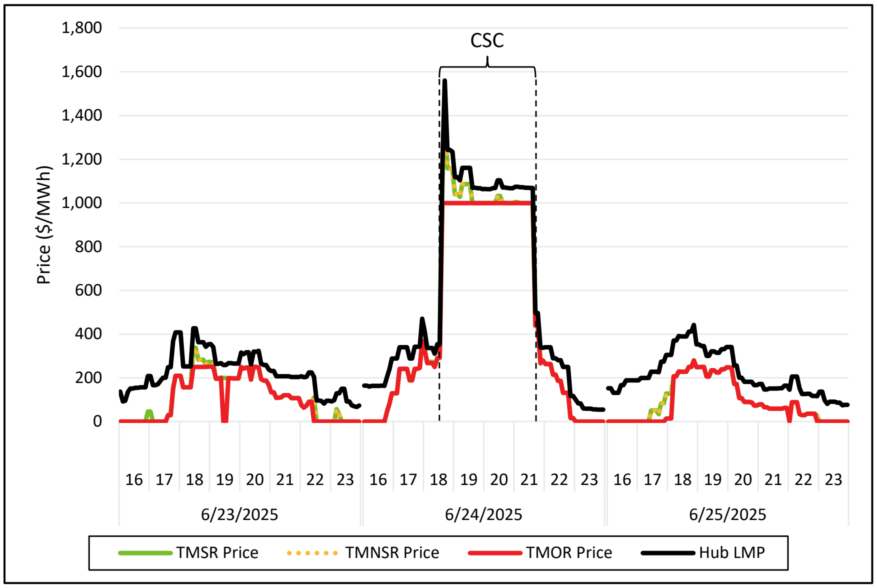
As indicated by the red bars above, oil-fired generators produced more energy in real-time than energy collectively cleared in the day-ahead energy market during the CSC hours. One large steam turbine and many smaller combustion turbines and internal combustion engines accounted for these real-time increases. Reductions in real-time gas generation were primarily driven by the unplanned outages of combined cycle generators during the event. Pumped-storage generators were dispatched down to provide reserves during the CSC and, therefore, delivered less real-time energy compared to energy volumes cleared in the day-ahead market.

2.4.3 Energy Prices, Reserve Prices, and Uplift

Energy and Reserve Prices

Five-minute Hub energy prices and system-wide reserve prices by product are shown for June 23-June 25 in Figure 2-12 below.

Figure 2-12: Five-Minute Energy and Reserve Prices, System Level, June 23-25



High prices in the three-hour time frame between 17:35 and 20:40 on June 24 reflected the $1,000/MWh 30-minute Reserve Constraint Penalty Factor, which is triggered when there is a deficiency of thirty-minute operating reserves. In addition, the ten-minute reserve requirement was binding for a portion of this period, resulting in 16 pricing intervals in which TMSR and TMNSR prices exceeded the TMOR price. The highest price for TMSR and TMNSR was $1,463/MWh, which occurred during one five-minute pricing interval, five minutes after the event started. 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 $1,561/MWh.

Uplift

Real-time uplift totaled $0.8 million on June 24. Given the high energy prices during the event, generators recovered the majority of their operating costs through energy market payments. Most of the real-time uplift on June 24 occurred after the event as fast-start generators remained online while energy prices fell. The majority of such payments were made to oil-fired generators and demand response resources.[21]

[21] Generators and demand response units might remain online to satisfy minimum run time or minimum reduction time constraints. Additionally, during tight system conditions, operators might manually hold committed units online.

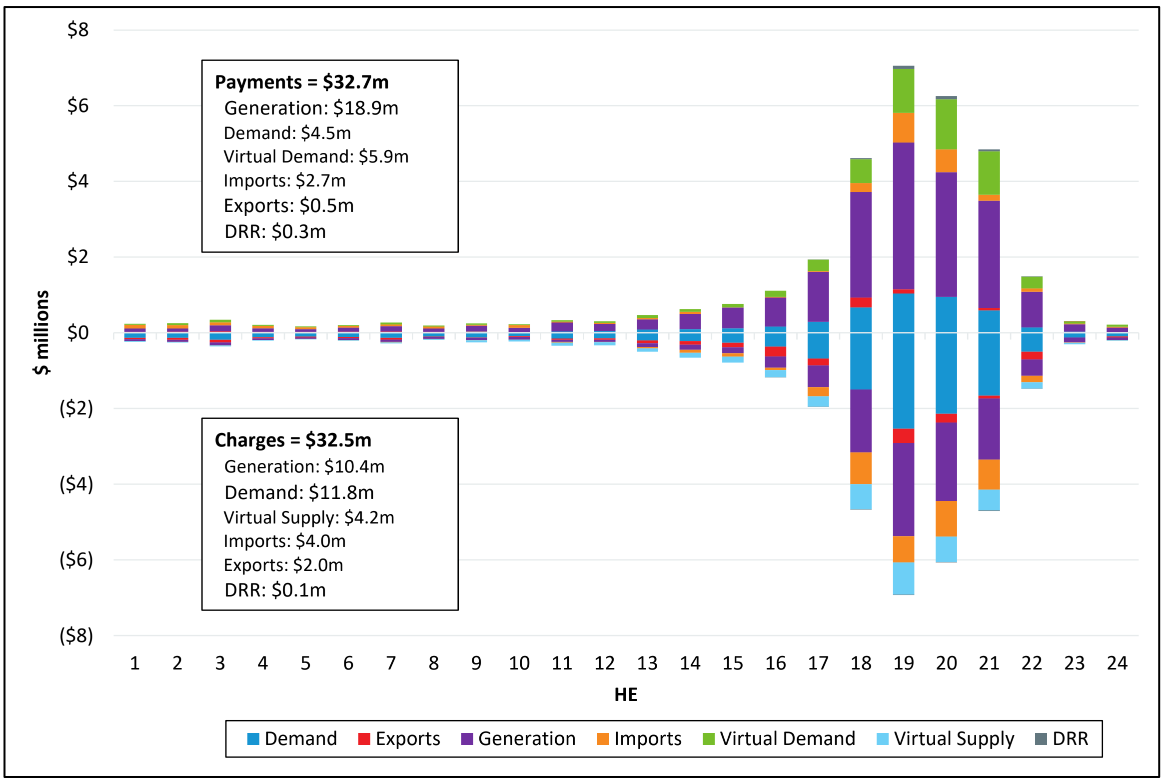
2.4.4 Two-Settlement System Outcomes

This subsection provides insight into under- and over-performers relative to forward positions on June 24. Coverage includes both the energy and the capacity markets.

Energy Charges and Payments

Total energy charges to demand on June 24 amounted to an estimated $93.5 million. Of this, $90.5 million (97%) were made in the day-ahead market, while net real-time charges accounted for the remaining $2.9 million (3%).[22] Gross payments for real-time deviations totaled $32.7 million, while gross charges totaled $32.5 million.[23] Real-time energy charges and payments by hour are shown in Figure 2-13 below.

Figure 2-13: Real-Time Deviation Energy Charges and Payments, June 24



Demand incurred the largest gross real-time charges ($11.8 million) on June 24.[24] Higher real-time load during the evening meant load-serving entities had to purchase additional real-time load at

[22] 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.

[23] 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.

[24] 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.).

higher real-time prices. Generation also incurred large real-time charges ($10.4 million). Given that numerous units with day-ahead awards experienced unplanned outages or reductions on June 24, these real-time charges to generators are to be expected. Notable charges also went to virtual supply ($4.2 million) and imports ($4.0 million). On the payments side, the majority of payments went to generators ($18.9 million) that produced more energy in real time than they had cleared in the day-ahead market. Significant payments were also made to demand ($4.5 million), virtual demand ($5.9 million) and imports ($2.7 million).

Forward Capacity Market (FCM) Pay-for-Performance

During capacity scarcity conditions, every FCM-participating resource, energy market asset, and import transaction is subject to Pay-for-Performance (PfP) credits or charges based on energy market performance. PfP payments or charges are settled at the Capacity Performance Payment Rate. The payment rate increased to $9,337/MWh for the June 2025-May 2026 Capacity Commitment Period, up from $5,455/MWh for June 2024-May 2025. A resource's PfP performance is assessed relative to their CSO times the balancing ratio, which is calculated as the sum of load and reserve requirements over total CSO.[25, 26] Assets or imports that do not have CSO may earn PfP credits for any capacity provided to the system. A capacity resource's final monthly settlement is also influenced by stop-loss limits[27] and the distribution of any excess or shortfall in net PfP settlements to capacity resources through the balancing fund. Figure 2-14 below shows PfP outcomes by resource type for both CSO and non-CSO resources for the June 24, 2025 event.[28]

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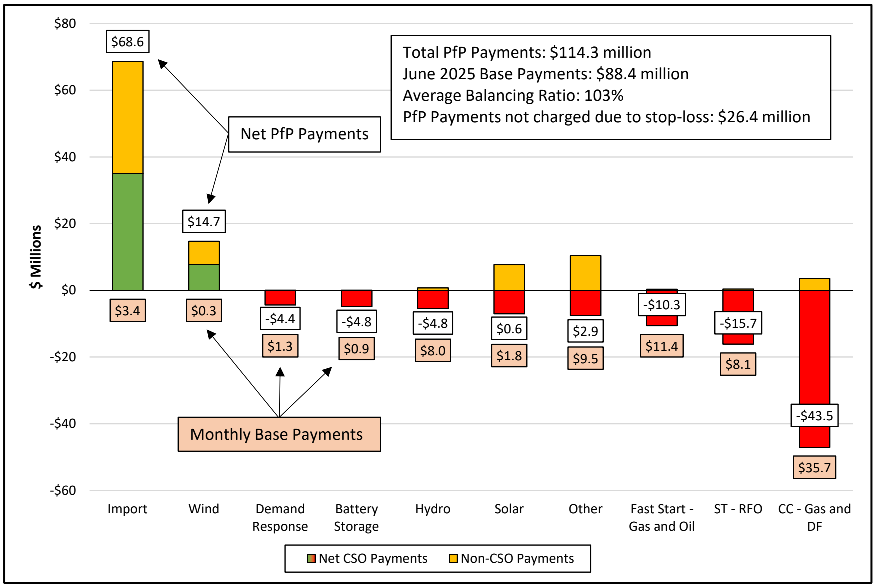
[25] For more information on the balancing ratio, see ISO's *Section III Market Rule 1 Standard Market Design*, section III.13.7.2.3, available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf .

[26] The balancing ratio calculation is defined over the system for systemwide reserve deficiencies, or specific capacity zones for local reserve deficiencies. The June 24 event was a systemwide reserve deficiency.

[27] For more information on stop-loss limits, see the 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 .

[28] In this figure, "Dual-fuel" refers to dual-fuel (gas/oil) resources and "CC" refers to combined-cycle resources. Total PfP Payments ($114.3 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. Finally, for the purposes of this graph and analysis, Non-CSO Payments include payments both to non-capacity assets and to capacity resources that have fully shed their CSO in June 2025.

Figure 2-14: Pay for Performance Settlements by Fuel Type, June 2025



Total PfP credits reached $114.3 million, exceeding both the PfP settlements from all prior events and the June 2025 base payments to capacity resources. Similar to previous PfP events, imports were the best-performing resource type. Imports with CSOs earned $35.0 million in net PfP payments, while non-capacity imports earned an additional $33.6 million. Most resource types received net PfP charges due to a combination of resource underperformance and the high balancing ratio (discussed below). Notably, gas- and dual-fuel combined cycle generators performed poorly during the event. Such generators accrued $43.5 million in net PfP charges, with losses beyond their $35.7 monthly base payment. This underperformance is attributable to gas system and generator performance; each major pipeline declared an Operational Flow Order (OFO) during the day, high ambient temperatures inhibited generator performance, and multiple gas units re-declared lower Eco Max values in real-time.

The balancing ratio averaged 103% during the scarcity event, marking the first time the balancing ratio exceeded 100% since the PfP settlement design implementation. A balancing ratio over 100% implies that available CSO was not sufficient to fully cover load and reserve requirements during the event. High demand was the primary driver of the high balancing ratio as load was estimated to be consistent with a 90/10 hotter-than-forecast day from the 2021 CELT report forecast for FCA 16.[29] In addition to high native electricity demand, 915 MW of exports further contributed to the

[29] For more information on the load forecasts effective at the time of FCA 16, see the *2021 CELT report*, available at https://www.iso-ne.com/system-planning/system-plans-studies/celt. Note that the *gross* load forecast distributions available on sheet 1.6 include load that is met by energy efficiency measures, while observed *net* loads do not include load that was prevented by energy efficiency. To estimate the range of load distributions net of energy efficiency, we first subtracted the 2025 50/50 load forecast reduced for BTM PV on sheet 1.5.1 and the load forecast reduced for both BTM PV and EE to yield a 3,473 MW load reduction attributable to EE. We applied this as a constant adjustment across the distribution of 2025 summer peak loads. Net Energy for Load averaged 26,551 MW in HE 18 during the event, just over the estimated EE-adjusted 90/10 load forecast (26,515 MW; equal to the 29,988 MW gross load forecast minus the estimated 3,473 MW of EE from the 50/50 forecast).

high balancing ratio.[30] While the balancing ratio would have exceeded 100% in some intervals even in the extreme scenario that no exports occurred during the event, charging exports the PfP rate (consistent with IMM recommendation) would have disincentivized exports during the scarcity event and would therefore likely have reduced the balancing ratio.[31] Notably, while the balancing ratio exceeded 100%, over 20,000 MW of capacity (70% of the capacity available during the event) did not perform up to CSO and would have been subject to performance penalties even if the balancing ratio had remained at 100%.

Unlike previous PfP events, the stop-loss mechanism contributed significantly to PfP settlement outcomes. Many resources reached monthly stop-loss limits due to the event duration and the high PfP rate. Table 2-2 below summarizes the impacts of the stop-loss and balancing ratio mechanism on PfP settlements.

Table 2-2: Stop-Loss and Balancing Fund Settlements

	$ Millions			
	PfP Charges Collected	PfP Payments Owed	Excess (Balancing Fund)	Total Stop-Loss Reallocations
Initial Event	$123.5	$114.3	$9.2	
Initial Stop-loss Charge Reduction	-$26.2		-$26.2	$26.2
First Stop-loss Total	$97.3	$114.3	-$17.0	$26.2
Incremental Stop-loss Charge Reductions due to Balancing Fund Distribution	-$0.2		-$0.2	$0.2
Final Stop-loss Total	$97.1	$114.3	-$17.2	$26.4
Balancing Fund Charge Distribution	$17.2		$17.2	
Final Settlement	$114.3	$114.3	$0	$26.4

Before any stop-loss or balancing fund adjustments, under-performing resources initially accrued $123.5 million in PfP charges while over-performing resources accrued $114.3 million in credits. The excess $9.2 million was credited to the initial balancing fund. As a direct result of the event, $26.2 million in charges were not collected from under-performing resources due to stop-loss limits. This more than cancelled the $9.2 million balancing fund excess, leading to a $17.0 million shortfall. This shortfall was iteratively distributed pro-rata to CSO while respecting resource stop-loss limits. As a result, an additional $0.2 million was not collected from resources that incrementally hit stop-loss, resulting in a final $17.2 million balancing fund deficit allocated to CSO. In total under the final settlement, there were $26.4 million in total reallocations of PfP charges away from resources that hit stop-loss limits to resources that did not reach limits.

2.4.5 Operator Actions

System operators use manual actions to ensure reliability during tight conditions. Below, Table 2-3 lists available operator actions and indicates whether each was used on June 24. We then give additional detail on each action used in chronological order.

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[30] The existence of a scarcity event does not require curtailment of all exports. ISO New England Operating Procedure No. 9 (OP 9) requires the curtailment of all non-CTS exports that did not clear the day-ahead market to meet load and operating reserve deficiencies. This allows exports that cleared the day-ahead market. Curtailment of day-ahead exports is only prescribed for meeting the ten-minute reserve requirement, which was not violated during the event. For more information, see ISO New England's *Operating Procedure No. 9 Scheduling and Dispatch of External Transactions,* available at https://www.iso-ne.com/participate/rules-procedures/operating-procedures.

[31] See our *2024 Annual Markets Report* (May 23, 2025), Section 6.2.1, available at https://www.iso-ne.com/markets-operations/market-monitoring-mitigation/internal-monitor .

Table 2-3: Operator Interventions on June 24

Action	Occurred on 6/24
Cuts To External Transactions	Yes
Posturing	No
Manual Dispatch	Yes
Manual Fast-Start Commitments	No
Supplemental Commitments	Yes
Fast-Start Reliability Flag	No
Reserve Bias Changes	No

Cuts to External Transactions: Operators cut real-time export transactions in HE 18 and HE 19 over the New York North interface. These cuts brought net interchange back to day-ahead cleared volumes at the interface.

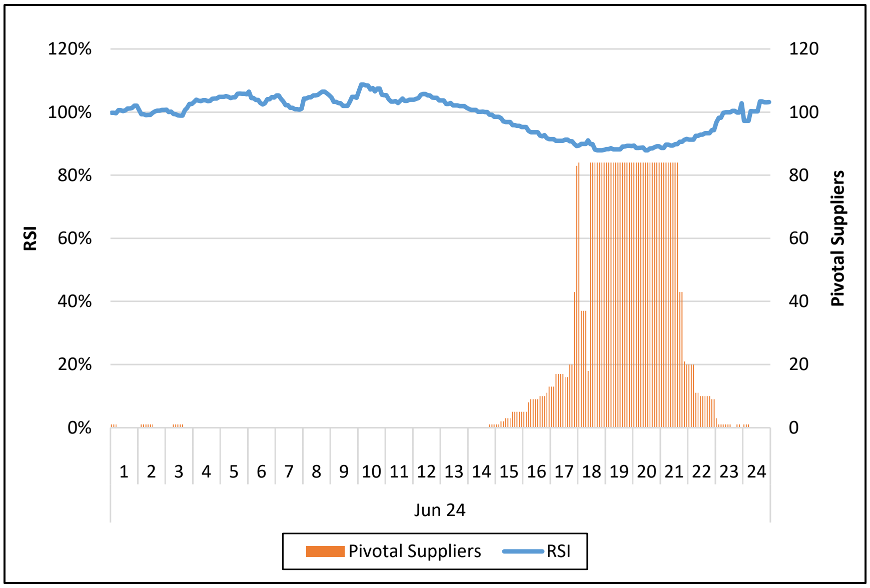
Supplemental commitments: At 16:10, operators issued a supplemental commitment for a 12 MW Demand Response Resource (DRR) due to capacity concerns.

Manual dispatch: At 17:20, the operators manually dispatched four generators and six DRRs 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.

2.4.6 Market Power Assessment and Mitigation

With tight system conditions on June 24, 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 2-15 depicts the real-time residual supply index (RSI) and number of pivotal suppliers for each five-minute pricing interval on June 24.

Figure 2-15: Residual Supply Index, June 24



On June 24, the RSI reached its lowest value of 87.9 for two intervals during HE 20, meaning the system could only meet about 88% of load and the reserve requirement without the largest supplier. During the shortage event intervals, all participants with available supply are considered pivotal since the load and reserve requirements could not be satisfied.

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 2-4 indicates the incidence of market power flags and mitigations.

Table 2-4: Market Power Flags and Mitigation during CSC, June 24

Type	RT Reliability	MDE	RT CAE	Pivotal Suppliers - GTCM
Market Power Flag - Asset Hours During Event	8	68	0	1,451
Mitigations - Asset Hours During Event	0	0	0	3

Only two pondage hydro assets were mitigated during the event, both for general threshold commitment mitigation (GTCM), in a total of 3 asset hours. As would be expected given the tight system conditions on June 24, 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. Despite the high number of pivotal suppliers, the relatively low number of mitigations are due to the relatively tolerant thresholds for general threshold commitment mitigation.

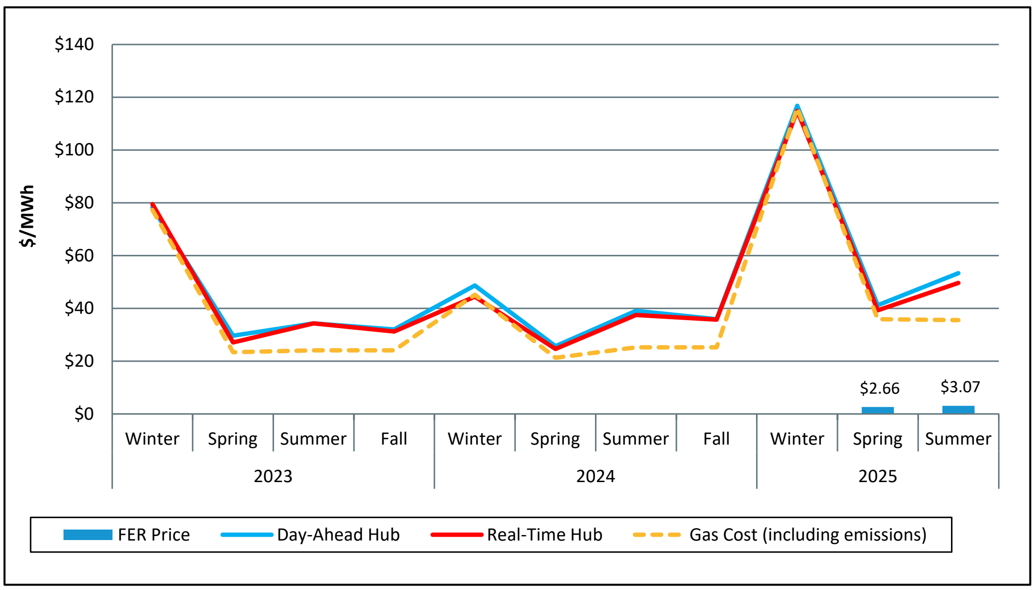
Section 3
Day-Ahead and Real-Time Markets

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

3.1 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 3-1 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.[32] Figure 3-1 includes the Forecasted Energy Requirement (FER) price which is paid to day-ahead cleared physical generation.

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



The average day-ahead and real-time Hub prices for Summer 2025 were $53.31 and $49.65/MWh, respectively. Additionally, the Forecast Energy Requirement (FER) price averaged $3.07/MWh leading to a day-ahead premium for load and physical generation of $6.73/MWh, the highest of the reporting period. Average energy prices in Summer 2025 were higher than Summer 2024 prices by $14/MWh (or 37%) and $12/MWh (or 33%) in the day-ahead and real-time markets, respectively. These increases were in line with the increased cost for natural gas generators, which averaged $35.55/MWh (up 41%). Estimated costs for natural gas generators increased due to higher gas prices in New England, which were up by 83% year-over-year.

On days with hot weather and high loads, day-ahead prices tended to be higher than real-time prices. Two main factors contributed to poor price convergence on these days: the level of cleared of virtual transactions and the co-optimization of reserves in the new Day-Ahead Ancillary Services

[32] 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.

market (DA/AS). On sunny days, participants clear virtual supply to replace cheap real-time renewable generation that materializes in real time. However, participants with virtual supply tended to clear less on days with hot weather and high loads, potentially to avoid the possibility of high prices or even scarcity conditions in real time. Contrarily, cleared virtual demand was often higher on these hot days. While load-serving entities and generators may use virtual demand to hedge against real-time price spikes, speculators may seek to profit off high real-time prices.

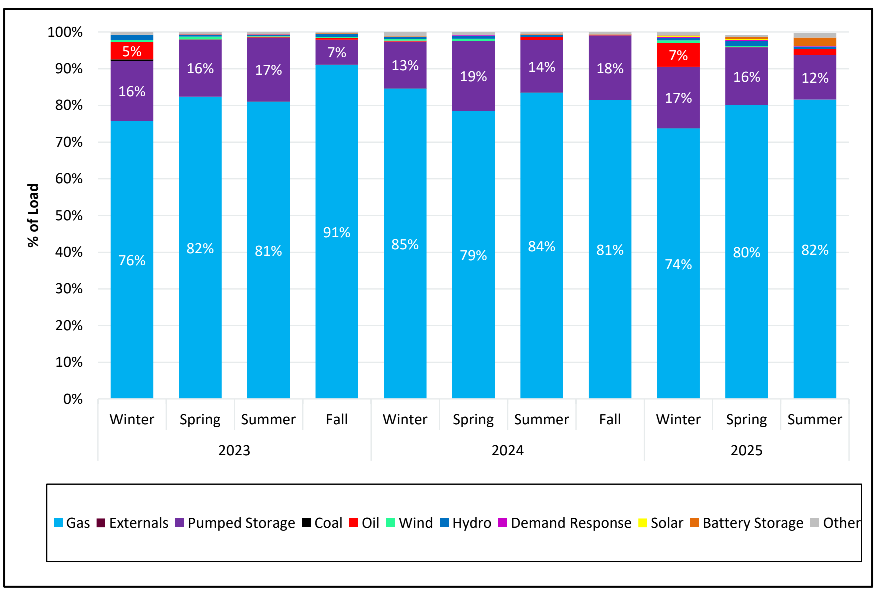
Under the DA/AS market, the capability of inframarginal generation may be used optimally to satisfy reserve requirements instead of clearing for energy. This can put upward pressure on day-ahead prices as a more expensive unit would set the day-ahead price. Though quarterly average real-time prices were lower than day-ahead prices, there were certain days when 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 24 are discussed in Section 2.4.

3.2 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.

The percentage of load for which each fuel type set price in the real-time market since Winter 2023 is shown in Figure 3-2 below.

Figure 3-2: Real-Time Marginal Units by Fuel Type



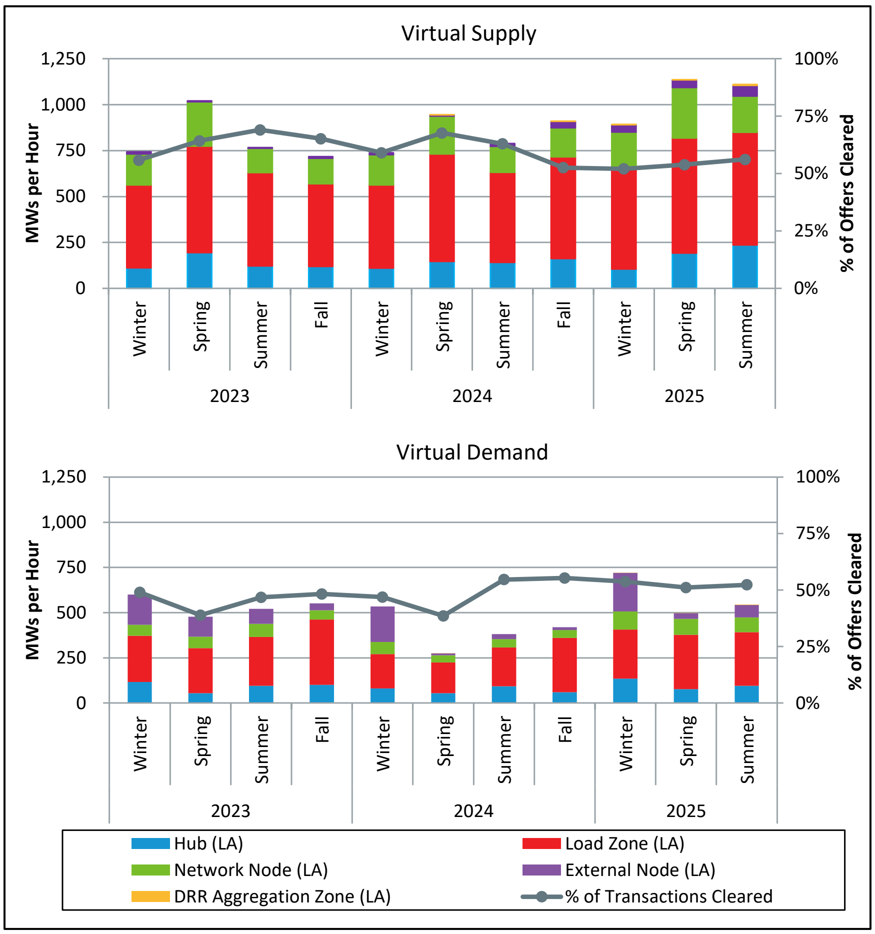
Natural gas-fired generators set price for the highest percentage of load in the real-time market in Summer 2025 (82%), and pumped-storage generators set price for the second highest percentage of load (12%). Notably, battery storage generation set price for 0.9% of load, marking the highest share of marginal battery storage over the sample period. Oil and battery storage set price during high-priced hours in Summer 2025.

3.3 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 3-3 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 3-3: Cleared Virtual Transactions by Location Type



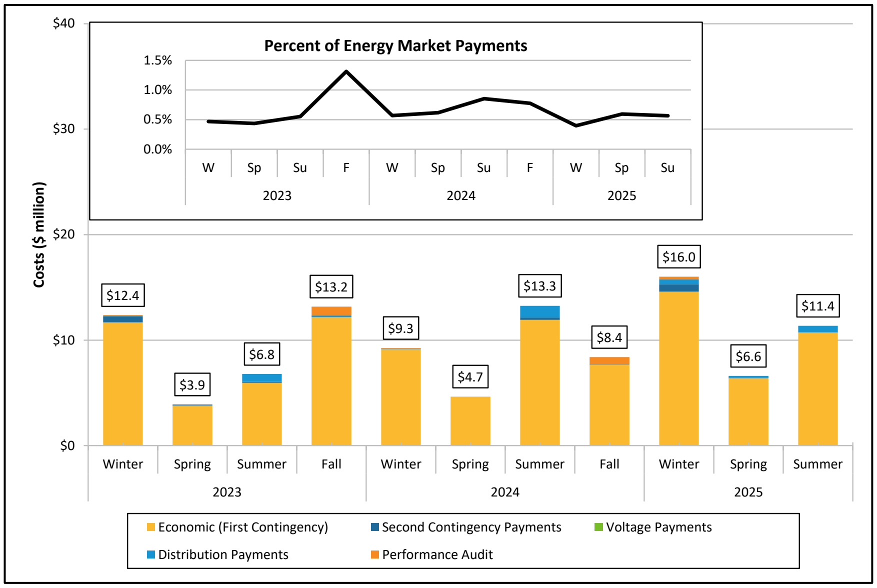
Total cleared virtual supply averaged 1,110 MW per hour in Summer 2025, up 41% from Summer 2024 (789 MW per hour). There were two notable factors behind this increase: first, the growing amount of solar settlement-only generation (SOG) and second, the day-ahead bidding behavior of wind and solar generation. By the end of Summer 2025, the installed capacity of solar SOGs was nearly 2,450 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. 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. Real-time renewable generation was 998 MW higher than day-ahead cleared volumes. This was up by about 200 MW from the prior summer.

Cleared virtual demand tends to increase during the summer as participants clear more transactions on high-load days, particularly around the peak load hours. In Summer 2025, cleared virtual demand averaged 544 MW per hour, up 43% from Summer 2024 (381 MW per hour). Greater volumes of virtual demand cleared across all location types, but was most notable at external nodes and load zones. At external interfaces, cleared virtual demand increased due to more clearing at the Highgate interface. At this interface, participants often clear virtual demand in conjunction with import transactions, which can help them gain real-time scheduling priority. The increase in clearing at load zones largely occurred in the Connecticut load zone and was driven by one participant.

3.4 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.[33] Figure 3-4 below shows total NCPC by category and quarter for 2023-2025. The inset graph shows quarterly NCPC payments as a percentage of total energy market payments.

Figure 3-4: NCPC by Category



NCPC payments totaled $11.4 million in Summer 2025, down from $13.3 million in Summer 2024. The majority of NCPC was economic uplift to generators committed to meet load and reserve requirements. Out of merit payments continued to comprise the largest share of economic NCPC in Summer 2025, totaling $7.1 million. Special constraint commitment payments for distribution networks are common in summer months, and such payments totaled $0.6 million. Local second contingency payments were minimal in Summer 2025.

[33] 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).

3.5 Day-Ahead Ancillary Services

The day-ahead ancillary services (DA A/S) market is designed to procure sufficient capability to satisfy both the operating reserve requirements and the load forecast through a market construct. This section provides details on the performance of this market between March 1, 2025 and August 31, 2025.[34]

3.5.1 Flexible Response Services

One set of ancillary service capabilities procured via the DA A/S market ensure that the ISO has enough fast-starting and fast-ramping capability to quickly respond to a large supply loss. These capabilities, commonly called operating reserve capabilities, are referred to as Flexible Response Services (FRS) under this market design. Requirements for FRS capabilities have analogs to those that exist in the real-time market, including the ten-minute spinning reserve, total ten-minute reserve, and total 30-minute reserve requirements.

To help satisfy these requirements, market participants make offers for the following products:

- day-ahead ten-minute spinning reserve (DA TMSR)
- day-ahead ten-minute non-spinning reserve (DA TMNSR)
- day-ahead thirty-minute operating reserve (DA TMOR)

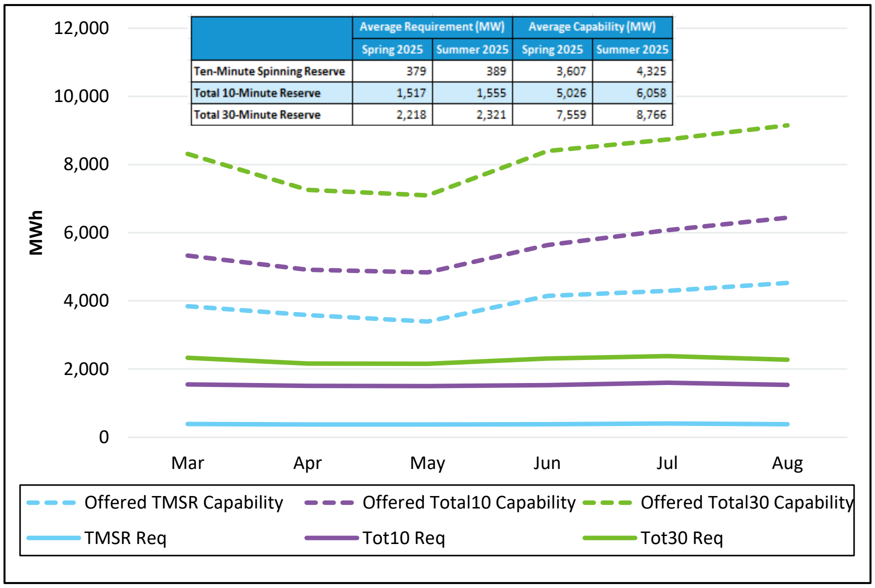
Requirements and Capability

In general, offered FRS capability has been many times larger than FRS requirements. This can be seen in Figure 3-5, which shows the FRS requirements relative to the offered DA A/S capability that could meet those requirements, averaged across each month.[35] This figure also includes average quarterly values in the inset table.

[34] The DA A/S market went live for the operating day of March 1, 2025.

[35] Offered capabilities reflect participant-submitted DA A/S offer quantities limited by physical resource characteristics (e.g., ramp rate, ecomax).

Figure 3-5: FRS Requirements and Offered Capabilities



On average, offered TMSR capability exceeded the TMSR requirement in Summer 2025 by a factor of over ten times the requirement, while offered total 10- and total 30-minute capabilities exceeded requirements by more than a factor of three.[36] While the FRS requirements – which are based on the projected first and second contingencies – did not change much quarter over quarter, the offered capability that could meet those requirements saw notable increases. This trend reflects increased participation by certain participants following IMM approval of their benchmark models[37] as well as some FRS capability returning to market following the spring outage season.

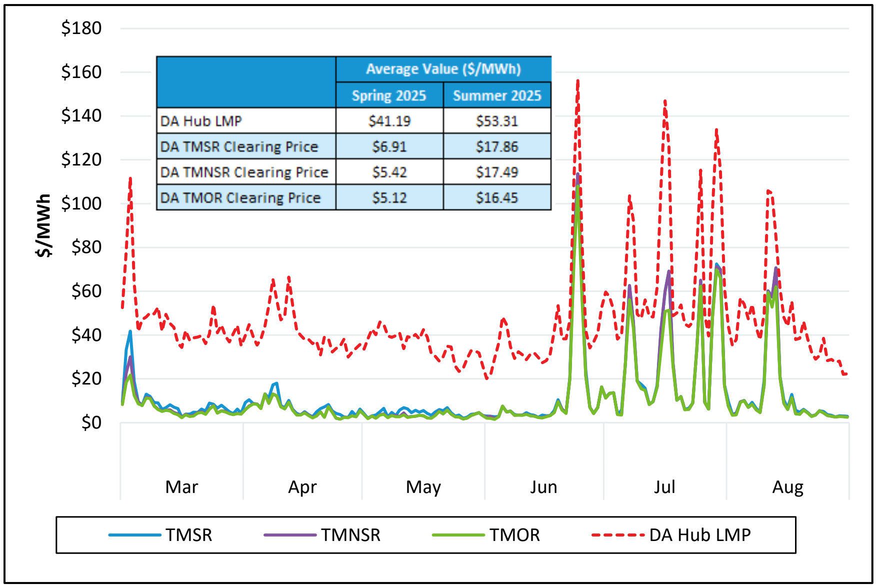
Clearing

FRS clearing prices were generally higher and more volatile in Summer 2025 than in Spring 2025. This can be seen in Figure 3-6 which shows daily average clearing price values over the first six months of the DA A/S market. This figure also includes average quarterly prices in the inset table.

[36] This figure does not account for several factors that reduce the amount of this capability that can be used to satisfy these requirements. First, some DA A/S capability may provide greater value to the system when cleared as day-ahead energy, and, if so, will clear as such. Second, some DA A/S capability is offered on resources that can only provide that capability from an online state, and these resources may or may not receive a day-ahead commitment. Third, some DA A/S capability may be offered on resources that prove unable to provide the service due to binding transmission constraints. Finally, some market participants may use maximum daily award limit (MDAL) parameter to limit the MWh of DA A/S awards an asset can receive during an operating day.

[37] Through the IMM consultation process, participants may establish their own DA A/S benchmark levels, which are used in the DA A/S mitigation evaluation. See Sections 3.5.5 and 3.5.6 for more information.

Figure 3-6: FRS Clearing Prices



There were 12 different days over Summer 2025 when the average daily clearing price for all three FRS products exceeded $50/MWh. These periods of elevated FRS clearing prices occurred during high-demand periods that also had high energy market prices. Opportunity costs can be highly impactful to FRS clearing prices during periods like this as the magnitude of the inframarginal energy market rents foregone by units that are "redispatched" to satisfy reserve requirements can be large.

3.5.2 Forecast Energy Requirement

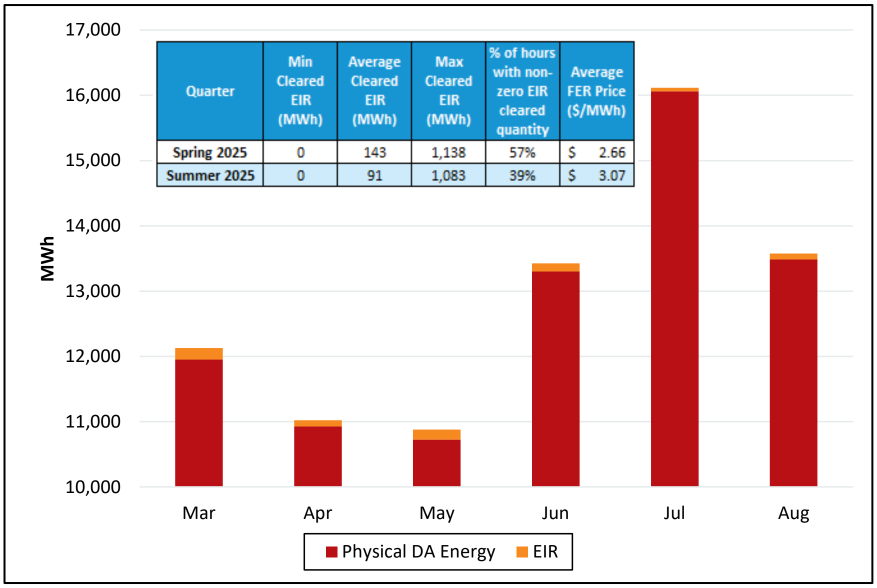
The other capability now procured in the DA A/S market is the capability to satisfy the load forecast. This capability is procured via the Forecast Energy Requirement (FER) constraint, which can be satisfied by a mix of day-ahead energy awards cleared on physical resources and Energy Imbalance Reserve (EIR) awards.

The need for EIR can depend on dynamics on both the supply and demand sides of the market. On the demand side, if load collectively bids less than the ISO forecast, procurement of EIR may be necessary to satisfy the load forecast. On the supply side, a combination of competitively priced virtual supply and EIR offers may prove to be the most cost-effective solution for satisfying the day-ahead market's requirements.

Clearing

Day-ahead energy awards to physical suppliers satisfy the vast majority of the FER demand, with relatively small amounts of EIR cleared periodically. This can be seen in Figure 3-7 shows the average MWh of supply that cleared to satisfy FER demand by product. This figure also includes relevant quarterly statistics in the inset table.

Figure 3-7: Forecast Energy Requirement Cleared Awards and Related Statistics



Quarter	Min Cleared EIR (MWh)	Average Cleared EIR (MWh)	Max Cleared EIR (MWh)	% of hours with non-zero EIR cleared quantity	Average FER Price ($/MWh)
Spring 2025	0	143	1,138	57%	$ 2.66
Summer 2025	0	91	1,083	39%	$ 3.07

Similar to Spring 2025, nearly all FER demand in Summer 2025 (~99%) was met by cleared energy awards to physical suppliers with only a small need for additional EIR procurement. In fact, the average volume of cleared EIR decreased between Spring 2025 and Summer 2025 (from 143 MWh to 91 MWh) as did the percentage of hours that any EIR was needed (from 57% of hours to 39% of hours). Meanwhile, the average FER price rose slightly between Spring 2025 ($2.66/MWh) and Summer 2025 ($3.07/MWh), indicating that, when there was a need for additional physical supply to meet the load forecast, it was, on average, more expensive to procure on a $/MWh basis.[38]

3.5.3 Settlements

The four DA A/S products are paid an initial credit at the applicable DA A/S clearing price and face a closeout charge whenever the real-time hub LMP exceeds the strike price. In addition, day-ahead energy awards to physical supply resources (i.e., generators, DRRs, and imports) are paid the FER price, as these energy awards are able to contribute to satisfying the load forecast. Table 3-1 shows the settlements of this new market for the first two quarters.

[38] The FER price is paid to cleared EIR awards as well as all day-ahead energy awards to physical supply resources (i.e., generators, DRRs, and imports).

Table 3-1: DA A/S and FER Settlements ($millions)

Concept	Spring 2025	Summer 2025	Total	% of Total
TMSR (net)	$3.7	$16.6	$20.3	8%
TMNSR (net)	$6.3	$26.1	$32.3	12%
TMOR (net)	$2.9	$13.3	$16.2	6%
EIR (net)	$0.2	$1.4	$1.6	1%
FER	$74	$122	$197	74%
Total	**$88**	**$180**	**$267**	**100%**
Total E&AS Costs[39]	$1,267	$2,328	$3,594	
% Total E&AS Cost	7%	8%	7%	

Total net ancillary services and FER payments increased substantially between Spring 2025 ($88 million) and Summer 2025 ($180 million). However, this increase was in-line with the change in total energy and ancillary services (E&AS) costs observed between the two periods – which was driven largely by higher loads and LMPs in the summer – and the end result was that DA A/S costs represented between 7-8% of E&AS costs in both quarters. While the FER credit paid to physical suppliers of day-ahead energy ($122 million) once again represented the largest share of DA A/S-related settlements in Summer 2025, there were notable increases in FRS net credits.

3.5.4 Profitability Assessment and a Risk/Return Framework

Like day-ahead energy positions, the DA /AS obligation creates downside risk that is central to creating strong incentives to cover the DA A/S position when real-time prices exceed a resource's short-run marginal costs (SRMC). If the closeout charge exceeds the clearing price and the resource fails to cover its position in real-time, it incurs a financial loss.

The objective of this analysis is to examine whether this "option-like" exposure yields a distribution of daily profits with heavy left tails and, if so, whether the remaining revenue streams offset that risk. If the conditions that trigger closeouts (RT Hub LMP above Strike) also coincide with strong RT energy margins or valuable RT reserve revenues, then the asset's combined portfolio should shift right (higher mean) and compress the left tail relative to DA A/S Net Revenues alone.

This section presents daily profit and loss (P&L) data for resources that take on DA A/S obligations over the first six months of implementation (March–August 2025).[40] We evaluate risk-return holistically—considering not only incremental returns from DA A/S positions but also total energy and real-time reserve revenues.

Risk preferences vary significantly across market participants and are influenced by factors such as portfolio size, liquidity, and corporate culture. These differences affect both the willingness and ability to assume financial risk under the DA A/S framework. While such preferences are difficult to quantify precisely, standard financial risk metrics offer useful insights. In this analysis, we apply the Sharpe Ratio and Conditional Value at Risk (CVaR) to assess risk-adjusted performance. These

[39] Total Energy and Ancillary Services costs include day-ahead and real-time energy, reserve, regulation, and NCPC costs.

[40] The results are robust to narrowing the set of assets based on their participation in DA A/S, i.e., requiring that assets pick up DA A/S awards on some minimum number of days, and conditional on picking up a DA A/S award, that the award correspond to some minimum share of the asset's maximum A/S capability.

metrics provide a foundation for understanding day-to-day loss risk and will be refined and expanded in future IMM evaluations of DA A/S.[41]

Key Takeaways

Coverage and sample. Gas Turbines (GT) and Combined Cycles (CC) have cleared much of DA A/S awards, at 64% and 28%, respectively (92% in total). As such, only these two technology classes are included in this assessment.[42,43]

GT (fleet view). On a fleetwide basis, GTs earn a significant share of their overall net revenue from DA A/S; $2.12/kW-month of $3.06/kW-month. The operating profile of GTs means that that such assets do not typically possess a strong physical hedge against DA A/S closeout charges due to their high SRMCs relative to real-time LMPs and Strike Prices. While DA A/S increases downside risk and variability in returns for GTs, our assessment suggests that the increase in returns over the first six months relative to the incremental downside risk of DA A/S appear sufficient to compensate and incentivize participation.

CC (fleet view). CCs earn a much smaller share of their overall revenue from DA A/S on a fleetwide basis, given the significant share of revenue from selling energy; DA A/S net revenue contributes just $0.23/kW-month to overall net revenue of $7.43/kW-month. DA A/S obligations do not materially change the risk-return metrics or downside risk of CC fleet.

Distributions of Revenue Sources and Risk Metrics

For each of the 66 GTs and 46 CCs in the sample, we construct three daily series: (1) Energy & RT Reserves Net Revenues; (2) DA A/S Net Revenues; and (3) Total Net Revenues.[44] We then construct similar P&Ls for representative GT and CC units using an Seasonal Claimed Capability-weighted average of the individual asset P&Ls.

We measure the risk associated with each distribution through the following metrics:

1. **Sharpe Ratio.** This is the average daily profit divided by its day-to-day volatility (standard deviation), reported in $/kW-month. A higher Sharpe ratio means the portfolio earns more typical profit per unit of routine volatility, i.e., that risk-adjusted performance improved.
2. **Conditional Value at Risk (CVaR) at 95%.** This measure focuses only on the left tail: it is the average loss on the worst five percent of days, expressed as a loss magnitude (again, in

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[41] The ISO-NE has previously presented a methodology for calculating risk premiums using the Sharpe ratio; see "Competitive Offer Price Formulations for Day-Ahead Ancillary Services as Options – Revised Edition," https://www.iso-ne.com/static-assets/documents/2023/06/a03a_mc_2023_06_06__dasi_competitive_offer_formulations_memo.pdf, at 42-44. We supplement this Sharpe-based analysis using the CVaR risk metric, which considers downside risk, a concern expressed by Participants during consultations with the IMM's Market Power Mitigation team.

[42] The analysis relies on settlement data for 66 GTs and 46 CCs.

[43] Further, while we lead with metrics for the entire classes, we recognize that this is not representative of any individual participant's portfolio. Therefore, we also present risk-return metrics for individual resources (masked) over the 6-month period.

[44] All net revenues are normalized to $/kW-month based on the asset's effective SCC. The different revenue components are defined in the Appendix.

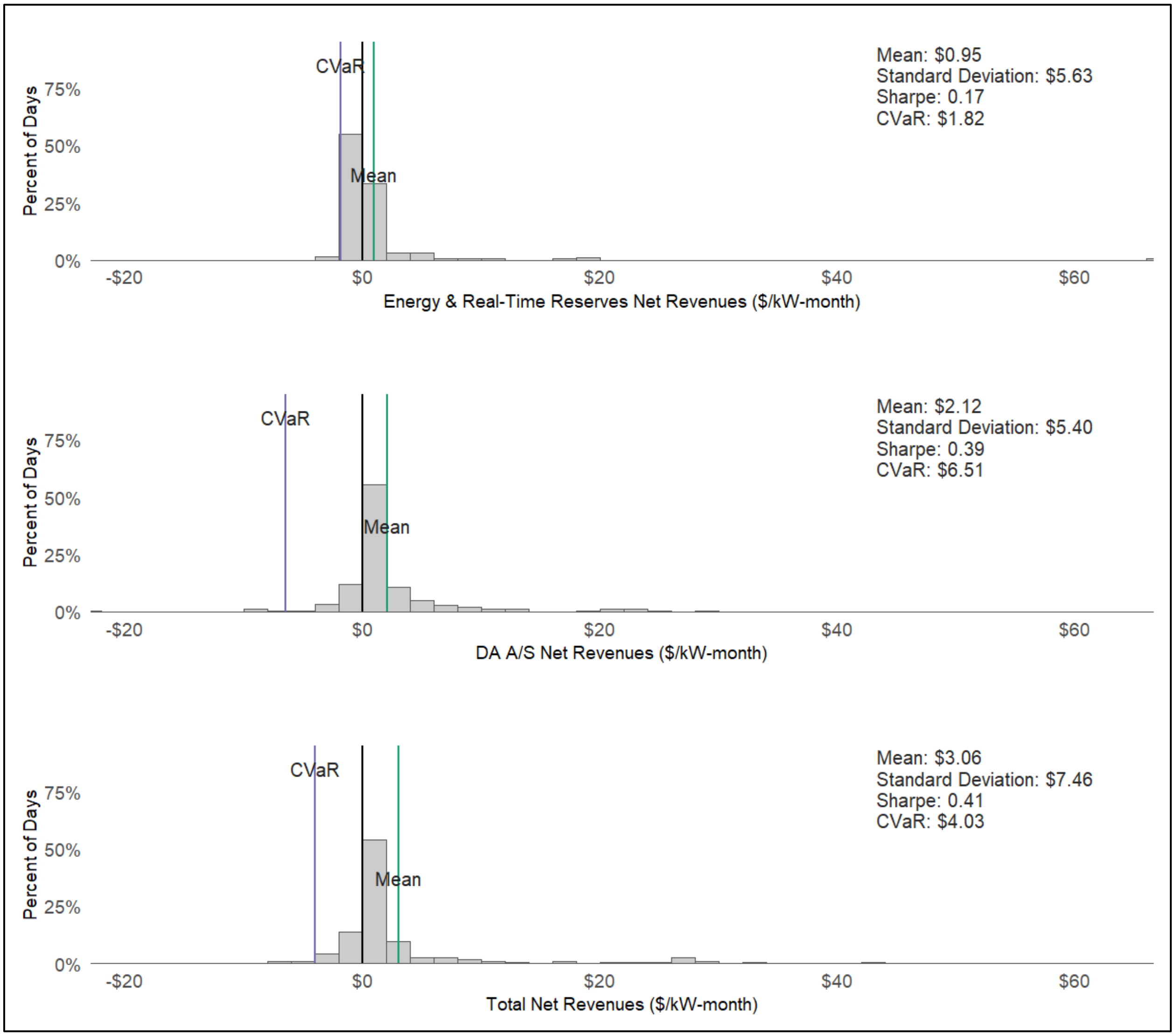
$/kW-month). A smaller CVaR means less severe bad-day outcomes, while a larger CVaR indicates deeper downside.

When comparing the distributions of Energy & RT Reserves Net Revenues and Total Net Revenues, we also report on the **Return on Incremental Risk**, which compares the change in average daily profit to the change in tail loss (CVaR at 95%). This metric shows how many dollars of "typical" profit an asset gains per additional dollar of worst-five percent loss. Comparing the Return on Incremental Risk to an asset owner's economic cost of holding economic capital to cover the worst-five-percent losses provides some insight into whether any added average profits adequately compensate the asset owner for the corresponding incremental variability in profits due to taking on a DA A/S obligation.[45]

Figure 3-8 shows the distributions of the three Net Revenues for the representative GT unit and summarizes these distributions.

[45] To fund losses on the worst-five percent of days, an asset owner must cover both the expected frequency of tail days (roughly 5%, given our assumed 95% CVaR metric) and the cost of capital held against these tail losses. So a minimal break-even condition requires the Return on Incremental Risk to exceed 0.05 plus the asset owner's daily WACC. See the Appendix for details.

Figure 3-8: Distribution of Net Revenues (GTs)



DA A/S Net Revenues vs Total Net Revenues. The SCC-weighted representative GT unit earns a mean DA A/S Net Revenue of $2.12/kW-month, rising to $3.06/kW-month once Energy and RT Reserves Net Revenues are included. Although there is a corresponding increase in variability (as reflected in the standard deviation increasing from $5.40/kW-month to $7.46/kW-month), the left tail tightens: the representative GT unit stands to lose, on average, $4.03/kW-month in the worst 5% of days, down from $6.51/kW-month when DA A/S Net Revenues are viewed in isolation. These patterns underscore that overall portfolio behavior, not DA A/S Net Revenues in isolation, determines realized risk. This insight is most apparent during the CSC on 6/24/2025: The day's $22.89/kW-month DA A/S net *loss* represents the representative unit's worst performance in terms of DA A/S Net Credits alone. However, the $66.55/kW-month earned in the Energy and RT reserves brings the unit's overall earnings to $43.66/kW-month, its best daily overall performance over the six-month study period.

Energy & RT Reserves Net Revenues vs Total Net Revenues. Including DA A/S Net Revenues yields a $2.12/kW-month = ($3.06/kW-month – $0.95/kW-month) increase in expected returns and an increase in the average loss across the worst-five-percent of days of \$2.20/kW-month = (\$4.03/kW-month – \$1.82/kW-month). Table 3-2 summarizes the key risk-return tradeoff for GTs.

Table 3-2: Risk-Return Summary (GTs)

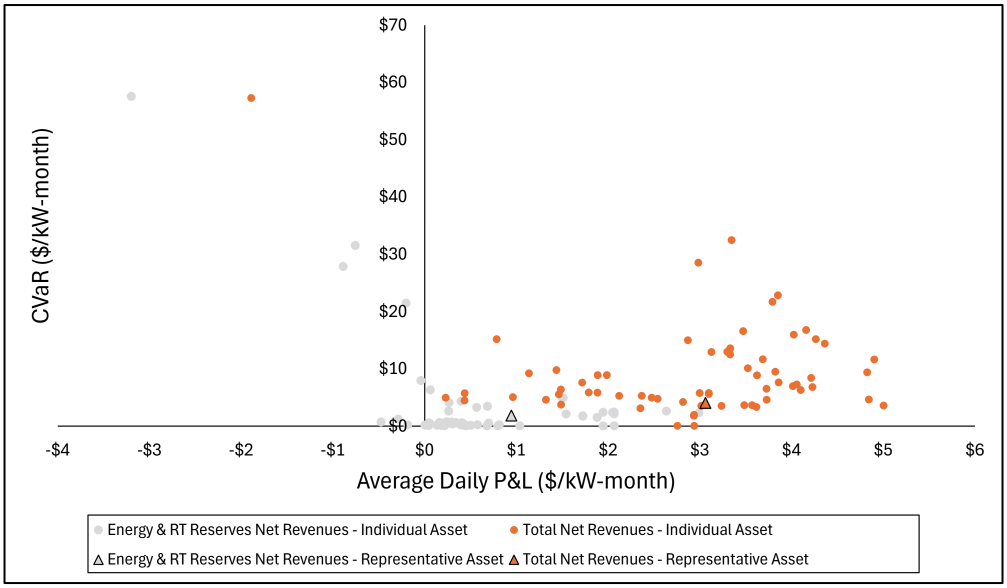
	Energy and RT Reserve Net Revenues (\$/kW-month)	Total Net Revenues (\$/kW-month)	Difference (\$/kW-month)
Mean	**\$0.95**	**\$3.06**	**\$2.12**
CVaR	**\$1.82**	**\$4.03**	**\$2.20**
Return on Incremental Risk	**= Change in Mean / Change in CVaR** **= \$2.10/kW-month / \$2.20/kW-month**		**0.96**

In terms of the Return on Incremental Risk, the asset effectively "acquires" \$2.12/kW-month of extra "everyday" profit at the cost of \$2.20/kW-month in deeper losses on the worst-five-percent days, i.e., each extra dollar of tail severity brings 2.12/2.20 = 0.96 extra dollars of average profits over the window. This value comfortably clears the economic-capital test, which compares this 96% Return on Incremental Risk to the cost of holding capital to cover the worst-five-percent losses.

The correlation between DA A/S Net Revenues and Energy & RT Reserves Net Revenues provides additional insight into tail behavior. Intuitively, if these two revenue streams were perfectly negatively correlated, then the asset's overall position would remain constant; the asset's Energy & RT Reserves position would provide a perfect hedge for its DA A/S position. For GTs, the correlation is slightly negative, at –0.14, implying weak hedging. This finding is heavily influenced by the CSC on 6/24/2025, precisely when hedging is valuable to the asset owner.

The class-level findings presented so far mask dispersion across individual GTs. Figure 3-9 summarizes the return and risk in the asset-specific Energy & RT Reserves Net Revenues (in grey) and Total Net Revenues (in orange) as captured by the mean and CVaR. Each circular point corresponds to an individual GT unit, and the triangles correspond to the representative GT unit.

Figure 3-9: Asset-Level Risk-Return Tradeoff (GTs)



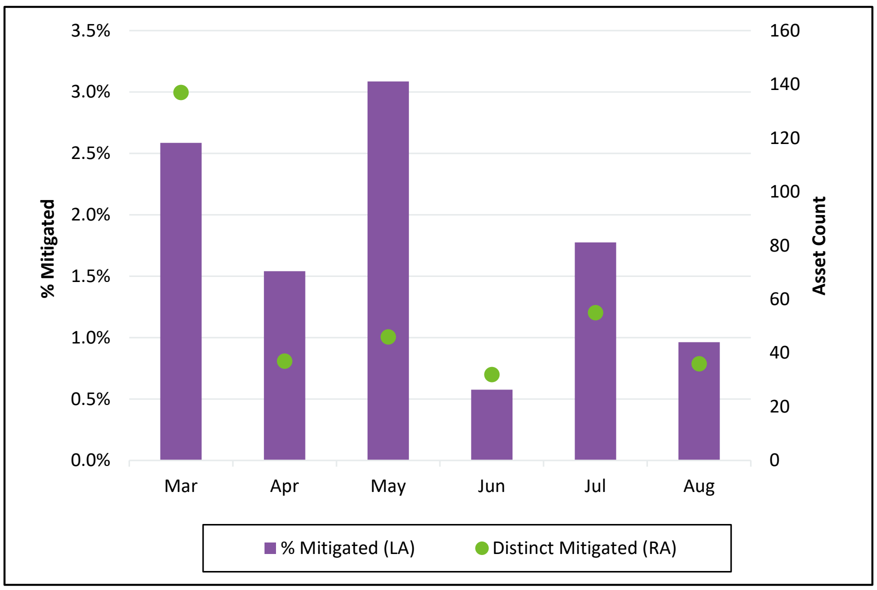
Average daily profit and tail loss are widely dispersed across individual assets, both with and without DA A/S Net Revenues included. However, the inclusion of DA A/S P&L significantly improves the average daily prospects of some assets. Energy & RT Reserves Net Revenues cluster at lower means and lower CVaR, while Total Net Revenues shift rightward to higher average profits and, for many units, sit slightly higher in CVaR, consistent with the representative asset's move from (Mean = $0.95/kW-month, CVaR = $1.82/kW-month) to (Mean = $3.06/kW-month, CVaR = $4.03/kW-month). This separation—Energy & RT Reserves Net Revenues concentrated in the lower left portion of the panel and Total Net Revenues more dispersed to the right with some higher CVaR outliers—captures the aggregate pattern: adding DA A/S raises the mean for most GTs and lifts CVaR to varying degrees.

3.5.5 Mitigation

DA A/S mitigation occurs when DA A/S offer prices exceed conduct test thresholds, and the impact of those offers on clearing prices is determined to exceed impact test thresholds.[46] One unique aspect of the DA A/S mitigation design is that a DA A/S product offer is mitigated in a given hour if the offer fails the conduct test in that hour and there is a price impact failure in *any* hour of that same day (i.e., the impact test failure does not need to occur in the same hour as the conduct test failure for DA A/S mitigation to occur).

The occurrence of DA A/S mitigation has generally decreased since the inception of the market. This can be seen in Figure 3-10 below, which shows the percentage of DA A/S offers that were mitigated on the left axis (LA)[47] and the count of the distinct assets that were mitigated on the right axis (RA).

Figure 3-10: DA A/S Mitigations



The percentage of all asset-product-hours that were mitigated fell from 2.4% in Spring 2025 to 1.1% in Summer 2025. The count of distinct assets that were mitigated has leveled off since March (when 136 assets were mitigated) and has ranged between 36-55 over the last five months. It is likely that a growing familiarity with the market design, as well as the approval of participant-submitted offer models, are reducing the incidence of mitigation in this market.

3.5.6 Gaussian Mixture Model Performance

In order to estimate several key values associated with the DA A/S market, the ISO developed a statistical model of real-time LMPs that depends on a set of explanatory variables that are known in

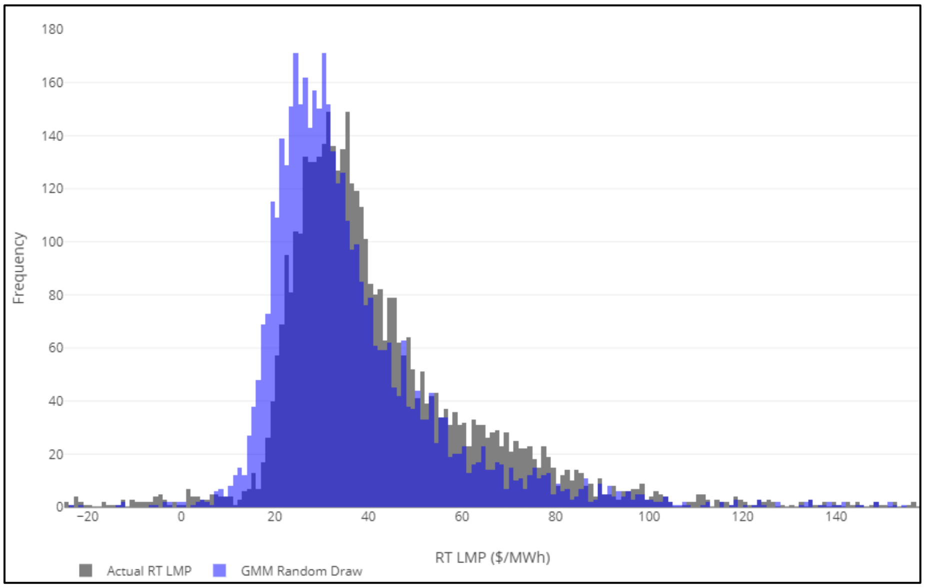
[46] For detailed rules regarding DA A/S conduct and impact tests, See the ISO's *Market Rule I*, Section III.A.8.1, available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf.

[47] Given that one asset can make offers on up to four DA A/S products per hour, this percentage represents the count of mitigated asset-product-hours relative to the total count of asset-product-hours in the period.

advance of the day-ahead market (e.g., load forecast, gas price).[48] The statistical model that the ISO employs is a Gaussian Mixture Model (GMM), which produces a set of normal (i.e., Gaussian) distributions whose means and variances change depending on the values of these explanatory variables.

One way to get a sense of how well the GMM distributions capture the true shape of the distribution of actual real-time LMPs is to take a random draw from the GMM distributions for each hour and compare this distribution against the distribution of the actual RT LMPs. This can be seen in Figure 3-11 below, which shows these values for each hour between March 1, 2025, and August 31, 2025.

Figure 3-11: Distribution of Actual LMP and Random Draw from the GMM



Although biased downward,[49] the shape of the distribution of random draws from the GMM generally matched the shape of the distribution of real-time LMPs. The standard deviation of the random draw distribution ($27.27/MWh) was lower than the distribution of actual real-time LMPs ($39.43/MWh). However, this was mostly driven by four hours on June 24 when the actual real-time LMP exceeded $700/MWh; excluding these outlier hours, the standard deviation of real-time LMPs ($28.27/MWh) was similar to the standard deviation of the random draw distribution.

Expected Real-Time LMP

The expected real-time LMP for an hour is the mean of the normal distributions produced by the GMM. This value is important because the hourly strike price, which is used in the settlement of DA A/S awards, is set equal to the expected real-time LMP for that hour plus a $10/MWh adder.

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[48] More information about the model that the ISO uses to forecast the real-time LMP can be found in the ISO's *Day-Ahead Ancillary Services Monthly Real-Time LMP Modeling Memo*, available at https://www.iso-ne.com/isoexpress/web/reports/pricing/-/tree/daas-monthly-memo.

[49] The mean of the distribution of random draws from the GMM depicted in this figure was $38.48/MWh. The mean of this distribution could change depending on the draws but one would expect it to be centered around the average expected real-time LMP of $38.50/MWh.

Through the first six months, the expected real-time LMP values that come from the GMM have tended to underpredict the actual real-time LMPs; the average expected real-time LMP ($38.50/MWh) was $5.96/MWh lower than the average actual real-time LMP ($44.45/MWh). This result isn't fully unexpected given that there were several hours when the actual real-time LMP exceeded $1,000/MWh (on June 24, 2025), while the expected real-time LMP never exceeded $180/MWh. The impact of these high actual real-time prices is muted when we compare the medians; the median expected real-time LMP ($34.44/MWh) was only $2.50/MWh lower than the median actual real-time LMP ($36.94/MWh).

Expected Closeout

The ISO's Gaussian Mixture Model also produces expected closeouts for each hour of an operating day. Recall that an asset with a DA A/S award incurs a closeout charge any time the real-time Hub LMP exceeds the strike price.[50] The *expected* closeout is the ISO's estimate of this closeout charge and is calculated using the normal distributions that are produced as part of the GMM. As the expected closeout charge is a cost that could otherwise be avoided by not taking on a DA A/S award, it forms a key part of an asset's competitive offer and its benchmark level.[51]

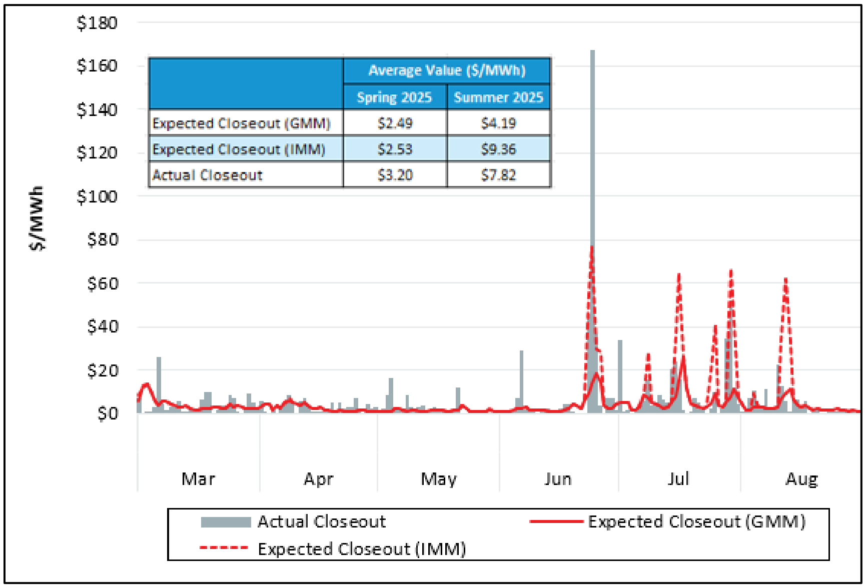
Individual observations of expected closeouts and actual closeouts are not expected to align precisely given that the former is a probabilistic expectation based upon a range of possible real-time outcomes, while the latter is a single realized outcome from this range of possibilities. This can be seen in Figure 3-12 below, which shows daily averages of actual and two different expected closeouts: the solid red line shows the value that comes directly from the GMM and the dashed red line shows the value after intervention by the IMM.[52] This figure also includes average quarterly values in the inset table.

[50] For more information, see Section 3.5.3.

[51] As mentioned earlier, participants are free to establish their own expected closeout values via consultation with the IMM.

[52] The IMM has a process to intervene in the setting of expected closeouts when the output from the GMM is not consistent with observable market conditions. When the IMM intervenes, the value set by the IMM becomes the effective value that is used in the DA A/S mitigation assessment. Absent this action, competitive DA A/S offers may be mitigated inappropriately.

Figure 3-12: Actual and Expected Closeouts



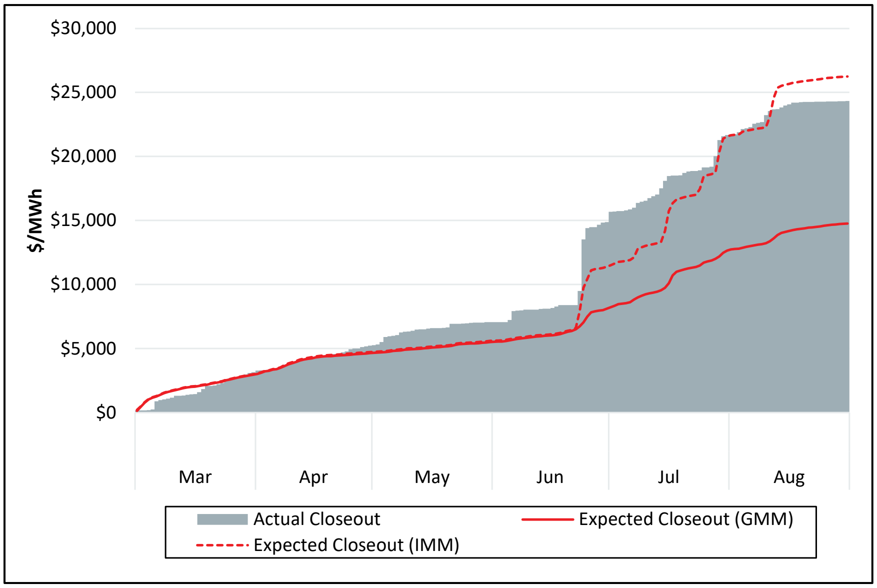
Expected closeouts frequently exceed actual closeouts. This is because expected closeout values are always greater than $0/MWh (as there is always some probability, however small, that the real-time LMP exceeds the strike price) while actual closeout values will be $0/MWh in many hours. Over the period from March 1, 2025, to August 31, 2025, the actual closeout was $0/MWh in ~73% of hours.

However, there are instances when actual closeouts significantly exceed expected closeouts. The most notable example of the latter was on June 24 (the day of the shortage event), when the average realized closeout charges were $167/MWh for the day. On this day, the price of electricity contracts observed on commodity trading platforms were significantly higher than the expected real-time LMPs that the GMM produced. The IMM intervened on this day, raising the average expected closeout for the day by over $60/MWh.[53] This was required to ensure that Benchmark Levels reflected prevailing expected market conditions and did not result in over mitigation.

While expected and actual closeouts will differ on an hourly basis, it is reasonable to expect that these values will align cumulatively over time. This relationship is observed in Figure 3-13 below, which shows the cumulative actual closeout with gray bars and the two cumulative expected closeouts.

[53] The IMM's intervention on June 24, 2025, varied by hour. The hour with the largest IMM intervention was HE20, when the IMM raised the expected closeout value by over $120/MWh from the initial GMM value of $30.06/MWh to a final value of $158.12/MWh. The actual closeout during this hour was $957.24/MWh. In other hours on this day, the IMM intervention was much smaller.

Figure 3-13: Actual and Expected Closeouts, Cumulative



The cumulative actual closeouts exceeded the cumulative expected closeouts that came directly from the GMM by a significant margin. This means that a hypothetical asset that cleared 1 MWh of DA A/S in every hour over this period would have incurred a loss (of over $10,000) if DA A/S clearing prices had been exactly equal to the GMM-produced expected closeouts.[54] The cumulative impact of the IMM intervention on expected closeouts resulted in this series exceeding the realized total by the end of the period.

3.5.7 DA A/S Incremental Cost Estimation

The IMM performed market simulations to better understand the incremental impact of DA A/S design on market outcomes relative to the day-ahead market (DAM) design that was in place prior to March 1, 2025. To perform these simulations, the IMM used an in-house market simulation tool known as the Integrated Market Simulator (IMS) that both replicates the logic of the day-ahead market (DAM) that exists in production today[55] and also provides the flexibility to modify constraints and other key inputs.

All simulations were performed for the period March 1, 2025, to August 31, 2025, and we assumed that there was no change in the real-time LMPs. Importantly, all results should be viewed as indicative given that they result from simulations.

[54] This result is concerning given that the expected closeout is supposed to be the basis of a competitive DA A/S offer and clearing prices based on it alone (and absent opportunity costs) would have resulted in a loss. It is important to note, however, that DA A/S clearing prices are not expected to equal the expected closeout for a variety of reasons, including that 1) clearing prices will include opportunity costs and 2) participants are allowed to offer up to the conduct test threshold price without triggering mitigation.

[55] IMS benchmarks very well against the GE market clearing engine (MCE) that is used in production at ISO-NE, although it does not produce exactly the same results.

Incremental Cost of DA A/S

In order to estimate the impact of the DA A/S market on total energy market costs, the following scenarios were simulated:

1) **No DA A/S**: a scenario in which all the DA A/S constraints in the DAM (FER, FRS) are 'turned off.' This scenario is intended to reflect the pre-March 2025 DAM.
2) **DA A/S:** a scenario in which all the DA A/S constraints in the DAM (FER, FRS) are 'turned on.' This scenario is intended to reflect the current DAM.

The following table provides a high-level comparison of these two cases.

Table 3-3: Estimated Change in Market Costs as a result of the DA A/S Market

Category	No DA A/S ($M)	DA A/S ($M)	Delta ($M)	Delta (%)
DA LMP	$3,375	$3,352	-$23	-0.7%
FER	$0	$206	$206	
FRS	$0	$130	$130	
EIR	$0	$4	$4	
Total DA Charges/Credits	**$3,375**	**$3,692**	**$317**	**9.4%**
Cost of Incremental RT Energy[56]	$34	$37	$3	9.1%
Actual Closeouts	$0	-$62	-$62	
Total Costs/Revenue Change	**$3,409**	**$3,667**	**$258**	**7.6%**

We estimate that the DA A/S market has resulted in an increase of $258 million (7.6%) in total energy market costs. Prior to June 22, 2025, the total incremental cost of DA A/S was $36M, a 2.3% increase in costs relative to the pre-DA A/S design over the same time period. However, there were significant incremental costs incurred after June 22, 2025, with 10 days in this summer period accounting for $130M. The high costs on these 10 days were primarily driven by opportunity costs impacting either the DA LMP, FER Price, and the clearing price for the FRS products.

Incremental Cost of FRS Alone

In order to study the impact of modelling only the 10- and 30-minute reserve requirements in the DAM, without the additional effects of the FER constraint, we simulated a third scenario:

3) **FRS Only:** a scenario in which the FER constraint is 'turned off' but the FRS constraints remain 'turned on.' This scenario is intended to reflect a modified version of the current DAM that doesn't have the FER constraint.

The following table provides a high-level comparison of this FRS Only case against the No DA A/S case.

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[56] This exists because one scenario may clear more energy supply in the day-ahead market relative to another and therefore need to procure less energy supply in real-time market. Consequently, this field is calculated as (real-time load obligation – day-ahead load obligation) * real-time LMP, mimicking the deviation settlement logic.

Table 3-4: Estimated Change in Market Costs as a result of FRS Only

Category	No DA A/S ($M)	FRS Only ($M)	Delta ($M)	Delta (%)
DA LMP	$3,375	$3,513	$138	4.1%
FER	$0	$0	$0	
FRS	$0	$123	$123	
EIR	$0	$0	$0	
Total DA Charges/Credits	**$3,375**	**$3,636**	**$261**	**7.7%**
Cost of Incremental RT Energy	$34	$43	$9	27.4%
Actual Closeouts	$0	-$60	-$60	
Total Costs/Revenue Change	**$3,409**	**$3,619**	**$210**	**6.2%**

We estimate that a DA A/S market with FRS constraints alone would have resulted in an increase of $210 million (6.2%) in total energy market costs. While the DA A/S scenario had FER costs as the primary incremental cost driver, the cost increase in the FRS Only scenario came largely via DA LMP-based costs. In both the DA A/S scenario and the FRS Only scenario, significant incremental costs occurred in the Summer as a result of FRS constraints creating opportunity costs that showed up in the clearing prices paid to day-ahead energy.

3.6 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.[57] 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 3-5 below.[58]

Table 3-5: Hours and Level of Non-Zero Reserve Pricing

Product	Summer 2025		Summer 2024		Summer 2023	
	Avg. Price $/MWh	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*
TMSR	$69.96	111.3	$48.57	215.5	$13.30	177.8
TMNSR	$211.89	34.3	$180.67	51.3	$270.38	5.4
TMOR	$256.30	26.1	$212.35	31.1	$275.29	3.5

[57] 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.

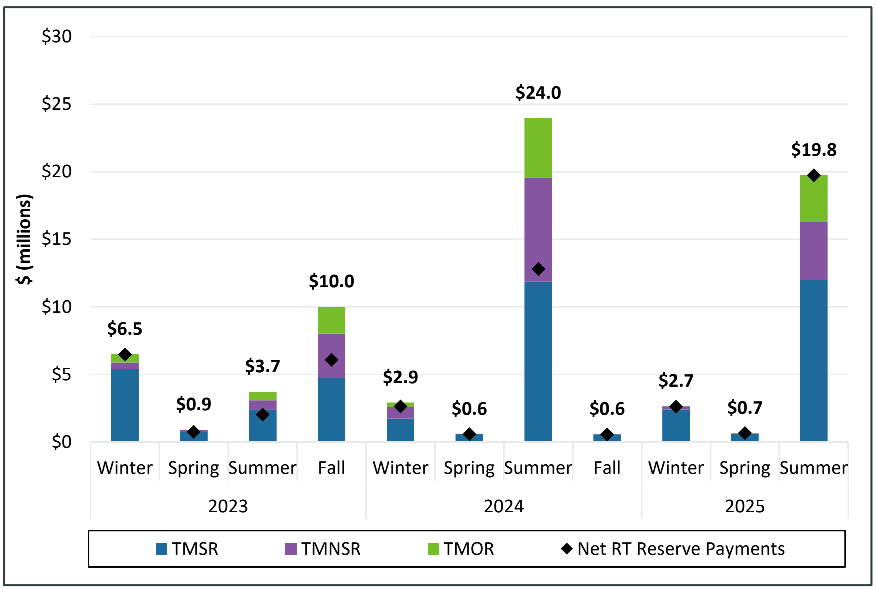
[58] The zonal thirty-minute reserve requirements did not bind in any of these summer seasons. As a result, real-time reserve prices in reserve zones were equal to those at the system level.

Summer 2025 had a relatively low frequency of TMSR pricing compared to past summers, despite similar requirements. The reduction in TMSR is primarily driven by contributions from energy storage in excess of previous years. TMNSR or TMOR pricing occurred on 15 separate days during the summer. The highest pricing occurred during the capacity scarcity condition on June 24, caused by a shortage of total 30 reserves. Almost half of the intervals in which there was TMNSR pricing occurred between June 23 and 25 and an additional quarter of intervals during July 28-30.

Real-time Reserve Payments

Real-time reserve payments by product and by zone are illustrated in Figure 3-14 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).[59]

Figure 3-14: Real-Time Reserve Payments by Product and Zone



Half of the real-time reserve payments in Summer 2025 occurred on a single day, June 24. On June 24 the Total 30 reserve constraint penalty factor (RCPF) was binding for three hours, causing a capacity scarcity condition event. The surrounding days, June 23 and June 25, accounted for an additional 25% of the total real-time reserve payments over the summer. July 28-30 produced $2.9 million in payments, or 14% of total payments. Reserve pricing between July 28 and 30 was primarily driven by elevated TMOR pricing, including the replacement reserve RCPF binding for over 1.5 hours.

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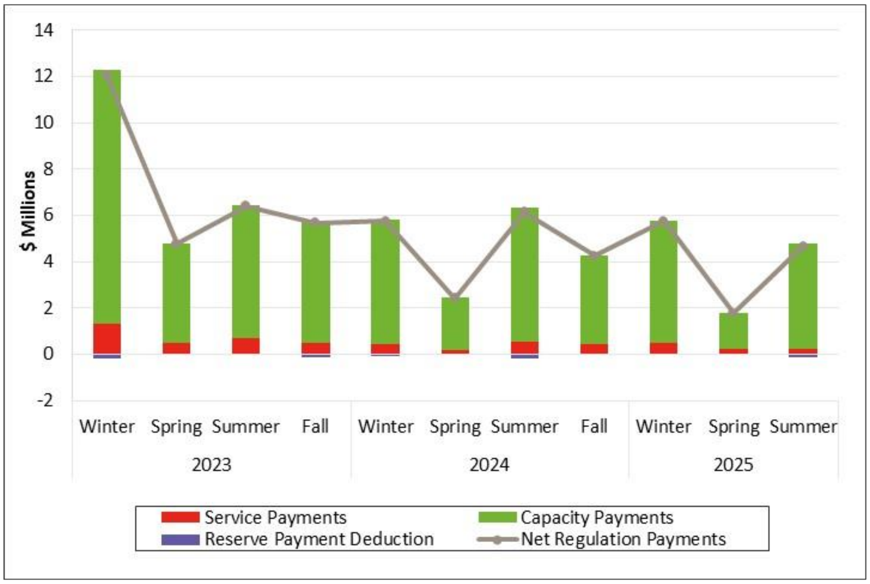
[59] The forward reserve market is a forward market that procures operating reserve capability in advance of the actual delivery period. Real-time reserve payments to resources designated to satisfy forward reserve obligations are reduced by a forward reserve obligation charge so that a resource is not 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 .

3.7 Regulation

Regulation is an essential reliability service provided by generators and other resources in the real-time energy market. Generators providing regulation allow the ISO to use a portion of their available capacity to match supply and demand (and to regulate frequency) over short time intervals. Quarterly regulation payments are shown in Figure 3-15 below.

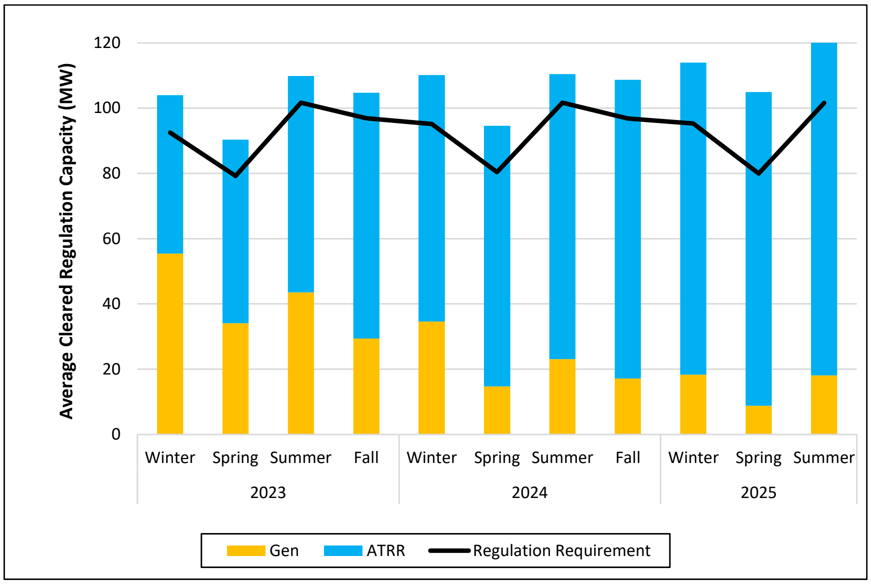
Figure 3-15: Regulation Payments



Total regulation market payments were $4.7 million during Summer 2025, down 24% from $6.1 million in Summer 2024. The decrease in payments resulted primarily from lower capacity prices (down 27%). 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 34%) from Summer 2024.

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 3-16 below.

Figure 3-16: Average Cleared Regulation MW by Resource Type



The resource mix of cleared regulation capacity has changed over the reporting period. In Winter 2023, ATRRs (blue bars) cleared an average of 49 MW of regulation capacity, making up 47% of total cleared regulation. In Summer 2025, ATRRs provided 103 MW or 85% of regulation. This change follows continuing increases in the installed capacity of battery resources in the region. Regulation capacity available from ATRRs increased to 428 MW on average in Summer 2025, up from 221 MW in Summer 2024. 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 4
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 4.1 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.

4.1 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 structural market power.[60] The RSI represents the percentage of demand and reserves 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 reserves and could potentially exercise market power if permitted. Further, if the RSI is less than 100, there are one or more pivotal suppliers.

Pivotal suppliers are identified at the five-minute level by comparing the real-time supply margin[61] to the sum of each participant's total supply that is available within 30 minutes.[62] 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 4-1 below.

[60] 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.

[61] 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*]

[62] 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 4-1: Residual Supply Index and Intervals with Pivotal Suppliers (Real-Time)

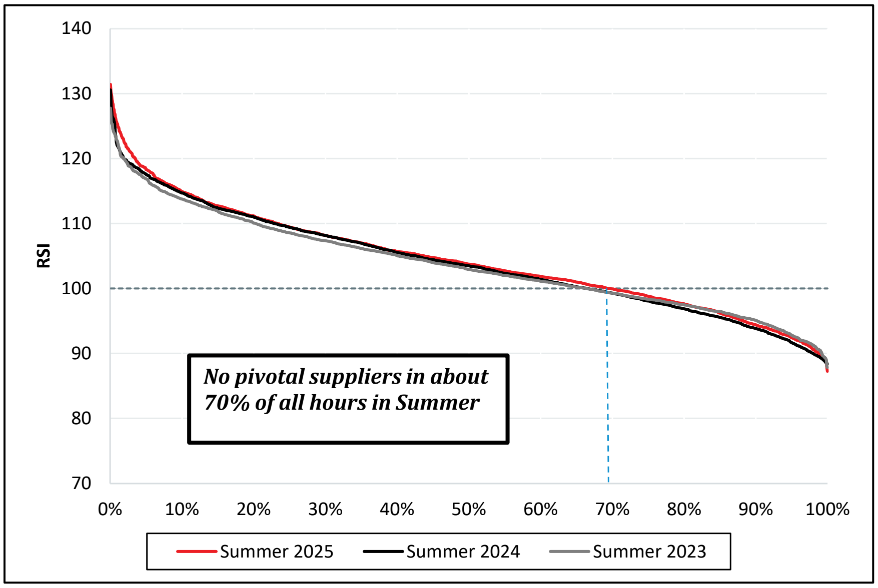
Quarter	RSI	% of Intervals With At Least 1 Pivotal Supplier
Winter 2023	105.2	20%
Spring 2023	107.7	22%
Summer 2023	103.8	34%
Fall 2023	98.9	60%
Winter 2024	101.7	45%
Spring 2024	105.5	29%
Summer 2024	104.0	34%
Fall 2024	104.7	31%
Winter 2025	101.3	47%
Spring 2025	105.7	25%
Summer 2025	104.4	31%

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.[63] There was at least one pivotal supplier in 31% of real-time pricing intervals in Summer 2025, which was slightly lower than previous summers. Although net imports decreased, 2025 saw lower loads than prior summers which contributed to a modestly higher reserve margin. Additionally, the reduction in net imports led to the Phase II interface being the first contingency less frequently than Summer 2024 which reduced reserve requirements.

Duration curves that rank the average hourly RSI over each summer quarter in descending order are illustrated in Figure 4-1 below. The figure shows the percentage 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.

[63] 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.

Figure 4-1: System-Wide Residual Supply Index Duration Curves



In Summer 2025, the RSI was lower than that of Summer 2024 in less than 4% of observations. The lowest Summer 2025 RSI value was 87.1 and occurred during the evening peak hour (HE 19) of August 10.

4.2 Energy Market Supply Offer Mitigation

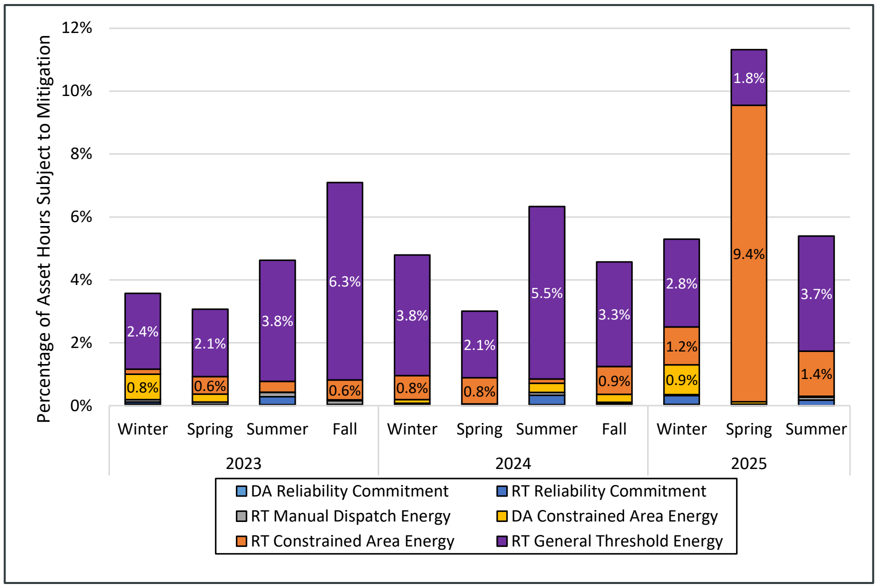
The IMM reviews energy market supply offers for generators in both the day-ahead and real-time energy markets. This review minimizes opportunities for participants to exercise market power. As in earlier periods, the mitigation of energy market supply offers occurred infrequently in Summer 2025.

Energy Market Mitigation Frequency

A structural test failure serves as the first indicator of potential market power in ISO New England's energy markets. The percentage of eligible asset hours with a structural test failure from Winter 2023 to Summer 2025 is shown below in Figure 4-2.[64]

[64] 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. The methodology for calculating RT General Threshold Energy Mitigation Structural Test Failures was updated in this report, resulting in lower structural test failure numbers. Only committed assets are eligible to be mitigated.

Figure 4-2: Energy Market Mitigation Structural Test Failures

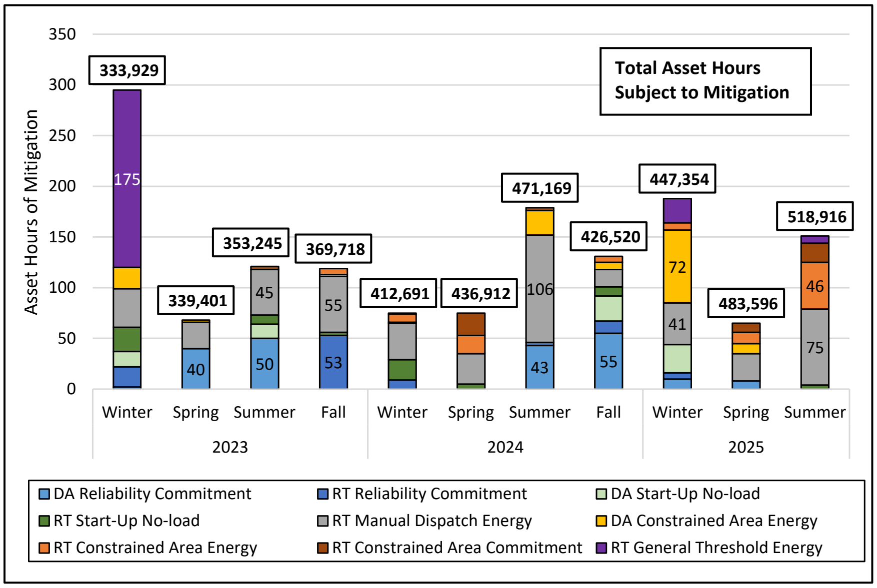


In Summer 2025, of nearly 519,000 total asset hours subject to mitigation, about 5.5% of asset hours (about 28,000) failed structural tests, slightly lower than in Summer 2024.[65] The structural test for general threshold energy mitigation fails the most often and is triggered when a committed generator is owned by a pivotal supplier. The structural test for constrained area energy indicates if an asset is in an import-constrained area caused by a binding constraint. Over two thirds of the real-time constrained area energy structural test failures were due to the Maine-New Hampshire constraint binding on five separate days over the summer, creating a large import-constrained area on the west side of the constraint. 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 4-3 along with the total amount of asset hours subject to mitigation (white boxes).

[65] The asset hours subject to mitigation are estimated as the sum of economically committed generation or self-scheduled generation 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 4-3: Energy Market Mitigation Asset Hours



Of the nearly 28,000 eligible asset hours that failed structural tests, there were only 151 asset hours of mitigation in Summer 2025. Real-time manual dispatch energy (MDE) mitigation occurred the most frequently in Summer 2025 with 75 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.[66]

With relatively tolerant conduct and market impact test thresholds, the frequency of constrained area mitigation is typically low relative to the frequency of structural test failures. In Summer 2025, there were 46 asset hours of constrained area mitigation, 40 of which occurred in the real-time market on June 24, the day of the CSC event, due to the binding Maine-New Hampshire interface. Although eight separate assets were mitigated for constrained area energy for five hours each on June 24, no constrained area energy mitigations occurred at the time of the actual capacity scarcity conditions.

[66] More information on Energy Market Mitigation types and thresholds can be found in *An Overview of New England's Wholesale Electricity Markets (2025 Update) (May 23, 2025)*, Section 11.2.1, available at https://www.iso-ne.com/static-assets/documents/100023/imm-markets-primer.pdf.

Section 5
Forward Markets

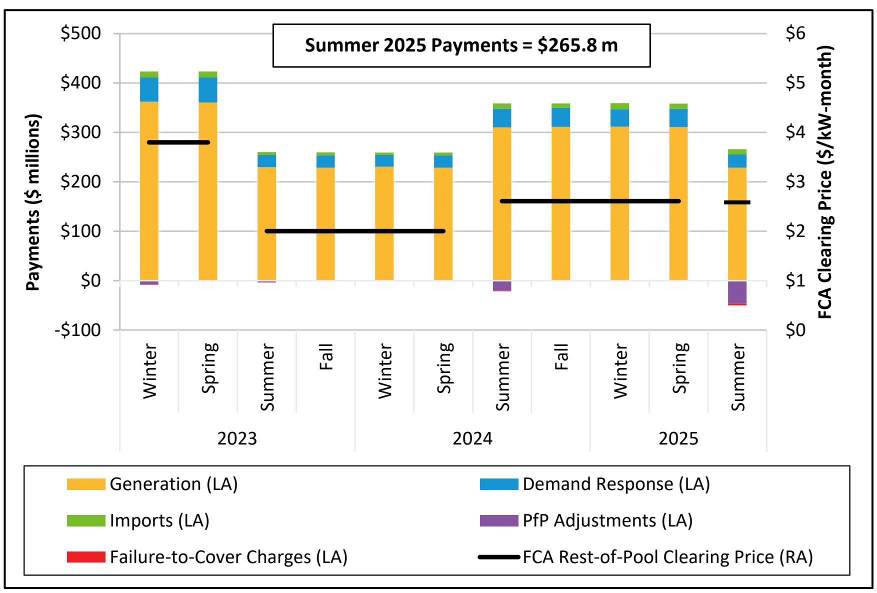
This section covers activity in the Forward Capacity Market (FCM), in Financial Transmission Rights (FTRs), and in the Summer 2025 Forward Reserve Auction.

5.1 Forward Capacity Market

The Capacity Commitment Period (CCP) associated with Summer 2025 started on June 1, 2025 and will end on May 31, 2026. The corresponding Forward Capacity Auction (FCA 16) cleared at $2.59/kW-month for the rest-of-pool capacity zone, with prices relatively unchanged from FCA 15 ($2.61/kW-month). The auction cleared with 32,810 MW of Capacity Supply Obligation (CSO), representing a surplus of more than 1,000 MW over the Net Installed Capacity Requirement (Net ICR; 31,645 MW). FCA 16 cleared with modest price separation; the import-constrained Southeast New England capacity prices cleared at $2.64/kW-month, while the export-constrained Northern New England and Maine capacity zones cleared at $2.53/kW-month. While new capacity additions totaled less than 400 MW for FCA 16, solar and battery resources comprised the largest shares of new capacity.

Total FCM payments, as well as the clearing prices for Winter 2023 through Summer 2025, are shown in Figure 5-1 below. The black lines (corresponding to the right axis, "RA") represent the FCA clearing prices for existing resources in the Rest-of-Pool capacity zone. The orange, blue, and green bars (corresponding to the left axis, "LA") represent payments made to generation, demand response, and import resources, respectively. The purple bar represents Pay-for-Performance (PfP) adjustments, while the red bar represents Failure-to-Cover charges.

Figure 5-1: Capacity Market Payments



Base Summer 2025 capacity payments totaled $265.8 million, down 26% from Summer 2024.[67] Capacity payments declined despite similar rest-of-pool clearing prices between FCA 15 and FCA 16, driven by a decrease in cleared capacity in FCA 16 and weaker upward price separation in the import-constrained Southeast New England capacity zone. As a result of the PfP event, under-performing capacity resources were charged $46.5 million to fund credits for performing non-capacity assets.[68] Resources that did not demonstrate the capability to produce output up to their CSO were subject to $3.5 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 2025 alongside the results of the relevant primary FCA are detailed in Table 5-1 below.

Table 5-1: Primary and Secondary Market Outcomes

				Capacity Zone/Interface Prices ($/kW-mo)				
FCA # (Commitment Period)	Auction Type	Period	Cleared MW*	Rest-of-Pool**	Maine	New Brunswick	Northern New England	Southeastern New England
FCA 16 (2025-2026)	Primary	12-month	32,810	2.59	2.53	2.53	2.53	2.64
	Monthly Reconfiguration	Aug-25	318	6.50	6.50	6.50	6.50	6.50
	Monthly Bilateral	Aug-25	19	2.55				
	Monthly Reconfiguration	Sep-25	455	8.02	8.02	8.02	8.02	8.02
	Monthly Bilateral	Sep-25	11	2.58				
	Monthly Reconfiguration	Oct-25	818	6.50	6.50	6.50	6.50	6.50
	Monthly Bilateral	Oct-25	203	4.72				
FCA 17 (2026-2027)	Primary	12-month	31,370	2.59	2.59	2.55	2.59	
	Annual Reconfiguration (2)	12-month	226, -305	5.00	5.00	5.00	5.00	
FCA 18 (2027-2028)	Primary	12-month	31,556	3.58	3.58	3.58	3.58	
	Annual Reconfiguration (1)	12-month	293, -48	5.13	5.13	5.13	5.13	

**represents cleared supply/demand*

***bilateral prices represent volume weighted average prices*

Reconfiguration auction outcomes during Summer 2025 generally reflect higher prices due to tighter supply. For example, the second Annual Reconfiguration Auction (ARA) for FCA 17 cleared at $5.00/kW-month, up from the $2.59/kW-month FCA 17 clearing price. Although the Net ICR for the second ARA was 30,600 MW, up from 30,305 MW in FCA 17, a net 78 MW of capacity exited the market. This tightening supply drove the higher clearing prices.

[67] The $265.8 million in base capacity payments does not include adjustments due to failure-to-cover or PfP charges.

[68] See 2.4.4 for more detail on PfP event settlements. Note that not all resources registered in the capacity market held CSO during June 2025. The $46.5 million reported in this section represents net PfP charges to all resources, including those that held zero CSO. By accounting, this is equal to the PfP credits paid to all assets outside of the capacity market. 2.4.4 treats capacity resources with zero CSO as effectively identical to non-capacity assets. Under this definition, under-performing resources with CSO were charged $63.9 million on a net basis, and equivalently, all units or imports without CSO (including both non-capacity assets and capacity resources with zero CSO in June) were credited $63.9 million on net.

The first ARA for CCP 18 cleared at $5.13/kW-month, up from $3.58/kW-month in the primary auction. The Net ICR was 30,415 MW, down marginally from 30,550 in FCA 18. Despite this, 245 MW of CSO entered the market on a net basis.

The monthly reconfiguration auctions (MRAs) for August 2025, September 2025, and October 2025 each cleared at higher prices than FCA 16. The higher prices were generally driven by tight supply of new capacity offering to take on CSO and strong demand of existing capacity to shed CSO. While supply offers totaled roughly 500 MW in the August and September auctions and 1,000 MW in the October auction, demand bids totaled around 4,000 MW in each auction.

5.2 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.

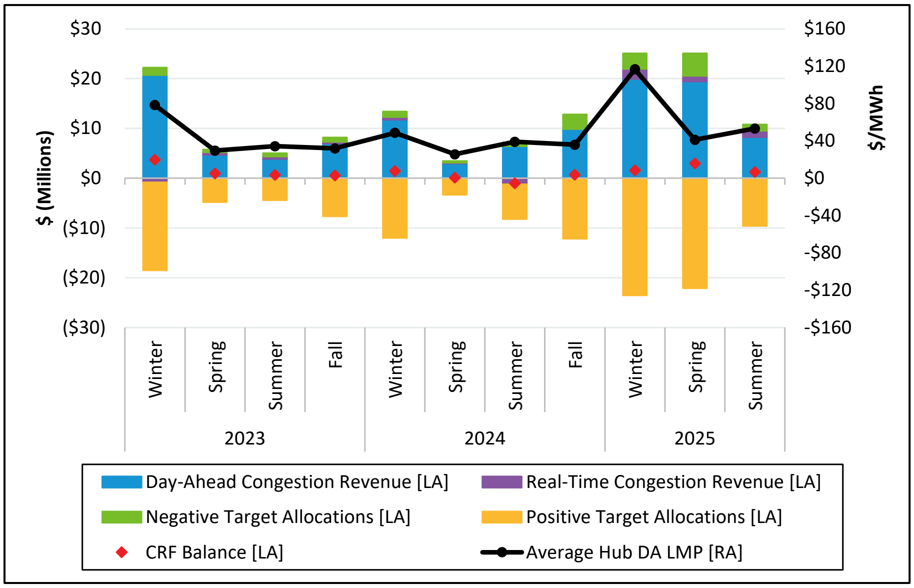
Figure 5-2 below shows, by quarter, the amount of congestion revenue from the day-ahead and real-time energy markets, the amount of positive and negative target allocations, and the congestion revenue fund (CRF) balance.[69,70] This figure also depicts the quarterly average day-ahead Hub LMP.[71]

[69] 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).

[70] Figure 5-2 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.

[71] 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”).

Figure 5-2: Congestion Revenue, Target Allocations, and Day-Ahead LMP by Quarter



Positive target allocations totaled $9.6 million in Summer 2025, down 57% from Spring 2025. The decline in congestion revenue and target allocations relative to Spring 2025 is partly attributable to the completion of some transmission work in preparation of the New England Clean Energy Connect (NECEC) line. The CRF was fully funded for each month of Summer 2025 and has been fully funded each month year-to-date.

Appendix A
Profitability Assessment and a Risk/Return Framework

This section provides additional information on the analysis in Section 3.5.4, which examines whether the "option-like" exposure from taking on DA A/S obligations yields a distribution of daily profits with heavy left tails and, if so, whether an asset's remaining revenue streams offset that risk.

We approach this question by constructing three daily aggregates:

1. **Energy & RT Reserves Net Revenues:** Energy revenues less production costs, two-settlement spread, real-time operating profits, FER credits paid to DA energy, NCPC, and real-time reserve revenues.
2. **DA A/S Net Revenues:** The sum, across the DA A/S (i.e., DA TMSR, DA TMNSR, DA TMOR, and EIR), of product credits minus closeout charges.
3. **Total Net Revenues:** The sum of Energy & RT Reserves Net Revenues and DA A/S Net Revenues.

Return on Incremental Risk

We can relate the Return on Incremental Risk to the risk premium that an asset-owner may demand for taking on a DA A/S obligation. Specifically, we can think of the extra tail risk that an asset takes on by adding DA A/S in two parts:

1. The (incremental) expected tail loss that the asset expects to realize over time, ΔCVaR. Because the worst-five percent happens, on average, 5% of the days, the expected drag on P&L from tail events is roughly 5% of the average incremental CVaR, i.e., 0.05 x ΔCVaR.
2. The capital tied up to survive those worst-five-percent days. Because the asset-owner holds economic capital to offset the additional tail loss, ΔCVaR, its cost of tying up that capital is r * ΔCVaR, where r is the asset owner's cost-of-capital.

Adding the two components, the asset owner would demand (0.05 + r) * ΔCVaR to be made whole on average; this would be its risk premium. In the present context, the asset owner may also enjoy an increase in average returns, ΔMean. This additional average payoff covers the risk premium if and only if

$$\Delta\text{Mean} \geq (0.05 + r) * \Delta\text{CVaR}.$$

Dividing through by ΔCVaR, this is equivalent to:

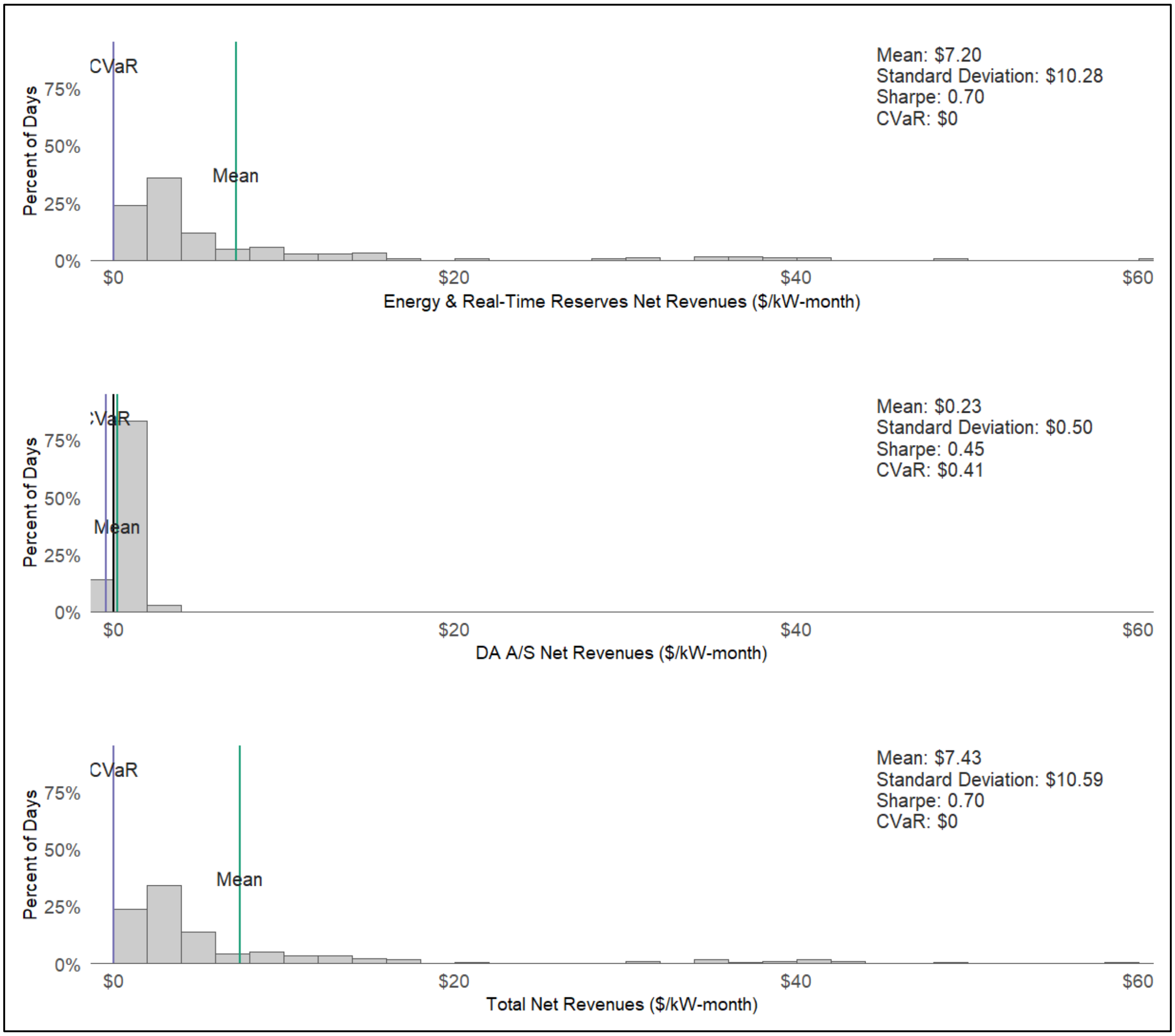
$$\underbrace{\Delta\text{Mean}/\Delta\text{CVaR}}_{\text{Return on Incremental Risk}} \geq 0.05 + r.$$

Requiring a Return on Incremental Risk above 1.0 would be conservative; it would require the incremental average daily profit to match a tail-day's average loss one-for-one. By contrast, the (0.05 + r) threshold is an economic-capital rule: the typical day must cover the expected tail loss frequency plus the opportunity cost of capital held for tail events. Because 0.05 + r < 1 for any reasonable (participant-specific) value of r, this rule is weaker.

Results for Combined Cycle Units

Figure A-1 shows the distributions of the three Net Revenues for the representative CC unit and summarizes these distributions.

Figure A-1: Distribution of Net Revenues (CCs)



DA A/S Net Revenues vs Total Net Revenues. For Combined Cycles, incorporating Energy & RT Reserves Net Revenues significantly increases the average daily profits (from $0.23/kW-month to $7.43/kW-month) effectively and eliminates tail risk; any perceived tail risk from selling DA A/S is swamped by the CC units' more active (relative to GTs) participation in the energy and RT reserves markets.

Energy & RT Reserves Net Revenues vs Total Net Revenues. Including DA A/S Net Revenues yields a $0.23/kW-month = ($7.43/kW-month – $7.20/kW-month) increase in expected returns with no corresponding tail (CVaR) increase. Table A-1 summarizes the key risk-return tradeoff for CCs.

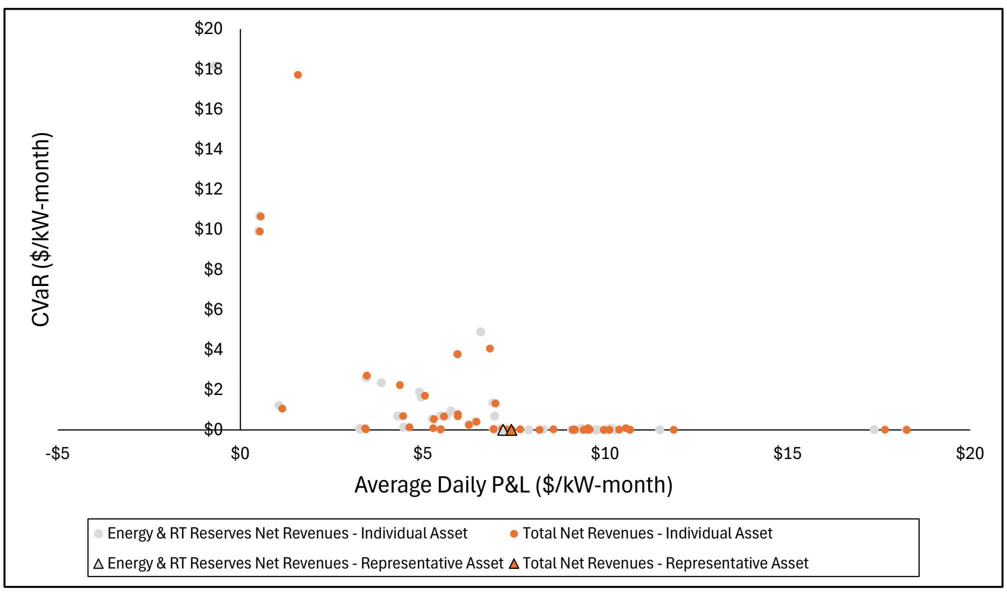
Table A-1: Risk-Return Summary (CCs)

	Energy and RT Reserve Net Revenues ($/kW-month)	Total Net Revenues ($/kW-month)	Difference ($/kW-month)
Mean	**$7.20**	**$7.43**	**$0.23**
CVaR	**$0.00**	**$0.00**	**$0.00**
Return on Incremental Risk	**= Change in Mean / Change in CVaR** **= $0.23/kW-month / $0.00/kW-month**		**N/A**

In terms of the Return on Incremental Risk, taking on DA A/S awards seemingly presents a "risk-free" return for the representative CC asset because the $0.23/kW-month difference in expected returns is not matched by an increase in tail risk.

Figure A-2 summarizes the return and risk in the asset-specific Energy & RT Reserves Net Revenues (in grey) and Total Net Revenues (in orange) as captured by the mean and CVaR. Each circular point corresponds to an individual CC unit, and the triangles correspond to the representative CC unit.

Figure A-2: Asset-Level Risk-Return Tradeoff (CCs)



Energy & RT Reserves Net Revenues are largely clustered between roughly $4/kW-month and $11/kW month of average profit with near zero CVaR, indicating benign bad-day outcomes across most CCs. Total Net Revenues largely shift right, showing a modest mean increase, with little shift in tail risk; only a few assets with low average daily profits exhibit elevated CVaR (above $10/kW-month). The slight separation—a dense band of Energy & RT Reserves Net Revenues near the x-axis (CVaR = 0) and a similarly dense band of Total Net Revenues slightly to the right with that same near zero tail—conveys the class-level message that adding DA A/S nudged average profits up without materially changing tail risk.