2025 Annual Markets Report

Internal Market Monitor

MAY 29, 2026

Date	Version	Remarks

Preface/Disclaimer

The Internal Market Monitor (IMM) of ISO New England (ISO) publishes an Annual Markets Report (AMR) that assesses the state of competition in the wholesale electricity markets operated by the ISO. The *2025 Annual Markets Report* covers the ISO's most recent operating year, January 1 to December 31, 2025. The report addresses the development, operation, and performance of the wholesale electricity markets administered by the ISO 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.17.2.4, *Market Monitoring, Reporting, and Market Power Mitigation*:

> *The Internal Market Monitor will prepare an annual state of the market report on market trends and the performance of the New England Markets and will present an annual review of the operations of the New England Markets. The annual report and review will include an evaluation of the procedures for the determination of energy, reserve and regulation clearing prices, Net Commitment-Period Compensation costs and the performance of the Forward Capacity Market and Financial Transmission Rights Auctions. The review will include a public forum to discuss the performance of the New England Markets, the state of competition, and the ISO's priorities for the coming year. In addition, the Internal Market Monitor will arrange a non-public meeting open to appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets, subject to the confidentiality protections of the ISO New England Information Policy, to the greatest extent permitted by law.*[1]

This report is being submitted simultaneously to the ISO and the Federal Energy Regulatory Commission (FERC) per FERC order:

> *The Commission has the statutory responsibility to ensure that public utilities selling in competitive bulk power markets do not engage in market power abuse and also to ensure that markets within the Commission's jurisdiction are free of design flaws and market power abuse. To that end, the Commission will expect to receive the reports and analyses of a Regional Transmission Organization's market monitor at the same time they are submitted to the RTO.*[2]

This report presents key findings, market outcomes, and market design changes of New England's wholesale electricity markets for 2025. The executive summary gives an overview of the region's wholesale electricity market outcomes, the important market issues and our recommendations for addressing these issues. It also addresses the overall competitiveness of the markets, and market mitigation and market reform activities. Sections 1 through 10 include more detailed discussions of each of the markets, market results, analysis and recommendations. A list of acronyms and abbreviations is included at the back of the report.

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[1] ISO New England Inc., *"Transmission, Markets, and Services Tariff (ISO tariff), Section III.A.17.2.4, Market Rule 1, Appendix A, Market Monitoring, Reporting, and Market Power Mitigation",* http://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf.

[2] FERC, PJM Interconnection, L.L.C. et al., "*Order Provisionally Granting RTO Status*", Docket No. RT01-2-000, 96 FERC ¶ 61, 061, July 12, 2001.

A number of external and internal audits are also conducted each year to ensure that the ISO followed the approved market rules and procedures and to provide transparency to New England stakeholders. Further details of these audits can be found on the ISO website.[3]

All information and data presented are the most recent as of the time of writing. The data presented in this report are not intended to be of settlement quality and some of the underlying data used are subject to resettlement.

In case of a discrepancy between this report and the ISO New England Tariff or Procedures, the meaning of the Tariff and Procedures shall govern.

Underlying natural gas data are furnished by the Intercontinental Exchange (ICE):

ICE Global markets in clear view

Underlying oil and coal pricing data are furnished by Argus Media.

[3] ISO New England Inc., "*Financial and Performance Reports*", https://www.iso-ne.com/about/corporate-governance/financial-performance .

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Executive Summary

The 2025 Annual Markets Report by the Internal Market Monitor (IMM) at ISO New England (ISO) reviews the development, operation, and performance of the region's wholesale electricity markets. The report provides an assessment of each market based on observed outcomes, market data, and established performance criteria.

Market participants transact energy in both the day-ahead and real-time markets, while also buying and selling a range of related products, including operating reserves, regulation service, financial transmission rights, and capacity, in the real-time and forward markets. Together, these markets and products are designed to promote the efficient and competitive supply of electricity while ensuring that sufficient resources are available to maintain reliable system operations across New England.

For additional background, the supporting document *An Overview of New England's Wholesale Electricity Markets: A Market Primer* provides a summary of key concepts and market mechanics.

This executive summary highlights key market trends, performance outcomes, and emerging issues, and concludes with a consolidated set of the IMM's recommendations to improve market design and rules based on findings from this and prior IMM reports.

Total wholesale electricity costs rose sharply in 2025 to $15 billion, nearly 50% higher than in 2024. These elevated costs were driven by higher natural gas costs, tighter supply conditions, and ongoing structural changes to the resource mix and market design. While overall market performance remained competitive, these factors increased costs, shifted reliance toward internal New England resources, and continued to highlight the growing importance of resource flexibility and energy security in maintaining reliability.

Higher natural gas prices were the principal driver of increased wholesale costs, rising 105% year-over-year to $6.27/MMBtu and elevating energy prices throughout the year. Carbon emissions costs also increased as allowance prices rose and emissions limits tightened, particularly under the Massachusetts Electricity Generator Emissions Limits (EGEL) program. Although fuel prices dominated cost increases in 2025, carbon costs are expected to play a larger role in generator economics as allowance availability tightens and compliance costs rise.

Higher energy prices also reflected a shift up the supply stack driven by greater reliance on internal generation. Continuing a multi-year trend, net imports declined further in 2025, reaching their lowest level in more than a decade due to reduced Canadian hydro availability and outages. While the interchange of electricity with neighboring power systems provided critical supply to New England during high-demand periods, lower import levels throughout the year meant that higher-cost resources located inside New England more frequently set the marginal price. At the same time, growth in solar generation continued to reshape load profiles, increasing the magnitude and variability of evening ramps and reinforcing the need for flexible, dispatchable resources.

Despite structural indicators pointing to tighter conditions—including a higher frequency of pivotal suppliers—market outcomes remained broadly competitive. The analysis indicates limited economic withholding, and market power mitigation levels remained minimal.

High-level market statistics for the five-year period covered in this report are presented below.

At a Glance: High-level Market Statistics

Demand (MW)	2021	2022	2023	2024	2025	% Change '24 to '25	Sparkline
Load (avg. hourly)	13,561	13,576	13,096	13,299	13,441	1.1%	
Weather-normalized load (avg. hourly)[a]	13,419	13,514	13,132	13,236	13,394	1.2%	
Peak load (MW)	25,801	24,780	24,043	24,871	26,586	6.9%	
Generation Fuel Costs ($/MWh)[b]							
Natural Gas	36.07	72.41	23.68	23.83	48.91	105.2%	
No.6 Oil	138.30	221.15	164.91	154.92	154.29	-0.4%	
Diesel	184.69	332.15	253.44	217.28	207.33	-4.6%	
Hub Electricity Prices: LMPs ($/MWh)							
Day-ahead (simple avg.)[c]	45.92	85.56	36.82	41.47	71.81	73.2%	
Real-time (simple avg.)	44.84	84.92	35.70	39.50	65.89	66.8%	
Day-ahead (load-weighted avg.)	48.30	91.36	39.19	44.52	78.44	76.2%	
Real-time (load-weighted avg.)	47.34	91.13	38.25	42.46	72.21	70.1%	
Estimated Wholesale Costs ($ billions)							
Energy	6.1	11.7	4.8	5.6	9.9	76.7%	
Capacity[d]	2.3	2.0	1.8	1.4	1.2	-16.4%	
Uplift (NCPC)	0.04	0.05	0.03	0.03	0.04	20.2%	
Ancillary Services[e]	0.1	0.1	0.2	0.2	0.2	37.6%	
Regional Network Load Costs	2.7	2.8	2.7	3.0	3.6	23.0%	
Total Wholesale Costs	**11.2**	**16.7**	**9.5**	**10.2**	**15.0**	**47.6%**	
Supply Mix[f]							
Natural Gas	45%	45%	48%	50%	50%	0.1%	
Nuclear	22%	23%	20%	22%	23%	0.7%	
Imports	16%	14%	13%	9%	7%	-1.9%	
Hydro	6%	6%	8%	7%	6%	-1.0%	
Other[g]	5%	4%	4%	4%	4%	0.1%	
Wind	3%	3%	3%	3%	4%	0.9%	
Solar	2%	3%	3%	4%	5%	0.6%	
Coal	0%	0%	0%	0.2%	0.2%	0.0%	
Oil	0%	2%	0%	0.3%	1.0%	0.7%	
Battery Storage	0%	0%	0%	0.3%	0.1%	-0.2%	

[a] Weather-normalized results are those that would have been observed if the weather were the same as the long-term average
[b] Generation costs are calculated by multiplying the daily fuel price ($/MMBtu) by the average standard efficiency of generators for each fuel (MMBtu/MWh)
[c] The Day Ahead LMP shown for 2025 is the total of the Day Ahead LMP and the Forecast Energy Requirement Price (FERP)
[d] Capacity costs in 2022-2024 include Mystic cost-of-service costs
[e] Ancillary Services also include inventoried energy program costs and DA A/S costs for the FRS products in 2025
[f] Provides a breakdown of total supply, which includes net imports; Note that section 1.2 provides a breakdown of native supply only
[g] The "Other" fuel category includes landfill gas, methane, wood, refuse and steam
⇨ denotes change is within a band of +/- 1%
Sparkline: Green = High Point, Red - Low Points

Looking ahead, several recent and near-term resource additions have the potential to significantly expand the region's supply capability, including the New England Clean Energy Connect (NECEC) transmission project (1,200 MW) and the Vineyard Wind offshore wind facility (805 MW), with Revolution Wind (704 MW) expected to enter service later in 2026. Together, these resources will make a meaningful contribution toward meeting the anticipated 8% growth in energy use over the next decade—equivalent to roughly 1,100 MW of additional average hourly demand. [4]

As New England transitions towards greater renewable generation and electrification-driven load growth, the performance of flexible resources and energy-secure supply are increasingly necessary to maintain reliability. Market design changes are addressing these evolving system conditions. The implementation of the Day-Ahead Ancillary Services (DA A/S) market in 2025 represents an important shift toward more transparent pricing and compensation for reliability services. Additionally, proposed capacity market reforms aim to ensure that system procurement better reflects resource capabilities, load conditions, and seasonal reliability risks. Together, these design changes will better align markets with the system's emerging reliability needs.

Joint Procurement of Energy and Ancillary Services Represents a Major Day-Ahead Market Enhancement

The Day-Ahead Ancillary Services (DA A/S) market, launched in March 2025, introduced a significant change to the energy market by replacing the Forward Reserve Market and effectively integrating the operators' next-day Resource Adequacy Analysis into market clearing. The new framework is intended to ensure the system is reliably positioned to meet the ISO's next-day operating needs, while compensating and incentivizing resources to be prepared to perform in real time.

In the day-ahead timeframe, the market jointly procures and prices operating reserves—ten- and thirty-minute Flexible Response Services (FRS) and the sixty-minute Energy Imbalance Reserve (EIR)—as well as physical energy to meet expected real-time load through the Forecast Energy Requirement (FER). Over the first ten months of implementation, net settlements for the four reserve products totaled approximately $137 million, representing about 2% of total energy and ancillary services (E&AS) costs.

The procurement of physical energy to satisfy the FER results in the Forecast Energy Requirement Price (FERP), which is credited to physical supply resources that satisfy the FER constraint, with corresponding charges to load-serving entities. FER costs totaled $529 million from March through December, accounting for more than 5% of total E&AS costs. Combined, DA A/S settlements totaled $666 million over the first ten months of implementation.

Importantly, these reforms increased transparency around the cost of meeting reliability needs by shifting compensation that was previously embedded in uplift or forward mechanisms into explicit day-ahead market prices, accompanied by stronger performance incentives. However, DA A/S costs have exceeded expectations to date, and based on our assessment of market performance to date, the IMM recommended targeted refinements to improve the cost-effectiveness of the

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[4] ISO New England Inc., "*2026 Capacity, Energy, Loads, and Transmission (CELT) Report: 2026–2035 Forecast*", May 1, 2026, https://www.iso-ne.com/system-planning/system-plans-studies/celt. Due to timing, several references to the CELT report elsewhere in this Annual Markets Report reflect the 2025 CELT forecast. The 2026 CELT update further revised projected peak demand and total energy use downward.

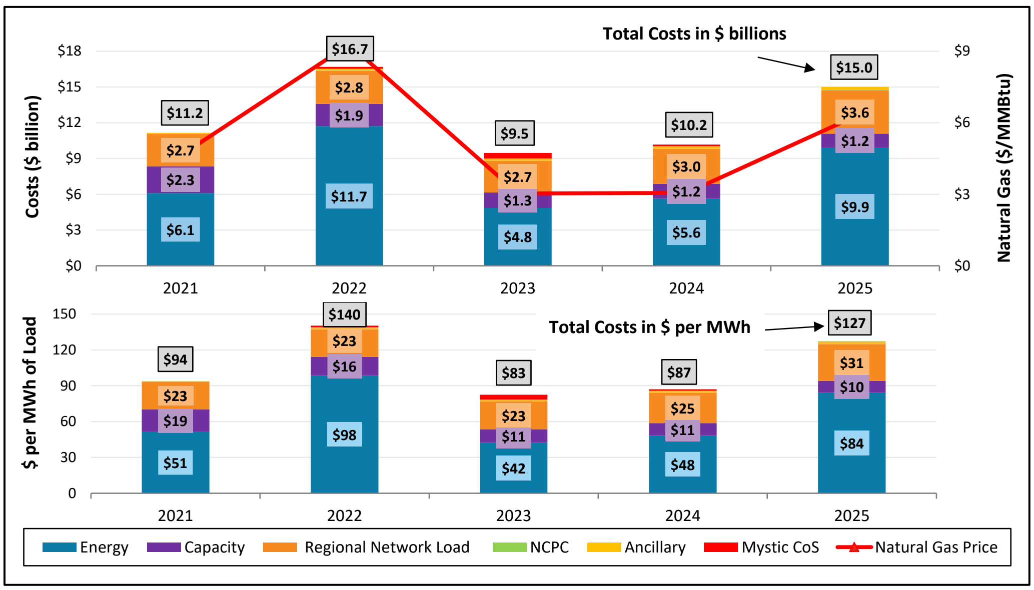
DA A/S design, including changes to strike prices, the FER construct, and reserve requirements.[5] ISO-NE is working with stakeholders on these recommendations and expects to file proposed revisions in the coming months.

The IMM is also issuing a report with a detailed assessment of DA A/S performance concurrent with this annual report.

Increasing Wholesale Costs in 2025 Reflect Higher Fuel Prices, New Market Design Elements, and Rising Transmission Costs

Wholesale electricity costs in New England rose sharply in 2025 to $15 billion, a 48% ($4.8 billion) increase from 2024.[6] Although costs remained below 2022 levels— when global commodity prices peaked following Russia's invasion of Ukraine—2025 marked the second-highest year for wholesale costs since 2008. The increase was driven primarily by energy costs, which rose 77% to $9.9 billion and accounted for nearly two-thirds of total wholesale costs.

Wholesale Costs ($ billions and $/MWh) and Average Natural Gas Prices



The rise in energy costs was largely attributable to higher natural gas prices, which more than doubled year-over-year; up 105%, from $3.06/MMBtu to $6.27/MMBtu. As discussed in the preceding section, beginning in March 2025 with the implementation of the DA A/S market, energy costs also reflected the introduction of the FERP, which compensates resources for providing the physical capability needed to meet the day-ahead load forecast. FER payments totaled $529 million from March through December, accounting for approximately 5.3% of total energy costs.

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[5] ISO New England Inc., Internal Market Monitor," *Recommended Changes to the Day-Ahead Ancillary Services Market"* memorandum to ISO New England (cc: NEPOOL Markets Committee), February 4, 2026, https://www.iso-ne.com/static-assets/documents/100032/2026_02-imm-memo-with-daas-recommendations.pdf .

[6] For context, the average retail electricity price in New England across all customer classes was 23.03 cents/kWh in 2024. By comparison, the all-in wholesale electricity cost in 2024 was approximately 8.7 cents/kWh, representing about 38% of the average retail price paid by end-use customers. Retail price data are from U.S. Energy Information Administration (EIA), Table 2.10: Average Price of Electricity to Ultimate Customers by End-Use Sector.

Regional Network Load (Transmission costs) increased to $3.6 billion, representing 24% of total wholesale costs, driven by higher regional network service rates and continued investment in transmission infrastructure, including reliability upgrades and asset-condition projects.

Capacity costs totaled $1.2 billion, reflecting payments associated with the fifteenth and sixteenth Forward Capacity Auctions held in 2021 and 2022. Capacity costs accounted for 8% of total wholesale costs and reflected surplus procurement relative to the Net Installed Capacity Requirement, with clearing prices of approximately $2.60/kW-month—well below the cost of new entry for a combustion turbine. Capacity costs have remained relatively stable over the past three years, and are expected to remain between $1.0 and $1.1 billion over the next two calendar years based on forward auction outcomes through May 2028.

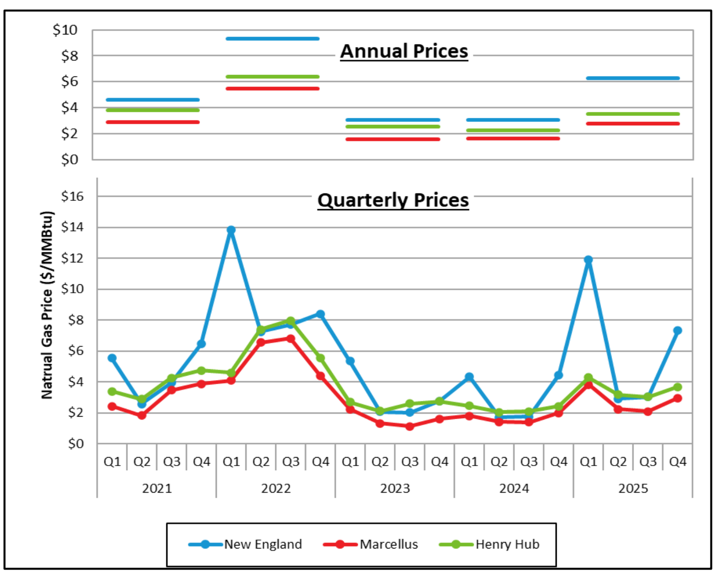
Ancillary services costs, which include payments for day-ahead and real-time reserves, regulation, and the temporary Inventoried Energy Program (IEP), totaled $242 million in 2025—an increase of $66 million (7%) from 2024. The increase was primarily due to the new day-ahead reserve products procured under the Day-Ahead Ancillary Services (DA A/S) market, which accounted for $137 million in costs, partially offset by lower IEP expenditures.

Net Commitment Period Compensation (NCPC), or uplift, totaled $42 million in 2025—an increase of $7 million from 2024—but remained a very small component of overall costs, representing just 0.4% of total energy costs, the lowest share in at least a decade. Consistent with prior years, first-contingency payments accounted for the majority of NCPC, driven primarily by real-time commitments made in economic merit order to meet load and reserve requirements

Natural Gas Price Increases and Rising Carbon Emissions Costs Drove Higher Generation Costs

Natural gas prices rose significantly in 2025, with annual average prices exceeding $6/MMBtu, a 105% increase from 2024. Prices peaked in the first quarter—particularly in January and February—when cold weather and a polar vortex drove regional hub prices to approximately $11/MMBtu, well above typical winter levels and the unusually low prices observed in early 2024.

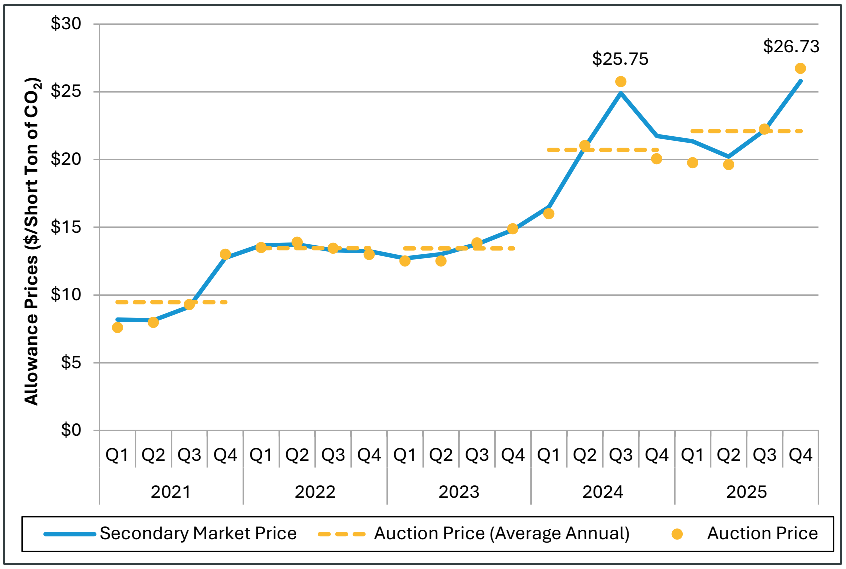
Wider Spread between New England and Marcellus/Henry Hub Benchmark Natural Gas Prices



Although prices declined as winter conditions eased, they remained elevated throughout the year relative to 2024. The increase reflected both higher national benchmark prices—including at Marcellus and Henry Hub—and stronger demand for heating and gas-fired generation during colder conditions. Prices in New England rose by more than national benchmarks, highlighting the region's heightened exposure to winter demand and pipeline constraints.

Carbon emissions costs also increased in 2025, reflecting rising allowance prices and tightening emissions limits across both regional and state programs that are established by state policymakers. Prices under the Regional Greenhouse Gas Initiative (RGGI) continued their upward trend, while Massachusetts Electricity Generator Emissions Limits (MA EGEL) prices rose sharply, driven by higher emissions, declining allowance surpluses, and expectations of future scarcity.

Rising Regional Greenhouse Gas Initiative (RGGI) Prices



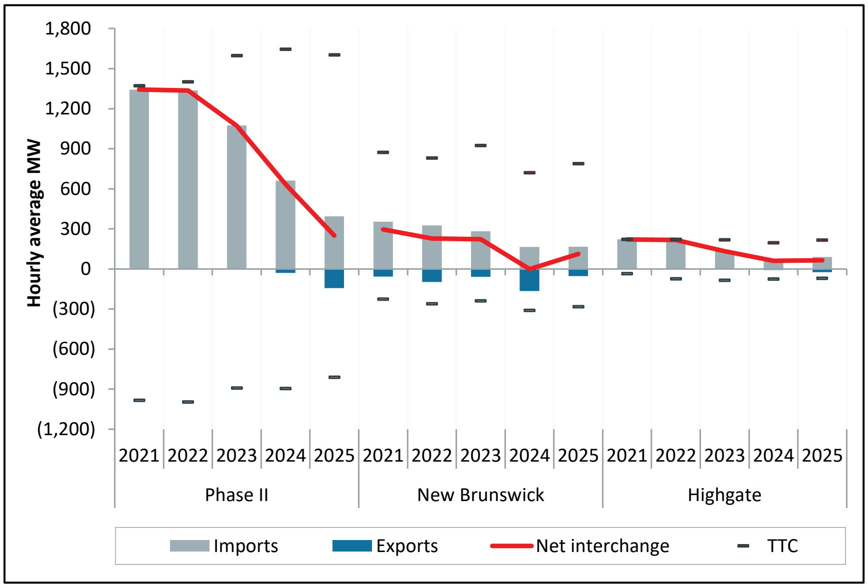
These dynamics increased the cost of operating fossil-fuel-fired generation, although emissions costs represented a smaller share of total generation costs than in 2024 due to the much larger increase in natural gas prices. RGGI allowance prices rose 6.5% year-over-year (to $22.38/short ton), while the average MA EGEL auction clearing price increased 290% (to $11.63/metric ton). These prices translate to estimated production cost adders of $10.21/MWh (RGGI) and $3.56/MWh (MA EGEL) for a typical natural-gas combined cycle unit. For context, fuel-related production costs alone averaged approximately $49/MWh for a combined cycle in 2025.

Overall, we estimate that carbon pricing programs increased average (load-weighted) energy prices by approximately $9/MWh in 2025 (up from $8/MWh in 2024), contributing about $1.1 billion to total energy costs. As emissions approach program caps, allowance availability is expected to tighten further, placing additional upward pressure on prices and reinforcing incentives for generators to reduce emissions through efficiency improvements, fuel switching, or lowering carbon-intensive output.

Declining Interchange Increased Reliance on Internal Supply; NECEC Expected to Partially Reverse the Trend

Net interchange into New England declined further in 2025, with real-time net imports averaging 932 MW per hour—about 7% of load—the lowest level since at least 2011. The decline was driven primarily by reduced Canadian imports due to dry hydro conditions in Quebec and a prolonged nuclear outage in New Brunswick, with Canada's share of total net imports falling to 47%. The volume of net interchange with New York remained relatively stable, with net imports across all three New York interfaces averaging nearly 500 MW per hour in 2025.

Continued Trend of Decreasing Net Interchange over the Phase II Interface



Despite the overall decline, interchange continued to play a critical role during periods of high demand and elevated prices. In hours when day-ahead prices exceeded $100/MWh, net imports averaged nearly 2,700 MW per hour, underscoring their importance during stressed system conditions. Day-ahead net interchange remained higher than real-time net interchange, driven largely by additional real-time scheduled exports at the New York North interface. When net real-time interchange is lower, New England must commit additional real-time native generation which can lead to higher real-time prices.

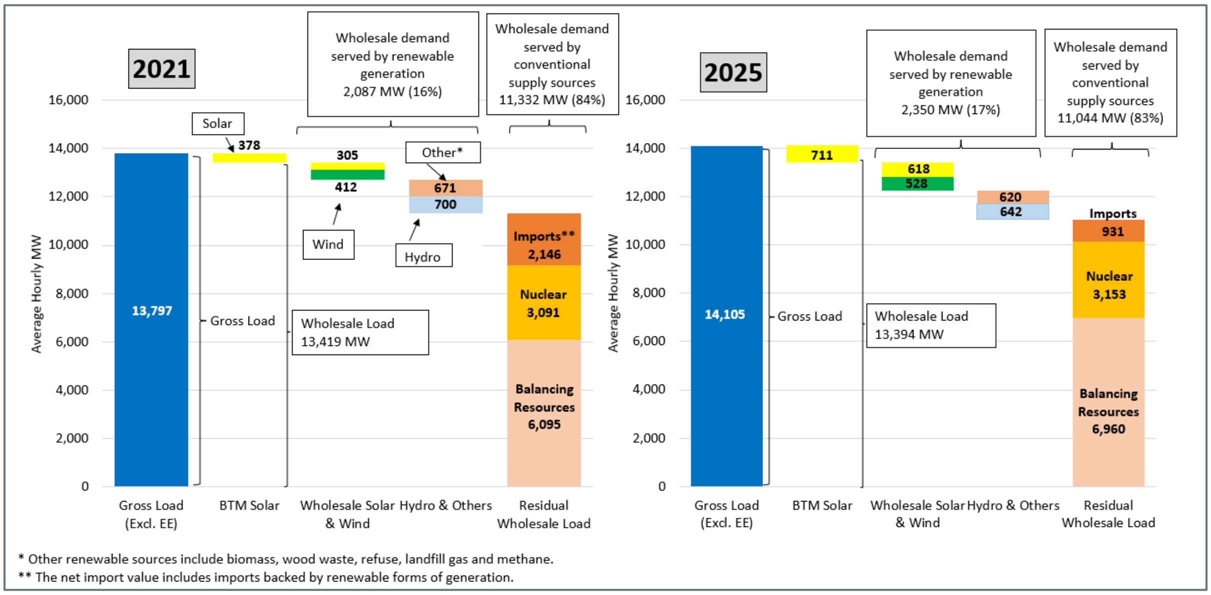
Looking ahead, the NECEC transmission line, which entered service in early 2026, has the capability to increase imports from Canada and partially offset the decline in interchange. This will ease pressure on internal resources and moderate reliance on higher-cost supply during tight system conditions.

Evolving Demand and Supply Conditions are Increasing Reliance on Flexible Resources

New England's demand and supply landscape continues to evolve as the region advances its clean energy transition, with growing levels of renewable resources and a critical reliance on dispatchable generation (balancing resources). In 2025, renewable supply met approximately 22% of gross demand, up from 18% in 2021, driven largely by growth in solar generation—including behind-the-meter installations.

At the wholesale level, the renewable share also increased more modestly, from 16% to 17%, as higher solar output offset reduced hydroelectric generation due to drought conditions and declines in other renewable sources. Over the same period, a 57% decline in net imports shifted a greater share of system needs onto internal balancing resources.

A Five-Year Snapshot of Demand and Supply, 2021 vs. 2025



Overall, the contribution of renewables to gross demand increased meaningfully over the five-year period. In the near term, major infrastructure projects—including Vineyard Wind I (806 MW), Revolution Wind (704 MW), and the New England Clean Energy Connect (1,200 MW) transmission line—are expected to significantly expand the region's renewable energy portfolio in the coming years.

We track the system and market impacts of the clean energy transition through a suite of metrics that reflect anticipated changes in demand patterns, supply flexibility, and price dynamics. Many of these anticipated trends have been examined in prior studies including ISO-NE's *Economic Planning for the Clean Energy Transition* and the Analysis Group's *Pathways Study*. However, observed impacts to date remain relatively muted, reflecting stable load growth and incremental renewable additions compared to the scale required for deep decarbonization. Nonetheless, the framework below provides a useful baseline for monitoring emerging conditions.

Trends in System and Market Metrics

Metric	Description of Expected Trend	Trend
Energy Usage	Sustained load growth, with winter energy use and peak demand increasing faster than summer demand.	▬
Seasonal/Annual Load Variability	Increasing variability in annual energy needs, driven primarily by winter heating demand and heightened sensitivity to cold weather.	▬
Morning and Evening Load Ramps	Steeper morning (down) and evening (up) load ramps as solar generation penetration increases.	▲
Downward Flexibility of Supply	More frequent periods where net load falls below the minimum stable operating levels of conventional generation.	▬
Fast-Start Generator Utilization	Greater reliance on fast-start, dispatchable resources to manage steeper and more volatile load ramps.	▲
Load Forecast Error	Increased difficulty forecasting load accurately, with a focus on day-ahead and intra-day timeframes.	▬
Negative Energy Prices	Increasing frequency of negative LMPs as renewable generation grows and negative offer prices become more prevalent.	▲
Energy Price Level	Downward pressure on energy prices associated with higher renewable generation levels.	▲
Energy Price Volatility	Price volatility driven by intermittent renewable output and changing net-load conditions remains consistent with prior years.	▬

The trend indicator reflecting our assessment of whether the underlying issue has increased (▲), remained stable (▬), or decreased (▼) in magnitude over time

Importantly, the most pronounced impacts are reflected at the hourly operational level rather than in annual averages. Behind-the-meter solar has significantly altered load profiles—reducing morning ramps while steepening evening ramps. Between 2021 and 2025, the evening ramp in residual load increased from 467 MW/hour to 826 MW/hour. Midday minimum load conditions have also become more frequent, with the system's lowest load shifting from nighttime to daytime hours in 51% of days in 2025, up from 7% in 2021, contributing to the emergence of a persistent "duck curve."

Despite these changes, the system has maintained adequate operational flexibility, with no material over-supply conditions or ramp constraints observed. However, growing net-load variability is increasing reliance on flexible, fast-start resources, particularly during the evening ramp. Looking ahead, projected load growth—8% higher energy usage by 2035, with winter peaks rising 30%—is expected to further increase the need for flexible and fuel-secure resources, especially under cold-weather conditions.

Competitive Market Outcomes Persisted Amid Tightening Supply

Energy market outcomes in 2025 remained broadly competitive, with supplier concentration at levels consistent with competitive market conditions. The four largest suppliers accounted for approximately 42% of generation, with shares relatively evenly distributed. At the same time, structural market power indicators reflected greater reliance on large suppliers under tighter supply conditions. In real time, at least one supplier was pivotal in roughly one-third of hours, consistent with recent years. These outcomes primarily reflect reduced import availability and tighter supply margins, but they did not translate into material realized market power concerns.

Indicators of supplier behavior continued to support this assessment. Economic withholding remained low, with economically withheld capacity below 2%, and the day-ahead price-cost markup at 2.7%, indicating limited impact of any divergence between observed offers and the IMM's competitive cost benchmarks. Mitigation activity remained minimal, totaling just 399 asset hours—approximately 0.02% of all asset hours subject to mitigation—consistent with prior years.

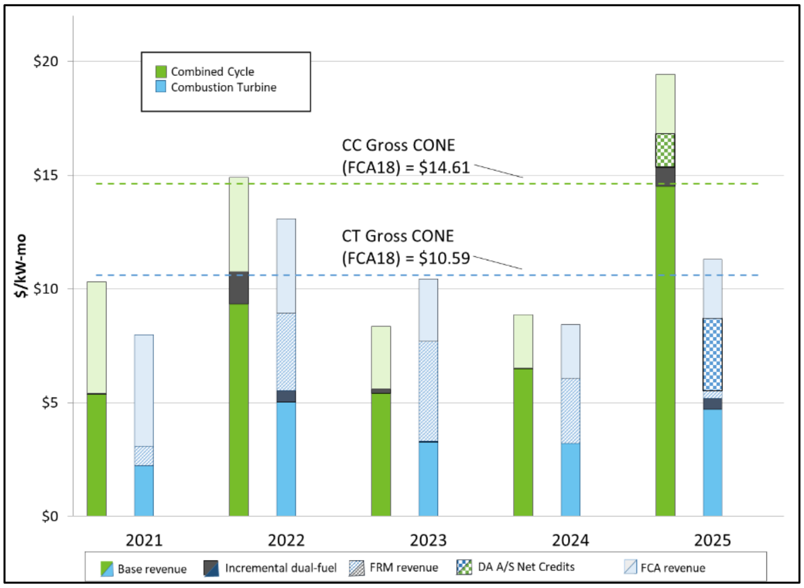
Other markets also remained competitive overall. The regulation market exhibited substantial excess supply, with residual supply index (RSI) values consistently above 900%, indicating the absence of pivotal suppliers. The Financial Transmission Rights (FTR) market remained active but concentrated, with the top four participants holding approximately 67% of MWs. FTR profitability totaled $34 million in 2025, driven primarily by increased congestion—particularly associated with scheduled transmission outages—rather than structural market power *concerns*.

We have made several market design recommendations in the energy market mitigation space over the past few years, including proposals to review conduct and price impact thresholds and to enhance the pivotal supplier screen (see Recommendations 2023-1 and 2015-3). The importance of these recommendations has increased in the context of heightened merger and acquisition activity, which is contributing to greater portfolio concentration. Accordingly, we encourage proactive action to ensure that mitigation rules remain appropriately calibrated to support competitive market outcomes going forward.

Market Revenues Improved in 2025, with Significant Variation across Resource Types

New resources: Wholesale market revenues increased significantly in 2025 due to higher natural gas prices, improving profitability metrics and signals for new entry. Energy and ancillary services revenues rose sharply for proxy new combined-cycle (CC) and combustion turbine (CT) units, with net revenues (excluding capacity) reaching approximately $16.8/kW-month for a CC and $8.4/kW-month for a CT. When combined with capacity revenues of $2.60/kW-month, total revenues for both technologies exceeded their estimated Gross Cost of New Entry, marking the second time in five years that aggregate market revenues were sufficient to support new entry.

Revenue and Cost of New Entry Estimates for a Combined Cycle and Combustion Turbine

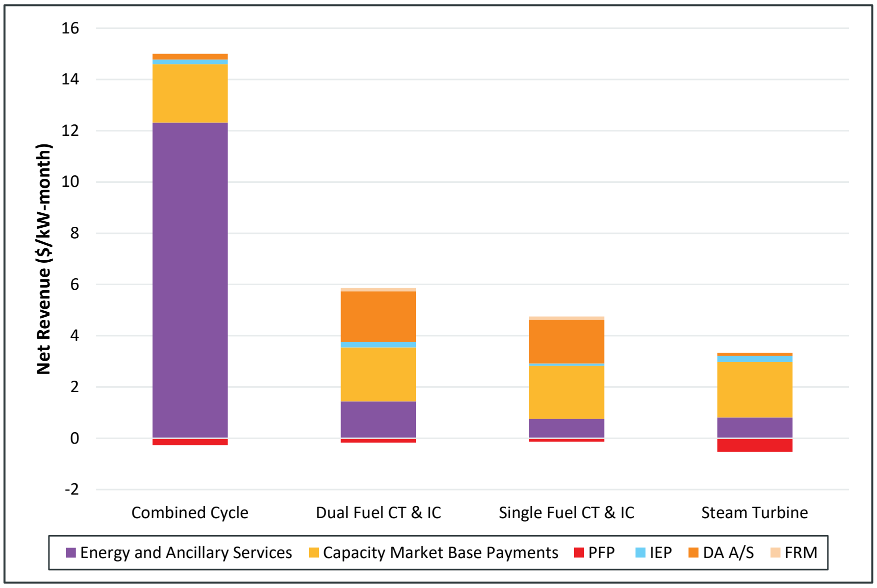


Renewable and storage resources: Profitability for renewable resources continued to depend heavily on out-of-market revenues. In 2025, Renewable Energy Certificate (REC) revenues accounted for approximately 33% of total wind revenues, down from prior years as higher energy prices increased market-based revenues. Solar resources remained predominantly supported by state incentives, with about 71% of revenues derived from the Solar Massachusetts Renewable Target (SMART) program. Battery storage revenues declined to just under $10/kW-month, reflecting lower revenues from the regulation market as clearing prices fell significantly amid increased participation by battery resources.

Existing resources: Among existing resources, combined-cycle (CC) units derived roughly 85% of revenues from the energy and ancillary services markets, while steam turbines relied on capacity payments for approximately 77% of revenues. Steam turbine resources, in aggregate, incurred performance charges under the Pay-for-Performance framework due to lower delivered capacity during scarcity events. These outcomes suggest that some older, less efficient resources will face increasing economic pressure—and potential retirement—if current market conditions persist.

For combustion turbines (CTs), revenues from the DA A/S market comprised ~35% of overall revenues, reducing reliance on capacity market payments. This pre-distribution of revenues will have important implications in terms of downward pressure on capacity market offers and potentially capacity costs in the future.

Existing Resource Net Revenues from Energy, Capacity and Ancillary Markets, 2025



Capacity Auction Reforms Address Resource Performance, Seasonal Reliability Risks, and Supply–Demand Uncertainty

ISO-NE's Capacity Auction Reform (CAR) initiative represents a significant evolution of the capacity market, aimed at better aligning capacity procurement with system reliability needs and reducing uncertainty for both supply and demand. The reforms are being implemented in two phases.

The first phase—**Capacity Auction Reform: Prompt and Deactivation (CAR-PD)—** replaces the three-year-forward capacity auction with a prompt auction conducted one month ahead of the commitment period, along with associated changes to resource deactivation rules. FERC approved CAR-PD tariff changes in early 2026, and the IMM supported these reforms as a meaningful improvement over the existing framework. The prompt auction design reduces uncertainty by shortening the load-forecast horizon and requiring resources to be fully constructed before participating, thereby improving price formation and eliminating reliance on unbuilt "phantom" capacity. The revised deactivation process replaces priced retirement bids with unpriced, irrevocable notices submitted one year in advance, better reflecting how market participants make exit decisions while preserving the ISO's ability to assess reliability impacts and mitigate potential market power concerns.

The second phase—**Capacity Auction Reform: Seasonal and Accreditation (CAR-SA)—** continues development toward a more reliability-focused capacity market. CAR-SA introduces separate summer and winter auctions and adopts marginal resource accreditation to better reflect how different resource types contribute to reliability under season-specific stress conditions. A key feature of CAR-SA is the introduction of a winter natural-gas resource constraint, which recognizes pipeline limitations and reduced fuel deliverability during cold-weather periods. By discounting the accredited capacity of gas-only generators that rely on constrained pipeline capacity, while exempting dual-fuel and firm-fuel resources, the reform improves investment signals and more accurately aligns compensation with expected reliability performance.

Together, the CAR-PD and CAR-SA reforms represent a shift toward a more timely, reliability-driven capacity market design that improves market efficiency, strengthens price formation, and better reflects evolving system risks—particularly winter reliability challenges driven by fuel constraints and changing resource characteristics.

Summary of IMM Market Enhancement Recommendations

One of the IMM's key functions is to recommend rule changes to enhance the performance of the markets. In practice, we communicate our recommendations through our reports, including our quarterly markets performance reports, memorandums, and comments filed with FERC on proposed rules changes.

The tables below summarize the IMM's recommended market enhancements, first showing issues with an "open" status, followed by recently closed issues. A hyperlink is provided to the document in which the recommendation was first put forward, along with the IMM's priority ranking of each recommendation. Recommendations included in this report for the first time are included in the first table. The second table summarizes recommendations included in prior year reports.

The priority ranking (High, Medium or Low) considers the potential market efficiency gains, as well as the potential complexity and cost of implementing each recommendation. High priority recommendations may deliver significant market efficiency gains, with the benefit outweighing the cost of implementing them. At the other end of the scale, low priority recommendations are not intended to indicate low importance, but rather issues that may not have as significant long-term efficiency gains (compared to high priority recommendations) and/or may be very costly to implement.

Summary of New IMM Recommendations since prior Annual Report

ID	Recommendation	When made	Status	Priority Ranking
2026-1	**Increase the Day-Ahead Ancillary Services (DA A/S) Strike Price** to better align with the short-run marginal costs (SRMCs) of resources that provide the majority of operating reserve capability. The current Strike Price frequently falls below resource SRMCs, which increases expected closeout risk, increases DA A/S offers, and discourages participation without delivering commensurate reliability benefits. Adjusting the Strike Price to better reflect cost fundamentals would reduce embedded risk premiums, improve participation, place downward pressure on DA A/S clearing prices, and better align price signals with periods of elevated system reliability risk while preserving strong real-time performance incentives.	2026 Memo to ISO New England/ NEPOOL Markets Committee	ISO New England is proposing changes to address this recommendation.	High
2026-2	**Reduce the Forecast Energy Requirement (FER) to account for expected real-time production from front-of-the-meter wind and solar resources that routinely exceed their day-ahead cleared awards.** The current FER overstates required physical supply by not accounting for renewable output that the ISO already relies upon operationally, resulting in unnecessary procurement of higher-cost physical generation or Energy Imbalance Reserves and higher DA A/S costs. Netting expected renewable production against the FER would improve consistency between day-ahead and real-time operations, reduce reliance on expensive physical supply, and place downward pressure on the combined LMP plus FERP, which represents the marginal cost of day-ahead physical energy under the joint energy and ancillary services design.	2026 Memo to ISO New England/ NEPOOL Markets Committee	ISO New England is proposing changes to address this recommendation.	High

ID	Recommendation	When made	Status	Priority Ranking
2026-3	**Reevaluate and consider a downward adjustment to the Non-Performance Factor (NPF) applied to ten- and thirty-minute operating reserve requirements** in light of strengthened performance incentives and improved observed resource performance. The current 20% NPF reflects historical conditions that predate Pay-for-Performance, higher reserve penalty prices, and the implementation of the DA A/S market, all of which have materially increased incentives for real-time performance. A data-driven reassessment could demonstrate that a lower NPF is appropriate, better aligning reserve requirements with demonstrated system needs, reducing DA A/S procurement costs, and avoiding systematic over-procurement while maintaining reliability.	2026 Memo to ISO New England/ NEPOOL Markets Committee	ISO New England implemented a reduced NPF (15%) on May 1, 2026	High

The following table summarizes IMM recommendations from prior year reports. The table includes a trend indicator reflecting our assessment of whether the underlying issue has been increasing (▲), remained stable (▬), or decreased (▼) in magnitude over time

Summary of Prior IMM Recommendations

ID	Recommendation	When made	Status	Priority Ranking	Trend
2025-6	**Adopt a Capacity and Impact (C&I) Approach for Single-Year Capacity Offers Subject to IMM Review** Implement a Capacity and Impact (C&I) framework for evaluating single-year capacity offers that are subject to IMM cost reviews. Eliminate the existing Pivotal Supplier Test (PST), under which only resources belonging to pivotal suppliers are subject to market power mitigation. The C&I framework provides a more accurate assessment of market power and reduces the risks of both over-mitigation and under-mitigation associated with the current PST and Conduct approach.	2024 AMR (May 2025)	Not in the scope of the ISO's current work plan.	High	▬
2025-5	**Review and clarify the time-out trigger for capacity resources to prevent inefficient transmission reservation** The current market rules state that a resource will be considered retired, and its interconnection rights terminated, if it does not "operate commercially" for three calendar years. The term "operate commercially" is not clearly defined, potentially allowing resources to retain interconnection rights by producing minimal energy output, even without plans to return to full operation. To prevent inefficient reservation of transmission capacity, the IMM recommends clarifying the Tariff to require that a resource demonstrates meaningful and sustained energy production to be considered commercially operational.	2024 AMR (May 2025)	Not in the scope of the ISO's current work plan.	Medium	▬

ID	Recommendation	When made	Status	Priority Ranking	Trend
2025-3	**Treatment of Export Transactions in Pay-for-Performance Settlements** The current Pay-for-Performance (PfP) rules create unequal incentives for imports and exports during scarcity events, crediting imports at the PfP rate but not applying a corresponding charge to all exports. While there is netting of imports and exports at the market participant level, this does not fully address the issue. This misalignment can lead to inefficiencies as it fails to address potential gaming opportunities, where related entities can profit from simultaneously scheduling imports and exports, receive credits for the import, and provide no reliability benefit.	2024 AMR (May 2025)	Currently in the ISO's work plan. The ISO's proposal will be voted on at the June 16-18, 2026 NEPOOL Participants Committee Meeting.	Medium	▲
2025-2	**Provide Clarity on Need to Shed a CSO During Outage Periods** The Tariff requires non-intermittent resources to offer their full CSO unless they are physically unavailable, but it lacks clear definitions and enforcement mechanisms for prolonged unavailability. The IMM considers a resource physically available if it is not on a forced or planned outage, consistent with other Tariff provisions and FERC rulings. However, resources can remain on outage and continue receiving capacity payments without being required to shed their CSO, which has led to enforcement actions in the past. Given the range of unavailability scenarios—such as early retirements, long-term outages, lack of fuel, or insufficient demand backing—the IMM recommends amending the Tariff to better define physical unavailability and to require resources to shed their CSO or face penalties if they cannot deliver capacity for extended periods.	2024 AMR (May 2025)	Not in the scope of the ISO's current work plan.	Medium	—
2024-1	**Publish generation retirements that have occurred either prior to the effective retirement date in the FCM or outside of the FCM process**. Retirement timings do not always align with capacity commitment periods and early retirements remain outside of the publication of information associated with capacity market qualification and results. We believe there is value in the release of such information in the interest of transparency and the free flow of important information to market participants.	2023 AMR (May 2024)	Implemented for FCA 19 under CAR-PD.	Medium	▼
2023-2	**Review reserve pricing mechanics under fast-start pricing.** Under current fast-start pricing rules, we have observed frequent non-zero reserve pricing in scenarios when resources' dispatch instructions were not impacted by the reserve constraint and the system had a surplus of reserves. Due to tradeoffs presented by the separation of the dispatch and pricing software, the ISO chose a pricing optimization methodology that minimizes false negatives (no reserve pricing when there is a physical reserve constraint binding) but allows false positives (reserve pricing when there is not a physical reserve constraint binding). This was an intentional decision	2022 AMR (May 2023)	Not in the scope of the ISO's current work plan.	Medium	—

ID	Recommendation	When made	Status	Priority Ranking	Trend
	when fast-start pricing was implemented, however, the frequency in which we have observed reserve pricing when there is not a physical reserve constraint binding has exceeded the frequency in which we expected these scenarios to occur, and the cost of reserve payments in these intervals warrants additional consideration of other solutions.				
2023-1	**Review mitigation thresholds and reference level methodologies, eliminate mitigation exemptions for non-capacity resources, and extend mitigation to export-constrained area.** Market power mitigation rules need to strike a reasonable balance between producer and consumer interests, and in turn prescribe adequate threshold tests to determine when market monitors override generator supply offers. The IMM has identified a number of potential rule improvements to better serve the mitigation function. 1. Review of the current mitigation thresholds that apply to instances of system-wide and local market power. The current thresholds allow for considerable latitude in supply offers levels over competitive benchmarks (300% and 50%) and have been in place for many years with little empirical support. 2. Eliminate the energy offer mitigation exemption for non-capacity resources in the day-ahead energy market. 3. Extend the scope of offer mitigation to cover the potential exercise of market power in export-constrained areas. 4. Review the methodologies for determining reference levels, which are used to evaluate if an offer is competitive (the “conduct test”). Currently, reference levels can be based on marginal cost, or historical fuel-adjusted accepted supply offers or LMPs. We have observed instances in which the latter two methodologies produce unreasonably high reference levels.	2022 AMR (May 2023)	Not in the scope of the ISO’s current work plan.	Medium	▲
2022-1	**Incentive rebuttal component of proposed Buyer-side Mitigation Rules** The ISO's proposed buyer-side mitigation rules will allow a Project Sponsor to demonstrate a lack of incentive through a Net Benefits Test to avoid mitigation of a below-cost supply offer from certain resources. The IMM has recommended that removing the incentive rebuttal provision from the proposal would make the buyer-side mitigation review more predictable and capable of being administered more reliably and with less subjectivity.	Filed Comments with FERC on MOPR Elimination and Buyer-side Mitigation Rules (Apr 2022)	Not in the scope of the ISO’s current work plan.	Low	—

ID	Recommendation	When made	Status	Priority Ranking	Trend
2020-1	**Reference level flexibility for multi-stage generation** Given that 2023-1 is not part of the ISO's workplan, and is unlikely to be developed for some time, we recommend related changes that could be made to the market power mitigation function in the meantime. We believe these changes will be less resource-intensive and complex to adopt, compared to incorporating multi-stage generation modeling into the day-ahead and real-time market and systems software. However, it is not a replacement of the above recommendation on reviewing mitigation thresholds and methodologies. The recommendation is to provide generators with the ability to dynamically select their active or planned configuration and to adjust reference levels to be consistent with their operating costs and their supply offers. This will address the current risk of false positive and negative errors in mitigation, given the potentially high costs differences between configurations. It may also eliminate a potential deterrent to generators from offering configurations to avoid the risk of mitigation, which may ultimately be more cost effective to consumers.	Winter 2020 QMR (May 2020)	Not in the scope of the ISO's current work plan.	Medium	▼
2018-1	**Unoffered Winter Capacity in the FCM** The IMM is concerned that generators may be contracting at, or close to, their maximum capacity (i.e. their winter qualified capacity), as determined by the ISO, even though that capacity is not deliverable in certain months given expected ambient temperatures. The IMM recommends that the ISO review its existing qualification rules to address the disconnect between the determination of qualified capacity for two broad time horizons (summer and winter), the ability of the generators to transact on a monthly basis, and the fluctuations in output capability based on ambient conditions. A possible solution would be for the ISO to develop more granular (e.g. monthly) ambient temperature-adjusted qualified capacity values, based on forecasted temperatures and the existing output/temperature curves that the ISO currently has for each generator.	Fall 2018 QMR (Mar 2019)	The IMM will evaluate this recommendation in the context of the ISO's planned revisions to its capacity accreditation methodology as part of the CAR project, which will separately account for summer and winter physical capabilities.	Medium	—
2017-1	**Treatment of multi-stage generation** Due to the ISO's current modeling limitations, multi-stage generator commitments can result in additional NCPC payments and suppressed energy prices. This issue was first raised by the external market monitor, Potomac Economics.[1] The IMM recommends that the ISO consider improvements to its current approach to multi-stage generator modeling. Two possible options are: a. Expanding the current pseudo-combined cycle (PCC) rules- Consider whether to make PCC rules a mandatory requirement for multi-stage generators through proposed rule changes , or b. Adopt multi-configuration resource modeling capability- More	Fall 2017 QMR (Feb 2018)	Not in the scope of the ISO's current work plan.	Medium	▼

ID	Recommendation	When made	Status	Priority Ranking	Trend
	dynamic approach to modeling operational constraints and costs of multiple configurations.				
2016-2	**Analyzing the effectiveness of Coordinated Transaction Scheduling:** ISO-NE should implement a process to routinely access the NYISO internal supply curve data that is used in the CTS scheduling process. This data is an important input into the assessment of the cost of under-utilization and counterintuitive flows across the CTS interface.	2016 AMR (May 2017)	Related to 2016-1. Not in the scope of the ISO's current work plan.	Medium	—
2016-1	**Improving price forecasting for Coordinated Transaction Scheduling:** There is a consistent bias in the ISO's internal price forecast at the New York North interface, which may reduce the effectiveness of CTS. To date, biases in ISO-NE and NYISO forecasts have been in opposite directions, which increase the price spread between the markets relative to actual spreads, and may produce inefficient tie schedules. ISO-NE should assess the causes of biases in the price forecast and assess how the accuracy of the forecast can be improved. ISO-NE should periodically report on the accuracy of its price forecast at the NYISO interface, as well as the differences between the ISO-NE and NYISO price forecasts.	2016 AMR (May 2017)	Not in the scope of the ISO's current work plan.	Medium	—
2015-3	**Pivotal supplier test calculations**: The ISO, working in conjunction with the IMM, enhance the real-time energy market mitigation pivotal supplier test to include (1) ramp-based accounting of supply recognizing the differences between energy and reserve products and (2) participant affiliations.	2015 AMR (May 2016)	IMM and ISO to assess the implementation requirements for this project. Not currently in ISO's workplan.	Medium	▲
2015-1	**Corporate relationships among market participants:** The ISO develop and maintain a database of corporate relationships and asset control that allows for accurate portfolio construction for the purpose of identifying uncompetitive participation, including the potential exercise of market power and market manipulation.	Q2 2015 QMR (Oct 2015)	The project is not in the scope of the ISO's current workplan. The IMM will continue to rely on a combination of internal data and its own market research to satisfy its monitoring needs.	Medium	▲
2010-1	**NCPC charges to virtual transactions:** The ISO develop and implement processes and mechanisms to reduce NCPC charges to virtual transactions (to better reflect the NCPC cost causation principle) in response to the historical decline in virtual trading activity. A reduction in NCPC charges to virtual	2010 AMR (Jun 2011)	Not in the scope of the ISO's current work plan.	Medium	▲

ID	Recommendation	When made	Status	Priority Ranking	Trend
	transactions will likely improve day-ahead scheduling by adjusting expectations of real-time conditions.				
2025-4	**Option for real-time-specific offer schedules to automatically be used in real-time energy dispatch, in support of renewable resources** Wind and solar capacity resources must offer into the day-ahead market but face uncertainty in real-time output. To manage this risk, these resources often submit higher day-ahead prices to account for volumetric uncertainty, while offering lower prices in real-time to reflect their low marginal costs. However, ISO-NE's bidding system automatically carries day-ahead offers into real-time if a resource receives a day-ahead award, requiring manual action by the participant to overwrite the supply offers. The IMM has observed several cases in which the participant failed to take the manual overwrite action, leading to unnecessary downward dispatch of low-cost renewables in real-time. The IMM recommends ISO-NE enhance its systems to allow separate day-ahead and real-time offers to prevent such issues, especially as renewable capacity grows.	2024 AMR (May 2025)	Not in the scope of the ISO's current work plan.	Low	—
2025-1	**Clearing mechanics used at External Interfaces** Participants have increasingly used virtual demand bids at the Highgate interface to secure real-time clearing priority for their imports. By pairing virtual demand bids with early-submitted import offers, participants can create counter-flow in the day-ahead market, enabling full clearing of their imports and gaining a timestamp advantage in real-time scheduling. While the direct costs of such strategies (e.g., uplift or transaction costs) appear to be mostly borne by the participants employing them, these transactions are not consistent with their intended purposes of hedging or promoting price convergence. Moreover, there may be efficiency gains if participants competed for import opportunities based on price rather than submission time. To address this, we recommend that ISO-NE reevaluate clearing rules at non-CTS external interfaces, particularly the use of timestamps as a tiebreaker, to reduce incentives for strategic virtual bidding and allow participants to submit more accurate, cost-reflective offers closer to the operating day.	2024 AMR (May 2025)	Not in the scope of the ISO's current work plan.	Low	—

ID	Recommendation	When made	Status	Priority Ranking	Trend
2024-2	**Establish an automated process to ensure transmission-constrained resources are not designated for reserves.** Resources in New England are not eligible to provide operating reserves if constrained by transmission limitations. In practice, this is achieved through a manual process performed by system operators. When a transmission constraint binds, operators are tasked with applying a 'reserve down' flag to resources limited by that constraint. ISO dispatch software will not designate reserves on units that have the reserve down flag applied. This reflects the fact that, due to the transmission constraint, the reserves that would normally be counted on such resources are not deliverable to the system as energy. While market impacts related to this issue are not large in magnitude, they consistently persist from year to year. Market outcomes could be improved in this regard if the ISO implemented an automated process for applying the reserve down flag to resources limited by binding transmission constraints.	2023 AMR (May 2024)	Not in the scope of the ISO's current work plan.	Low	—
2021-1	**Develop Offer Review Trigger Price (ORTP) for co-located solar/battery facilities.** Under the current rules, the ORTP for a co-located battery and solar project is based on the weighted average of the individual technologies. This results in a value that is below the true "missing money" for the combined resource, allowing such resources to offer in at prices below competitive levels without review and mitigation, and undermining the protections put in place by the minimum offer price rule (MOPR). In our opinion, a bottom-up calculation is preferable because it accurately represents the constraints that co-located solar/battery facilities face and results in a more precise cost estimate.	Filed Comments with FERC on ORTP Recalculation (Apr 2021	**Closed:** This issue is moot with the elimination of MOPR.	Low	▼
2013-1	**Limited energy generator rules:** The ISO modify the market rules as necessary to ensure that the use of the limited-energy generator (LEG) provisions in both the day-ahead and real-time markets are restricted to instances when the availability of fuel is physically limited.	2013 AMR (May 2014)	Not in the scope of the ISO's current work plan.	Low	—

Section 1
Overall Market Conditions

This section provides an overview of key trends in the wholesale markets. It covers the underlying supply and demand conditions behind those trends and provides important context for the more detailed discussions on market outcomes and performance in later sections of this report.

The implementation of Day-Ahead Ancillary Services (DA A/S) in 2025 represents a significant change to the structure of the energy markets. Prior to this change, day-ahead Locational Marginal Prices (LMPs) reflected the marginal cost of energy. With DA A/S, the market co-optimizes energy and ancillary services, so clearing outcomes reflect both the cost of serving load as well as the cost of satisfying system operating reserve constraints. Accordingly, care is required when comparing prices to prior years.

It is important to note that in this report, we define the marginal cost of physical energy as the sum of the Day-Ahead Locational Marginal Price (LMP) and the Forecast Energy Requirement Price (FERP). Under the DA A/S framework, FERP reflects the value of meeting the system's physical energy requirement and must be included to capture the full marginal cost of serving load. In other words, the LMP alone does not reflect this component and will understate energy costs when this constraint is binding.

1.1 Wholesale Cost of Electricity

Key Takeaways

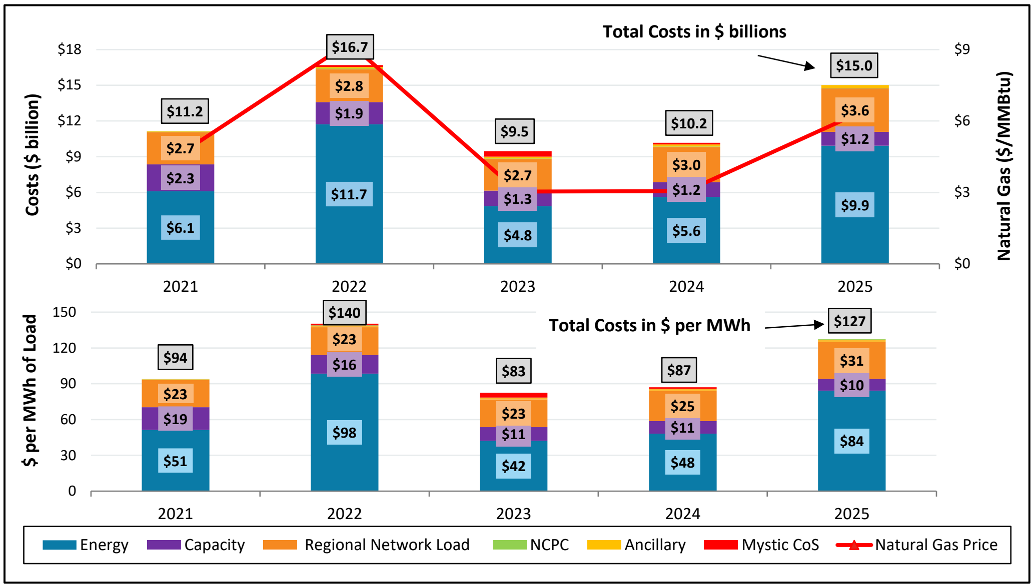
Wholesale market costs totaled $15 billion in 2025, a 48% ($4.8 billion) increase from 2024. The increase was driven primarily by higher energy costs, which rose to $9.9 billion, up 77% ($4.3 billion) year-over-year.

Higher energy costs were largely attributable to natural gas prices, which increased by 105% in 2025 (from $3.06/MMBtu to $6.27/MMBtu). In addition, the introduction of the Day-Ahead Ancillary Services (DA A/S) market on March 1, 2025—including Forecast Energy Requirement (FER) costs—added approximately $666 million in settlement costs over the first ten months of implementation.

Figure 1-1 below gives an overview of wholesale electricity costs and average natural gas prices over the past five years, including significant changes in each cost category.[7]

[7] The figure includes the Mystic Cost-of-Service Agreement. This agreement ended in 2024 and is covered in prior IMM reports.

Figure 1-1: Wholesale Costs ($ billions and $/MWh) and Average Natural Gas Prices



Energy costs accounted for 66% of wholesale electricity costs in 2025. Total energy costs of $9.9 billion increased 77% from 2024. While energy costs were high this year, they remained below costs in 2022, which was the highest total in the last 17 years.[8] Energy costs increased largely because of higher natural gas prices, which were up by 105% compared to 2024 prices ($6.27/MMBtu vs. $3.06/MMBtu).[9]

Energy costs reflect volumes settled at the day-ahead LMP and Forecast Energy Requirement price (FERP). Introduced on March 1, 2025, as part of the Day-Ahead Ancillary Services Initiative (DASI), the Forecast Energy Requirement (FER) ensures that the day-ahead market clears sufficient physical capability to meet the ISO's day-ahead load forecast. The FER credit compensates physical supply resources—including generators, demand response resources, and imports—with day-ahead energy awards for their contribution to meeting the FER constraint. FER credits totaled $524 million from March through December 2025.

Regional network load (RNL) costs, or transmission costs, include the costs associated with pool transmission infrastructure operation, maintenance, and investment borne by the transmission

[8] Energy costs in 2022 were the highest since 2008, due to significant increases in natural gas prices. Natural gas prices were driven by a combination of market conditions and events at an international and national level, in addition to regional New England winter issues. These factors included the Russian-Ukrainian conflict and the significant uptick in international demand for Liquefied Natural Gas (LNG), higher US demand and periods of sustained cold weather in New England. ISO New England Inc., Internal Market Monitor, "*2022 Annual Markets Report* ", June 5, 2023, https://www.iso-ne.com/static-assets/documents/2023/06/2022-annual-markets-report.pdf

[9] 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, Tennessee gas pipeline Z6-200L, Tennessee North gas, Tennessee South gas, and Maritimes and Northeast. 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.

owners as well as certain reliability and administrative costs.[10] RNL costs in 2025 were $3.6 billion, representing nearly 24% of total wholesale costs and a $681 million increase over 2024 costs.[11] Transmission costs are recovered based on monthly peak demand through the regional network service (RNS) rate, which rose from $154.35/kW-year in 2024 to $185.28/kW-year in 2025.[12] The RNS rate primarily increased because of 1) an under-collection of transmission costs in 2023 and 2) project additions across the region requiring cost recovery.

Transmission costs in New England have increased in recent years as transmission owners have made investments to respond to reliability needs identified by the ISO as well as to replace aging transmission equipment within their local systems (known as "Asset Condition" projects). Notable projects undertaken by transmission owners to improve greater system reliability that were placed in-service in 2025 included work done to increase the load serving capability of greater Boston as well as to resolve thermal overloads in Maine.[13] Numerous asset condition projects across New England also went in-service in 2025.

Capacity costs comprise payments to supply resources in the Forward Capacity Market, and fell slightly in 2025, accounting for 8% of wholesale costs. Capacity clearing prices increased in 2025 relative to 2024, with prices of $2.61/kW-month in capacity commitment period (CCP) 15, which includes January-May 2025, and $2.59/kW-month in CCP 16, which includes June-December 2025. While clearing prices increased, cleared capacity fell in CCP 16, and there was less upward price separation in the import-constrained Southeast New England capacity zone.

Ancillary service costs include payments to supply resources for providing day-ahead reserves, real-time reserves, regulation services, and the costs of the Inventoried Energy Program (IEP). Ancillary service costs totaled $242 million in 2025, up $66 million (7%) on 2024 costs due to the day-ahead reserve products included in the DA A/S market. The four day-ahead ancillary products cost $137 million in 2025. The sunsetting for Forward Reserve Market and lower IEP costs offset some of the increase in ancillary service costs.[14]

Net Commitment Period Compensation (NCPC) costs, or uplift, covers supply resource production costs not recovered through energy prices. NCPC totaled $42 million in 2025, up $7

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[10] The reliability costs include costs associated with resources retained for reliability (RFR) in the Forward Capacity Market (FCM), voltage support, high-voltage control, and system restoration. The administrative costs include local and system level dispatch and control costs as well as the budget for the New England States Committee on Electricity. ISO New England Inc., "*Monthly Regional Network Load Cost Report December 2025",* February 19, 2026) https://www.iso-ne.com/static-assets/documents/100032/2025_12_nlcr_final.pdf.

[11] The annual figure is the sum of the monthly Total RNL Costs. ISO New England Inc., "*Monthly Regional Network Load Cost Reports"*, https://www.iso-ne.com/markets-operations/market-performance/load-costs/.

[12] RNS rates are established using a prescribed methodology and then shared with FERC via an informational filing. More information about the determination of the 2025 RNS rate can be found in the following presentation: ISO New England Inc., *"RNS Rate Effective January 1, 2025"*, August 13, 2024, https://www.iso-ne.com/static-assets/documents/100014/a05.1_2024_08_1314_tc_rns_rates_presentation.pdf.

[13] For more information about the transmission projects that went into service in 2025, see the following June and October presentations: ISO New England Inc., "*RSP Project List and Asset Condition List*" June,16, 2025 & October 23, 2025, https://www.iso-ne.com/static-assets/documents/100025/final_project_list_presentation_jun_2025.pdf and https://www.iso-ne.com/static-assets/documents/100029/final_project_list_presentation_oct_2025.pdf. These presentations are updated three times per year.

[14] IEP costs decreased because 2025 was the final two months of the winter program (January and February) while 2024 included three total months (January, February and December).

million from 2024, and comprised a small component of total energy costs at 0.4%. First contingency or "economic" payments made up 94% of total NCPC payments, a comparable share to 2024. Real-time uplift payments to resources committed in economic merit order to meet load and reserve requirements continued to drive the majority of NCPC payments.

1.2 Fuel and Emissions Costs

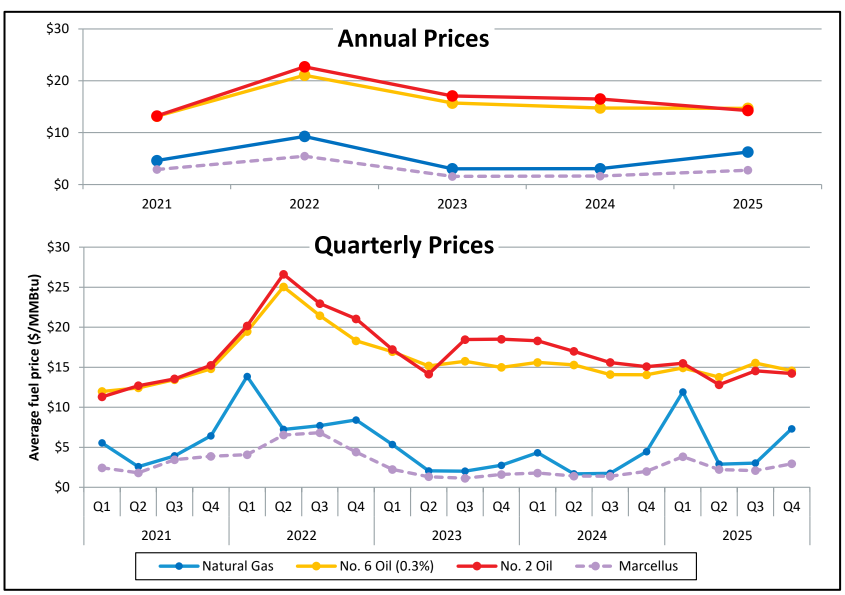
Fuel and emissions costs are major drivers of electricity prices. While oil prices were down year-over-year, both natural gas and CO_2 allowance prices were higher in 2025 than in 2024.

> ***Key Takeaways***
>
> Annual average fuel prices changed significantly from 2024 to 2025. Natural gas prices increased sharply, rising by approximately 105% due to higher demand and colder than normal winter conditions across the Northeast and the broader U.S, while oil prices declined by about 13% due to oversupply conditions.
>
> Carbon allowance prices rose under both the Regional Greenhouse Gas Initiative (RGGI) and Massachusetts Electricity Generator Emissions Limits (EGEL) programs, due to tightening emissions limits and increased demand for allowances. CO_2 emissions costs continue to be a notable driver of energy prices; we estimate that carbon programs contributed approximately $9/MWh to the average annual load-weighted energy price and added about $1.1 billion to total energy costs.

1.3 Fuel Costs

Annual and quarterly trends in fuel prices are shown in Figure 1-2 below.

Figure 1-2: Average Fuel Prices by Quarter and Year



Natural Gas

Annual average gas prices exceeded $6/MMBtu in 2025, a 105% increase from 2024. Price increases were most pronounced during Q1, especially in January and February, due to cold temperatures and a polar vortex. During this period, regional hub natural gas prices, such as Henry Hub and Marcellus, averaged approximately $11/MMBtu, which was higher than typical winter levels and well above the unusually low prices observed in early 2024, when benchmark prices averaged around $4/MMBtu. Although prices decreased as winter conditions eased, monthly average regional hub prices remained above 2024 levels.[15]

In 2025, higher national natural gas basin prices, including at major upstream benchmarks such as Marcellus and Henry Hub, increased baseline fuel costs for New England as colder seasonal conditions raised demand for both space heating and gas-fired generation, contributing to year-over-year price increases across most U.S. trading hubs. In addition, prices in New England increased by a greater margin due to region-specific factors, as the U.S. Energy Information Administration reported that prices at constrained Northeast delivery hubs, such as Algonquin Citygate and Transco Zone 6 New York, increased substantially more than Henry Hub prices, reflecting winter demand sensitivity and limited pipeline capacity relative to national benchmarks.[16]

Oil

Crude oil prices declined in 2025 as global supply exceeded demand.[17] No. 2 oil prices averaged $14/MMBtu in 2025, down 13% from 2024, and No. 6 oil prices averaged $15/MMBtu in 2025 similar to 2024. Oil-fired generation accounted for only a small share of total output in 2025, as lower-cost natural gas generators more frequently set market prices, with oil-fired generators largely dispatched only during cold winter conditions.

1.4 Emissions Costs

New England Carbon Emissions Programs

New England's carbon programs, the Regional Greenhouse Gas Initiative (RGGI) and the Massachusetts Electricity Generator Emission Limits (MA EGEL), are designed to reduce greenhouse gas emissions by directly pricing CO_2 emissions. RGGI creates a unified carbon market across the Northeast, incorporating all New England states as well as Delaware, Maryland, New Jersey, and New York, while MA EGEL imposes additional emissions constraints on Massachusetts

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[15] ISO New England Inc., Internal Market Monitor, "*Fall 2025 Quarterly Markets Report*", https://www.iso-ne.com/static-assets/documents/100032/a04_mc_2026_02_10-11_imm_fall_2025_qmr_presentation.pdf.

[16] U.S. Energy Information Administration (EIA), "*In 2025, U.S. natural gas spot prices increased from 2024's record low*", January 9, 2026, https://www.eia.gov/todayinenergy/detail.php?id=66984.

[17] U.S. Energy Information Administration (EIA), "*Crude oil prices fell in 2025 amid oversupply*," January 5, 2026, https://www.eia.gov/todayinenergy/detail.php?id=66944.

generators.[18,19] These frameworks influence generator operating costs and wholesale electricity prices by making the cost of carbon an integral factor in generation production costs.

At the heart of these programs is the cap-and-trade mechanism in which a limit (or cap) is set on total emissions. The cap is ratcheted down each year in line with carbon reduction goals. Generators must hold permits for each ton of CO_2 they emit. These permits are distributed through competitive auctions, allowing the market to establish a transparent, real-time value for pollution. As fossil fuel-based generators face higher costs under these systems, they are incentivized to invest in cleaner technologies and more efficient operations. In addition, auction revenues are strategically reinvested into initiatives that support environmental initiatives such as energy efficiency, clean and renewable generation, and greenhouse gas abatement and climate change adaptation. Some states also use RGGI funds for direct consumer bill assistance.

Estimation of CO_2 Emission Programs Impact on LMP and Other Market Outcomes

In 2025, carbon allowance prices rose under both the RGGI and MA EGEL programs. RGGI allowance spot prices increased by 6.5% compared to 2024, while the average annual MA EGEL auction clearing price rose 290% year-over-year. Both carbon markets recorded their highest quarterly auction clearing price to date during 2025. In Section 4 below, we describe pricing trends for both carbon programs in more detail and provide estimates of the annual average cost of emissions compliance by generator fuel type.

In this section, we present the results of day-ahead energy market simulations assessing the impact of carbon allowance prices on wholesale energy prices. The simulations, shown over the past 3 years in Table 1-1, indicate that CO_2 compliance programs increased average energy prices by about $9/MWh, consisting of roughly a $7/MWh increase in the LMP and a $2/MWh increase in the FERP. In aggregate, CO_2 programs added just over $1.1 billion to total energy market costs, accounting for about 12% of the approximately $9.9 billion in total energy market costs.[20]

Table 1-1: Impact of Carbon Allowance Prices on Day-Ahead Energy Market Prices

	2023	2024	2025
Energy Price Impact[(a)]	$6/MWh	$8/MWh	$9/MWh
Energy Cost Impact	$690 million	$910 million	$1.1 billion

(a) The 2025 Energy Price Impact includes the Day-Ahead LMP for all months plus the FERP for March to December 2025.

In Figure 1-3 below, we summarize at a high-level the flow of carbon program funds from the auctions to energy initiatives and the impacts on wholesale market costs.[21] In 2025, the total cost

[18] Massachusetts Department of Environmental Protection, "*Electricity Generator Emissions Limits (310 CMR 7.74)*", https://www.mass.gov/guides/electricity-generator-emissions-limits-310-cmr-774.

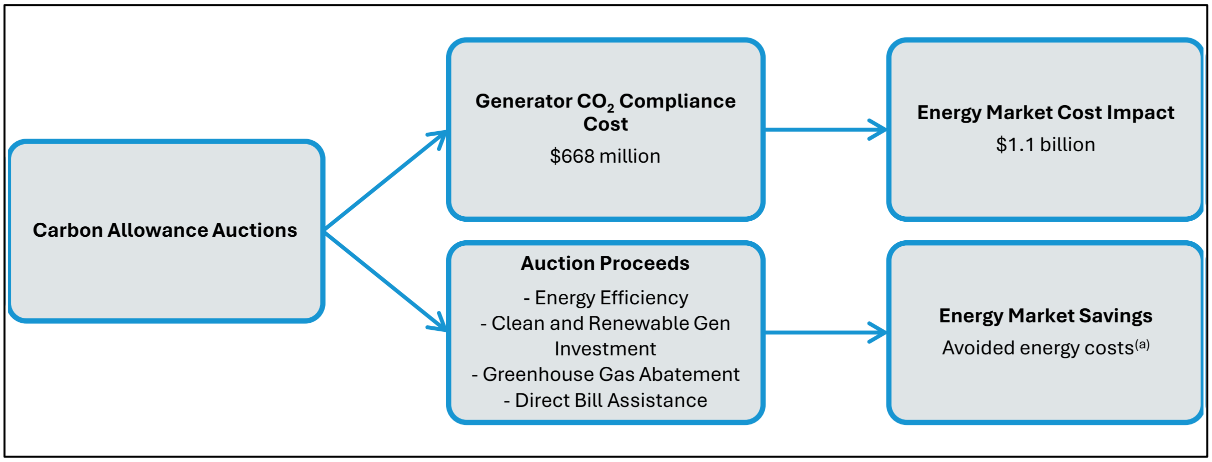
[19] State participation in RGGI has changed over time. In 2025, Pennsylvania withdrew from RGGI, though its participation in the cap-and-trade program had been held up in courts for over three years. Virginia will re-join RGGI in July 2026 after having withdrawn in 2023.

[20] The simulation study compared two cases; the first based on actual supply offers and the second with the daily price of CO_2 emissions for both RGGI and MA EGEL programs subtracted from supply offers.

[21] This high-level conceptual flow chart is provided as a visual aid and is not intended to depict the precise uses of auction proceeds or the full funding mechanisms for energy efficiency (EE) programs, which are typically funded in part through retail electricity charges.

for carbon compliance, based on spot prices for allowances, was about $668 million.[22] The total cost of carbon allowances is lower than the total cost to the energy market because when fossil fuel-fired generators are on the margin, the inclusion of carbon costs raises the market clearing price. This affects all cleared supply, even from those resources that do not require carbon allowances, e.g., renewable generators, nuclear generation and imports.

Figure 1-3: Flow Chart of Carbon Market Impacts



(a) In the 2024 Annual Markets Report we calculated estimated avoided energy costs of $757 million based on ISO-NE's estimate of energy savings from energy efficiency programs. The ISO has changed its methodology for integrating energy efficiency savings into the load forecast. For that reason, we do not present an estimate of avoided energy costs in this report. The reader may refer to the RGGI *Investments of Proceeds* reports for more information on how states allocate their auction proceeds and for estimated impacts of RGGI investments.

While the gross energy market impact is significantly higher than the total cost of compliance for generators, the energy market net cost of these carbon programs is significantly lower because the proceeds from auctioning the allowance credits are invested in initiatives that focus on reducing emissions, such as energy efficiency programs and clean and renewable energy. For example, two-thirds of auction proceeds from RGGI are invested by the New England States in energy efficiency programs.[23] Similarly, most proceeds from MA EGEL auctions are invested in supporting programs or projects to reduce greenhouse gas emissions.[24]

In addition to price impacts, CO_2 costs can also influence dispatch patterns. Our simulation results showed modest changes to the day-ahead generation mix. Without carbon pricing, there is a slight reduction in imports into New England in response to lower energy prices and the simulation showed a slight increase in natural gas generation and oil generation particularly during cold winter periods when natural gas and oil price converge.[25] However, these effects are muted,

[22] The value of emissions is estimated using reported daily emissions data for New England generators for 2025 sourced from the EPA together with daily prices for RGGI and/or MA EGEL from an external vendor. United States Environmental Protection Agency, "*Clean Air Markets Program Data*", https://campd.epa.gov/data.

[23] The Regional Greenhouse Gas Initiative, *"Investments of Proceeds"* reports, https://www.rggi.org/investments/proceeds-investments#:~:text=The%20RGGI%20states%20issue%20CO,strategic%20energy%20and%20consumer%20programs.

[24] Commonwealth of Massachusetts (Mass.gov),*"310 CMR 7.74 Public Hearing Draft to Final Redline, Allowance Auction Procedures (6.h.1.i.)"*, https://www.mass.gov/doc/310-cmr-774-amendments-to-electricity-generator-emissions-limits-0/download

[25] The simulation did not remove CO_2 costs from New York, which also participates in RGGI.

as combined-cycle natural gas-fired generators remain the dominant balancing resource, and production cost differences among these units are relatively small. As a result, carbon pricing tends to result in a parallel shift in the supply curve. This raises prices across the market rather than causing substantial changes to the dispatch order.

1.5 Supply Conditions

Below, we present an overview of New England's generation and capacity mix by fuel type, location, and age. The composition of the system supply portfolio provides context to the relationship between fuel and wholesale prices, as well as emerging operational challenges.

Key Takeaways

Overall: Combined-cycle generators, including dual-fuel units, remained the largest resource type in 2025, accounting for nearly 50% of contracted capacity in the Forward Capacity Market (FCM). Natural gas and nuclear resources together supplied almost 75% of total energy, similar to 2024. Notably, solar and wind generation increased to 8.4% of total energy production, supplying a larger share of energy than net imports.

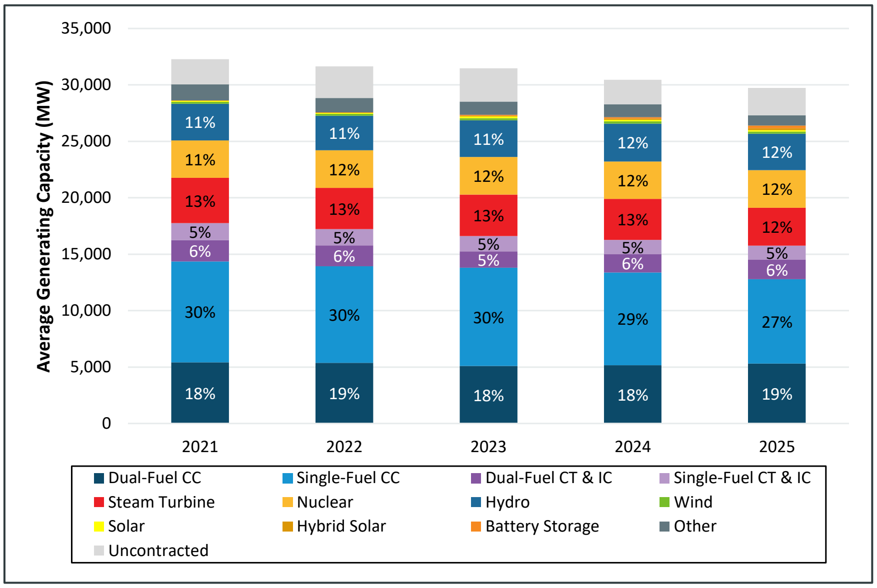
Capacity: Overall capacity composition remained relatively stable in 2025. Combined-cycle resources represented approximately 45% of total contracted capacity (about 12,800 MW), with roughly a 40/60 split between dual-fuel and single-fuel generators. Single-fuel combined-cycle capacity declined by about 700 MW, reflecting the retirement of the Mystic generators in May 2024. Other fossil fuel-fired resources—combustion turbines, internal combustion engines, and steam turbines—retained a 23% share of the capacity mix. Nuclear and hydro resources each accounted for about 12%, while solar, wind, and battery storage together totaled 740 MW, or roughly 3% of total capacity.
About 2,400 MW of generation capacity did not have a capacity supply obligation in the FCM. About 20% of this uncontracted capacity was associated with solar and wind resources, with an additional ~1,500 MW of uncontracted fossil fuel capacity.

Energy: The share of energy produced by natural gas generation and nuclear generation was similar to 2024. In 2024, increased reliance on natural gas generation (at 50%) stemmed from a reduction in net interchange from the Canadian provinces. This decrease persisted in 2025, and was primarily driven by extended dry weather conditions in Canada, which limited hydroelectric generation. The dry weather conditions also led to a decrease in New England hydroelectric generation, which went from 13% in 2023 to 7% in 2025. In 2025, net interchange with Canadian and New York balancing areas combined was at its lowest level in thirteen years (since 2011).

Generation Capacity

Capacity by generator fuel type in Figure 1-4 below shows the breakdown of total capacity contracted in the FCM, as well as capacity without a capacity supply obligation.[26]

Figure 1-4: Average Capacity by Fuel Type[27]



Average contracted generating capacity declined slightly in 2025, as generator retirements exceeded new additions. This continued a five-year downward trend consistent with the decline in the Net Installed Capacity Requirement (Net ICR). Overall, the capacity mix was largely unchanged from 2024, although contracted single-fuel combined-cycle capacity fell by 2% following the retirement of the Mystic Generation Station in FCA 15 (2024/25).

The amount of installed generation capacity without a capacity market position is significant at about 2.4 GW. About 20% of uncontracted capacity is from wind and solar resources that may not assume capacity supply obligations, potentially to avoid pay-for-performance risk, given the variable nature of their fuel. About half of claimed capability is backed by a capacity supply obligation. Fossil fuel-fired units, including combined cycles, CTs and ICs, and steam turbines are 92% backed by capacity supply obligations.

Energy Supply Mix

Energy production by fuel type is shown in Figure 1-5 below. The figure presents average hourly generation by fuel type within the New England control area, along with average net interchange with neighboring control areas.

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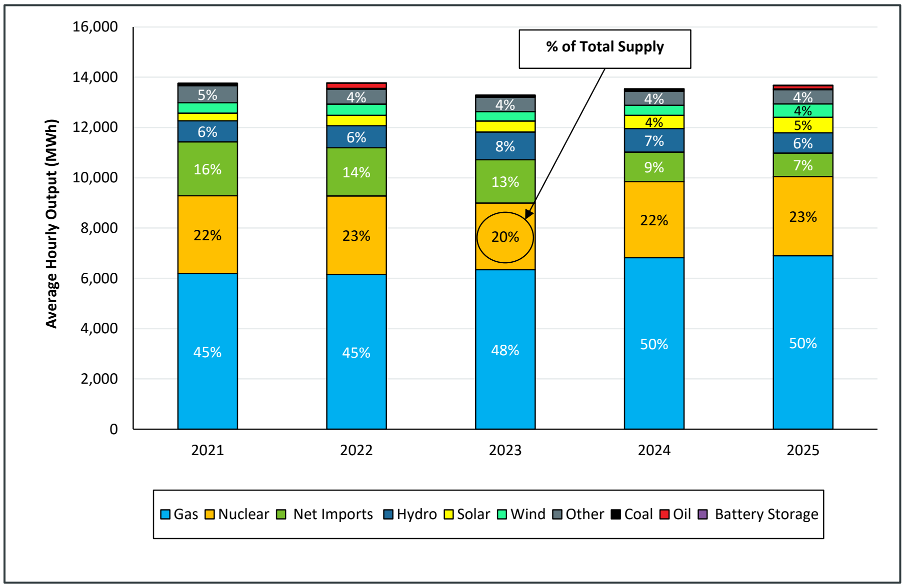
[26] This figure shows generating capacity, which excludes imports and demand response units. We calculate "uncontracted capacity" as the total claimed capability of the generation fleet minus the total contracted capacity of the generation fleet.

[27] The "Other" category includes active capacity demand response, landfill gas, methane, refuse, steam, coal, and wood. Generator Types: CC: Combined Cycle, CT: Combustion Turbine, IC: Internal Combustion

Figure 1-5: Average Output and Share of Electricity Supply by Fuel Type



Natural gas generation accounted for half of all energy supply in 2025, more than twice the next largest fuel type, nuclear. Net imports—historically a key source of baseload energy—continued to decline, supplying just 7% of total energy, the lowest level since 2011 due to reduced imports from Canada.

Solar and wind production exceeded net imports in 2025, reflecting continued growth in renewable generation. State and federal policies have driven additional wholesale (front-of-the-meter) solar and wind energy production, with both accounting for 8.4% of total supply in 2025, an increase from 5.2% in the five-year period (since 2021).[28]

Generation and Consumption by State

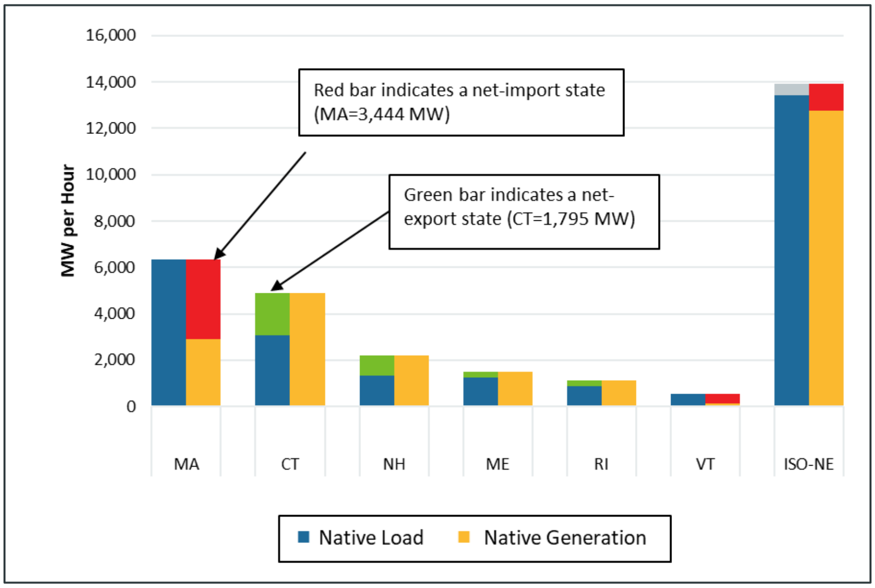
A breakdown of energy production and consumption within each state and aggregated across the ISO-NE market is shown in Figure 1-6 below.[29] Blue bars show state load, while yellow bars show state generation. The red and green bars simply show the difference between production and consumption; the red bars illustrate net imports into each state, and the blue bars net exports out of the state.[30] Systemwide net imports are also shown in red, and system losses are shown in light grey.

[28] Section 4.3 discusses the impact of solar generation on load from both behind- and front-of-the-meter solar.

[29] The state breakdown shows native energy production and consumption within each state; it does not include imports into the state from neighboring jurisdictions.

[30] Net imports in this context are not necessarily from neighboring jurisdictions outside of New England (New York or Canada) but refer to any imports from outside the state.

Figure 1-6: Average Electricity Generation and Load by State[31]



Because of their larger populations, Massachusetts and Connecticut are the largest consumers and producers of electricity in New England, together accounting for about 70% of regional load. Connecticut continues to be a significant net exporter of energy, consistent with recent years. Higher local supply combined with transmission constraints contributed to lower energy prices in Connecticut, where annual average prices were approximately $1/MWh below the Hub price in 2025 (see Section 4.1). Massachusetts, by contrast, remains a significant net importer of energy.

Average native load in New England was relatively static in recent years, indicating that expectations of significant future load growth due to increased electrification of the heating and transportation sectors have not yet materialized as of 2025.[32] New England continues to be a net importer of power, although its reliance on imports fell significantly in 2025, by more than 1,000 MW (a decrease of about two-thirds) in the past two years. This occurred primarily due to lower imports over the Phase II interface (see Section 5 for further discussion).

Capacity Additions and Retirements

The supply mix in New England continues to evolve in response to aging infrastructure, market economics, and state policy objectives. Many existing generators are reaching advanced ages, requiring higher ongoing maintenance and capital investment to remain operational. Fossil fuel-fired generation also faces rising compliance costs as a result of public policies designed to reduce greenhouse gas emissions. In contrast, new resource entry has been driven predominantly by state policy incentives, with solar, wind, and battery storage resources accounting for the vast majority of recent additions to the generation fleet.

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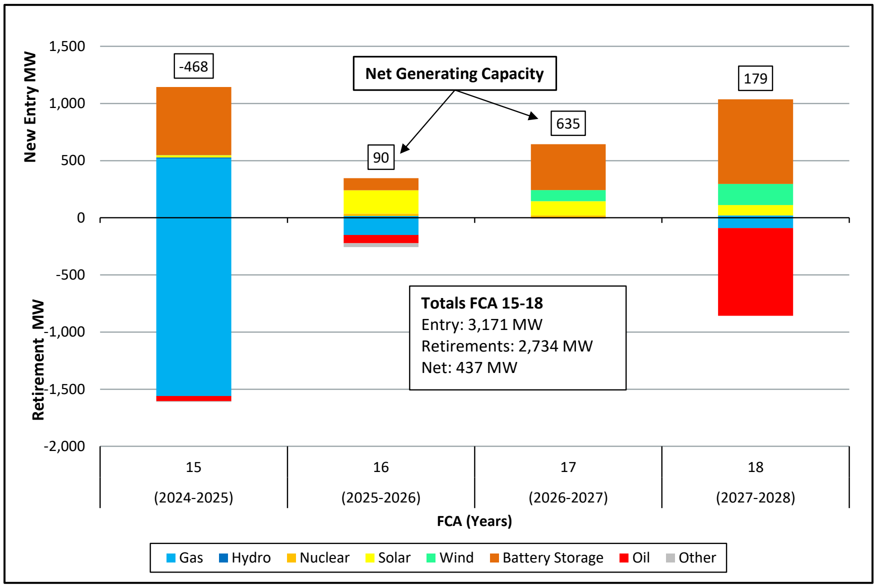
[31] Note: MW values are rounded to the nearest 10 MW.

[32] For more detailed analysis of future grid electrification, see ISO New England Inc., "*2025 CELT report*", May 1, 2025, https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fwww.iso-ne.com%2Fstatic-assets%2Fdocuments%2F100023%2F2025_celt.xlsx&wdOrigin=BROWSELINK.

Generator additions and retirements for the Forward Capacity Auctions for Capacity Commitment Periods 2024-25 (FCA 15) through 2027-28 (FCA 18) are shown in Figure 1-7 below, along with net surplus capacity (new capacity minus retired capacity).[33]

Figure 1-7: Generator Additions and Retirements



On a net basis, generating capacity entered the market from FCA 15-18. Solar, wind, and battery storage comprised the majority (81%) of new generating capacity over this period. While new gas capacity entered the market in FCA 15 following a repowering project, all subsequent additions were overwhelmingly renewable generation and battery resources. Accredited capacity values for battery storage generators are likely to change under the CAR-SA initiative, as marginal accreditation methodology may penalize resources that are limited in duration relative to potential shortages.[34] Therefore, battery storage cleared capacity as a share of nameplate capacity will decrease in future CCPs under CAR-SA.

Relatively old oil- and gas-fired generators comprised the majority of asset retirements. The largest retirements occurred during FCA 15 with the delayed retirement of over 1,400 MW of gas-fired generation at the Mystic station.

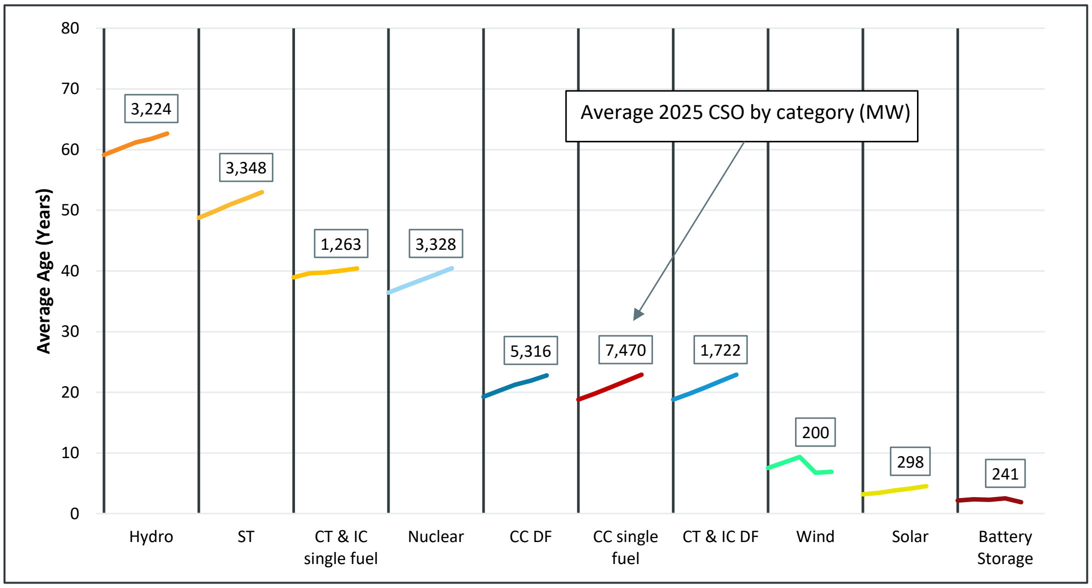
[33] The ISO did not administer a forward auction for CCP 19 in 2025. Capacity auction changes, including the transition to a prompt rather than forward capacity auction, are included in the Capacity Auction Reforms (CAR) key project. ISO New England Inc., "*Capacity Auction Reforms Key Project* " webpage, https://www.iso-ne.com/committees/key-projects/capacity-auction-reforms-key-project.

[34] ISO New England Inc., *"Capacity Auction Reforms: Seasonal/Accreditation, Resource Accreditation Modeling Impact Analysis Follow-up",* April 15, 2026, https://www.iso-ne.com/static-assets/documents/100034/a07.d_mc_rc_2026_04_14-16_carsa_ia_ram.pdf.

Average Age of Generators by Fuel Type

The average age of New England's generation fleet is presented in Figure 1-8, providing insight into how the region's supply mix is changing and how it may evolve over time.

Figure 1-8: Average Age of New England Generator Capacity by Fuel Type (2021 - 2025)[35]



Hydro (average age of 63 years), steam turbines (53 years), and single fuel combustion turbines and internal combustion generators (40 years) comprise about one-third of FCM capacity, and are among the oldest generator types in New England, with virtually no new resource entry in these categories. Steam turbines, in particular, face growing economic pressure to retire due to competition from lower-cost resources, increasing emissions costs, and higher maintenance expenses associated with aging infrastructure and infrequent dispatch. Despite these economic challenges, oil and dual-fuel steam turbines continue to provide important reliability value—especially during winter periods when natural gas generation may be limited by pipeline constraints and renewable output is reduced.[36]

The region's newer supply of generators includes relatively efficient single and dual-fuel combined cycles generators (23 years) and an increasing share of renewable resources.

Renewable, Battery Storage, and Hybrid Capacity

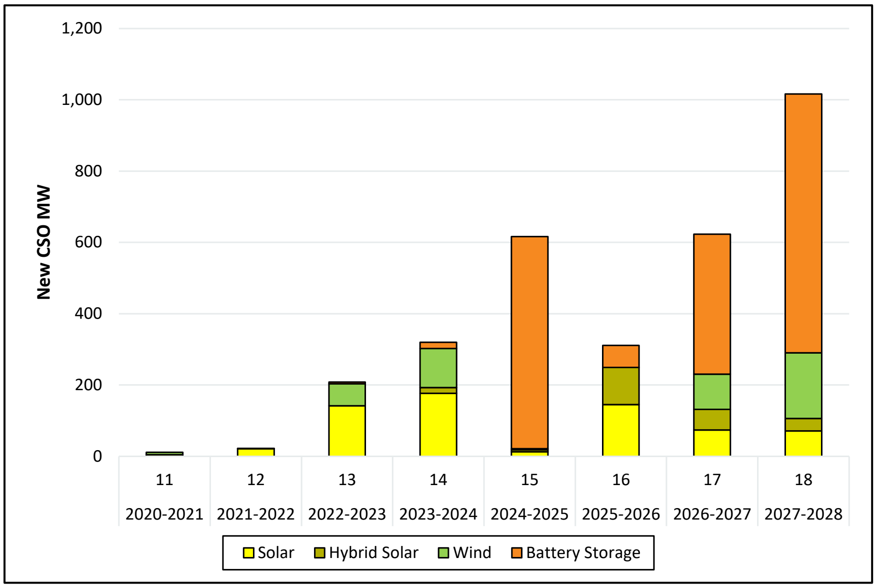
Renewable and battery storage generators are among the most recent additions to the generation fleet, with new capacity anticipated to grow in the coming years. Figure 1-9 below shows new

[35] Age is determined based on the generator's first day of commercial operation. The average values are weighted by the max net output for each generator within the fuel type. If there were no retirements or new generation, we would expect each colored line to increase by one year as generators age. Either an influx of new generators or a retirement of old generators can cause a decline in average age. Data labels above the bars show average total FCM capacity in 2025 by fuel type.

[36] The IMM discusses winter oil utilization in its winter quarterly reports, including the Winter 2025 report. ISO New England Inc., Internal Market Monitor, *"Winter 2025 Quarterly Markets Report"*, June 4 , 2025, https://www.iso-ne.com/static-assets/documents/100024/2025-winter-quarterly-markets-report.pdf.

capacity additions for these technologies by Forward Capacity Auction (FCA) commitment period. Solar facilities are separated into traditional and hybrid storage types.

Figure 1-9: New Renewable Capacity by Commitment Period



Solar, wind, and battery storage capacity accounted for the majority of capacity additions since FCA 15. Most recent wind capacity additions were offshore, with more than 100 MW of new cleared capacity in FCA 17 and FCA 18. Battery storage has also played a significant role, exceeding 500 MW of new capacity in FCA 15 and representing the largest share of new additions in FCA 17 and FCA 18. Hybrid solar resources—which account for over one-quarter of new solar capacity since FCA 15—pair solar generation with storage to shift output into higher-value hours following the solar peak.

As of February 2026, more than 600 MW of battery resources entered service between CCP 15 and CCP 16, and batteries have increasingly contributed to both the system supply mix and the set of marginal (price-setting) resources.[37] Many of these projects are supported by state renewable incentive programs, such as the Massachusetts Clean Peak Energy Portfolio Standard[38], which link compensation to charging and discharging during specified or peak load hours. These incentives were reflected in battery dispatch behavior during 2025.

The interconnection queue continues to be overwhelmingly comprised of wind, solar, and battery storage resources (>99%), including roughly 6,000 MW of offshore wind.[39] As of early 2026, these

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[37] See above in this section for information on the supply mix and see Section 4.2.3 for information on real-time marginal resources.

[38] Commonwealth of Massachusetts (Mass.gov), Department of Energy Resources, "*Clean Peak Energy Portfolio Standard 225 CMR 21.00*", https://www.mass.gov/doc/225-cmr-21-clean-peak-energy-portfolio-standard-cps/download.

[39] ISO New England Inc., "*Resource Mix*" webpage, updated January 28, 2026, https://www.iso-ne.com/about/key-stats/resource-mix.

renewable fuel types comprised the largest shares of capacity likely to complete construction within the next year.[40]

1.6 Demand Conditions

This section covers trends and underlying drivers of historic and anticipated energy demand, including the impact of weather and behind-the-meter solar generation.

Key Takeaways

Average load levels in New England have been stable over the past five years, with a variation of +/- 2% from the five-year average. In 2025, load levels rose slightly (1%), averaging 13,441 MW per hour. Behind-the-meter (BTM) solar continues to contribute to load reductions, with an estimated 711 MW per hour in 2025. Peak load reached 26,586 MW in 2025, exceeding the Capacity Commitment Period 16 (2025/26) peak load forecast of 24,552 MW by approximately 8%.

Historically, actual load growth has tended to fall below forecast, reflecting uncertainty around the pace and timing of electrification. Forthcoming changes under the prompt capacity auction framework are expected to reduce forecast uncertainty by shortening the forecast horizon used to determine the Net Installed Capacity Requirement that anchors the capacity market demand curve.

Wholesale Demand

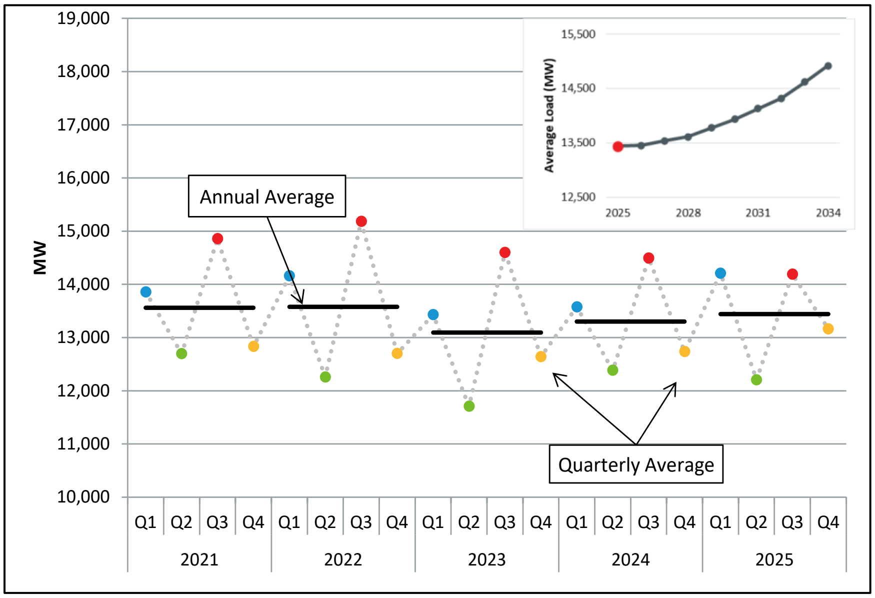
There has been slight year-over-year variation in wholesale demand over the past five years.[41] Average annual load increased from 13,299 MW per hour in 2024 to 13,441 MW in 2025, a 1% increase. Annual and quarterly average loads from 2021 to 2025 are shown in Figure 1-10, along with projected load growth through 2034.[42]

[40] ISO New England Inc., "*System and Market Operations Report - February 2026*", https://www.iso-ne.com/static-assets/documents/100032/system-and-market-ops-report-feb-2026.pdf.

[41] Wholesale electricity demand or Net Energy for Load (NEL) excludes both electricity demand that is met by behind-the-meter generation and asset-related demand for pumped-storage or battery-storage facilities.

[42] To view load forecasts through 2034, see ISO New England Inc., "*2025-2034 Forecast Report of Capacity, Energy, Loads, and Transmission (CELT) report",* May 6, 2025, https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fwww.iso-ne.com%2Fstatic-assets%2Fdocuments%2F100023%2F2025_celt.xlsx&wdOrigin=BROWSELINK. Forecasted annual load in GWh is converted into average hourly MW values. Note that the forecasts shown are net of BTM solar.

Figure 1-10: Average Hourly Load by Quarter and Year



Wholesale load increased modestly in 2025, while Q3 demand declined slightly, consistent with similar average summer weather conditions and the growth in behind-the-meter (BTM) solar. For the first time in this five-year period, Q3 average demand was less than Q1 demand. The decline in Q3 demand relative to Q1 levels is primarily attributable to weather. Summer 2025 experienced relatively mild temperatures, limiting cooling demand and reducing overall load during what are typically peak months.

BTM solar continues to shape net load outcomes, with strong midday production increasingly reducing wholesale demand by 711 MW on an average hourly basis—representing a 14% increase from 2024. As a result, summer loads—historically the highest of the year—have continued a gradual downward trend as expanding BTM resources offset underlying load growth.

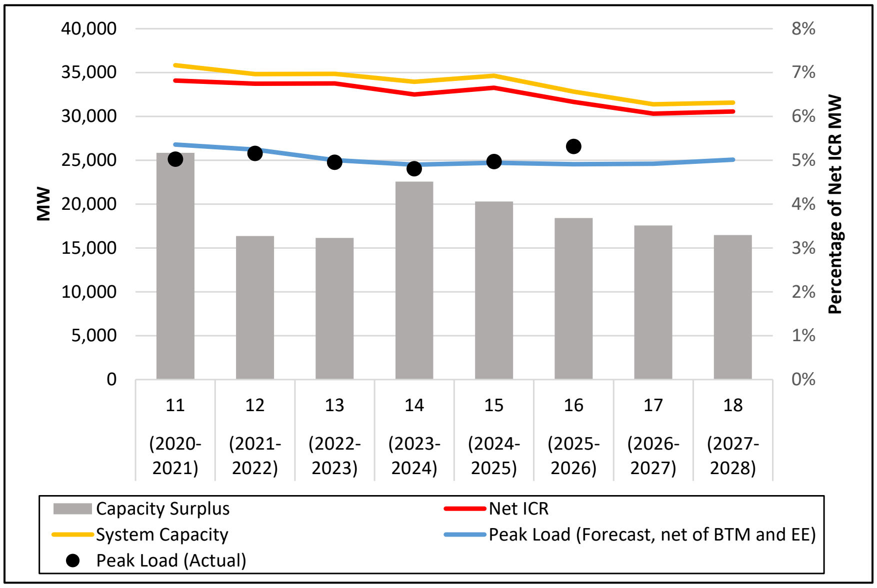
Capacity Market Requirements

The Net Installed Capacity Requirement (Net ICR) is the amount of capacity needed to meet the region's 1-in-10-year reliability standard.[43] The Net ICR value is used to anchor the administrative system demand curve for the FCA and is a significant determinant of auction clearing prices.

Trends in system capacity requirements (Net ICR, peak load forecast) and system capacity procurement (system capacity, capacity surplus) are shown in Figure 1-11 below. The Net ICR, peak load forecast, and system capacity are represented as line series aligned with the left axis. Capacity surplus as a percentage of Net ICR is represented as a bar series aligned with the right axis.

[43] The ICR requirements are designed such that non-interruptible customers can expect to have their load curtailed not more than one day every ten years. When developing the target capacity to be procured in the Forward Capacity Auction (FCA), the ISO utilizes a combination of variables such as anticipated demand of local consumers and anticipated supply from neighboring control areas.

Figure 1-11: NICR, Peak Load Forecast, and Capacity MW for FCA 11-18



Net ICR and peak load forecast have steadily declined since FCA 11 (2020/21). For CCP 16, peak loads exceeded the load forecasts on June 24, 2025, when loads peaked at 26,586 MW relative to a forecast of 24,552 MW.[44] Under the FCM structure, significant load forecasting uncertainty exists within the Net ICR calculation due to the time between the capacity auction and the commitment period. Forthcoming changes under CAR-PD will introduce prompt capacity auctions, which should reduce load forecasting uncertainty in the capacity market.[45]

[44] Note that the 24,552 MW load forecast is net of load met through BTM solar or Energy Efficiency. This allows for a direct comparison between NEL (which excludes BTM and EE) and the load forecast. Note that the Net ICR was set to reflect loads inclusive of Energy Efficiency.

[45] For more information on CAR-PD, see Section 7.1.1.

1.7 Generator Profitability

Wholesale electricity markets coordinate the efficient entry and exit of supply resources through price signals that reflect system reliability needs and compensate resources for the costs of providing system services. The profitability metrics presented here evaluate the financial incentives conveyed by New England markets to two types of decision-makers: prospective investors considering new entry, and current owners assessing whether to remain in the market.

> ***Key Takeaways***
>
> **New Entry:** Market-based revenues in 2025 were sufficient to support new entry for a hypothetical new combined cycle (CC) and a combustion turbine (CT) for the second time in five years. Wind and solar units continued to rely heavily on out-of-market revenues, though elevated energy prices in 2025 reduced wind's dependence on Renewable Energy Certificate (REC) revenues relative to prior years; solar remained predominantly supported by incentives from the Solar Massachusetts Renewable Target (SMART) program.
>
> **Existing Resources:** CC plants have generally earned energy market and ancillary services revenues that exceed their revenues from the capacity market, while simple-cycle peaking units—combustion turbines (CTs) and internal combustion (IC) engines—have relied on the capacity market to a greater extent. Steam turbine (ST) resources have earned very little in the energy market, relying nearly entirely on the capacity market. These observations indicate that some older, less efficient units could face exit decisions if current market conditions persist, especially when faced with large capital and fixed operating expenses.

1.7.1 New Resource Profitability Metrics

In this subsection, we examine whether the revenue available from the ISO-NE wholesale markets and other relevant markets and programs (e.g., Renewable Energy Certificates (REC) markets and the Solar Massachusetts Renewable Target (SMART) program) is sufficient to support the entry of certain types of new generation (gas-fired, solar, wind, and battery resources).

Gas-fired Generators

Here, we present estimates of the net revenues that hypothetical new gas-fired generators (combined cycle (CC) and combustion turbine (CT)) could have earned in the energy and ancillary services markets in each of the previous five years. In addition to providing a basis for the revenue required from the capacity market to build a new generator, the analysis highlights the incremental revenue that could be earned from dual-fuel capability and includes participation in the now-obsolete Forward Reserve Market for CT generators.[46]

The analysis is based on simulations of generator scheduling under an objective that maximizes net revenue while enforcing operational constraints, i.e., ramp rates, minimum run and down

[46] Until the Forward Reserve Market was phased out in March 2025, a participating resource could receive revenue from the Forward Reserve Auction, but it would forego real-time reserve payments and, in most hours where the energy price was within a normal range, also forego energy revenue since it was held in reserve. When the energy price was very high, as in the case of a scarcity event, the forward reserve resource may have been dispatched for energy and would then receive net revenue (above variable cost) for those high-priced periods.

times, and economic limits.[47] The simulation model also includes a Regional Greenhouse Gas Initiative (RGGI) cost for every short ton of CO_2 emitted.[48]

A key update is that the simulations now incorporate the new Day-Ahead Ancillary Services (DA A/S) market; for each resource, the model jointly chooses day-ahead energy schedules and day-ahead ancillary service awards (subject to the market's eligibility and capability rules) and then determines real-time outcomes and settlements consistent with a two-settlement design.[49]

Figure 1-12 shows the result of the simulations. Each stacked bar represents revenue components for a generator type and year. The simulation produces baseline revenue (energy and real-time reserves), DA A/S net credit (DA A/S revenues less realized closeout charges), and incremental dual-fuel revenue numbers for 2021-2025.[50] Note that day-ahead (DA) energy is credited the DA LMP and the FER Price. The FCA revenue numbers shown are calculated using the actual payment rates applied to calendar years. For reference, the most recent Gross Cost of New Entry (Gross CONE) values for CC and CT generators in the Forward Capacity Auction for the 2027-2028 Capacity Commitment Period (FCA 18) are also shown.[51]

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[47] The simulation uses historical market prices, which implies that the generator's dispatch decisions do not have an impact on day-ahead or real-time energy prices. Results should be considered in the high range for potential revenue estimates because this analysis does not account for forced outages (which should be infrequent for a new generator).

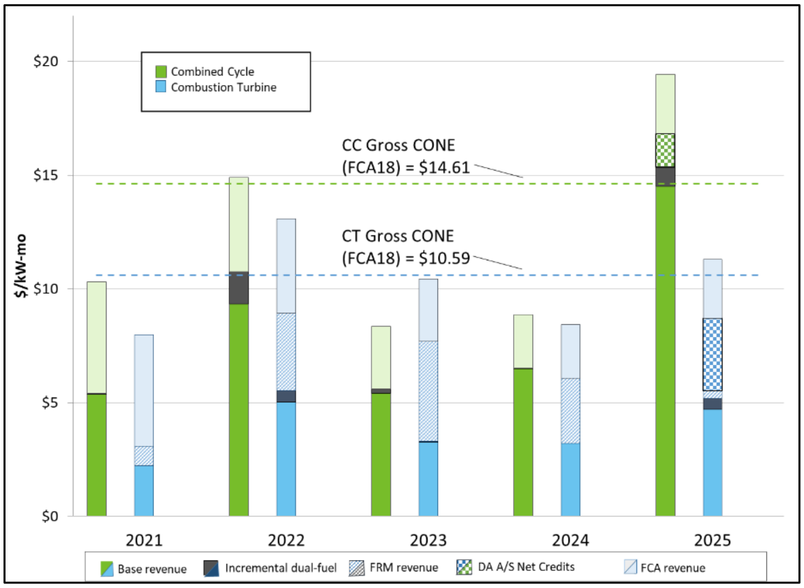
[48] In the model, the RGGI cost for each year is the average auction clearing price for RGGI allowances in that year. The Regional Green House Gas Initiative, "*Allowance Prices and Volumes*" data, https://www.rggi.org/auctions/auction-results/prices-volumes.

[49] Day-ahead decisions internalize expected real-time outcomes using provided expectation series (e.g., expected RTLMP and expected closeout), while real-time dispatch and real-time reserve provisions are based on realized prices; the model is implemented as a rolling-horizon optimization with limited look-ahead rather than perfect foresight. Expected closeout and estimates of the expected "dispatch option value" are computed from ISO-NE's hour-specific Gaussian mixture model (GMM) for RTLMP; these values are precomputed and passed into the optimization as inputs.

[50] Incremental dual-fuel energy revenue is earned by the generator when running on its second fuel type.

[51] The Gross CONE values for the CC and CT gas-fired generators reflect Net CONE values of $10.50/kW-month and $6.33/kW-month with the difference between gross and net figures attributed to net revenue from energy and ancillary service sales. ISO New England Inc., "*2027-2028 CCP Forward Capacity Auction 18 ISO Offer Review Trigger Price*" update, https://www.iso-ne.com/static-assets/documents/2023/03/2027-2028-ccp-forward-capacity-auction-18-iso-offer-review-trigger-price.xlsm.

Figure 1-12: Estimated Net Revenue for New Gas-fired Generators



The remainder of this section discusses estimated base revenues, incremental dual-fuel revenues, and the revenue attributable to the forward sale of ancillary services, before comparing the total estimated revenues to Gross CONE benchmarks.

In 2025, estimated net energy and ancillary services revenues increased substantially for both the CC and CT proxy units, marking the largest year-over-year revenue gains observed in the five-year simulation horizon. Relative to 2024, base revenues (inclusive of the FER credit embedded in day-ahead LMPs) rose by approximately 124% for the CC unit (from $6.49/kW-month to $14.50/kW-month) and by roughly 47% for the CT unit (from $3.19/kW-month to $4.70/kW-month). These increases reflect a marked broad-based rise in day-ahead and real-time energy prices during 2025,[52] with CC units benefitting more from the increase due to their higher utilization and relatively stable day-ahead scheduling pattern.

Consistent with their operational design, CC units remain predominantly day-ahead committed, enabling them to realize the benefits of sustained increases in day-ahead energy prices, including the FER component introduced beginning in 2025. In contrast, CTs continue to rely on real-time dispatch and benefit disproportionately from episodic high-price real-time intervals. Although real-time volatility played a somewhat larger role in 2025, the magnitude and frequency of day-ahead price increases resulted in proportionally larger revenue gains for CC units. As a result, the CC unit's base revenue growth outpaced that of the CT, consistent with the technology-specific revenue patterns observed in prior years.

Incremental revenues from dual-fuel capability remained modest again in 2025. For the CC unit, the dual-fuel adder increased annualized revenues by approximately $0.86/kW-month, while for the CT, dual-fuel capability added $0.48/kW-month. Although both represent slightly larger contributions than in 2024, these values remain small relative to base energy revenues. Lower natural gas prices for much of the year (compared with oil prices) and the scarcity of extended

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[52] See Section 4 for more detail on energy prices.

high-price oil-burning opportunities limited the economic value of dual-fuel capability for both technologies.

Seasonal patterns were pronounced in 2025: CC revenues peaked in winter (totaling $17–19/kW-month depending on dual-fuel capability), while CT revenues were highest in summer (reaching roughly $9.40/kW-month), reflecting the differing seasonal scarcity conditions each technology is positioned to capture. Dual-fuel capability contributed most in winter (particularly for CCs) suggesting that under a seasonal capacity market design, its economic value may concentrate in the winter season.

A major structural change in 2025 was the retirement of the Forward Reserve Market (FRM) in March and the initiation of the new Day-Ahead Ancillary Services (DA A/S) market. As a result, FRM revenues for CTs, which contributed $2.88/kW-month in 2024, were no longer available for most of 2025. Instead, DA A/S net credits contributed $1.47/kW-month to the CC unit and $3.18/kW-month to the CT unit. For CTs, the DA A/S market provided meaningful offsetting value, replacing a significant portion of the former FRM contribution.

Overall, total energy-plus-ancillary services net revenues reached $16.83/kW-month for the CC unit and $8.36/kW-month for the CT unit in 2025. Comparing these simulated market revenues to Gross CONE provides some insight into the "missing money" that such units may seek to recover through the capacity market. While 2025 represented a significantly more profitable year for both technologies in the energy and ancillary services markets, total expected revenues from energy and ancillary services alone (i.e., absent capacity payments) would still fall short of levels required to support new entry for a proxy new gas-fired CT in the region.[53] However, capacity market revenues bring total market revenues above the Gross CONE benchmarks for the second time in the five-year horizon.

Wind and Solar Units

This section evaluates the profitability of wind and solar investments in the ISO New England markets. Renewable energy projects in the region receive significant portions of their overall revenue from state-level programs that exist outside the standard wholesale electricity markets. These "out-of-market" streams, such as Renewable Energy Certificates (RECs) or the Solar Massachusetts Target (SMART) program, offer price supports or production-based incentives that can be critical for a project's financial viability. Out-of-market revenues may also impact an eligible facility's bidding behavior, potentially distorting the energy market price signal. This analysis examines how the interaction between state policies and market conditions affects the profitability of these renewable resources.

In the analysis, we consider two representative units: (1) an onshore wind unit whose generation profile reflects typical wind generators in New England, and (2) a solar unit whose profile matches

[53] Note that CONE benchmarks are produced from financial and engineering studies that estimate the cost of adding green-field generators. In practice, the cost of new entry for a generator may be lower than the current CONE benchmarks for a number of reasons. In particular, when new generating units are built on existing generation sites or when there are material additions to the capacity of an existing operational plant, the presence of existing infrastructure tends to lower fixed costs.

that of solar installations across the region. Both resource types are assumed to offer 53% of their generation into the day-ahead energy market at their short-run marginal costs.[54]

Although solar and wind resources have approximately zero marginal costs, which would imply economic offers at $0/MWh, such resources typically have out-of-market arrangements that provide revenues when they generate energy and thus have an incentive to offer their energy into wholesale markets at negative prices. In our analysis, the wind unit offers into the day-ahead and real-time energy markets at a price equal to the negative of the annual average MA Class I REC price, while the solar unit offers at the negative of the SMART program compensation rate. In both cases, the units clear the energy market whenever the LMP at the Hub exceeds their offers.[55] In our analysis, the units do not provide ancillary services. However, the units earn FCA revenues in proportion to the qualified capacities assumed in recent offer review trigger price (ORTP) analyses.[56] Figure 1-13 summarizes the findings.

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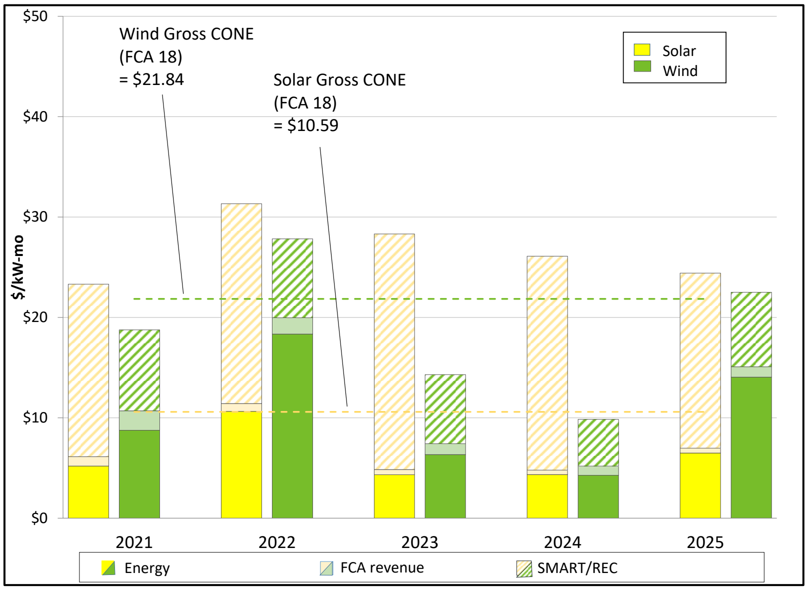
[54] ISO New England Inc., "*ISO-NE Net CONE and ORTP Analysis – An Evaluation of the Net Cost of New Entry and Offer Review Trigger Price Parameters to be Used in the Forward Capacity Auction FCA-16 and Forward*", December 2020, p. 88, https://www.iso-ne.com/static-assets/documents/2020/12/updates_cone_net_cone_cap_perf_pay.pdf

[55] This analysis does not account for revenue streams from Power Purchase Agreements (PPAs), focusing instead on RECs and the SMART program. The SMART program is a Massachusetts tariff-based incentive structure that provides eligible facilities a fixed base compensation rate per MWh of electricity generated. The base compensation rates decline over time through a capacity block structure – as each capacity block (representing a set amount of capacity added to the system) is filled, the base rate for the next block decreases. Under the SMART program, a standalone facility receives a total compensation rate comprised of the base rate plus any applicable adders. When the wholesale price is below this all-in rate, the program makes up the difference so that the facility's effective revenue per MWh is topped up to the all-in rate. If the LMP rises above the all-in rate, the solar facility does not receive a top-up payment and instead earns its revenue entirely from the wholesale market.

To determine the SMART compensation rate for the hypothetical solar unit, we set its characteristics to match the most popular combination of electric distribution company (and corresponding capacity block), unit capacity, and land type among standalone, commercial units that went commercial during the analysis year. For example, in 2025, this corresponds to a building-mounted facility with between 25 kW AC and 250 kW AC in capacity block 8 of Eversource's MA East service territory. Based on these assumptions, the solar unit is eligible for a base compensation rate of $0.19162/kWh, consistent with the eighth capacity block established for Eversource MA East, and a $0.01920/kWh location adder, resulting in a total SMART compensation rate of $0.19164/kWh. Specifically, this total compensation rate is used to "top up" the unit's hourly real-time energy revenues to $191.64/MWh whenever the hourly real-time LMP is less than $191.64/MWh. For each unit of energy generated in real-time in a given year, the wind unit earns the average Massachusetts Class I REC Index price in that year.

[56] Solar and wind units earn 18.9% and 39.3% respectively of the $/kW-month FCA revenue for each kW capacity. ISO New England Inc., "*2027-2028 CCP Forward Capacity Auction 18 ISO Offer Review Trigger Price*" update, 'Assumptions' sheet, https://www.iso-ne.com/static-assets/documents/2023/03/2027-2028-ccp-forward-capacity-auction-18-iso-offer-review-trigger-price.xlsm.

Figure 1-13: Estimated Net Revenue for Solar- and Wind-Powered Units



The profitability of wind and solar units in the region continues to depend heavily on state policy support and out-of-market revenue streams, with both resource types generally relying on additional revenue streams to those in the wholesale markets to be economically viable. Historically (2021-2024), the solar unit would have received the majority of their earnings (typically 75% to 90%) from the SMART program. Wind units showed a similar pattern, with roughly half of their revenues in most years attributable to RECs.

It is important to note that the Gross CONE benchmarks referenced for solar and wind reflect federal incentive assumptions in place at the time those values were developed.[57] Subsequent changes to federal policy have materially reduced the availability and certainty of such incentives for new renewable projects. As a result, these Gross CONE estimates may understate current entry costs for solar and wind resources, which should be considered when assessing profitability and cost recovery under present policy conditions.

In 2025, however, the wind unit experienced a notable shift. Energy revenues increased sharply, more than doubling from 2024. As a result, wind's reliance on out-of-market revenues dropped meaningfully; REC revenues accounted for 33% of total wind profits in 2025, down from 47% in 2024 and well below earlier years.

Even with this shift, out-of-market revenues continue to play a significant role in wind's financial performance, and they remain essential for ensuring full cost recovery. Solar, by contrast, continues to show high dependence on out-of-market revenues in 2025, with SMART revenues making up 71% of solar revenues. While these policies help to meet the region's clean energy targets, their economic impact on wholesale market prices due to their operational and bidding strategies require careful consideration to maintain market efficiency and reliability.[58]

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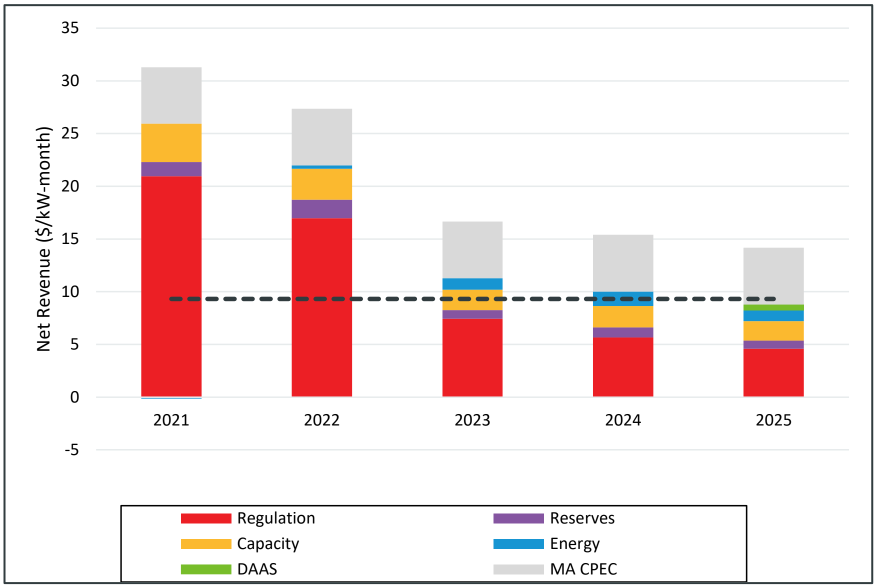
[57] ISO New England Inc., "*2027-2028 CCP Forward Capacity Auction 18 ISO Offer Review Trigger Price* "update, https://www.iso-ne.com/static-assets/documents/2023/03/2027-2028-ccp-forward-capacity-auction-18-iso-offer-review-trigger-price.xlsm.

[58] For example, energy market prices may be distorted, with negative clearing prices prevailing whenever solar or wind units benefiting from these policies are marginal.

Battery Storage

To assess the profitability of a proxy battery unit, we rely on data from ISO settlement records, including day-ahead and real-time energy sales and purchases, ancillary services, NCPC credits and charges, and Pay-for-Performance. Capacity prices are calculated using the FCA clearing price multiplied by the percentage of accredited capacity associated with a CSO. Figure 1-14 shows the different revenue sources available to batteries in the region. [59] The maximum revenue a generator can earn through Massachusetts clean peak energy certificates (CPEC) are also shown, with a grey bar.[60]

Figure 1-14: Net Revenues for Battery Resources



Total net revenues across battery resources peaked in 2021 at nearly $26/kW-month and gradually declined to just under $10/kW-month in 2025. This high-water mark in 2021 was largely driven by substantial revenue from regulation service, which diminished over subsequent years. Although capacity payments declined steadily—from $3.62/kW-month to $1.84/kW-month by 2025, the decline in regulation credits was the primary driver of the falling prices. Energy margins, meanwhile, were initially small or negative in 2021 and 2022, reflecting the cost of charging the battery from the grid; by 2023, these margins became, and have stayed, modestly positive. DA A/S revenues were also a small contributor to battery revenues in 2025. Batteries in Massachusetts benefit from Massachusetts Clean Peak Energy Certificates (CPECs). A battery maximizing credits would have made about $5.38/kW-month in 2025. CPEC credits have strongly shaped battery operating strategies to date, incentivizing dispatch during CPEC hours in ways that can reduce operational flexibility and result in missed price-arbitrage opportunities in non-CPEC hours. We plan to follow up with further analysis on this issue in a future report.

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[59] To preserve confidentiality of participant information, only 2021 through 2025 are shown due to low sample size in 2020.

[60] Massachusetts Department of Energy Resources, Renewable and Alternative Energy Division, "*Clean Peak Energy Standards*" webpage, https://www.mass.gov/clean-peak-energy-standard.

When compared with a gross CONE estimate of $9.31/kW-month, the total net revenues for these batteries (varying from about $8 to $11/kW-month between 2023 and 2025) indicate that market participation remains critical for them to meet or exceed the benchmark. Overall, these findings underscore how essential it is for battery resources to capture multiple revenue streams—especially regulation credits and capacity payments—to secure a viable return in New England's markets.

1.7.2 Existing Resource Profitability Metrics

Over the past five years, combined-cycle (CC) plants have generally earned energy market and ancillary services revenues that exceed their revenues from the capacity market, while simple-cycle peaking units—combustion turbines (CTs) and internal combustion (IC) engines—have been much more reliant on the capacity market. Steam turbine (ST) resources have earned very little in the energy market, relying nearly entirely on the capacity market over the same period.[61] These observations indicate that some older, less efficient units could face exit decisions if current market conditions persist, especially when faced with large capital and fixed operating expenses.

Using ISO settlement data and submitted offer data, we estimated revenues and costs for each resource in the ISO-NE footprint. Specifically, we used day-ahead and real-time energy, reserves, regulation, NCPC credits and charges, DA A/S payments and closeouts, forward reserves, capacity base payment, pay-for-performance (PfP), and inventoried energy program (IEP) revenue data. We estimated generator costs using participant-submitted offers.[62]

Figure 1-15 below shows the net revenues of CTs and ICs per kW-month (of seasonal claimed capability) between 2021 and 2025. Note, to allow for easier visual comparison, the scale for each technology type is fixed from -$2 to +$16/kW-month. Revenues are broken into five categories:

- The first five include energy and ancillary services (including energy, FER payments, regulation, real-time reserves, and NCPC), forward reserves, PFP credits/charges, DA A/S net credits from the sale of reserve and EIR products, and IEP estimates between 2021 and 2025 and are based on actual revenues.
- The sixth category of capacity market base payments is calculated using the capacity auction clearing price, adjusted for the percentage of seasonal claimed capability that has a capacity supply obligation.[63]

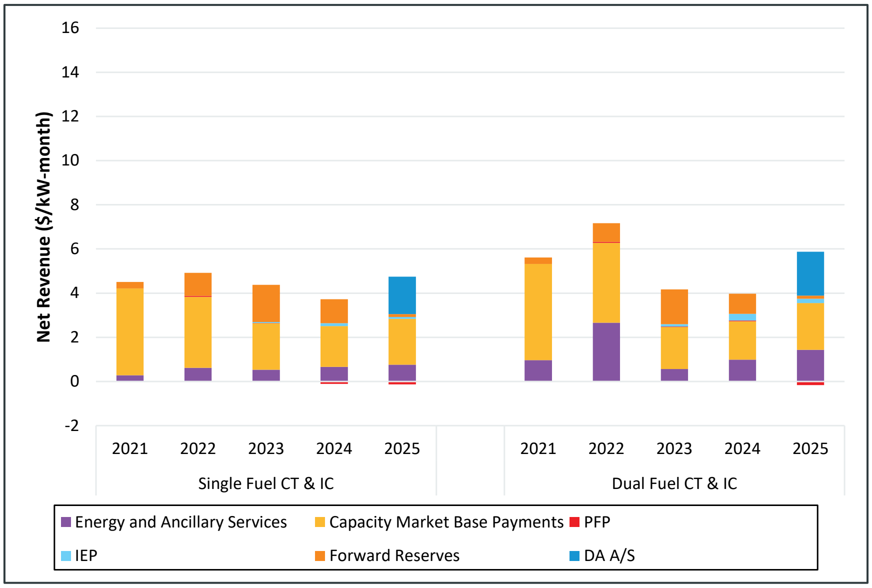
[61] Combined cycle units are typically newer, more efficient, and slower-starting units (the average commercial year of combined cycle units is 1998). Gas turbines and internal combustion generators are combined in the charts below. Gas turbines tend to be newer (average commercial date in 1989), faster (nearly all fast-start capable), and are mostly oil-fired or dual-fuel units. Internal combustion engines are typically oil-fired, older (average commercial date in 1975), and are a mix of fast-start-capable and slower-starting units. Steam turbines are the oldest units, on average (average commercial date in 1967), non-fast-start units that are oil-fired.

[62] About 2% of total asset-year observations were omitted from the analysis due to unique circumstances in which generators' known incentives do not align with a typical generator in each category.

[63] This provides a realistic picture of the capacity revenues a generator in these categories can expect to receive. For example, in 2025 80% of the CT and IC single-fuel asset seasonal claimed capability (SCC) was linked to a capacity supply obligation. The average 2025 FCA clearing price was $2.60/kW-month of CSO, giving a per-kW-month of SCC capacity base payment of $2.07 ($2.60 times 80%).

Note that the IMM does not have going forward cost (GFC) data that is either reliable or that can be published with this analysis. Comparing the net revenues shown below to GFC data would provide an indication of whether the technology type receives sufficient revenues from the wholesale markets to cover its fixed operating and amortized capital costs.

Figure 1-15: Combustion Turbine and Internal Combustion Generator Net Revenues



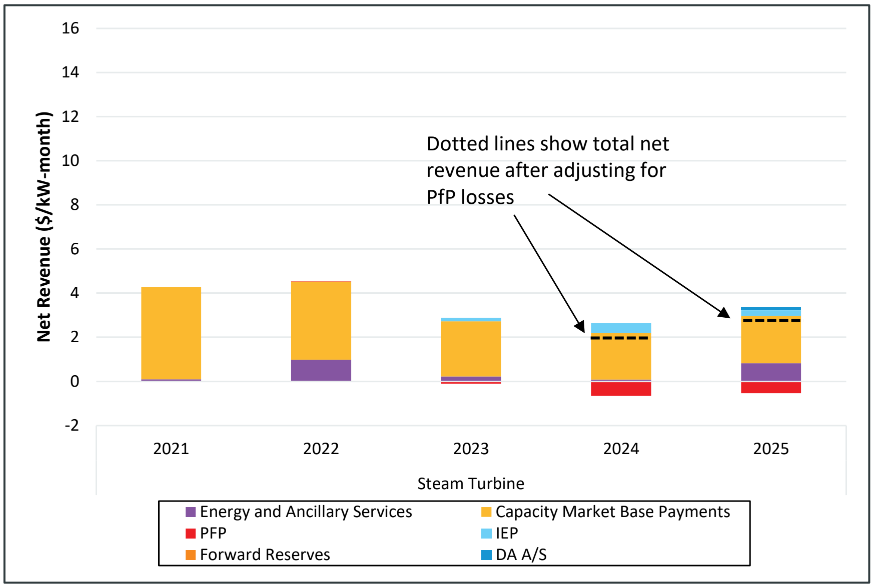
CTs and ICs are fast-start generators with relatively high operating costs and low utilization rates, typically dispatched during peak demand periods. In 2025, net revenues from the energy and ancillary services markets (excluding DA A/S) represented a relatively small share of total net revenues—about 16% for single-fuel and 25% for dual-fuel units.

Nearly 40% of total revenues came from the Forward Reserve Market (FRM) and the Day-Ahead Ancillary Services (DA A/S) market, a share comparable to 2023. CTs and ICs are well positioned to earn DA A/S revenues because they are less frequently dispatched for energy than combined-cycle units and can often provide operating reserves from an offline state.

Capacity market base payments accounted for less than half of total revenues in 2025. The now-expired Inventoried Energy Program (IEP) provided only a modest incremental contribution, accounting for under 5% of revenues.

Figure 1-16 shows the net revenues of steam turbines (STs) per kW-month of seasonal claimed capability between 2021 and 2025, broken into the same categories as the above graph.

Figure 1-16: Steam Turbine Generator Net Revenues

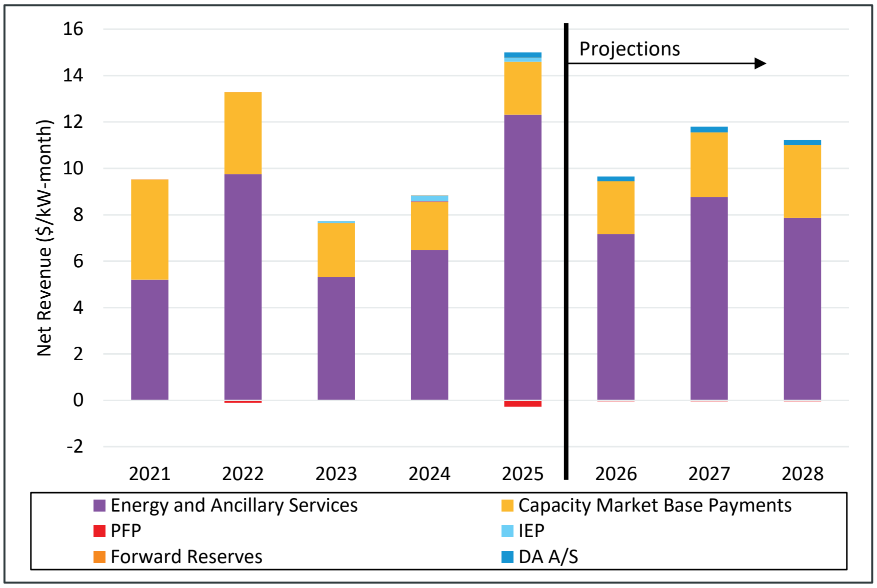


Steam turbines are highly reliant on capacity market base payments (77% in 2025). Pay-for-performance represented a net cost to these resources, reducing capacity payments by 25% in 2025, due to resource economics and long-lead times that prevented them from reacting to unanticipated and transient capacity scarcity conditions. The energy and ancillary services markets provided 29% of the net revenue, while IEP provided 9% of incremental revenues in 2025, as capacity factors rose from 1% to 3% and high gas prices resulted in higher spark spreads.

Figure 1-17 below shows the net revenues of combined cycle units (CCs) per kW-month of seasonal claimed capability between 2021 and 2025. In addition, projected revenues for 2026-2028 are shown based on forward commodity pricing data.[64] Gas and dual-fuel units are not separated in this chart, because dual-fuel capability did not produce incremental revenues in the observed outcomes.

[64] Energy and ancillary revenues are projected by scaling the average historical net revenue by the forward clean spark spread. The clean spark spread is estimated using historic and future on-peak energy prices, AGT gas prices, and RGGI prices sourced from S&P, Bloomberg, and ICE. Forward RGGI prices were only available until 2027, therefore 2027 prices are applied to 2028. The forward projections are not adjusted for the impact of DA A/S on energy and ancillary service numbers given the infancy of that market. FCM base revenues are projected forward using actual FCA cleared prices. PFP revenues are projected by taking the average PFP settlements between 2020 and 2024. The PFP revenues are projected forward using the average PFP revenues from those years, scaled by the increases in the PFP rate ($2,000/MWh from June 2018 until May 2021, $3,500/MWh from June 2021 until May 2024, $5,455/MWh in June 2024 and $9,337/MWh in June 2025).

Figure 1-17: Combined Cycle Generator Net Revenues



Combined cycles generators are relatively efficient with significantly higher utilization rates than the other technologies covered up to this point. About 85% of combined cycle net revenues were from the energy and ancillary services market in 2025, with almost all the remaining revenue (16% on average) earned through capacity market base payments.

Forward prices indicate that clean spark spreads will decrease in 2026 and increase in following years. Specifically, an increase in gas prices together with a smaller increase in energy prices is projected to reduce energy profits. LMP future prices in 2026 and 2027 are higher than in 2025 (7% increase in day-ahead on-peak hub LMPs from 2025 to 2026) but are more than offset by an increase in gas prices (20% increase in gas prices between 2025 and 2026).

Section 2
Markets and the Energy Transition: The Evolving Demand and Supply Landscape

The New England states continue to invest heavily in the power sector as a key strategy for achieving their decarbonization goals, including investments in energy efficiency (EE) measures, storage, and renewable supply at both the wholesale market and retail levels (behind-the-meter generation). Notable growth has occurred in solar generation, and offshore wind and energy storage capacity are also expected to increase significantly in the coming years.

We track the system and market impacts of the clean energy transition through a suite of metrics that reflect anticipated changes in demand patterns, supply flexibility, and price dynamics.

Table 2-1 provides an overview of these metrics presented in this section, the associated expected trends, and the trends observed empirically to date. Many of these anticipated trends have been examined in prior studies including ISO-NE's *Economic Planning for the Clean Energy Transition* and the Analysis Group's *Pathways Study*.[65,66] However, observed impacts to date remain relatively muted, reflecting stable load growth and incremental renewable additions compared to the scale required for deep decarbonization. Nonetheless, the framework below provides a useful baseline for monitoring emerging conditions.

Table 2-1: Trends in System and Market Metrics

Metric	Description of Expected Trend	Trend
Energy Usage	Sustained load growth, with winter energy use and peak demand increasing faster than summer demand.	—
Seasonal/Annual Load Variability	Increasing variability in annual energy needs, driven primarily by winter heating demand and heightened sensitivity to cold weather.	—
Morning and Evening Load Ramps	Steeper morning (down) and evening (up) load ramps as solar generation penetration increases.	▲
Downward Flexibility of Supply	More frequent periods where net load falls below the minimum stable operating levels of conventional generation, with impacts on renewable generation curtailment.	—
Fast-Start Generator Utilization	Greater reliance on fast-start, dispatchable resources to manage steeper and more volatile load ramps.	▲
Load Forecast Error	Increased difficulty forecasting load accurately, with a focus on day-ahead and intra-day timeframes.	—
Negative Energy Prices	Increasing frequency of negative LMPs as renewable generation grows and negative offer prices become more prevalent.	▲
Energy Price Level	Downward pressure on energy prices associated with higher renewable generation levels.	▲

[65] Analysis Group, "*Pathways Study: Evaluation of Pathways to a Future Grid*", April 2022, https://www.analysisgroup.com/Insights/publishing/pathways-study-evaluation-of-pathways-to-a-future-grid/.

[66] ISO New England Inc., *"Economic Planning for the Clean Energy Transition: Illuminating the Challenges of Tomorrow's Grid",* October 24, 2024, https://www.iso-ne.com/static-assets/documents/100016/2024-epcet-report.pdf .

Metric	Description of Expected Trend	Trend
Energy Price Volatility	Price volatility driven by intermittent renewable output and changing net-load conditions remains consistent with prior years.	▬

The trend indicator reflecting our assessment of whether the underlying issue has increased (▲), remained stable (▬), or decreased (▼) in magnitude over time

Key Takeaways

High-Level Changes: The growth in the renewable energy sector has been led by solar at both the retail (behind-the-meter) and wholesale levels. From 2021 to 2025, the contribution of renewables to meeting gross demand increased from 18% to 22%, though the wholesale share was relatively flat with a slight increase from 16% to 18%. Over the same period, residual wholesale load (load net of renewable generation) remained relatively stable; however, a sharp 57% decline in net imports has increased the system's reliance on internal balancing resources.

Load Profiles and Ramps: While the overall impact of additional renewable resources has been relatively small at an annual and seasonal average level, the time-of-day impacts are demonstrably more pronounced. BTM solar generation has significantly altered hourly load profiles, reducing morning wholesale load ramps while steepening evening ramps. Between 2021 and 2025, the evening ramp in residual wholesale load increased from 467 MW per hour to 826 MW per hour. Consistent with these changes, real-time energy prices now tend to rise earlier in the morning, decline during mid-morning hours with increased solar production, and increase sharply during the evening ramp as higher-cost generation is dispatched to meet rising load.

Low Midday Loads: The wholesale demand "duck curve" has become a regular feature of system operations over the past five years. With solar capacity projected to continue expanding over the next decade, associated challenges for market operations and system reliability are expected to intensify. Historically, minimum demand occurred overnight; however, the frequency of minimum residual wholesale load occurring between 8 a.m. and 3 p.m. increased markedly—from 7% of days in 2021 to 51% in 2025.

Load Forecasting: Load uncertainty and forecasting challenges are expected to increase, and ISO-NE has already invested in enhancing short- and long-term forecasting techniques, with continued improvements planned. Despite the growth in BTM solar generation, there has been no discernible deterioration in day-ahead load forecast accuracy. Long-term, ISO-NE projects an 11% increase in average hourly load between 2025 and 2034, largely driven by the electrification of transportation and heating. Summer and winter peak loads are expected to rise by 8% and 24%, respectively, between 2025 and 2034, with additional uncertainty stemming from extreme weather conditions particularly during cold winter periods. Attracting and maintaining sufficient balancing resources to meet expected but infrequent surges in winter demand will be critical.

Downward Supply Flexibility To date, low wholesale load levels are not resulting in over supply conditions or limited downward flexibility of supply during high solar output hours that could result in operators curtailing supply and negative energy prices. Further, with lower wholesale prices tracking lower midday load, we have observed changes in flexible demand (energy storage) shifting consumption from overnight to midday hours, though the aggregate annual impact of these changes remains modest.

Renewable Generation Curtailment: Curtailment levels remained very small in magnitude—accounting for less than 0.1% of total energy supply. Most curtailed energy was driven by localized transmission constraints, with a smaller share occurring during periods of low or negative system prices or due to economic offer behavior in export-constrained areas.

Reliance on fast-start generation: Reliance has increased during the evening ramp as steeper post-solar load ramps require rapid, flexible supply to meet rising demand. Peak evening fast-start output rose from 1,825 MW in 2021 to 1,991 MW in 2025, reflecting more frequent high-magnitude dispatch events. Despite this increase, evening fast-start dispatch remains well below total offered fast-start capacity, indicating that sufficient operational headroom remains available.
By contrast, reliance on fast-start generation during the morning ramp has declined and become more stable over time, as behind-the-meter solar offsets early-day load increases and reduces the need for fast-responding supply during these hours.

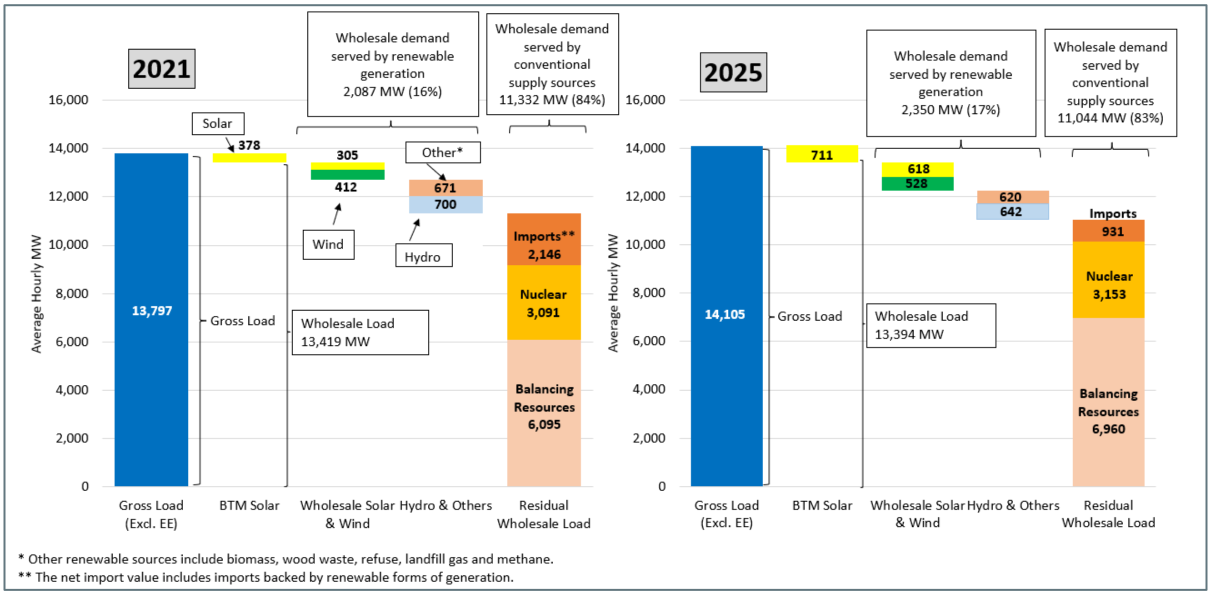
2.1 Trends in Demand and Supply Composition

Figure 2-1 below provides a five-year snapshot of changes in the region's electricity demand and the forms of generation that serve both gross demand (a proxy for retail demand) and wholesale demand. [67, 68]

[67] Demand is weather-normalized to allow for a clearer comparison. Weather-normalized load adjusts observed load for the effects of weather, leap year and non-holiday weekdays.

[68] Behind-the-meter solar production estimates are provided by ISO New England's system planning department. Note that estimated energy efficiency savings are not shown in this year's exhibit since this data is no longer available.

Figure 2-1: A Five-Year Snapshot of Demand and Supply, 2021 vs. 2025



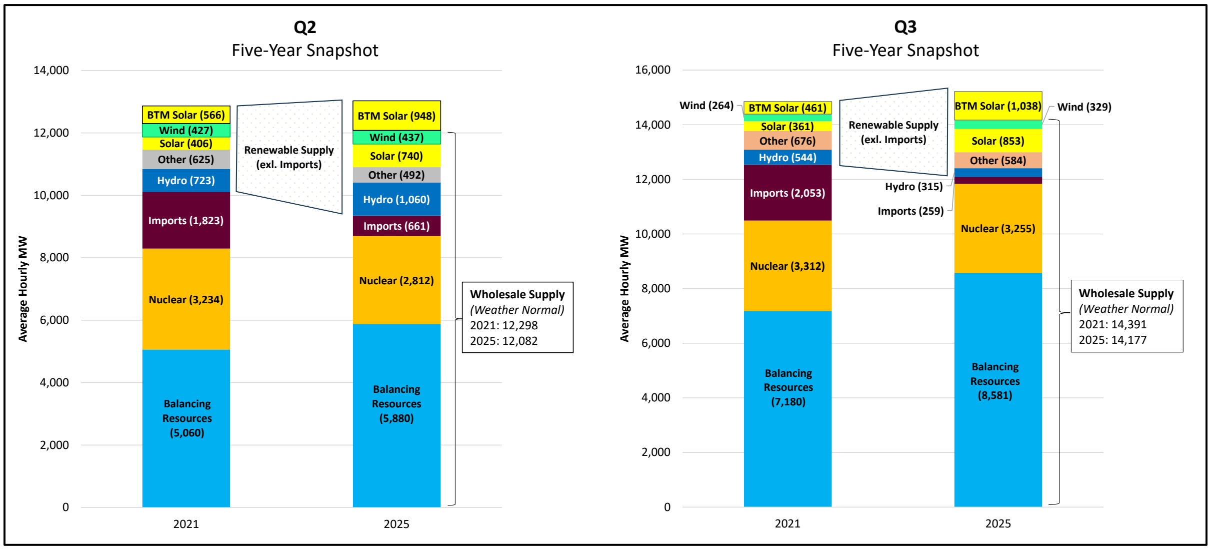
The most significant growth in the renewable energy sector has occurred in solar, at both the retail and wholesale levels. Overall, the contribution of renewables to meeting gross demand increased from 18% to 22%. At the wholesale load level, the share increased from 16% to 18%, as higher solar output offset reduced hydroelectric generation due to drought conditions and a decline in other renewable sources. Looking ahead, the commissioning of major infrastructure projects—including Vineyard Wind I (806 MW), Revolution Wind (704 MW), and the New England Clean Energy Connect (1,200 MW) transmission line—will significantly expand the region's renewable energy portfolio over the coming years.[69]

Finally, demand met by remaining supply technologies—referred to as Residual Wholesale Load—has decreased by 2.5% (or 300 MW) in 2025 with respect to 2021. The composition of supply meeting this residual demand shifted significantly in 2025. Notably, the contribution of net imports declined by approximately 57% in the five-year period, leading to an increase of roughly 870 MW per hour in non-renewable dispatchable generation, referred to as Balancing Resources in the above figure.

In the prior section on demand conditions, we noted that wholesale energy demand in Q3 2025 fell below Q1 levels, in part reflecting the growing influence of BTM solar generation. Figure 2-2 presents the composition of supply using a similar framework to the preceding chart but focuses on a five-year snapshot of Q2 and Q3 outcomes to illustrate the seasonality of supply source contributions.

[69] Values shown are nameplate capacities and are sourced from each project's respective website.

Figure 2-2: Q2 and Q3 Five-Year Snapshot of Demand and Supply, 2021 vs. 2025



Three key trends emerge. First, wholesale energy demand during Q2 and Q3 has declined over time in the five-year period, reflecting the growing impact of behind-the-meter solar. Second, renewable resources, particularly solar generation, have played a growing role in meeting regional energy needs during summer months. Third, the reduction in net imports into the region has increased reliance on dispatchable balancing resources to meet residual demand, highlighting an ongoing shift in how the system is supplied as the resource mix evolves.

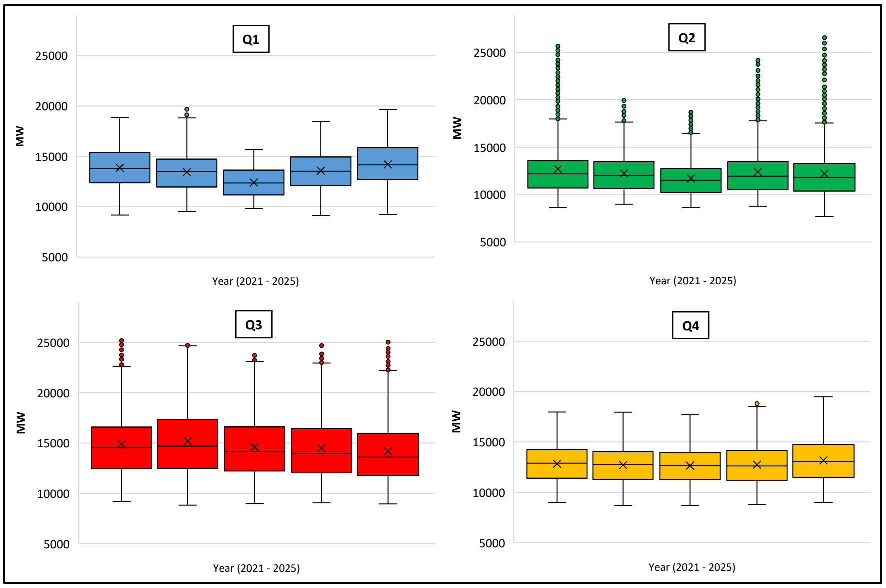
Quarterly Wholesale Loads

Variability in annual average and peak loads is expected to increase significantly in future years particularly driven by heating demand for electricity during the winter and the sensitivity of demand to winter temperatures. Further, with the growth of BTM solar generation, challenging minimum load conditions may occur which could lead to curtailed supply. While current load profiles already show significant day-to-day and intraday variability due to BTM solar output, a clear trend of increased variation at the annual or quarterly level is yet to emerge.

Figure 2-3 below presents a summary of wholesale load distributions by quarter over the past five years. The box plots show several statistical measures of load levels and variability, including minimum, maximum, median, mean, as well as the interquartile range (IQR).[70]

[70] The IQR represents the middle 50% of the data, with 25th percentile and 75th percentile marking the boundaries. The higher the IQR, the larger is the variability of data. Upper whiskers extend from the 75*th* quantile to the highest data point that falls within 1.5 times the IQR. Lower whiskers extend from the 25*th* quantile to the lowest data point that falls within 1.5 times the IQR. The whiskers determine the upper limit of what is considered a “typical” value. This is intended to separate unusually high values from the rest of the data. Data points above that limit are plotted individually (as dots).

Figure 2-3: Quarterly Wholesale Load Distributions



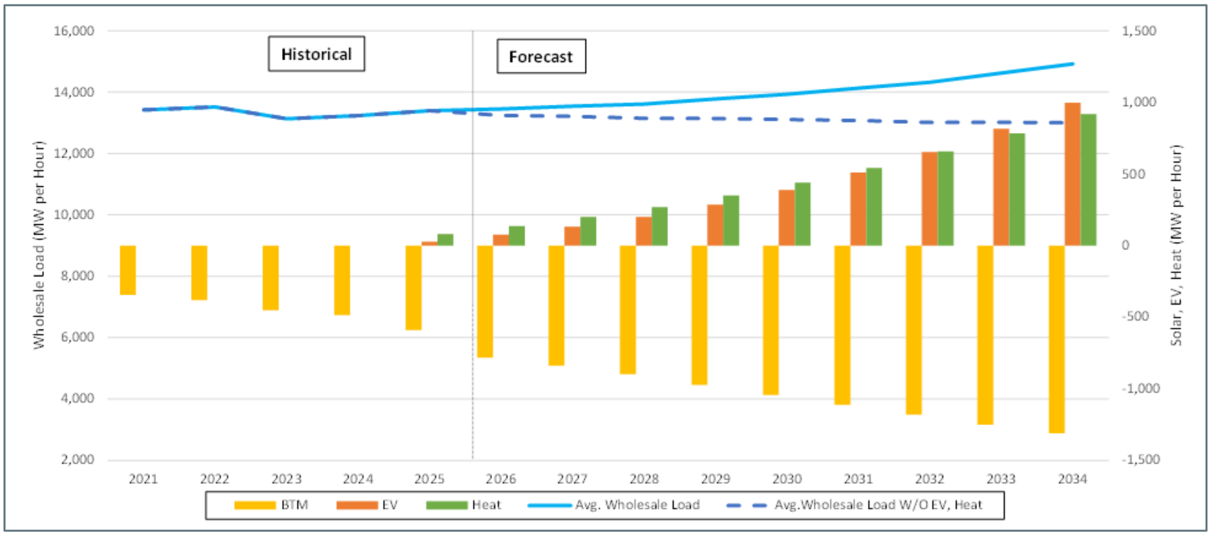
Quarterly load distributions show greater variation in Q3, when summer demand is more sensitive to fluctuations in temperature and humidity. For example, the average interquartile range (IQR) in Q3 was approximately 4,400 MW, compared to about 2,800 MW in Q2 over the same five-year period. Average and peak demand during the colder Q1 months continues to be significantly lower than Q3 levels, a statistic that is expected to reverse in a decade.

2.2 Level and Drivers of Expected Load Growth

The ISO develops peak load and the energy forecast for the ISO-NE Control area every year. Figure 2-4 below shows the historical and 10-year forecast of average annual load, along with the major drivers. [71]

[71] Since this was report was written, the ISO has updated its long-run energy and peaks forecast. The 2026 draft forecast has revised down the forecast of energy and summer & winter peaks. For example, in 2034, the average hourly load is 3.9% lower than the most recent published forecast. Summer and winter peak projections for 2034 are down by 1.3% and 2.5% in the summer and winter respectively

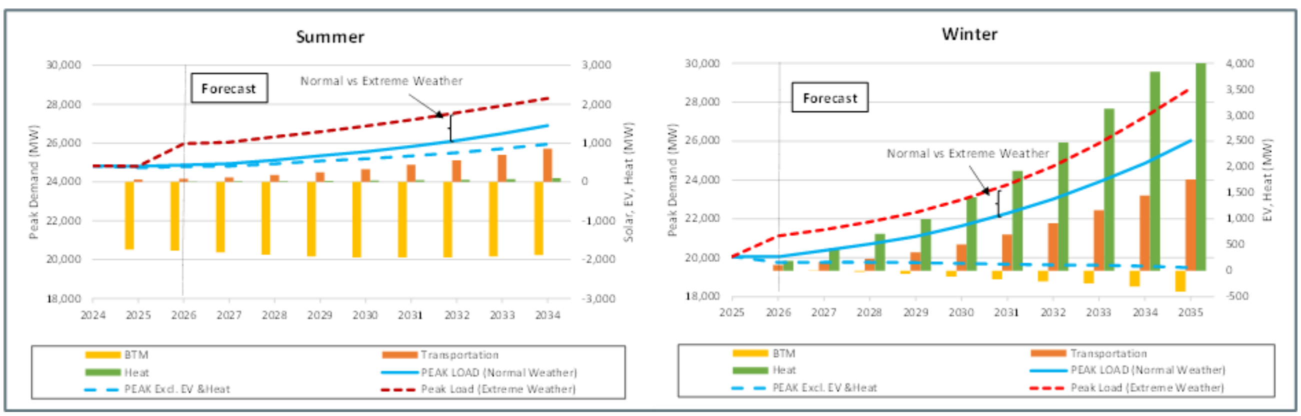
Figure 2-4: Historical and Forecast Average Hourly Load and Major Drivers (BTM solar, EV, and Heat)



ISO-NE projects an increase in average hourly load of 11% between 2025 and 2034, driven by the adoption of electric vehicles as well as extensive electrification of space heating and water heating in the residential and commercial sectors. Transportation and heat electrification are expected to play a pivotal role in the achievement of New England state greenhouse gas (GHG) reduction mandates and goals.

A similar trend is expected for the summer and winter peak loads as shown in Figure 2-5 below.

Figure 2-5: Forecast of Summer and Winter Peaks Under Expected and Extreme Weather Conditions



Summer and winter peak loads are expected to grow between 2025 and 2034 by 8% and ~24%, respectively. Without transportation and heating electrification, the average hourly load, summer, and winter peaks would remain flat or even negative in the case of the winter peak (dotted lines, left axis).

In the summer, the reliability contribution of BTM solar is expected to slow as the marginal impact of reducing the peak will decline as installed capacity grows. In the winter, however, as winter peak time is forecasted to move from evening to morning during the forecast period, the contribution of BTM solar is expected to increase, reducing the winter peak over time. By 2034, the impacts of EV adoption add about 852 MW and 1,450 MW to the summer and winter peak loads, respectively. By

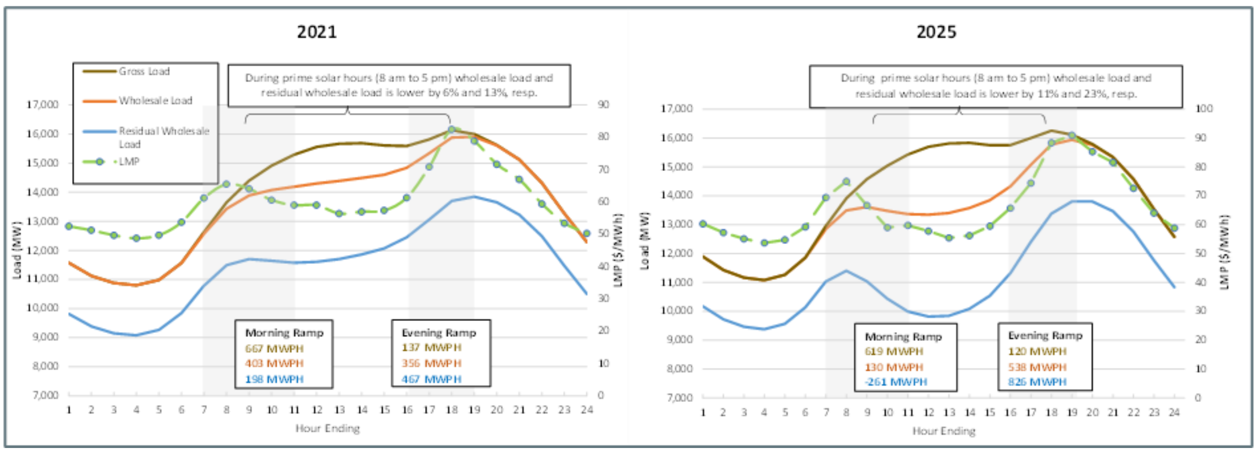
2034, the difference between summer and winter peak loads is expected to shrink from 4,700 MW in 2024 to 1,630 MW. This is because heating electrification will contribute to increasing the winter peak every year, adding up to 3,830 MW of heating load by 2034.

The uncertainty around the expected summer and winter peak load due to extreme hot or cold weather conditions is also captured in the above figure. Summer peak loads under extreme weather conditions are about 1,400 MW higher than the expected peaks. In the summer, the difference between expected and extreme forecast remains close to the average impact during the entire forecast period. However, the impact of extreme weather on winter peaks grows much faster due to the increasing penetration of heat pumps replacing alternative fuels.

2.3 Load and Pricing Profiles

While the overall impact of additional intermittent resources (such as wind and solar) has been relatively small at an annual and seasonal average level, the time-of-day impacts are demonstrably more pronounced. Figure 2-6 below compares the hourly load profiles for 2021 and 2025, with emphasis on the morning (7am to 11am) and evening ramp (4pm to 7pm) periods and the correlation with LMPs.[72]

Figure 2-6: Hourly Real-Time LMP and Demand Profiles, 2021 vs. 2025



There is a substantial change in the hourly load profiles between 2021 and 2025, with BTM solar moderating wholesale load ramps in the morning and increasing evening load ramps. In particular, the impact on morning and evening ramps has grown; for example, the ramp in "residual wholesale load" during the evening hours has increased from an average of 467 MW per hour to 826 MW per hour between 2021 and 2025.

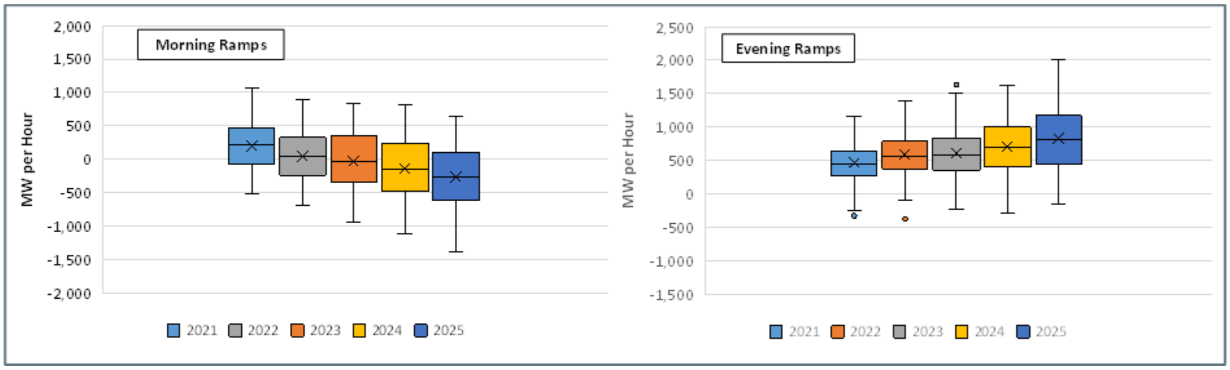
Real-time prices increase early in the morning then dip in mid-morning as solar production increases and consequently load decreases. Energy prices have become higher during the morning

[72] We do not attempt to quantify the impacts on pricing levels here but rather focus on the time-of-day pricing impacts. However, to allow for a more direct comparison between the two bookend years in this report section, we adjusted 2021 prices to account for differences in natural gas prices (with the important caveat that other supply and demand factors also impact energy prices). The hourly average 2021 LMP is adjusted by the ratio of 2025 average natural gas price to the 2021 average gas price.

ramp, and to a greater extent during the steeper evening ramp, when more expensive supply is dispatched to meet load.

Higher penetration of intermittent resources has not only changed average hourly ramps but also their variability and therefore uncertainty about the amount of dispatchable generation needed to meet the residual wholesale load[73] during the morning and evening peaks. Figure 2-7 below shows the daily morning and evening ramps distribution for residual wholesale load between 2021 and 2025.

Figure 2-7: Morning (7am to 11am) and Evening Ramps (4pm to 7pm) Distribution



The interquartile range (IQR) has increased over the period during the evening *upward* ramps, from 375 MW per hour in 2021 to 712 MW per hour in 2025 (or 92% increase) indicating a larger spread in ramp rates in the middle 50% of the distribution. The first and third quartiles (Q1 and Q3) also increased by 69% and 82%, respectively. For example, in 2025, ramps were at least 1,170 MW per hour in 25% of the days; in 2021, that statistic was 643 MW.

The impact of intermittent generation in the morning ramps is increasing *downward* ramping. For example, during half of all days ramps were below *negative* 270 MW per hour (positive 215 MW per hour in 2021) and in 25% of the days, ramps were below *negative* 610 MW per hour in 2025 (but negative 80 MW per hour in 2021). The IQR has increased by 30% from 550 MW per hour (2021) to 712 MW per hour (2025). As the grid transitions to include more intermittent generation, large changes in residual wholesale demand will place a premium on flexible, dispatchable generation.

The wholesale demand “duck curve” has become a common occurrence over the last five years, and with solar capacity projected to double over the next 10 years, it will increasingly present challenges for both markets and system operations. Lower demand in the middle of the day will put downward pressure on real-time prices that could have negative impacts on profitability of dispatchable generation that cannot reduce output. Historically, the lowest demand occurred at night, but there has been a notable increase in the frequency of minimum residual wholesale load occurring later - between 8 am and 3 pm. The frequency has increased from 7% in 2021 to 51% in 2025.

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[73] The portion of load that cannot be met by intermittent generation.

To date, we have not observed over supply conditions or limited downward flexibility of supply during the high solar output hours that could result in operators curtailing supply and negative energy prices. Further, with lower wholesale prices tracking lower midday load, we have observed changes in flexible demand[74] shifting consumption from overnight to midday hours, albeit with a quite moderate load impact on an aggregate load. Low energy prices in the early afternoon hours will create opportunities for the growing amount of energy storage resources to charge in anticipation of higher prices during the evening load ramp, thereby smoothing out wholesale load and price changes.

While impacting the load ramp, solar generation has not increased the frequency with which the system is ramp constrained, and the number of ramp-constrained intervals has remained very low in the past five years.

2.4 Load Forecasting and Operational Uncertainties

As the system evolves to comprise more weather dependent supply (including BTM solar and storage), operational uncertainties and challenges due to unanticipated changes in demand are expected to increase. The ISO's multi-year roadmap and annual workplan has a number of important initiatives geared towards aligning market design and systems/tools with operational and reliability challenges, including:[75]

- short-term probabilistic load forecasting methodologies to account for load uncertainty,
- forward-looking intra-day (real-time) market clearing and multi-interval pricing to position and optimize supply to meet changes in net load and load uncertainty,
- evaluating the system's needs for flexible response capabilities and market products to address greater operational uncertainties.

The IMM strongly supports these initiatives, as they reflect a proactive approach to aligning emerging and future reliability needs with wholesale market tools and products. These efforts are critical for price formation and market efficiency, helping to avoid reliance on manual reliability actions that are neither priced nor visible to the market.

While load uncertainty and forecasting challenges are expected to grow in the future, it is worth examining trends in load forecast error in recent years.[76] To assess this, we reviewed the accuracy of the day-ahead load forecast compared to real-time load and found that there is no discernable deterioration in the accuracy of the load forecast.

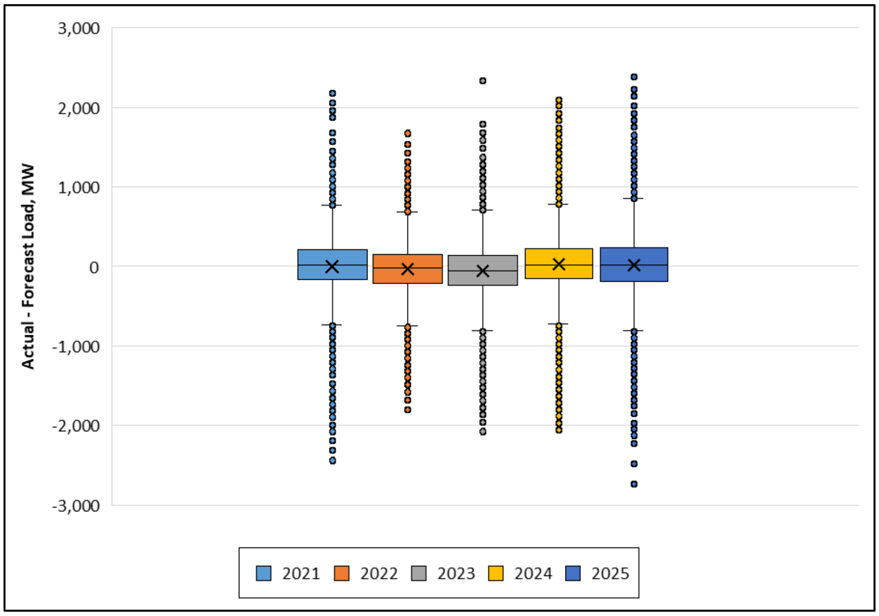
[74] Pumped and battery storage resources.

[75] ISO New England Inc., "*2024 Open Meeting of the ISO New England Board of Director, Multi-Year Roadmap*", November 6, 2024, https://www.iso-ne.com/static-assets/documents/100017/nov-6-2024-iso-bod-open-meeting-master-slides-final.pdf.

[76] In recent years, the ISO has made significant investments to better forecast BTM solar generation. For more information on ISO New England's investment in forecasting behind-the-meter solar generation, see: Energy Systems Integration Group, "*Building data intelligence for short-term load forecasting with behind-the-meter PV*", March 27, 2019, https://www.esig.energy/building-data-intelligence-for-short-term-load-forecasting-with-behind-the-meter-pv/.

The ISO publishes a day-ahead load forecast around 9:30 am as the last load projection prior to the close of the day-ahead market for the next operating day.[77] Since the implementation of Day-Ahead Ancillary Service in March 2025[78], the ISO forecast is a direct input into the day-ahead market through the Forecast Energy Requirement constraint. Its publication also provides transparency into operational planning and is often referenced by participants submitting day-ahead demand bids.[79] Load forecast error historically has a statistically significant impact on day-ahead and real-time price differences. Figure 2-8 below illustrates annual hourly load forecast error with boxplots.[80]

Figure 2-8: Hourly Load Forecast Error



Hourly load forecast error followed a similar distribution in 2025 relative to prior years. Forecast errors remained centered near zero (MW) in both 2024 and 2025, indicating an unbiased forecast on average. In 2025, the middle 50% of errors (IQR) fell between -180 MW to +232 MW. The tails widened in 2025 where hourly errors ranged from about -805 MW to +854 MW, the broadest range in the five-year view. These results show stable typical accuracy with larger extreme deviations in 2025. As discussed in Section 4.4.3, large hourly errors can materially affect price convergence between the day-to-hour operating outcomes.

Forecast error varies by time of day. Morning and evening ramp periods exhibit wider dispersion and fatter tails than the all-hours distribution, reflecting the added uncertainty from behind the

[77] Twice a day, the ISO produces a three-day load forecast that projects load for the current day and the following two days. The first forecast is typically released around 4:30am and the second, and typically final forecast, is published near 9:30am. ISO New England Inc., "*Three-Day System Demand Forecast*" *web*page, https://www.iso-ne.com/markets-operations/system-forecast-status/three-day-system-demand-forecast .

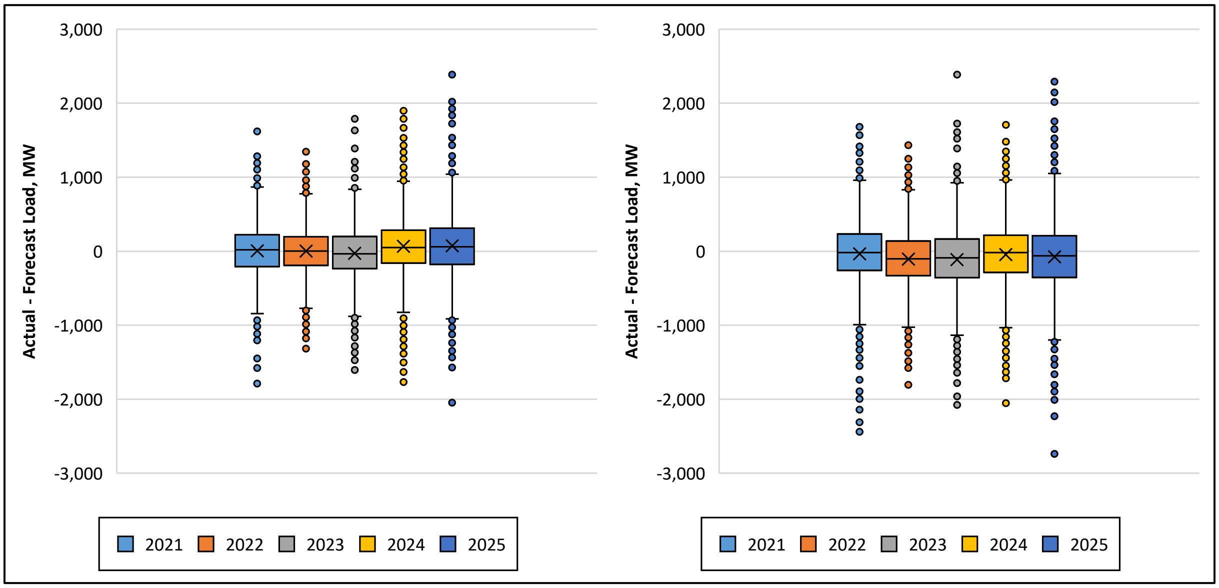
[78] With Day-Ahead Ancillary Services the load forecast is a direct input and constraint that prices and procures sufficient energy for physical supply in the day-ahead market.

[79] Load Serving Entities (LSEs) may also rely on their own in-house or third party forecasting tools to inform their day-ahead bidding strategy.

[80] For this visualization, forecast error is defined as actual load minus forecasted load. Outliers are suppressed in this graph.

meter (BTM) solar during these transitions; morning ramps more often produce negative errors when solar output exceeds expectations, while evening ramps tend to show positive errors as solar production declines. Figure 2-9 illustrates these ramp period distributions.[81]

Figure 2-9: Hourly Load Forecast Error during Morning and Evening Ramp Periods



Hourly load forecast error widens during ramp periods. For instance, in the morning ramp, errors stay close to 0 MW but tend to lean positive, and outliers can reach about 2,000 MW in either direction. In the evening ramp, errors also center near 0 MW but lean negative, with tails extending up to roughly 2,300 MW on the high side and 2,700 MW on the low side. In 2025, both ramp periods showed more variation than in earlier years, with more frequent and more extreme outliers. The negative morning skew reflects higher than expected behind-the-meter solar reducing actual load, while the positive evening skew reflects declining solar output and steeper ramps increasing actual load relative to forecast.

2.5 Negative Pricing and Price Volatility

As renewable generation increases over the coming decade, more frequent periods of negative energy prices—driven by supply-side bidding behavior—and greater price volatility are expected. These changes have implications for price formation and revenue adequacy, with a potential shift in revenue reliance for some resources toward the capacity market.

Because many renewable resources are compensated for their real-time output through prices specified in Power Purchase Agreements (PPAs) and are willing to clear at negative prices, this puts downward pressure on energy clearing prices. The Economic Planning for the Clean Energy

[81] The morning ramp period is defined as 7-11 am, and the evening ramp period is defined as 4-7 pm.

Transition (EPCET) study assessed how extended periods of negative LMPs could impact revenues of baseload resources, which cannot ramp down quickly due to operational constraints.[82]

Negative Prices

The frequency of negative LMPs at the Hub, load zones, and nodes remains very low but increased in 2025. Table 2-2 below presents statistics for 2021-2025.

Table 2-2: Percentage of Five-Minute Intervals with Negative Real-Time Prices

Year	Negative Hub LMPs	Negative Zonal LMPs	Negative Nodal LMPs
2021	0.27%	0.28%	0.42%
2022	0.46%	0.46%	0.56%
2023	0.34%	0.34%	0.39%
2024	0.35%	0.35%	0.40%
2025	0.81%	0.89%	1.19%

Negative real-time Hub LMPs have been infrequent but occurred more than twice as often in 2025 compared to 2024. Despite the increase, negative real-time Hub LMPs occurred at the Hub and load zones in less than 0.9% of hours. For context, the Pathways Study indicated that negative prices might occur in 33% of hours by 2040 under the current energy market construct.[83]

In 2025, negative nodal LMPs occurred in nearly three times as many intervals as in 2024. Negative nodal LMPs occur more frequently due to export-constrained regions where renewable generation sets the clearing price below zero due to out-of-market revenues like PPAs and Renewable Energy Certificates. We expect zonal and nodal negative pricing intervals to increase in 2026 due to the New England Clean Energy Connect transmission line.

In addition to considering the frequency of negative LMPs, we also assessed the duration of negative prices. Negative prices may ultimately be relatively short-lived depending on the extent to which market participants can respond by increasing exports, reducing generation, or charging storage resources—the latter capability is expected to expand significantly in the coming years. Statistics on the duration of negative real-time LMPs are shown in Table 2-3 below.

[82] ISO New England Inc., *"Economic Planning for the Clean Energy Transition: Illuminating the Challenges of Tomorrow's Grid",* October 24, 2024, https://www.iso-ne.com/static-assets/documents/100016/2024-epcet-report.pdf .The report discusses how negative LMPs and low loads could impact baseload resources in the following report sections: 1.6.2 Effect of Deep Decarbonization on Energy Markets, and 1.8.1 Challenging Minimum Load Conditions.

[83] Analysis Group, "*Pathways Study: Evaluation of Pathways to a Future Grid*", April 2022, https://www.analysisgroup.com/Insights/publishing/pathways-study-evaluation-of-pathways-to-a-future-grid/. *See* Table VI-2: Summary Statistics for Energy Market LMPs by Policy Approach, 2040.

Table 2-3: Negative Real-Time Hub LMP Durations, in Minutes

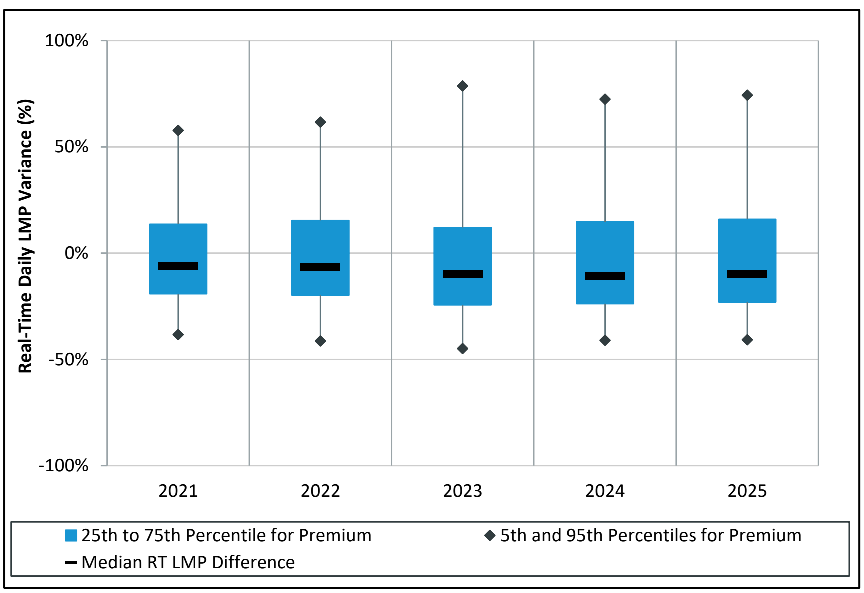
	Mean Duration	Median Duration	Mode Duration	Max Duration
2021	23	15	5	120
2022	24	15	10	190
2023	17	10	10	85
2024	17	10	10	105
2025	25	15	10	240

The median duration of negative real-time Hub LMPs ranged from 10 to 15 minutes over the reporting period, indicating that periods of negative pricing are currently relatively short-lived.

Price Volatility

As renewable generation increases, real-time LMPs are expected to be more volatile. Renewable resources can at times be marginal, setting system prices at or below $0/MWh, particularly during periods of high solar or wind output. The growth of behind-the-meter generation—especially solar—further suppresses net load during daylight hours, often reducing the amount of dispatchable supply available to set marginal prices. As solar output declines in the evening, net load ramps become steeper, requiring rapid responses from a narrower set of fast-ramping resources. These conditions increase the likelihood of sharper price movements and elevated real-time prices during ramping periods, contributing to wider intraday price swings overall. Figure 2-10 below shows the distribution (box plot) of real-time Hub LMPs as a percentage of the daily average Hub LMP.

Figure 2-10: Real-Time LMP Variance



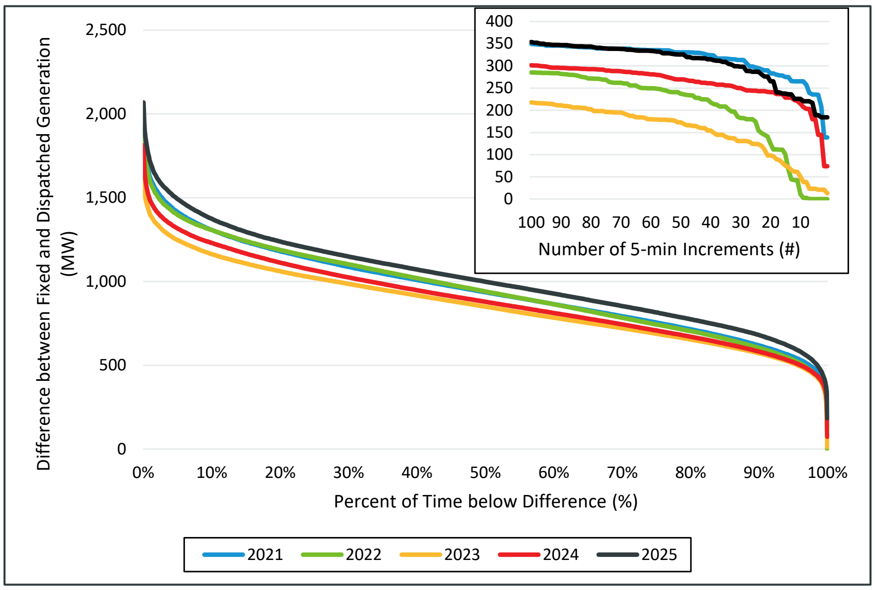
Real-time LMP volatility remained consistent with prior years. Half of all real-time LMPs were 23% lower than or 16% higher than the daily average LMP. As discussed above, negative real-time Hub LMPs occurred at the Hub in less than 1% of real-time intervals and don't influence outcomes shown in Figure 2-10.

2.6 Downward Flexibility of Supply

Minimum generation events, or over supply conditions, occur when fixed (i.e., non-dispatchable) supply is at risk of exceeding load. By 2032, high BTM solar penetration may, under certain scenarios, result in baseload generation levels exceeding wholesale demand, according to ISO-NE's 2024 EPCET study.[84] In such cases, baseload generation—particularly inflexible nuclear units—may exceed wholesale demand, resulting in the curtailment of renewable resources. While some conventional generators may be able to decommit, their long start-up times can limit flexibility and hinder their ability to respond to later increases in load.

Examining the difference between dispatchable and fixed generation on the system in an interval provides an assessment of the risk of over-supply conditions. Figure 2-11 below shows a duration curve of downward flexibility on the system. Fixed generation is defined as generation up to economic minimum output, plus any energy each generator must produce due to ramp constraints.

Figure 2-11: Downward Flexibility of Supply



Between 2021 and 2025, there has not been a significant downward shift in the duration curves, as we would expect if the risk of minimum generation conditions was increasing. The average downward flexibility of supply in the tightest 1% of intervals in 2025 was 428 MW, higher than the average between 2021 and 2024 of 369 MW. Looking at the tightest 100 intervals (inset chart), 2025 was also on the higher side of the past five years. On May 21, 2022, there were 35 minutes in which there was no downward flexibility of supply in the generation fleet and the ISO declared a minimum generation emergency. There have not been any minimum generation emergencies since.

2.7 Renewable Generation Curtailment

At times, renewable resources must be dispatched below their available maximum output (i.e., curtailed) despite having zero or negative marginal costs and sufficient fuel to produce at levels

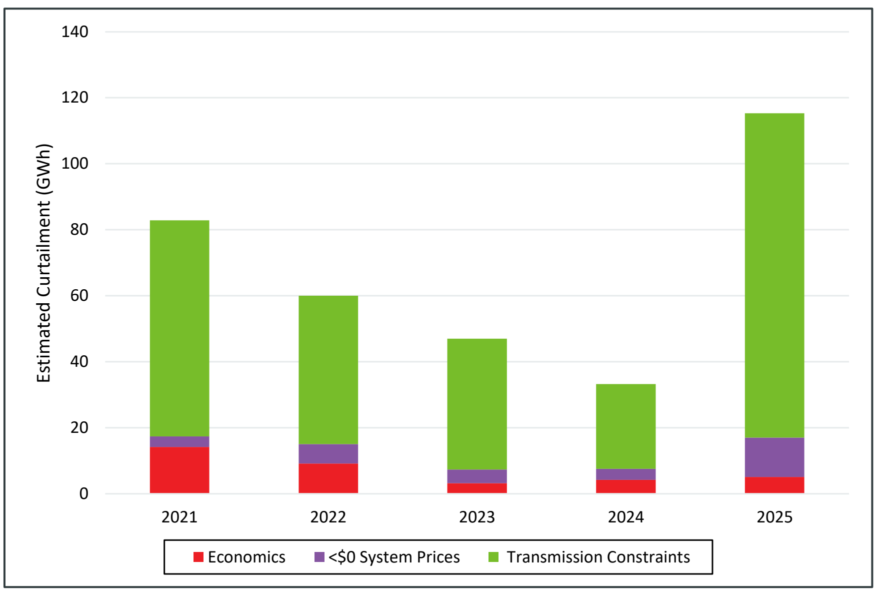
[84] ISO New England Inc., *"Economic Planning for the Clean Energy Transition: Illuminating the Challenges of Tomorrow's Grid",* October 24, 2024, https://www.iso-ne.com/static-assets/documents/100016/2024-epcet-report.pdf.

exceeding their dispatch. Curtailments result in the loss of low-cost energy, which can increase total system production costs and ultimately raise consumer costs. These outcomes also raise important policy questions about the cost-effectiveness of transmission investments and the value of expanding storage capacity to better integrate renewable generation.

Figure 2-12 below shows renewable curtailment between 2021 and 2025, segmented by the reason for curtailment. Only resources qualified for do-not-exceed dispatch are included in the following analysis.[85] The curtailment reasons categorized in the chart are:

- **Transmission Constraints**: includes cases when the system price is >$0/MWh, indicating that $0/MWh marginal cost renewable energy would be utilized by the system if it was available. However, in these cases transmission limitations result in a nodal price <= $0/MWh and a dispatch below the unit's full capability.
- **<$0/MWh System Prices**: includes cases when the system price is <= $0/MWh, indicating that system load is being met using only fixed generation (i.e., generation up-to EcoMin) and low-cost, typically renewable, energy. In these cases, only the lowest-cost renewable energy is produced and some $0/MWh (or even-lower-priced) energy will be curtailed.
- **Economics**: includes cases when the nodal price is >$0/MWh but energy is offered at positive prices and is not dispatched due to economics.[86]

Figure 2-12: Renewable Curtailment by Reason



Curtailment of renewable generation more than tripled between 2024 and 2025 from 34 GWh to 117 GWh. Despite the large increase, curtailment removed low overall; 117 GWh is the equivalent

[85] Do-not-exceed dispatch allows renewable resources to be dispatched below their maximum potential output by the market-clearing software. Wind and hydro resources have been able to participate since 2016, while solar units were required to begin participating in December of 2023. ISO New England Inc., "*Do Not Exceed Dispatch (DNE) Project" web*page, https://www.iso-ne.com/participate/support/participant-readiness-outlook/do-not-exceed-dispatch.

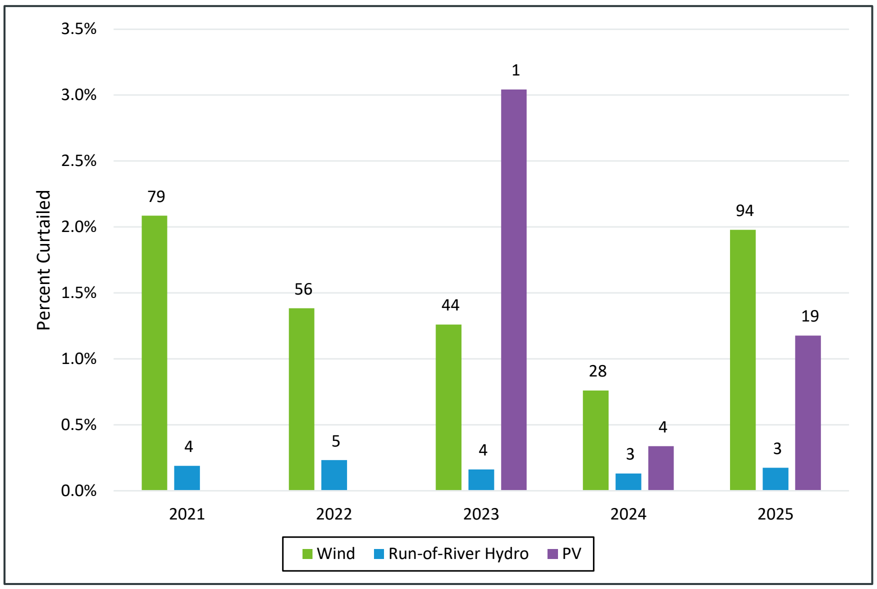
[86] Related to this observation, in the 2022 AMR, we recommended the ISO expand mitigation to export-constrained areas, which would help reduce market-power concerns introduced by renewable generation offering above marginal cost with limited competition in these areas. We continue to recommend the ISO expand mitigation to export-constrained areas, first proposed in the 2022 Annual Markets Report. ISO New England Inc., Internal Market Monitor, "*2022 Annual Markets Report",* June 5, 2025, https://www.iso-ne.com/static-assets/documents/2023/06/2022-annual-markets-report.pdf.

of 13.3 MW per hour or less than 0.1% of total energy supply. Transmission constraints have driven about 79% of the curtailed renewables between 2021-2025. Because renewable resources do not have 100% capacity factors, they may be incentivized to build units that exceed the transfer capability of their locally-constrained area to maximize the average output of the generator when fuel is not 100% available.

About 8% of curtailed renewable energy occurs when the system price falls below $0/MWh, and inexpensive energy from renewables and fixed generation (i.e. generation up-to EcoMin that cannot be backed down) is plentiful. The remaining 13% of curtailed energy was not dispatched despite nodal LMPs exceeding $0/MWh due to offers exceeding the nodal LMP. These offer segments are subject to mitigation and could be addressed with the outstanding IMM recommendation to expand mitigation to export-constrained areas.

Figure 2-13, below, shows the percentage of potential renewable output that was curtailed in each year, by fuel type.[87] Labels show the GWhs that were curtailed.

Figure 2-13: Renewable Curtailment by Fuel Type



Wind drives about 80% of curtailed renewable energy, but as a percentage of total wind capability it is low, only about 2% on average in 2025.

The cost of transmission upgrades necessary to eliminate the current minimal volume of curtailed renewable energy are likely more costly than the potential benefits to the system. However, in the future, batteries may be able to reduce curtailment and allow renewables to produce at higher levels when fuel is abundant and deliver the energy when supply and demand conditions are more favorable.[88]

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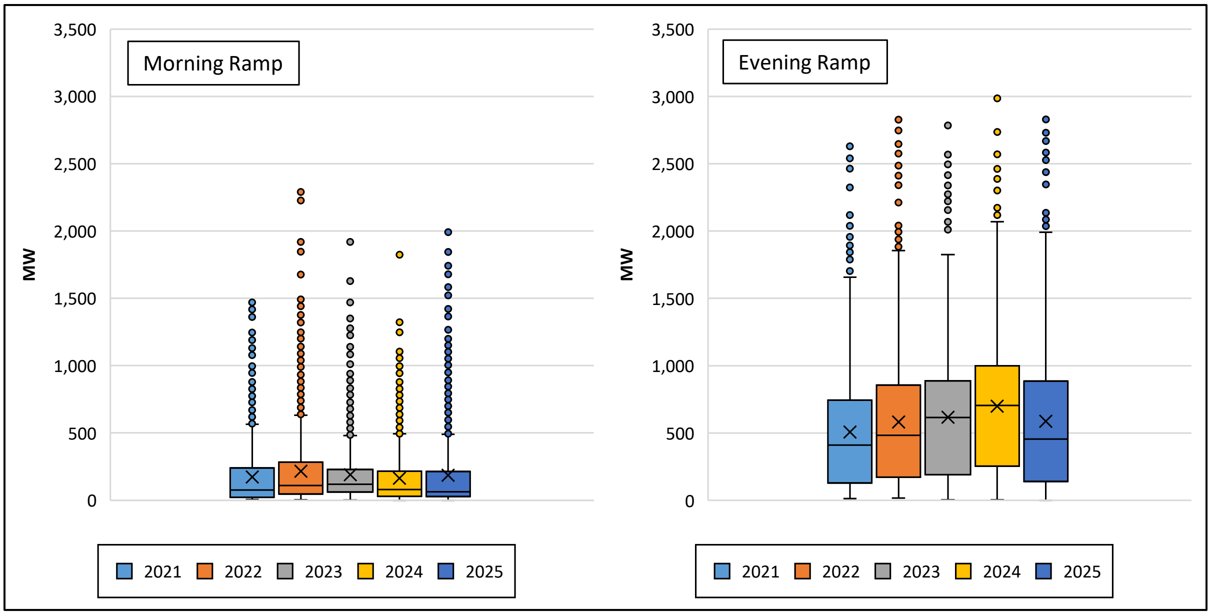
[87] Photovoltaic output in 2023 is omitted due to the December 2023 implementation date of PV DNE rules. 0.8 GWh of PV, or 3% of available PV participating in DNE, was curtailed in December 2023.
[88] The Economic Planning for the Clean Energy Transition (EPCET) study discusses the necessary renewable generation, battery capacity, and transmission build required to reduce, or eliminate, carbon in New England. ISO New England Inc., *"Economic Planning for the Clean Energy Transition: Illuminating the Challenges of Tomorrow's Grid",* October 24, 2024, https://www.iso-ne.com/static-assets/documents/100016/2024-epcet-report.pdf.

2.8 Reliance on Existing Fast-Start Generation is Increasing during Evening Ramps

Fast-start units provide operational flexibility, which may be relied upon during ramping periods. Figure 2-14 shows the distribution of hourly fast-start generation during morning and evening ramp periods.

Figure 2-14: Fast-Start Generation during Morning and Evening Ramp Periods



Fast-start generation plays a more significant role in the steep evening ramp period than in the morning ramp period. Fast-start generation during the morning ramp (7 am–11 am) declined over 2021–2025, with the median and upper range lower and the distribution narrower in 2025, indicating reduced reliance to manage early day load increases. By contrast, fast-start generation during evening ramps (4 pm–7 pm) increased over time, with higher levels and a higher operating floor than in 2021. Peak evening ramp fast-start generation reached approximately 1,991MW in 2025 (up from 1,825 MW in 2021), reflecting more frequent high magnitude dispatch events. While evening fast-start generation has increased, surplus fast-start capability remains available, as evening ramp generation levels in 2025 continued to remain below total offered fast-start capacity, providing headroom to meet growing ramps.[89]

[89] Fast-start offered capacity is calculated as the sum of hourly offered economic maximum limits from units that are both fast-start capable and fast-start qualified.

Section 3
Market Structure and Competitiveness Assessment

In this section, we assess the level of competition in the wholesale electricity markets. Competition ensures that the prices consumers pay and that producers receive are the result of competitive forces, and are not unduly influenced by market power. If electricity markets are unable to achieve competitive outcomes due to the potential exercise of market power, mitigation controls are necessary. The IMM performs reviews across various ISO electricity markets to identify these situations and limits their impact through the market power mitigation process and through its monitoring and investigation functions.

The section is structured as follows:

- Energy Market (3.1) followed by energy market mitigation (3.2),
- Ancillary Services Markets (3.3), and
- Financial Transmission Rights (3.4).

In prior years, the IMM has made a number of market design recommendations pertaining to aspects of the market power mitigation framework, including recommendations to review mitigation thresholds in the energy market. The IMM continues to believe that a focused assessment of the mitigation rules is valuable to ensure that these rules provide appropriate safeguards against the exercise of market power while supporting efficient market outcomes.

The Forward Capacity Market is currently undergoing a significant reform process, and no Forward Capacity Auction has been held since FCA 18 (held in 2024). Because there has not been a capacity auction since then, this report does not include an assessment of capacity market competitiveness. An evaluation of auction competitiveness will be included following the completion of the reform effort and the resumption of capacity auctions.[90]

3.1 Energy Market Competitiveness

A number of complementary metrics—intended to be viewed jointly rather than as standalone indicators—are utilized to assess the structure and competitiveness of the energy markets; specifically:

- high-level market concentration measures for supply (3.1.1) and demand (3.1.2) in the real-time market,
- supply-side structural market power tests in the day-ahead and real-time markets (3.1.3): pivotal supplier test (PST) and the residual supply index (RSI),
- supply offer cost mark-up metrics in the day-ahead and real-time markets (3.1.4), and
- the level of capacity economically withheld in the real-time market (3.1.5).

[90] The IMM's 2023 Annual Markets Report provides an assessment of the competitiveness of prior Forward Capacity Auctions. ISO New England Inc., Internal Market Monitor, "*2023 Annual Markets Report*", May 24, 2024, https://www.iso-ne.com/static-assets/documents/100011/2023-annual-markets-report.pdf.

Key Takeaways

Market outcomes were competitive overall, and the exercise of market power was generally not a concern.

Price Cost Mark-Up: Although price-cost markup metrics in both the day-ahead and real-time markets were higher than in previous years, they remained well below the tightest mitigation threshold of 10%. These results indicate that competition among suppliers effectively limited the ability to inflate LMPs by submitting offers above marginal cost.

Market Concentration: The share controlled by the largest four firms (the "C4" metric) remained consistent with the past five years; approximately 42% on the supply side and 55% on the demand side in the real-time market, with no single firm highly dominant.

Pivotal Suppliers: The frequency of pivotal suppliers was relatively low in the day-ahead market, occurring in ~ 4% of hours. In the real-time market, pivotal suppliers were present in 33% of hours, which was similar to 2024. Over the last five years, the number of pivotal suppliers has increased in both markets due to the decrease in net interchange and an increased reliance on native generation.

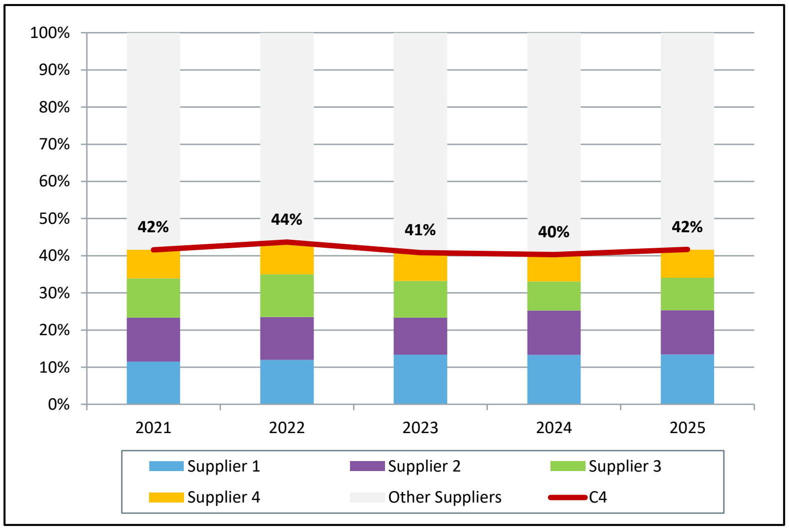
Economic Withholding: We estimate that only 1.3% of capacity was economically withheld in the real-time market on average in 2025. This level of economically withheld capacity was in line with recent years, which had ranged from an average of 1.1% to 1.3%. Levels of economic withholding did not increase when reserve margins were low, suggesting that suppliers did not attempt or did not face incentives to withhold during periods of tight system conditions.

3.1.1 C4 Concentration Ratio for Generation

Supplier market concentration among the largest firms controlling generation and scheduled import transactions is commonly measured by the "C4" index, which represents the combined market share of the four largest firms. This metric is useful for tracking trends in supply concentration over time, as companies enter, exit, or consolidate their positions in the New England market. As shown in Figure 3-1 below, the C4 values in the real-time energy market remained within a narrow range and increased slightly during on-peak hours in 2025.[91]

[91] The C4 is the simple sum of the percentages of system-wide market supply provided by the four largest firms in on-peak hours, which are the hours are from hour-ending (HE) 8 to HE 23 on non-holiday weekdays, and accounts for affiliate relationships among suppliers. The C4 analyses for both supply and demand do not account for market participants with both load and generation positions. These firms generally have less incentive to exercise market power. Any spot market actions that would tend to raise prices to benefit their generation would come at a cost to their load position. Any actions that would suppress prices to benefit their load would come at a cost to their generation position.

Figure 3-1: Real-time System-wide Supply Shares of the Four Largest Firms



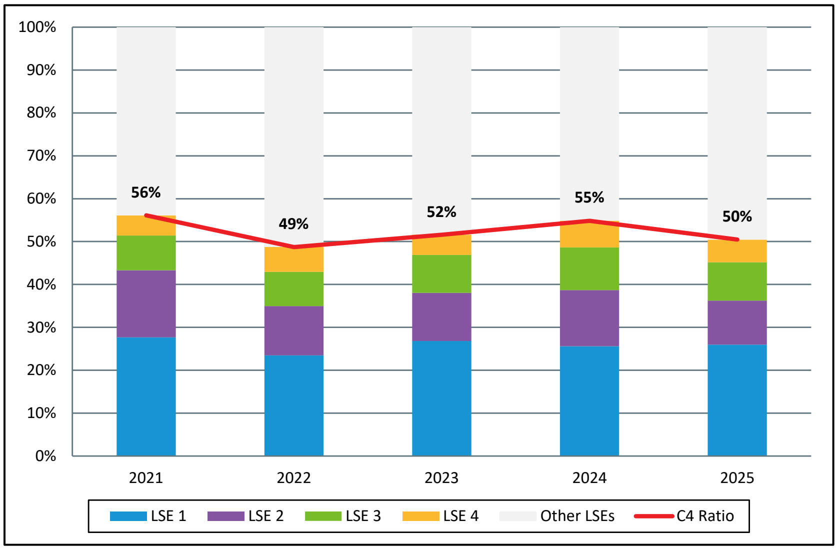
The metric is indicative of low levels of system-wide market concentration, particularly because the market shares are not highly concentrated in any one company. In 2025, 42% of energy supply came from the four largest suppliers, with supply shares relatively evenly distributed among the four largest firms.

3.1.2 C4 Concentration Ratio for Load

The C4 index for load measures market concentration among the four largest load-serving entities (LSEs) in the real-time energy market, as illustrated in Figure 3-2.[92]

[92] The C4 load metric accounts for affiliations among different LSEs and includes on-peak hours only. The metric uses Real-time load obligation (RTLO) to measure load. RTLO is measured as all end-use wholesale load in the ISO New England region, along with all exports. The difference between RTLO and real-time generation obligation represents energy losses.

Figure 3-2: Real-time System-wide Demand Shares of the Four Largest Firms[93]



In 2025, the top four load-serving entities purchased 50% of the total real-time load position in the New England day-ahead market, down from 55% in 2024. There is no evidence to suggest that LSEs exhibited energy market bidding behavior consistent with the exercise of buyer-side market power (deflating price). On average, over 100% of demand cleared in the day-ahead market, and the aggregate demand curve remained relatively price-insensitive around expected LMPs (see Section 4.3.2 on demand bidding).

3.1.3 Residual Supply Index and the Pivotal Supplier Test

The pivotal supplier test (PST)[94] and the residual supply index (RSI)[95] are two widely-used structural market tests that provide an indication of opportunities for participants to exercise market power.

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[93] The firms labeled "LSE 1", "LSE 2" and so on are not necessarily the same LSE across all years; these are generic labels for the top four firms during a given year.

[94] Pivotal suppliers are identified for every five-minute pricing interval by comparing the real-time supply margin to the sum of each participant's total supply that is available within 30 minutes. When a participant's available supply exceeds the supply margin, they are considered pivotal. The number of five-minute intervals with at least one pivotal supplier are divided by the total number of five-minute intervals in each year to obtain the percentage of intervals with pivotal suppliers.

[95] The RSI represents the amount of demand that the system can satisfy without the largest supplier's available energy and reserves. If the value is less than 100, the largest supplier is needed to meet demand and could potentially exercise market power (if permitted). Further, if the RSI is less than 100, there is at least one pivotal supplier. Conversely, when the RSI exceeds 100, there is enough supply available to meet demand without any generation from the largest supplier. In this case, no individual supplier is pivotal and sufficient competition exists in the market. The data used to calculate the RSI come from the ISO's real-time market software (the Unit Dispatch System, or UDS). Based on these data, the RSI for an interval *t* is calculated as follows:

$$RSI_t = \frac{Total\ Available\ Supply_t - Largest\ Supplier's\ Supply_t}{Load_t + Reserve\ Requirements_t}$$

Day-Ahead Energy Market

Table below shows the percentage of hours with at least one pivotal supplier. [96]

Table 3-1: Percentage of Hours with Pivotal Suppliers

Year	% of Hours with at least one Pivotal Supplier
2021	0.2%
2022	0.9%
2023	0.1%
2024	2.2%
2025	4.1%

In 2025, tighter supply margins—driven by reduced availability of both imports and native supply—combined with relatively higher projected day-ahead load, led to an increase in the number of hours with pivotal suppliers. The number of hours with pivotal suppliers was lower in the day-ahead market than in the real-time market. This is expected given there is more supply available to the system the day before the operating day, whereas in real time offline long-lead time resources are not included in the PST. In the real-time energy market, the clearing process is more constrained, and the market is exposed to unexpected events that could result in sudden changes in available capacity and demand requirements.

Real-Time Energy Market

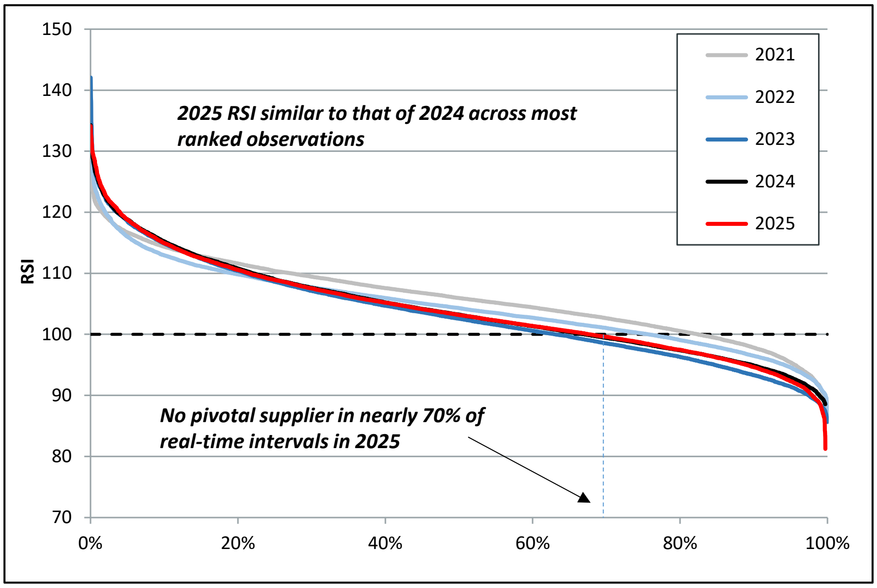
The average RSI for all five-minute real-time pricing intervals and the percentage of five-minute intervals with pivotal suppliers are presented in Table 3-2 below. Duration curves that rank the average hourly RSI over each year in descending order are illustrated in Figure 3-3. The figure shows the percent of hours when the RSI was above or below 100 for each year, indicating the presence of at least one pivotal supplier.

Table 3-2: Residual Supply Index and Intervals with Pivotal Suppliers (Real-time)

Year	% of Intervals with at Least one Pivotal Supplier	RSI
2021	18.0%	106.0
2022	24.9%	104.6
2023	37.3%	103.5
2024	33.3%	104.2
2025	32.6%	104.2

[96] Pivotal suppliers are identified for each hour by comparing each participant's total available supply to the supply margin. When a participant's available supply exceeds the supply margin, it is considered pivotal. Virtual capacity is excluded. The number of hours with a least one pivotal supplier is divided by the total number of hours in each year to obtain the percentage with pivotal suppliers.

Figure 3-3: System-wide Residual Supply Index Duration Curves



There were more five-minute intervals with pivotal suppliers over the last three years (2023 to 2025) compared to 2021 and 2022. This indicates that suppliers faced relatively less competition in these three years than during the first two years of the reporting period. Since 2023, net interchange has decreased each year meaning that native generation has made up a growing share of generation needed to meet load. Overall, supply margins and intervals with at least one pivotal supplier remained similar to 2024 levels.

3.1.4 Day-Ahead and Real-Time Price-Cost Markups

In a perfectly competitive market, all market participants' energy supply offers would equal their marginal costs. The energy component of the LMP would then be set by the supply offer or demand bid on the margin. However, in practice, participants can raise their supply offers above marginal costs. Uncompetitive offers priced above marginal cost can distort prices and impact generator commitments and dispatch, leading to inefficient market outcomes. Though the IMM administers mitigation rules in the energy market to prevent the exercise of market power, participants are allowed to increase their offers within a certain threshold before mitigation is applied.

The price-cost markup estimates the divergence of the observed market outcomes from the ideal scenario in which all energy supply is offered at marginal cost. The results provide insight into how uncompetitive offer behavior affects the energy markets. A larger price-cost markup means that a larger component of the LMP is the result of inflated supply offers. This analysis used different methods for the day-ahead and real-time price-cost markup calculations. For the day-ahead metric, we simulated the market clearing using supply offer and marginal cost scenarios.[97] [98] Following ISO-NE's incorporation of Day-Ahead Ancillary Services (DA A/S), the relevant day-ahead settlement rate for physical energy supply is the sum of the day-ahead LMP and the Forward Reserve (FER) price. The real-time analysis calculated (load-weighted) LMPs by creating supply curves for 1) available generation[99] by offer price and 2) available generation by marginal cost estimate, and then intersecting real-time demand with each.

The annual price-cost markup values from the day-ahead simulation and real-time analysis are shown in Table 3-3 below.

Table 3-3: Energy Market Price-Cost Markup, %

Year	Day-Ahead Price-Cost Markup	Real-Time Price-Cost Markup
2021	-0.6%	0.2%
2022	-1.8%	-1.7%
2023	-2.2%	-3.6%
2024	2.4%	6.8%
2025	2.7%	5.9%

In the day-ahead market, the price-cost markup increased to 2.7% in 2025, slightly higher than in 2024. This indicates that marginal resources, on average, continued to offer slightly above estimated marginal costs. The resulting increase in the generation-weighted day-ahead price (LMP plus FER price) was modest and remained well below mitigation thresholds, indicating competitive outcomes under the current day-ahead market design.

In the real-time market, annual load-weighted markups were close to zero or negative during 2020–2023, increased to 6.8% in 2024, and remained at a similar level at 5.9% in 2025. The 2025 result therefore does not represent a material change from 2024 conditions. As in 2024, the elevated markup relative to earlier years was primarily due to the offer behavior of gas-fired generators, which have the largest impact on annual markup values in both markets. There continued to be fewer instances of gas-fired generators offering below marginal cost compared with prior years.

Though the markup percentages in both markets were higher than in previous years, the figures still remained below the tightest mitigation threshold (10%). These results indicate that competition

[97] To perform these simulations, the IMM used an in-house market simulation model, the Integrated Market Simulator (IMS), which replicates the logic of the production day-ahead market and allows for modifications to energy offers and other key inputs. The price-cost markup is calculated using the outcomes of two scenarios: (1) an offer case that uses actual day-ahead energy market supply offers submitted by market participants; and (2) a marginal-cost case that sets generator energy offers at estimates of short-run marginal cost and sets day-ahead ancillary service offer prices at IMM-estimated levels. The price-cost markup is defined as the percentage difference between the annual generation-weighted (LMP + FER price) in the offer case and the marginal-cost case.

[98] Prior to the 2022 Annual Markets Report, this metric used a different methodology to estimate marginal costs. This is why the values in this report are lower than values for the same years in previous reports.

[99] Available generation is equal to on-line generation plus generation capacity that can come on-line within 30 minutes. It comes from on-line generators (both long lead-time and fast-start) and off-line fast-start generators.

among suppliers in the day-ahead and real-time markets limited their ability to inflate LMPs by submitting offers above marginal cost.[100]

In this assessment, we also reviewed day-ahead price-cost markup values at an hourly level and compared the peak load hour price-cost markup with the forecasted supply margin at peak. Comparing these elements provides insight into whether participants take advantage of tight system conditions, when market power tends to be more of a concern, by increasing offer markups during those times. There was no meaningful correlation between the price-cost markup and the supply margin in 2025, indicating that the day-ahead market remained competitive even when the ISO expected supply margins to be low and market power was present. We also reviewed real-time price-cost markup and reserve margin values at an hourly level. Despite outlier days with high markups and tight conditions, there was no significant correlation between margins and markups over the year.

3.1.5 Real-Time Economic Withholding

Economic withholding refers to suppliers offering their energy above cost. This action can lead to market harm if it results in higher prices that load must pay to purchase energy. Suppliers may engage in this type of behavior if they believe it could be profitable to their portfolio. However, the price impact of this action will depend on the competitiveness of the market. In more competitive markets, the price impact is more likely to be limited. Mitigation, discussed in more detail in Section 3.2, can also limit the market impact of withholding.

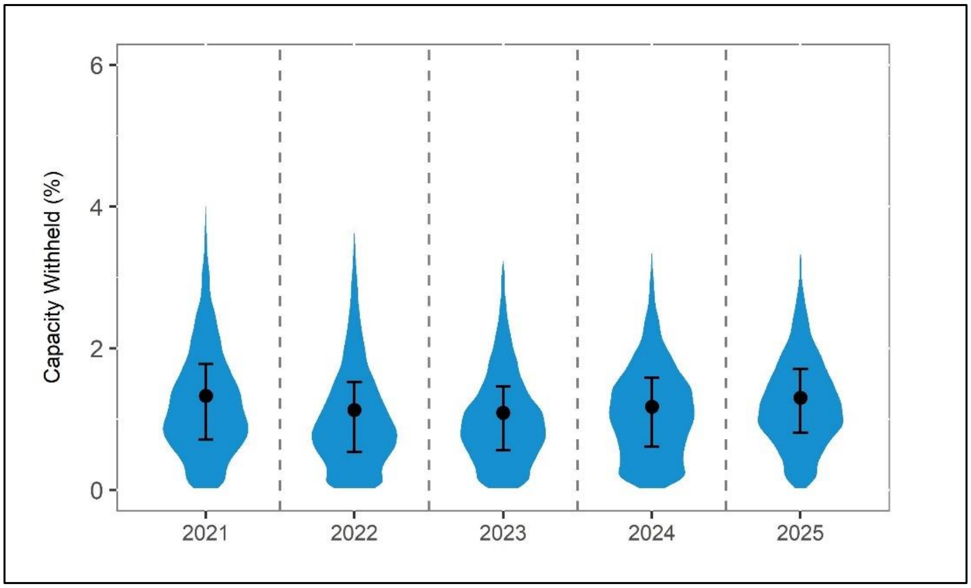
Economic withholding in the real-time market continued to be low in 2025. [101] This can be seen in Figure 3-4 below, which shows the distribution of hourly economic withholding (as a percent of capacity) for each of the past five years.[102] The figure also shows, by year, the 25th and 75th percentiles (the black dashes), the interquartile range (the lines between the dashes), and the mean (the black circle).

[100] Differences between the real-time and day-ahead price-cost markups values are due to several factors, including: 1) differences in the methodologies used to calculate the price-cost markup in each respective market; 2) modeling differences between the day-ahead and real-time energy markets; and 3) real-time events that the day-ahead market did not anticipate.

[101] We estimate the economically withheld capacity for each generator in every real-time interval as the difference between: a) the quantity that was economic (i.e., the sum of MWs where marginal cost ≤ LMP) and b) the actual quantity offered (i.e., the sum of MWs where offer price ≤ LMP). In cases where the quantity offered exceeds the quantity that was economic, the withheld MWs are set to zero (i.e., withheld MWs cannot be negative). This analysis considers non-fast-start generators that are online and all fast-start generators (i.e., those that are online or offline); it does not assess potential withholding by offline, non-fast-start generators.

[102] Figure 3-4 presents hourly real-time economic withholding percentages using a violin plot, which combines features of a box plot and a density plot. The curves depict the distribution of hourly withholding, where the widest sections of each curve represent the most-frequently observed levels.

Figure 3-4: Hourly Real-time Economic Withholding



We estimate that only 1.3% of capacity was economically withheld in the real-time market on average in 2025. This level of economically withheld capacity was in line with recent years, which had ranged from an average of 1.1% to 1.3%. In 2025, the middle 50% of observations (the inner quartile range) fell between 0.8% to 1.7%, which was slightly higher than the values from 2024 (0.6% to 1.6%) but still generally in-line with prior years.

Although not presented in the figure, levels of economic withholding did not increase when reserve margins were low, suggesting that suppliers were either unable or did not attempt to take advantage of tight system conditions by economically withholding.

3.2 Energy Market Mitigation

The IMM reviews supply offers in both the day-ahead and real-time energy markets with the objective of identifying and mitigating opportunities for participants to exercise market power.[103] Under certain conditions, the IMM will mitigate generator supply offers, which results in submitted supply offers (i.e., start-up, no load, and segment energy offer prices) being replaced with "reference" values.[104] In this section we review the level and underlying drivers of the various forms of mitigation in the day-ahead and real-time energy markets.

Key Takeaways

Supply offer mitigation remained low in 2025. There were 399 asset hours of mitigation, representing just 0.02% of all asset hours subject to mitigation, a level similar to past years. This outcome is consistent with the system-level competitiveness metrics discussed above, as well as the limited instances of localized market power (e.g., in import-constrained areas or due to local reliability commitments).

We continue to emphasize the importance of reviewing and strengthening mitigation rules to ensure their robustness under a range of competitive conditions. In prior reports, we issued several recommendations, which can be categorized as follows:

- Review conduct and impact tests and thresholds, including the exemption for non-capacity resources from day-ahead mitigation.
- Enhance indicators of structural market power, both at the system level and for localized areas.
- Improve the accuracy of reference level calculations, with a focus on greater reliance on cost-based reference levels. We also supported the FERC-approved proposal to introduce MW-dependent Fuel Price Adjustments, which will better capture variations in natural gas costs based on quantity.

A ***structural test*** serves as the first indicator of potential market power in the energy markets. The percentage of commitment asset hours in which a structural test failure occurred from 2021 to 2025 is shown in Figure 3-5 below.[105]

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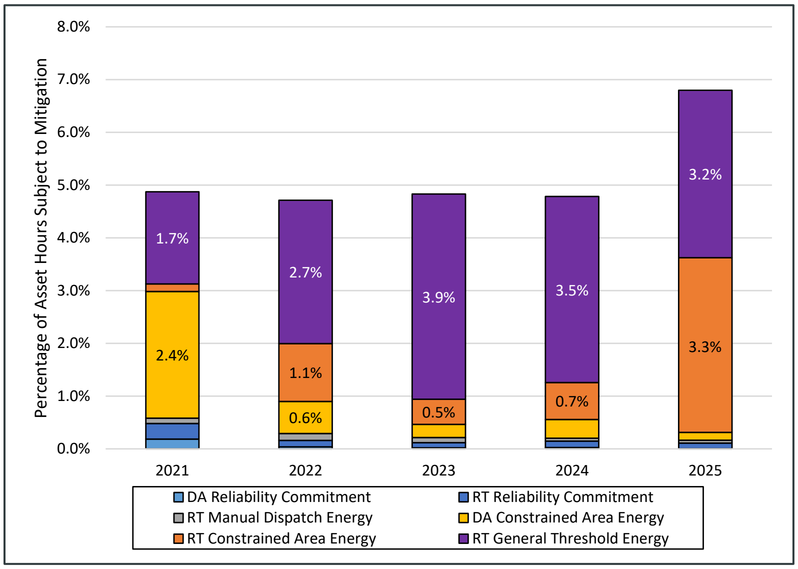
[103] This review of supply offers is automated (along with the offer mitigation process) and occurs within the ISO's energy market software.

[104] The reference values are estimated and maintained by the IMM; these values are used in mitigation to reduce impacts on energy market pricing (LMPs) and uplift payments (NCPC) from participant offers that appear to overstate a generator's operating costs. Seven mitigation types utilize mitigation tests and are used in ex-ante supply offer mitigation. An eighth mitigation type for dual-fuel generators is performed after-the-fact, when a dual-fuel generator burns a low-priced fuel but submits supply offers based on a higher-cost fuel.

[105] A structural test failure depends on the type of mitigation analyzed. The definitions of the structural test applied in general threshold and constrained area mitigation can be found in the Market Rule. ISO New England Inc., "*Transmission, Markets, and Services Tariff (ISO tariff), Section III.A.5.2, Market Rule 1, Appendix A, Market Monitoring, Reporting, and Market Power Mitigation*", http://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf. The conditions to pursue manual dispatch energy and reliability commitment mitigation are found in Sections III.A.5.5.3 and III.A.5.5.6.1, respectively.

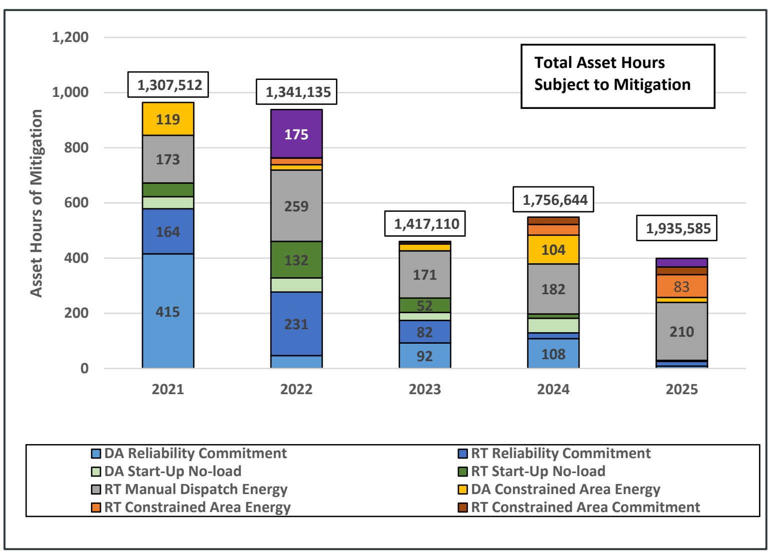
Figure 3-5: Energy Market Mitigation Structural Test Failures



In 2025, the total asset hours subject to mitigation reached 1.9 million asset hours, in which approximately 132 thousand asset hours (7%) failed structural tests.[106] The structural test for general threshold energy mitigation fails the most often and triggers any time a committed generator is owned by a pivotal supplier. Overall, asset hours of structural test failures represent a very small fraction of potential asset hours subject to mitigation and, consequently, lead to an even smaller fraction of asset hours mitigated.

Asset hours of mitigation by type are shown in Figure 3-6 along with the total amount of asset hours subject to mitigation (white boxes).

Figure 3-6: Energy Market Mitigation Asset Hours



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

In 2025, there were 399 asset hours of mitigation or just 0.3% of all asset hours subject to mitigation, lower than that of 2024 (548 asset hours).[107]

Manual dispatch energy (MDE) mitigation: The ISO will assign manual dispatch points to utilize flexible generation in addressing short-term issues on the transmission grid. As a result, gas or dual-fuel generators receive manual dispatches most often, accounting for 76% of the 1,106 asset hours of manual dispatch in 2025. Due to a relatively tight conduct test (10%), manual dispatch energy mitigation occurs more often than any other mitigation type, reaching a total of 210 asset hours in 2025.

Constrained area (CAE/CACM) mitigation: The frequency of transmission-constrained areas follows the incidence of transmission congestion and import-constrained areas within New England. Day-ahead constrained area mitigations decreased from 104 to 18 between 2024 and 2025, although real-time constrained area mitigations occurred more frequently, increasing from 39 to 83 asset hours of mitigation. In the real-time market, most constrained area energy mitigations occurred in a limited number of instances due to large import constrained areas in southern New England (rather than localized load pockets). In June, the Maine-New Hampshire constraint was binding on two separate days during tight conditions surrounding the pay-for-performance event on June 24. In December, the North-South New England Import Interface was constrained as a result of flows associated with NECEC testing. However, the Maine-New Hampshire and North-East constraints may bind more frequently in 2026 due to additional supply in Maine from the NECEC external interface.

Reliability commitment mitigation: Reliability commitments primarily occur to satisfy local reliability needs, and are generally due to routine transmission line outages, outages facilitating upgrade projects, or localized distribution system support.[108] In 2025, reliability commitments totaled 106 asset hours in the day-ahead (a 74% decrease from 2024) and 1,982 asset hours in the real-time markets (an 8% decrease from 2024). About 90% of real-time reliability commitment asset hours occurred in the Southeastern Massachusetts load zone. There were only 25 reliability commitment mitigations in 2025, or just 1% of reliability commitment asset hours.

Start-up and no-load (SUNL) commitment mitigation: This mitigation type addresses grossly over-stated commitment costs (relative to reference values), which could otherwise result in very high uplift.[109] SUNL mitigations occur very infrequently and may reflect a participant's failure to update energy market supply offers as fuel prices fluctuate – particularly natural gas. In 2025, only three participants were associated with 68 asset hours of SUNL commitment mitigation.

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[107] ISO New England Inc., Internal Market Monitor, "*An Overview of New England's Wholesale Electricity Markets",* May 23, 2025, https://www.iso-ne.com/static-assets/documents/100023/imm-markets-primer.pdf. This document is updated periodically, particularly to reflect changes to market design. It includes more information on Energy Market Mitigation types and thresholds.

[108] This mitigation category applies to most types of "out-of-merit" commitments, including local first contingency, local second contingency, voltage, distribution, dual-fuel resource auditing, and any manual commitment needed for a reason other than meeting system load and operating reserve constraints. ISO New England Inc., "*Transmission, Markets, and Services Tariff (ISO tariff), Section III.A.5.5.6.1, Market Rule 1, Appendix A, Market Monitoring, Reporting, and Market Power Mitigation"*, http://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf.

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

General threshold energy (GTE) mitigation: Despite having the highest frequency of structural test failures, general threshold energy mitigation occurs with the least frequency of all mitigation types. Across the reporting period, over 60,000 asset hours of pivotal supplier energy were subject to mitigation each year on average; mitigation has occurred for only 206 asset hours, 31 of which occurred in 2025 and 175 in 2022. As expected, structural test failures tend to occur for lead market participants with the largest portfolios of generators, with six participants accounting for 75% of the structural test failures in 2025.

We continue to emphasize the importance of reviewing and improving mitigation rules to ensure their robustness under changing competitive conditions. To that end we have issued a number of recommendations in prior reports, which are summarized in the Executive Summary and can be categorized as follows:

- Review conduct and impact tests and thresholds, and the day-ahead mitigation exemption for non-capacity resources.
- Improve indicators of structural market power at a system level (accounting for company affiliations, generator ramping) as well as for local market power (export-constrained areas).
- Improve the accuracy of reference level calculations, such as prioritizing reliance on cost-based reference levels. During 2024, we supported the ISO's proposal to introduce MW-dependent Fuel Price Adjustments (FPAs), which will reflect that natural gas costs can vary by quantity, and which FERC ultimately approved.[110]

[110] See the FERC filing regarding MW-dependent FPAs: Federal Energy Regulatory Commission, "*Order Accepting Tariff Revisions, Terminating Show Cause Proceeding, and Directing Informational Filing*", issued November 21, 2024, https://www.iso-ne.com/static-assets/documents/100017/er24-2584_el23-62_order_accept_revisions_terminate_show_cause_direct_info_filing.pdf.
Also see: ISO New England Inc., Internal Market Monitor, "*Comments of the Internal Market Monitor on Fuel Price Adjustment Modifications*", https://www.iso-ne.com/static-assets/documents/100014/imm_comments_on_mw-adjusted_fpas.pdf

3.3 Ancillary Services

Below, we review the competitiveness of the Day-Ahead Ancillary Services (DA A/S) market and the regulation market.[111] The first subsection (3.3.1) provides an assessment of the DA A/S market. The second subsection (3.3.2) reviews available regulation capacity relative to the regulation requirement and indicates the RSI for 2024.

> ***Key Takeaways***
>
> **Day-ahead ancillary services** (DA A/S) outcomes over the review period were broadly consistent with competitive market behavior, with no meaningful evidence of physical or economic withholding affecting costs.
>
> **Regulation Market:** The regulation market remained structurally competitive in 2025. Available supply consistently exceeded regulation requirements, and no supplier controlled a sufficient share of supply to raise market power concerns.

3.3.1 Day-Ahead Ancillary Services

We conducted a one-year review of the competitiveness of Day-Ahead Ancillary Services in the day-ahead market. The results of this assessment will be published in a standalone report in June 2026[112]. Here, we summarize our insights on DA A/S competitiveness.

DA A/S market outcomes indicate that costs were broadly consistent with what we would expect from competitive market behavior during the period. We find no evidence that physical withholding materially affected market outcomes. Participation levels have generally increased as market participants gained experience under the new design, and offered capability was typically sufficient to meet both load and reserve requirements. However, participation levels remain an important driver of outcomes, particularly during high-load or stressed system conditions when the availability of flexible resources is most consequential. In these periods, lower participation can contribute to tighter supply conditions and higher prices, although the observed outcomes do not suggest systematic withholding behavior.

In addition, we found little indication of economic withholding affecting overall market costs. Observed DA A/S costs were consistent with simulated outcomes based on competitive offer benchmarks, indicating that offers submitted by participating resources were broadly aligned with competitive, risk-adjusted behavior.

Although structural indicators show that market concentration can arise in certain products and time periods, particularly under tighter system conditions, these conditions did not translate into non-competitive outcomes. Measures of concentration, including pivotal supplier conditions in some reserve products, indicate that the potential for market power exists at times. Nevertheless, observed prices and costs remained consistent with competitive benchmarks, suggesting that suppliers' behavior was disciplined by market design, participation, and mitigation measures.

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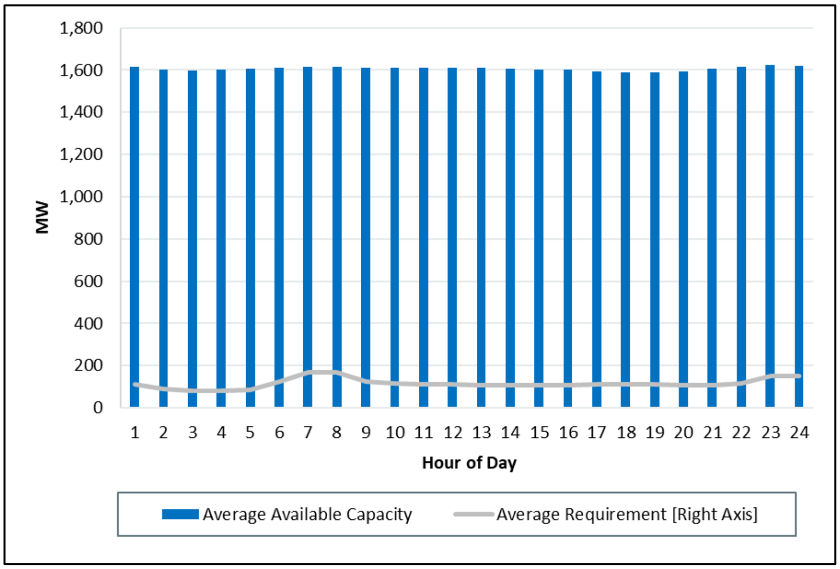
[111] The DA A/S market went live on February 28, 2025, for the operating day of March 1, 2025. More information about this market can be found in Section 8.2.

[112] The report will be available at https://www.iso-ne.com/markets-operations/market-monitoring-mitigation/internal-monitor.

3.3.2 Regulation Market

We reviewed the competitiveness of the regulation market by examining market structure and resource availability. The abundance of regulation resources and the relatively unconcentrated control of that supply reduces any opportunity to engage in economic or physical withholding, as indicated in Figure 3-7 below.

Figure 3-7: Average Regulation Market Requirement and Available Capacity, 2025



On average, during every hour of the day, available supply far exceeds the regulation requirements. However, an abundance of available supply alone is not a dispositive indicator of market competitiveness, as one - or a small number of suppliers - could control the available supply and seek to exercise market power.

The Residual Supply Index RSI provides a better indicator of the structural competitiveness of the regulation market. As shown in Figure 3-8, the regulation requirement (right axis) and RSI (left axis) are inversely correlated (the lower the requirement the higher the RSI).

Figure 3-8: Average Regulation Requirement and Residual Supply Index, 2025

In 2025, the lowest hourly average RSI remained high as in prior years, with values consistently staying above 1,000% except during Hours Ending 7 and 8, when RSI briefly dipped but remained above 900%. Even in those hours, the system still had nine times the regulation requirement available without the largest regulation supplier, meaning the supplier was not pivotal. Accordingly, we find the regulation market was competitive in 2025.

3.4 Financial Transmission Rights Market

In this section, we look at the competitiveness of the Financial Transmission Rights (FTR) market, with a specific focus on market concentration. In this context, market concentration refers to the extent to which FTR MWs are concentrated among market participants.

Key Takeaways

Ownership of FTR paths was relatively concentrated in 2025, with the top four participants holding over 60% of FTR MWs. High concentration levels have been observed in all five years of the reporting period. However, the FTR market remained fairly active in 2025 with over 30 unique participants bidding in the auctions over the course of the year.

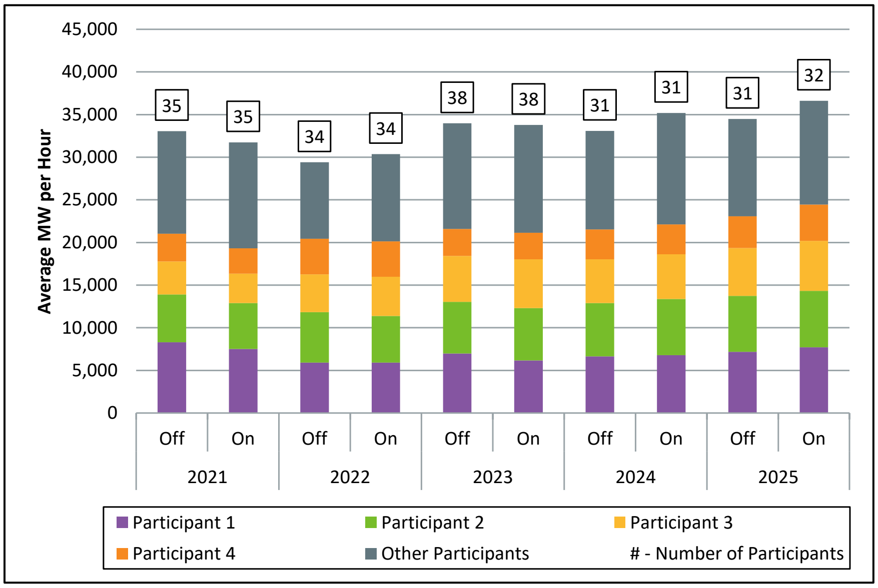
As discussed in Section 9.2, FTRs were profitable in 2025, earning a net profit of $34 million and reversing a trend of negative or near-zero profitability since 2022. The increase in FTR profits was driven by an increase in system congestion and higher system LMPs throughout the year.

Determining what constitutes a competitive level of FTR ownership is complex, as it is unlikely to align with system-level shares of load-serving or generation ownership. This is because there are not clear commercial motives for all market participants to hold FTR positions – for example, load-serving entities or participants with generation that is not exposed to transmission constraints likely do not have incentives to purchase FTR positions. Even those participants that may benefit from hedging basis risk can have risk preferences that favor exposure to day-ahead congestion over managing that exposure with the purchase of an FTR. Further, FTR market design permits the purchase of FTRs for financial speculation, so many FTR holders have no load or generation position at all.

The concentration of FTR MWs among market participants in 2025 was slightly higher than in prior years. The average amount of FTRs held per hour by the top four participants with the most MWs each year is shown in Figure 3-9 below.[113] This figure also shows the number of different participants that held FTRs each year (indicated by the number above each stacked column). This information is broken down separately for the on-peak and off-peak periods.

[113] The firms labeled "Participant 1," "Participant 2" and so on are not necessarily the same companies across all years; these are generic labels for the top four firms during a given year.

Figure 3-9: Average FTR MWs Held per Hour by Top Four FTR Holders by Year and Period



The top four FTR market participants held 67% of both on-peak and off-peak MWs in 2025. This concentration among the top four participants is slightly higher than the five-year average (~65%), coinciding with a slightly smaller count of individual participants in 2024-2025 than in 2021-2023. FTR profits totaled $34 million in 2025, reversing a trend of negative or near-zero profits since 2022. As discussed in Section 9.2, FTR profits were driven by an increase in overall system congestion, largely attributable to temporary transmission work. Therefore, the increased FTR profits in 2025 do not indicate structural market power concerns as unforeseen congestion patterns were the main driver of FTR profitability.

Section 4
Day-Ahead and Real-Time Energy Market

We examine key trends and drivers of energy market outcomes in this section, which is structured as follows:

- Day-ahead and real-time energy prices across a number of dimensions, including location, time-of-day, and convergence (4.1)
- Factors that influence supply and demand participation (4.2 & 4.3)
- Energy markets and system reliability interactions (4.4)
- Net commitment period compensation (NCPC) payments (4.5)
- Summary of system events during 2025 (4.6)[114]
- Demand response resource (DRR) participation in the energy markets (4.7)

Day-ahead and real-time energy prices increased significantly in 2025 (83% and 67%, respectively) relative to 2024. These increases were driven primarily by a substantial rise in natural gas prices, which increased by 105% year-over-year. Higher energy prices also reflected increased emissions costs and greater reliance on natural gas-fired generation as net imports declined. During periods of high summer demand, prices were further elevated as dispatch extended into the higher-cost ranges of gas-fired capacity.

Uplift (NCPC) totaled $42 million in 2025, comprising 0.4% of total energy market costs, the lowest share in at least a decade. Most NCPC payments occurred in the real-time market ($31 million, 75%). The majority of payments were made to resources committed in economic merit order to meet load and reserve requirements.

4.1 Energy Prices

Below, we evaluate energy prices across a number of dimensions, including by energy market (i.e., day-ahead LMP plus Forecast Energy Requirement, FER, price, and real-time LMP), time-of-day, and location. These perspectives offer useful context for understanding differences in energy prices over the review period.

The first subsection (4.1.1) summarizes energy market pricing over a five-year period, reviews price separation across load zones, and examines load-weighted LMPs, which provide an indication of the effective prices that load-serving entities pay for energy. The second subsection (4.1.2) examines the extent to which prices converged across the day-ahead and real-time energy markets—an important indicator of market efficiency. Finally, the third subsection (4.1.3) estimates the impacts of fast-start pricing rules on LMPs and other market outcomes.

[114] For a detailed assessment of system events, see: ISO New England Inc., Internal Market Monitor, "*Quarterly Markets Reports*", https://www.iso-ne.com/markets-operations/market-monitoring-mitigation/internal-monitor

Key Takeaways

Price Levels and Drivers: Day-ahead and real-time energy prices increased by 83% and 67% year-over-year, respectively; the increased energy prices were largely due to higher natural gas prices (up 105%). Prices were nearly $6/MWh higher in the day-market compared to the real-time market. The day-ahead price includes the Forecast Energy Requirement price (FERP), a new component of energy prices introduced as part of the Day-Ahead Ancillary Services (DA A/S) initiative in March 2025. The FER price is paid to day-ahead cleared physical supply for meeting the ISO's load forecast. The day-ahead LMP and the FERP averaged $67.86/MWh and $3.95/MWh, respectively.

- The annual simple average Hub price was $71.81/MWh in the day-ahead market (incl. $3.95/MWh FER price) and $65.87/MWh in real time.
- The day-ahead price premium of $6/MWh represents the highest average price divergence since the start of the Standard Market Design. We have observed higher day-ahead prices since the addition of the FER.
- There was minimal congestion in 2025. When congestion did manifest, the Connecticut and Maine load zones tended to have the lowest average LMPs compared to the Hub.

Fast-Start Pricing: The fast-start pricing rules in the real-time market are generally achieving their key design objective of improving price formation by better reflecting the production costs of flexible, fast-start resources in energy prices and reducing uplift payments. However, there continued to be significant periods of non-zero reserve pricing and payments even when reserve constraints were not impacting the physical dispatch of resources and there was a physical surplus of reserves. We continue to recommend that the ISO assess this issue.

4.1.1 Day-Ahead and Real-Time Energy Price

Day-ahead and real-time energy prices at the Hub and the eight New England load zones are presented below. These prices are evaluated across a number of dimensions: time-of-use (i.e., peak, off-peak hours), location, and load-weighting.

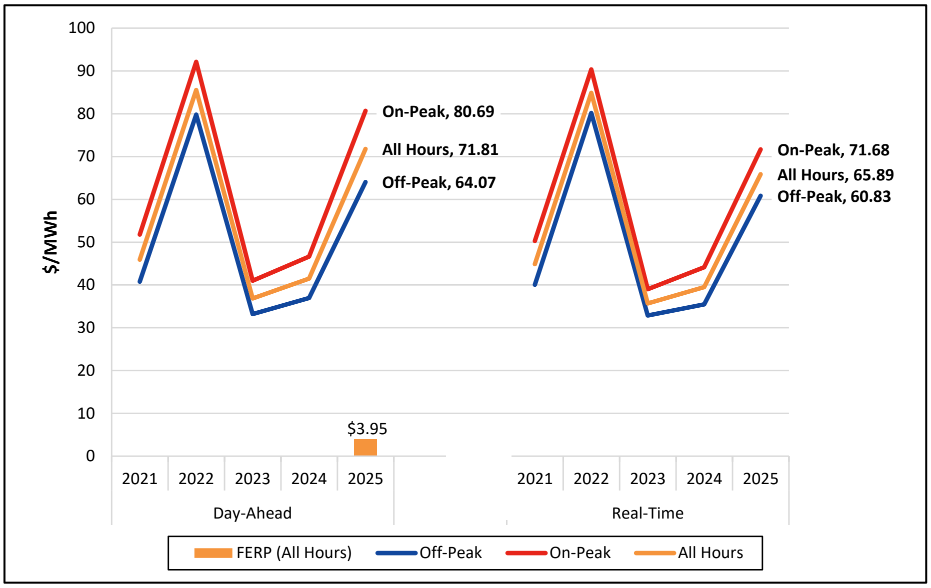
Hub Prices by Time-of-use and Market

First, Figure 4-1 shows simple average Hub prices in the day-ahead (incl. Forecast Energy Requirement price)[115] and real-time markets for three time tranches: all hours, peak, and off-peak hours.[116]

[115] Day-Ahead energy prices include the Forecast Energy Requirement (FER) price, which was introduced on March 1, 2025, as part of the Day-Ahead Ancillary Services Initiative. The average FER value includes zeros for January and February 2025.

[116] On-peak periods are weekday hours ending 8 to 23 (i.e., Monday through Friday, excluding North American Electric Reliability Corporation (NERC) holidays); the off-peak period consists of all other hours.

Figure 4-1: Annual Simple Average Hub Price



Average Hub prices in 2025 increased compared to 2024 due to higher natural gas prices, especially during the winter. In 2025, the simple annual average Hub price (in *all hours*) was $71.81/MWh in the day-ahead market[117] and $65.89/MWh in the real-time market. These prices represent increases over the prior year's averages of 73% and 67%, respectively. Time-of-day pricing in 2025 (i.e., on-peak and off-peak) followed a similar upward trend, and on-peak prices remained 26% higher than off-peak prices in the day-ahead market.

These price changes are consistent with observed market conditions, including input fuel costs, load levels, and generator operations. Natural gas prices, which are the primary driver of energy prices in New England, more than doubled in 2025 (up 105%). Additionally, net imports declined significantly for the fourth consecutive year. The decrease in net interchange leads to a shift in the supply curve with greater reliance on more expensive generation.

Prices by Load Zone and Market

At the *zonal* level, price differences were small in 2025 in both the day-ahead and real-time energy markets. Load zone prices were quite close to the Hub price, with an absolute average price difference between the Hub and zones of $0.76/MWh in the day-ahead market and $0.71/MWh in real time, reflective of a system that is generally uncongested. As in prior years, the Connecticut and Maine load zones had the lowest average LMPs in both day-ahead and real-time markets (about 2% to 3% lower than the Hub). Upward pricing separation tended to be small in the day-ahead and real-time markets.

Consumer Prices: Load-Weighted Prices

Figure 4-2 below shows the relatively small differences in system-level day-ahead energy prices across the region on a monthly basis.

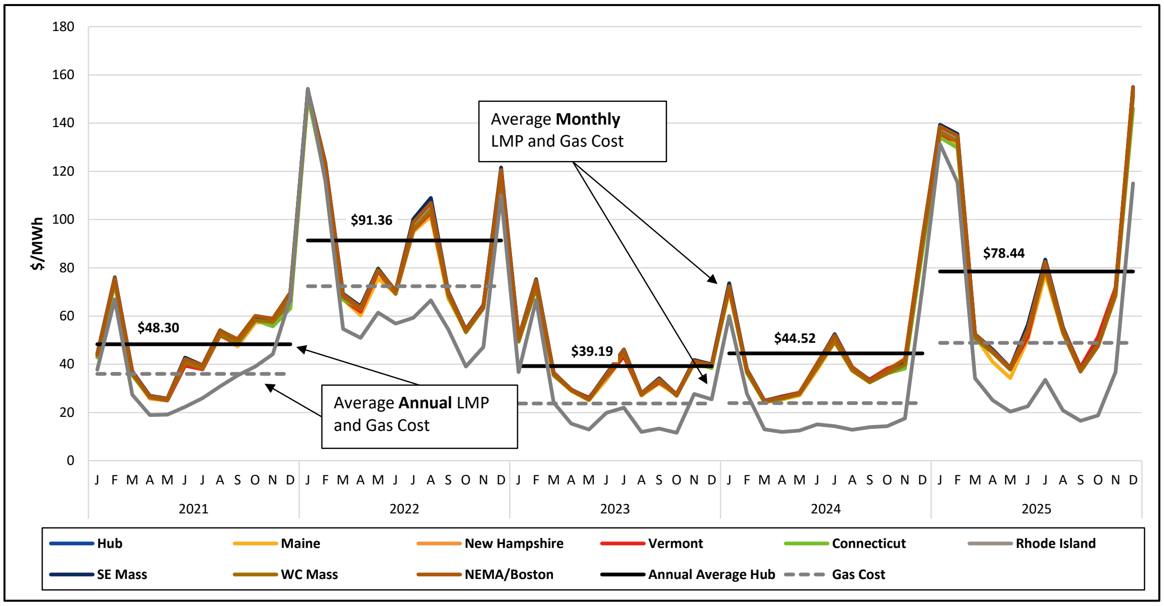
Compared to simple average prices, load-weighted prices provide a more accurate measure of the average energy costs faced by load-serving entities (LSEs). Because energy consumption varies

[117] The day-ahead LMP and the Forecast Energy Requirement price (FERP) averaged $67.86/MWh and $3.95/MWh, respectively.

significantly by hour, load-weighted prices better capture the cost of meeting demand during peak periods, when higher consumption requires dispatching more expensive generation resources. As a result, load-weighted prices are typically higher than simple averages. In 2025, the average day-ahead load-weighted price was $78.27/MWh.

Monthly day-ahead load-weighted prices across load zones over the past five years are shown in Figure 4-2 below. The figure illustrates significant monthly variability in LMPs, particularly during winter months with fuel price volatility.

Figure 4-2: Day-Ahead Load-Weighted Prices



Load-weighted energy prices by load zone from 2021 to 2025 indicate a pattern that varies considerably by year and by month, but typically not by load zone. Winter periods with high fuel prices and summer months with elevated load variability typically have the highest load-weighted prices; a similar trend applies to the real-time market. The effect of natural gas prices in 2025 is evident in the figure above, with day-ahead LMPs highest in January, February and December of this year during these cold winter months when gas demand was high.

4.1.2 Energy Price Convergence

Price convergence refers to the extent to which prices aligned between the day-ahead and real-time energy markets. Price convergence can serve as a metric for market efficiency – which, in this case, means achieving the necessary real-time generator commitments at the lowest possible cost. One way to assess price convergence is to look at the difference between the day-ahead LMP plus the Forecast Energy Requirement price (FERP) and real-time LMPs (i.e., the day-ahead price premium).[118] In an efficient market, day-ahead (forward) prices should generally reflect expected real-time (spot) prices. While day-ahead prices will almost never perfectly match real-time prices in any given hour (because real-time conditions will usually differ from expectations), one might expect to see similar average prices between the two markets over time.

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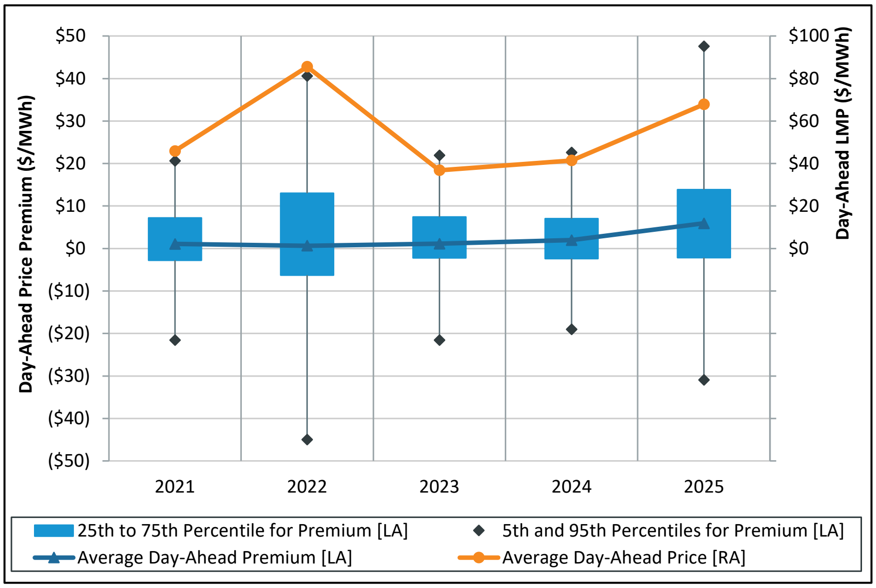
[118] The day-ahead price premium is defined as the day-ahead LMP plus FER price *minus* the real-time LMP.

Convergence Across all Hours

The average Hub day-ahead price premium increased in 2025 following the beginning of the Day-Ahead Ancillary Services Market (DA A/S) on March 1, 2025. The day-ahead market price now includes the day-ahead LMP and the FERP which is paid to day-ahead cleared physical supply. This constraint ensures day-ahead cleared physical generation is sufficient to meet the ISO's load forecast. Figure 4-3 shows the distribution of the day-ahead price premium (incl. FER price) at the Hub between 2021 and 2025 using a box-and-whiskers diagram.[119] This figure also shows the average annual day-ahead price (2021-2024), or the day-ahead LMP plus the FER price (2025).

Figure 4-3: Average Annual Day-Ahead Price Premium at the Hub and Average Day-Ahead Hub LMP



The day-ahead premium at the Hub averaged $5.93/MWh in 2025, the highest premium over the five-year period. The only two months with higher real-time LMPs were 1) January 2025 ($1.52/MWh higher), which was prior to the DA A/S market and 2) June 2025 ($0.66/MWh higher), which included over three hours of capacity scarcity conditions.

In percentage terms (as a percentage of the day-ahead price), the 2025 price premium (9%) was also the highest in the reporting period. Between 2021 and 2025, the average price premium ranged from as low as $0.64/MWh (in 2022) up to the high seen this year. The variability in day-ahead price premiums increased in 2025. However, these percentiles generally track the average day-ahead Hub price (orange series, right axis).

Convergence by Time of Day

The average day-ahead price premium (DA LMP + FERP – RT LMP) tended to be higher during the evening peak during 2025. Figure 4-4 below shows, by hour, the average day-ahead price premium at the Hub (blue line). The gray bars show the interquartile range (i.e., the middle 50 percent) of the day-ahead price premium.

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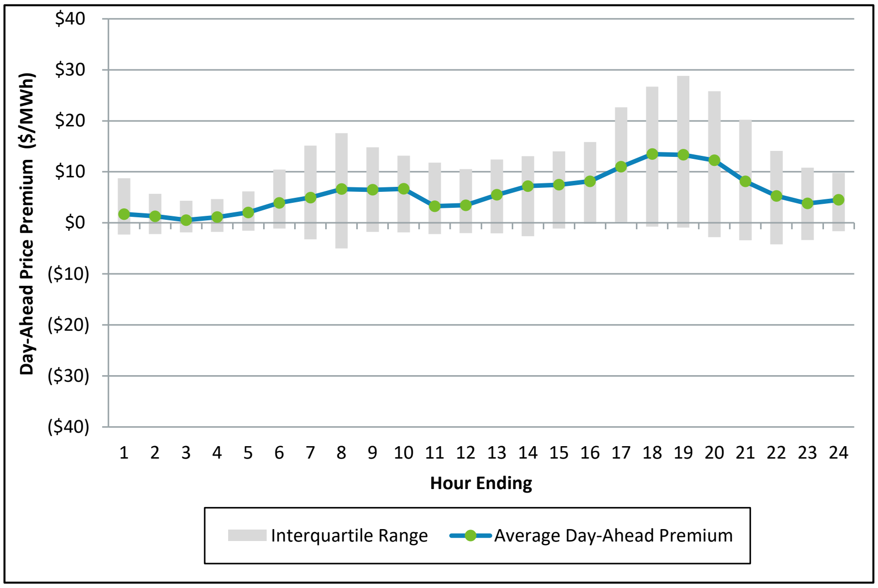
[119] The day-ahead price premium is measured on the left axis ("LA"), while the average annual day-ahead Hub LMP is measured on the right axis ("RA").

Figure 4-4: Average Hourly Day-Ahead to Real-Time Hub Price Differences, 2025



The average day-ahead price at the Hub exceeded the average real-time price during every hour and ranged from $0.53/MWh to $13.47/MWh. The price premium tended to be higher during the peak load hours (HE 17 through HE 20) with the day-ahead premium above $10/MWh in these four hours. Under the prior market design, virtual supply could clear in the day-ahead market and profit off the day-ahead price premiums; these bids would likely help converge day-ahead and real-time prices. The DA A/S market has largely hampered virtual supply's price converging ability when the FER constraint is active. If a virtual trader anticipates lower real-time prices, physical supply is still needed to help meet the FER constraint. In this situation, an inframarginal virtual supply bid can lower the day-ahead LMP but would likely lead to a larger FER price.

4.1.3 Fast-Start Pricing: Impact on Real-Time Outcomes

The fast-start pricing rules in the real-time energy market continue to have notable impacts on pricing and market costs. The purpose of fast-start pricing rules is to improve energy price formation when fast-start units are operating. Fast-start pricing rules allow LMPs to better reflect the marginal cost of fast-start resource deployment and, therefore, send more transparent short- and long-term market signals about the cost to operate the system.

We find that fast-start pricing is generally meeting the design's key objective of improving real-time price formation by better reflecting the production costs of flexible fast-start resources in energy prices.[120] In 2025, fast-start pricing impacts were similar to prior years. There continued to be significant periods of non-zero pricing (and payments) during times when the reserve constraint was not impacting the physical dispatch of resources and there was a physical surplus of reserves. We recommended that the ISO assess this issue in our 2022 Annual Report.[121]

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[120] For more detail on fast-start pricing, see: ISO New England Inc., Internal Market Monitor, "*Summer 2017 Quarterly Markets report*", December 20, 2017, Section 5.5, https://www.iso-ne.com/static-assets/documents/2017/12/2017-summer-quarterly-markets-report.pdf

[121] A summary of this and other recommendations can be found in the executive summary of this report.

Table 4-1 below compares a number of actual and estimated counterfactual market outcomes. The column labeled *Fast-Start Pricing* details actual pricing and settlement outcomes. The column labeled *Non-Fast-Start Pricing* provides estimates of counter-factual outcomes if fast-start pricing had not been implemented using data produced by the dispatch software.

Table 4-1: Fast-Start Pricing Outcome Summary, 2025

Market Outcome	Fast-Start Pricing (Actual Outcomes)	Non Fast-Start Pricing (Counterfactual Outcomes)	Difference
System LMP ($/MWh)[122]	$65.63	$61.56	**$4.06 (7%)**
Real-Time Energy Payments ($, Millions)[123]	$146.4	$128.3	**$18.1 (14%)**
NCPC Payments ($, Millions)[124]	$22.3	$32.7	**-$10.4 (-32%)**
Reserve Prices ($/MWh)[125]	$1.78	$0.94	**$0.85 (90%)**
Real-Time Reserve Payments ($, Millions)[126]	$27.4	$12.5	**$14.9 (119%)**
Percent of Intervals with Reserve Pricing (%)	6.9%	4.3%	**2.7% (62%)**
Intervals Fast-Start Resource Marginal[127]	24.2%	10.0%	**14.2% (142%)**

To summarize the key takeaways, the fast-start pricing mechanics:

- resulted in a higher frequency of fast-start resources setting price, mostly driven by fast-start generator price-setting frequency (+4.9% from asset-related demand, +9.2% from generation)
- increased the average annual system LMP by 7% and increased real-time energy payments by 14%,
- decreased real-time NCPC paid to generators and asset-related demand (ARDs) by 32%[128], and

[122] The system LMP shown here is the energy component of the LMP in each interval.

[123] This value is different than the real-time payments value reported in the wholesale cost section of the report because, here, real-time load deviations are only considered for locations and customers with physical load (i.e., exports and day-ahead demand that does not correspond to physical load are excluded).

[124] NCPC payments included in this analysis are Commitment-Out-Of-Merit (COOM), Dispatch-Out-Of-Merit (DOOM), and Rapid Response Pricing Opportunity Cost (RRPOC) payments for generators and asset-related demand resources (ARDs). Due to data limitations, counterfactual LMPs were not available in every interval so estimated payments are slightly less than actual payments. Actual payments (i.e., not based on IMM estimates like the data shown in the table) in 2025 were $22.9 million.

[125] These reserve prices represent the average reserve price in every interval – including $0/MWh reserve price intervals.

[126] The netting of real-time payments for a participant's forward reserve market obligations is not accounted for in the reported reserve payments. For more information on the impact of fast-start pricing on reserves, see Section 8.1.

[127] This metric represents the percentage of intervals in which at least one fast-start generator was marginal (i.e., set price).

[128] Breaking down the reduction further, fast-start pricing reduced commitment-out-of-merit and dispatch-out-of-merit NCPC to generators that did not recover their costs when following ISO dispatch instructions by 41%. The decrease was offset by an increase in Rapid Response Pricing Opportunity Cost (RRPOC) NCPC.

- had a substantial impact on reserve pricing and payments, with non-zero pricing occurring in 62% more intervals. Overall, average reserve prices were 90% higher in the fast-start-pricing case than in the non-fast-start-pricing case, and payments were 119% higher.

4.2 Supply-side Factors

This section explores the key supply factors impacting energy market outcomes. Section 4.2.1 looks at trends in both fuel and emissions costs. Section 4.2.2 examines utilization rates of different generator technologies. Section 4.2.3 summarizes price-setting statistics by resource type. And lastly, Section 4.2.4 looks into priced versus unpriced offer behavior.

Key Takeaways

Fuel and Emissions Costs: Natural gas generation costs rose sharply in 2025, averaging $49/MWh—up 105% from 2024—driven by elevated winter gas prices, pipeline constraints, and strong heating demand. Production costs peaked during the coldest periods ($93/MWh in Q1 and $57/MWh in Q4). Summer conditions supported relatively strong spark spreads (~$23/MWh in Q3), particularly during peak hours when gas units were operating near full utilization. Although fuel prices eased after winter, average regional hub prices remained above 2024 levels throughout the year.
Emissions compliance costs also increased in 2025, with RGGI adding $10.21/MWh to combined-cycle production costs and MA EGEL costs more than doubling to $3.56/MWh. Higher allowance prices reflect tightening emissions limits and growing demand for allowances. As compliance costs rise and allowances become more scarce, less-efficient fossil fuel-fired generators may face increased pressure to reduce output, invest in lower-emitting technologies, or retire entirely.

Generator Utilization Trends: In 2025, generator utilization patterns reflected changing supply conditions and resource availability. Hydroelectric capacity factors declined due to drier weather, while single-fuel combined-cycle units operated at higher utilization following the retirement of the lower-performing Mystic units. Steam turbines also saw increased output, though they continued to operate at low utilization overall, with generation concentrated in winter months and during periods of elevated demand.

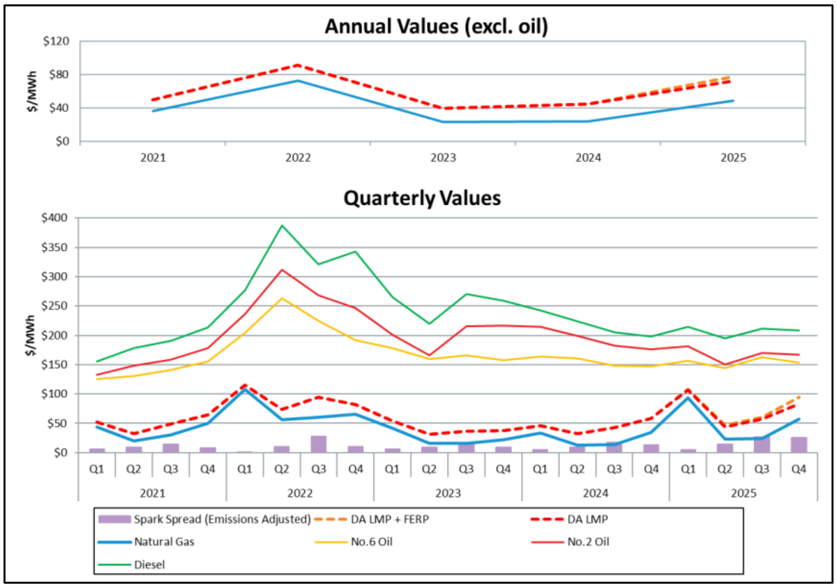
Price-Setting: Natural gas continued to play a central role in price formation in 2025; gas generators were marginal for 79% of load in the real-time market.

Non-Price-Setting Supply: Approximately two-thirds of total supply in both the day-ahead and real-time markets came from non-price-setting resources, consistent with prior years. The presence of large volumes of non-price-setting supply can lead to low or negative prices, although the frequency of negative prices remained relatively low in 2025.

4.2.1 Generation Costs and Profitability

Day-ahead and real-time electricity prices remain closely correlated with the estimated cost of operating a natural gas-fired generator. In 2025, natural gas-fired generators continued to be the dominant price setters and comprised half of total system supply. The relationship between electricity prices and generation fuel costs is shown in Figure 4-5 below, alongside the estimated spark spread (gross margin) for an average natural gas-fired generator.[129]

Figure 4-5: Estimated Generation Costs and On-Peak LMPs



Natural gas generation costs increased sharply in 2025, averaging $49/MWh (up 105% from 2024). This increase was in part due to elevated winter natural gas prices, with production costs peaking during the coldest months ($93/MWh in Q1 and $57/MWh in Q4) as pipeline constraints and strong heating demand tightened regional gas supply. Summer demand conditions supported relatively strong spark spreads (~$23/MWh in Q3), with higher values occurring during peak load hours when gas-fired generators approached full utilization and higher-cost resources more frequently set marginal prices. Although natural gas costs decreased as winter conditions eased, monthly average regional hub prices remained above 2024 levels. Emissions costs also increased materially, representing a larger share of total gas-fired generation costs in 2025.[130]

The relationship between New England gas prices and Henry Hub and Marcellus prices is shown in Figure 4-6 below.

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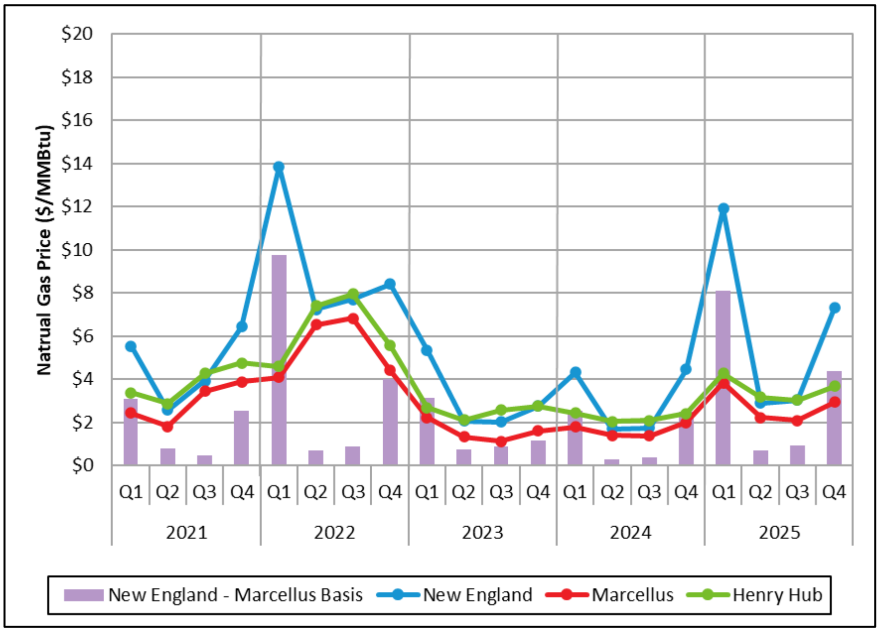
[129] Variable generation costs are calculated by multiplying the average daily fuel price ($/MMBtu) by the average standard efficiency of generators of a given technology and fuel type. Our standard heat rates are measured in MMBtu/MWh as follows: Natural Gas 7.8, Coal – 10.0, No. 6 Oil – 10.7, No. 2 Oil – 11.7. The spark spread is the difference between the day-ahead on-peak LMP and the fuel cost of a gas-fired generator with a heat rate of 7.8, adjusted for the additional estimated emissions costs of a standard gas-fired generator.

[130] ISO New England Inc., Internal Market Monitor, "*Summer 2024 Quarterly Markets Report*", December 18, 2024, Section 4.1, https://www.iso-ne.com/static-assets/documents/100017/2024-summer-quarterly-markets-report.pdf.

Figure 4-6: New England vs. Henry Hub and Marcellus Natural Gas Prices



New England natural gas prices closely track upstream benchmark hub prices—particularly Marcellus—while exhibiting significant sensitivity to regional pipeline constraints during periods of elevated demand. In 2025, benchmark prices increased materially relative to 2024 (Henry Hub averaged $3.53/MMBtu, up 57%; Marcellus averaged $2.77/MMBtu, up 69%), reflecting tighter national market conditions. During the warmer months (Q2 and Q3), when demand is lower and pipeline capacity is generally unconstrained, basis differentials between New England and Marcellus hubs remained relatively narrow, indicating broad access to regional and national supply. In contrast, during colder months (Q1 and Q4), higher heating demand absorbs much of the available pipeline capacity, resulting in more frequent constraints and wider regional price differentials, consistent with observed winter deliverability limitations into New England.

Industry-Standard Profitability Metrics

Industry-standard profitability metrics for gas-fired generators include implied heat rates and spark spreads. Implied heat rates reflect the efficiency of a generator that would break even at given LMPs and gas prices after adjusting for estimated emission prices. Spark spreads reflect the gross profit margin between LMPs and gas prices for generators of a given heat rate. Notable reference heat rates include 7,800 Btu/kWh, the average heat rate for a typical New England natural gas generator, and 6,451 Btu/kWh, the standard efficiency of a new entrant combined cycle gas-fired generator. Emissions adjusted implied heat rates and corresponding spark spreads across these and other reference heat rates for 2021 through 2025 are shown in Table 4-2, reflecting how rising natural gas prices and higher day ahead on peak LMPs in 2025 contributed to higher implied margins relative to 2024.[131]

Table 4-2: Annual Average On-Peak Implied Heat Rates and Spark Spreads (Clean)

Year	Day-Ahead On- Peak LMP ($/MWh)	Day-Ahead On-Peak LMP plus FERP (2025, $/MWh)	Gas Price ($/MMBtu)	Implied Heat Rate with Emission Costs (Btu/kWh)	Spread ($/MWh) corresponding to Heat Rate (Btu/kWh) (Emissions-adjusted)					
					6,451	7,000	7,800	8,000	9,000	10,000
2021	51.77	51.77	4.62	9,985	18.32	15.48	11.33	10.29	5.11	-0.08
2022	92.17	92.17	9.28	9,150	27.19	21.66	13.60	11.58	1.51	-8.56
2023	41.02	41.02	3.04	10,710	16.31	14.21	11.15	10.38	6.55	2.72
2024	46.62	46.62	3.06	10,878	18.97	16.62	13.19	12.34	8.05	3.76
2025	75.67	80.69	6.27	10,645	31.79	27.63	21.57	20.05	12.47	4.89

The average natural gas price increased from $3.06/MMBtu in 2024 to $6.27/MMBtu in 2025, an increase of about 105%, which largely explains the higher spark spreads observed in 2025 given that fuel cost increases are reflected in marginal energy prices.[132] Over the same period, the day-ahead on-peak LMP increased from $46.62/MWh to $75.67/MWh, an increase of about 62%.The larger percentage increase in gas prices relative to LMPs is consistent with tighter winter pipeline conditions and higher benchmark hub levels in 2025, which increased generator production costs and, in turn, lifted day ahead on-peak prices.

Natural Gas Price-Adjusted LMP

Although there is a significant positive correlation between changes in LMPs and changes in natural gas prices, LMPs are also influenced by other factors such as shifts in the energy supply mix, emissions costs, system demand, and unforeseen events such as unplanned equipment outages. The gas price-adjusted LMP is a high-level metric used to estimate the impact of these non-gas price factors on the energy price and is shown in Figure 4-7 below.[133]

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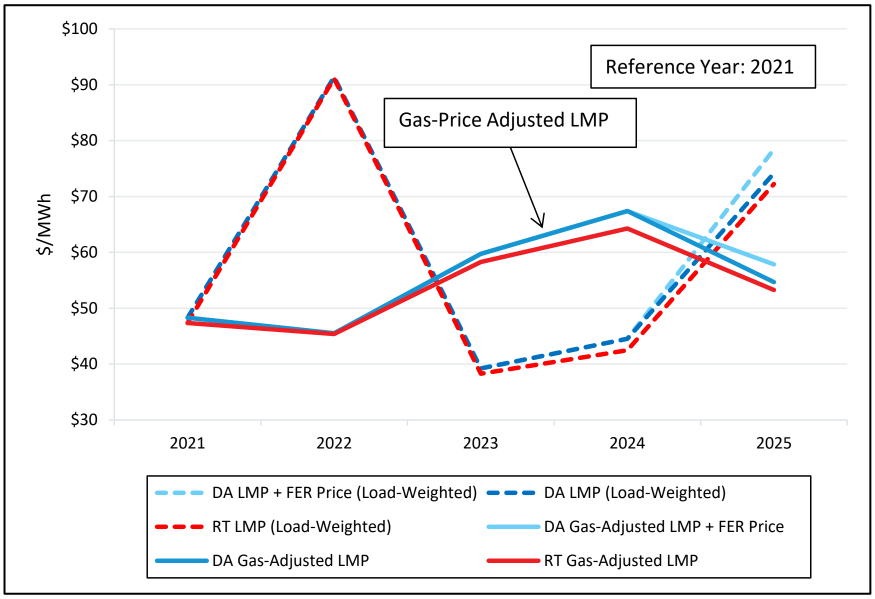
[131] The IMM uses 7,800 Btu/kWh to represent the average heat rate of New England natural gas generators. The estimated new entrant combined cycle heat rate is provided in the ISO-NE Net Cone and ORTP Analysis performed by Concentric Energy Advisors, Inc. and cited in ISO filings to the Federal Energy Regulatory Commission for FCA 16. The analysis estimates that a new entrant combined-cycle unit would have a heat rate of 6,394 Btu/kWh in shoulder seasons, 6,573 Btu/kWh in summer, and 6,429 Btu/kWh in winter. Weighting these estimates by the number of days in a year yields an average heat rate of 6,451 Btu/kWh.

See: ISO New England Inc., *"ISO Net CONE and ORTP Analysis – An Evaluation of the Net Cost of New Entry and Offer Review Trigger Price Parameters to be Used in the Forward Capacity Auction FCA-16 and Forward",* December 2020", p. 35, https://www.iso-ne.com/static-assets/documents/2020/12/updates_cone_net_cone_cap_perf_pay.pdf

[132] 2025 IHR and spark spreads reflect Day-Ahead on-peak LMPs inclusive of the Forecast Energy Requirement Price (FERP)

[133] The gas price-adjusted LMP is derived by dividing the reference year natural gas price (2020) by the current year natural gas price, then multiplying by the load-weighted LMP.

Figure 4-7: Annual Average Natural Gas Price-Adjusted LMPs



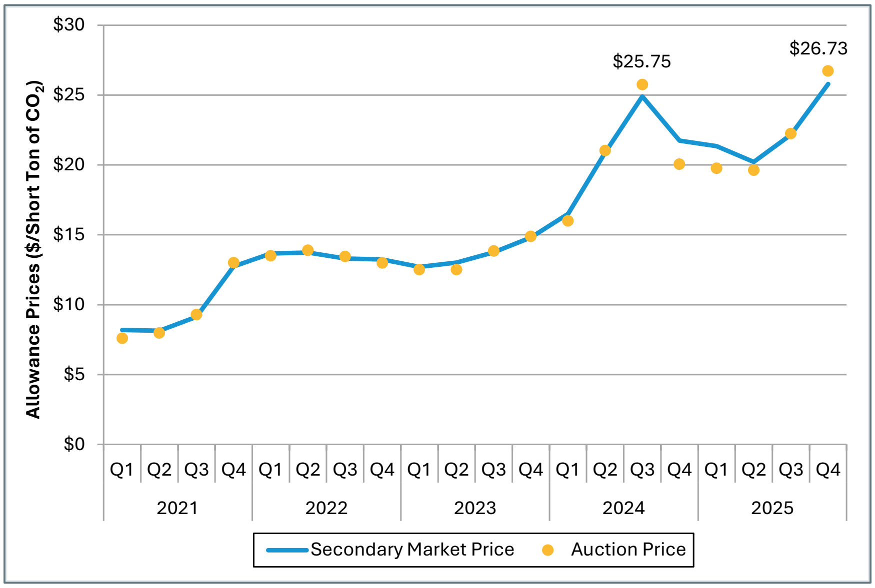
In 2025, gas-adjusted LMPs declined to $54.68/MWh in the day-ahead market and $53.26/MWh in the real-time market. The difference between nominal and gas-adjusted LMPs indicates that higher natural gas prices were the primary source of upward pressure on LMPs in 2025. This result is consistent with natural gas continuing to serve as the marginal price-setting fuel in New England, while also indicating that non-fuel factors continued to influence energy price outcomes. The year also continued the pattern of day-ahead LMPs exceeding real-time LMPs (see Section 4.1). While natural gas prices increased in 2025 relative to 2023–2024, the decline in gas-adjusted LMPs indicates that underlying market conditions such as behind-the meter solar generation—separate from fuel price increases—exerted downward pressure on energy prices.

Regional Greenhouse Gas Initiative (RGGI) Prices

The RGGI program is the primary source of emission costs for fossil fuel-fired generators in New England.[134] Average annual RGGI allowance prices have risen in each of the past 5 years, as shown in Figure 4-8. In 2025, RGGI allowance prices rose slightly (6.5%), from an average of $21.01 per short ton of CO_2 in 2024 to $22.38 per short ton in 2025.

[134] The Regional Greenhouse Gas Initiative, "*Elements of RGGI" webpage*, https://www.rggi.org/program-overview-and-design/elements

Figure 4-8: Regional Greenhouse Gas Initiative (RGGI) Prices



Prices increased steadily in the last three quarters of 2025, peaking in the fourth quarter with a secondary market price of $25.79/short ton of CO_2. The December RGGI auction cleared at $26.73/short ton, about a dollar more than the previous highest auction clearing price from the third quarter of 2024.

The higher RGGI prices exhibited in 2025 are due to a combination of the following market dynamics:

- *Reduced future emissions limits*: The third RGGI program review, completed in July 2025, set stricter emissions limits than those implemented after the 2017 program review.[135] These stricter limits begin in 2027 when the emissions cap will be 69.8 million short tons of CO_2, compared to 75.7 million short tons under the previous rule. From 2027, the emissions cap will decrease at a steeper rate (10.5% through 2033) than originally planned. By 2037, the allowance cap will be about 9 million short tons of CO_2, with an additional 23.5 million allowances potentially available each year through the Cost Containment Reserve.
- *Increased demand for allowances*: While the RGGI CO_2 emissions cap decreases each year, emissions from generators in New England increased by an estimated 3% (to 27 million short tons of CO_2) in 2025 compared to 2024. Generator emissions in all RGGI states increased by about 5% to approximately 87 million short tons of CO_2.[136]*Allowance cost controls*: The Cost Containment Reserve (CCR), a mechanism to help moderate price spikes by releasing additional allowances, was fully depleted in the first auction of the year.

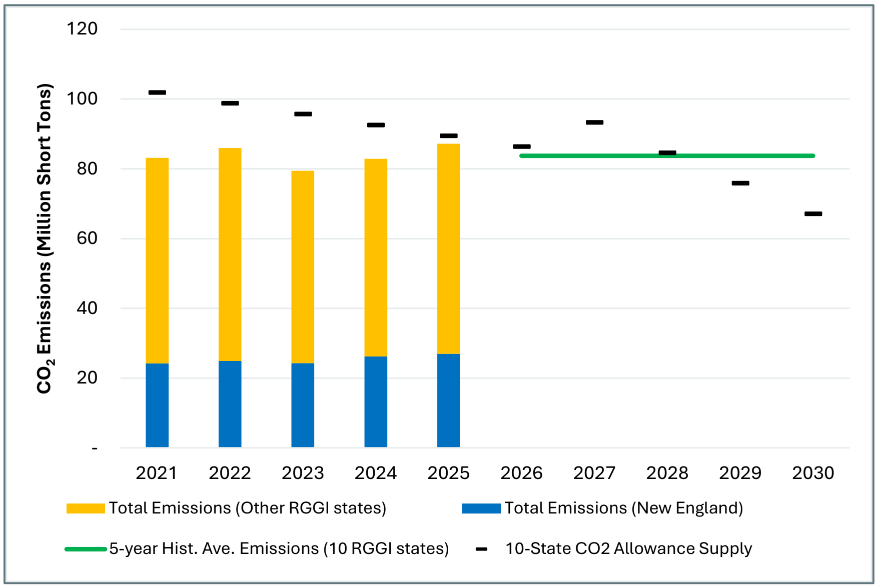
[135] The Regional Greenhouse Gas Initiative, "*Program Review*" webpage, https://www.rggi.org/program-overview-and-design/program-review.

[136] Annual emissions data are taken from EPA. Environmental Protection Agency, Clean Air Markets Program Data, "*Power plant emissions, compliance, and allowance data*" webpage, https://campd.epa.gov/.

When prices later in the year exceeded the CCR trigger of $17.03/short ton, no additional supply was available to moderate the price increase.[137]

Overall, clearing prices reflect electricity generators' compliance needs and market expectations. Decreasing allowance caps will create increased scarcity and put upward pressure on allowance prices. In Figure 4-9 we show the total supply of allowances each year (the allowance cap plus all allowances from the CCR) compared to actual emissions in the RGGI states.[138]

Figure 4-9: RGGI Emissions Levels and Allowance Supply



In 2025, total estimated emissions (approximately 87 million short tons of CO_2) across the 10 RGGI states came close to the total number of allowances available (about 89.5 million allowances, including the CCR). The total allowance supply will increase in 2027, before decreasing in each following year.[139] The figure shows that by 2029 total emissions from RGGI states could exceed the number of available allowances if emissions levels track closely to the five-year average.

As allowances become increasingly scarce and expensive, generators that are either unable or unwilling to purchase higher-priced allowances will need to reduce emissions—either by investing in more efficient, lower-emitting technologies or by reducing output. Over time, these market dynamics could render some less-efficient fossil fuel-fired generators uneconomic, ultimately leading to their retirement.

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[137] The CCR will be replenished in March 2026. Potomac Economics, "*Market Monitor Report for Auction 67*", March 14, 2025, p. 3, https://www.rggi.org/sites/default/files/Uploads/Auction-Materials/67/Auction_67_Market_Monitor_Report.pdf.

[138] The figure includes only the ten RGGI states that have participated in RGGI continuously since 2021. The CO_2 allowance supply for 2021 to 2023, when Virginia was a member state, has been prorated to exclude Virginia.

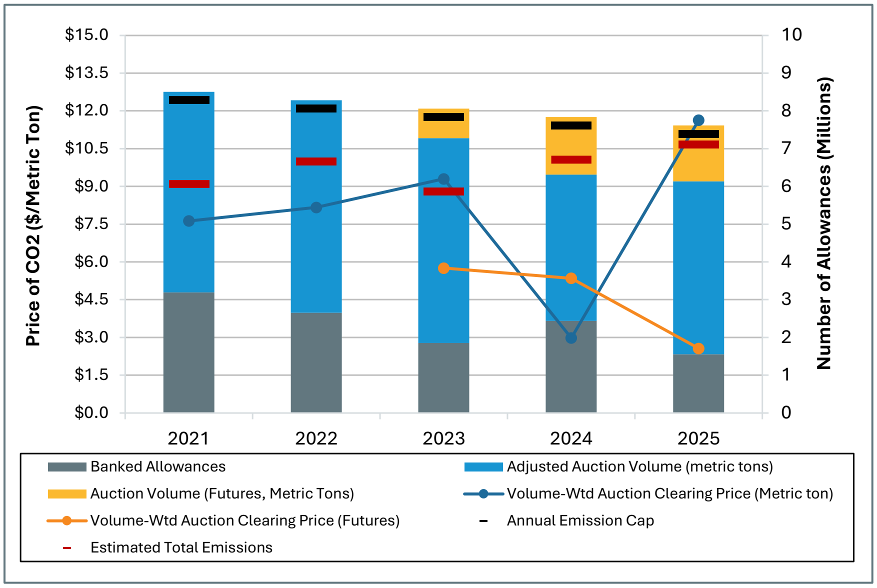
[139] One outcome of the Third Program Review, completed in July 2025, was an increase in the number of allowances in the CCR. Currently there is one tier of the CCR sized at 10% of the regional allowance cap (in 2025, the CCR contained about 7.8 million allowances). Starting in 2027 there will be two tiers of the CCR, each composed of 11.75 million allowances.

Massachusetts EGEL (MA EGEL) Prices (310 CMR 7.74)

In addition to the RGGI program, Massachusetts generators must also comply with requirements administered by the Massachusetts Department of Environmental Protection (MassDEP).[140] The MA EGEL program places an annual cap on aggregate CO_2 production for the majority of fossil fuel-fired generators within the state.[141] The cap will be lowered every year until the target annual CO_2 emission rate is reached in 2050.[142]

The annual quantity and volume-weighted clearing prices for CO_2 allowances sold as current and future vintages during the MA EGEL auctions, as well as the quantity of banked allowances carried over from prior compliance periods, are shown in Figure 4-10 below.[143]

Figure 4-10: Massachusetts EGEL Auction Results



Notes: The volume-weight auction clearing price for futures and the volume of future allowances reflect the price and quantity of allowances sold as futures for the year shown on the x-axis. For example, the auction volume of futures shown in the 2025 column reflects the volume of 2025 allowances sold as futures during the 2024 auctions.

The average 2025 volume-weighted auction price for current vintage allowances increased 290% year-over-year to $11.63/metric ton of CO_2, the highest average annual auction price observed to date. The average annual prices shown in the figure reflect the clearing price of each of the eight

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140 Massachusetts Department of Environmental Protection (MassDEP), "*Electricity Generator Emissions Limits (310 CMR 7.74)*" webpage, https://www.mass.gov/guides/electricity-generator-emissions-limits-310-cmr-774

141 Participating generators are fossil fuel-fired generators with a nameplate capacity of 25 MW or more. Massachusetts Department of Environmental Protection, (MassDEP), "*310 CMR 7.00: Air Pollution Control*", https://www.mass.gov/doc/310-cmr-700-air-pollution-control-regulations/download.

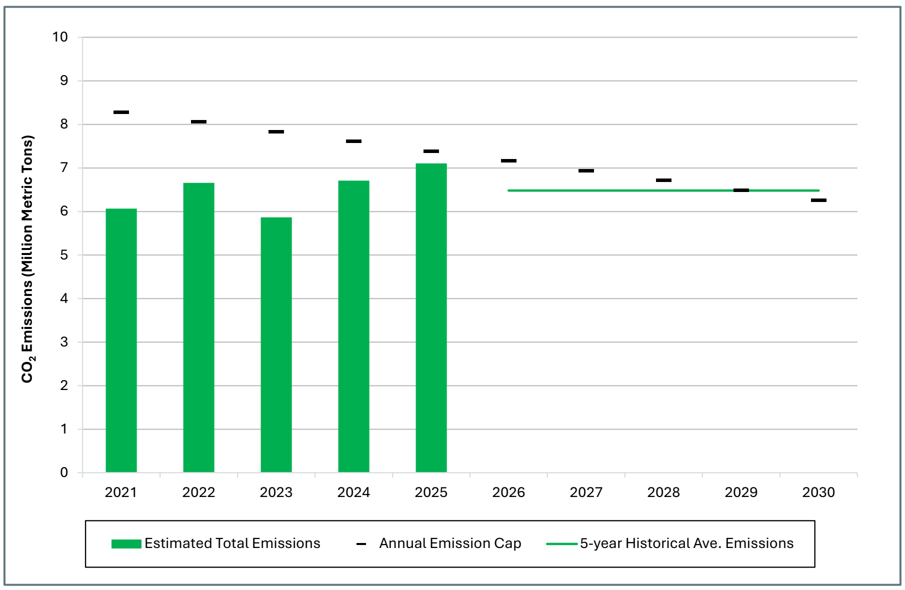
142 The annual emissions cap for 310 CMR 7.74 will reduce by 223,876 metric tons in each subsequent year, eventually reaching 1,791,019 metric tons in 2050.

143 MA EGEL holds auctions in March, June, September, and December of each year. During each auction it sells a certain quantity of the current year's vintage of allowances as well as (starting in mid-2022) a smaller quantity of the future year's vintage of allowances. For example, 2025 allowances were sold as futures in the December 2023 and March, June, and September 2024 auctions and as the current vintage in the December 2024 and March, June, and September 2025 auctions.

quarterly auctions in which allowances for a given year are sold. Clearing prices for 2025 allowances in the quarterly auctions ranged from $1.75-$5.50/metric ton when sold as futures in the 2024 auctions but jumped to $6.06-$15.03/metric ton when sold as the current vintage in the 2025 auctions. Prices for 2026 allowances (not shown in figure) have also increased, selling for $4.99-$12.00/metric ton as futures and for $22.00/metric ton as the current vintage in the December 2025 auction. The $22.00/metric ton clearing price was the highest observed to date.

Like RGGI, MA EGEL clearing prices reflect electricity generators' compliance needs and market expectations. As noted above, increased emissions in 2025 have likely created some near-term scarcity pressure and an expectation that allowances surpluses will continue to shrink.[144] While generators continue to factor allowance costs into their energy market offers,[145] the thin secondary market could expose participants needing additional allowances to significant price premiums in the future.[146] Figure 4-11 shows the annual emissions cap for the past five years and next five years, compared to actual emissions.

Figure 4-11: MA EGEL Emissions Levels and Cap



In 2025, estimated emissions in Massachusetts from regulated resources reached 96% of the 2025 emissions cap. Assuming future annual emissions equal to the average of the past five years' actual emissions, Massachusetts generators would reach the annual cap in 2029.

[144] Potomac Economics, "*Market Monitor Report on the Electricity Generator Emissions Limits Program (310 CMR 7.74): Auction 2026-1"*, December 12, 2025, https://www.mass.gov/doc/market-monitor-report-auction-2026-1/download.

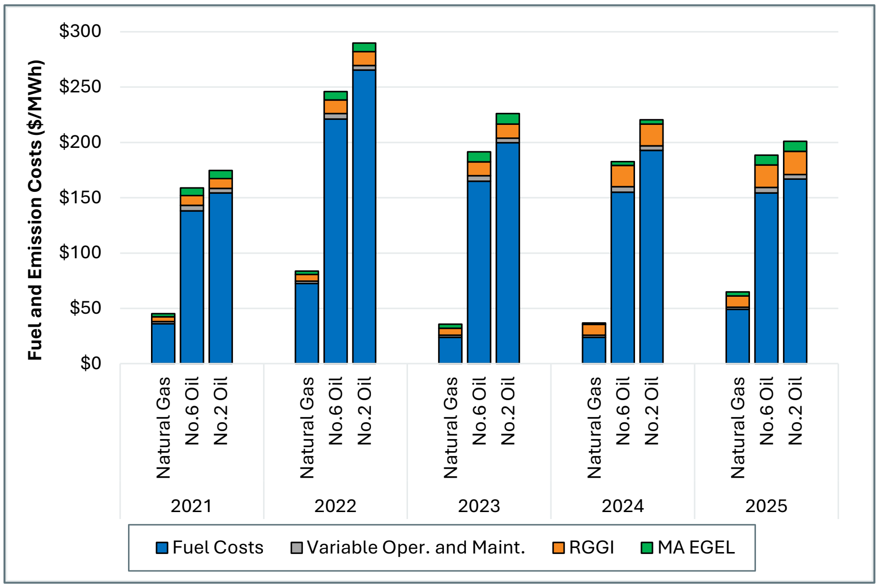
[145] To incorporate the cost of these allowances into generator reference levels, the IMM uses an adder that values the allowances based on recent trades and auction results.

[146] Potomac Economics, "*Quarterly Report on the Electricity Generator Emissions Limits Program (310 CMR 7.74) Third Quarter* 2025", November 2025, https://www.mass.gov/doc/market-monitor-quarterly-report-2025-q3/download.

Impact of Carbon Emissions Programs on Generator Operating Costs[147]

Our estimates of the average annual cost of emissions compliance by generator fuel type for both carbon programs are illustrated in Figure 4-12 below.

Figure 4-12: Annual Estimated Average Costs of Generation and Emissions[148]



2025 Emissions Costs	Natural Gas	No. 6 Oil	No. 2 Oil
RGGI Costs ($/MWh)	$10.21	$20.44	$21.08
RGGI % of Generation Costs	17%	11%	11%
MA EGEL Costs ($/MWh)	$3.56	$8.70	$8.97
Total CO_2 % of Generation Costs	21%	15%	15%

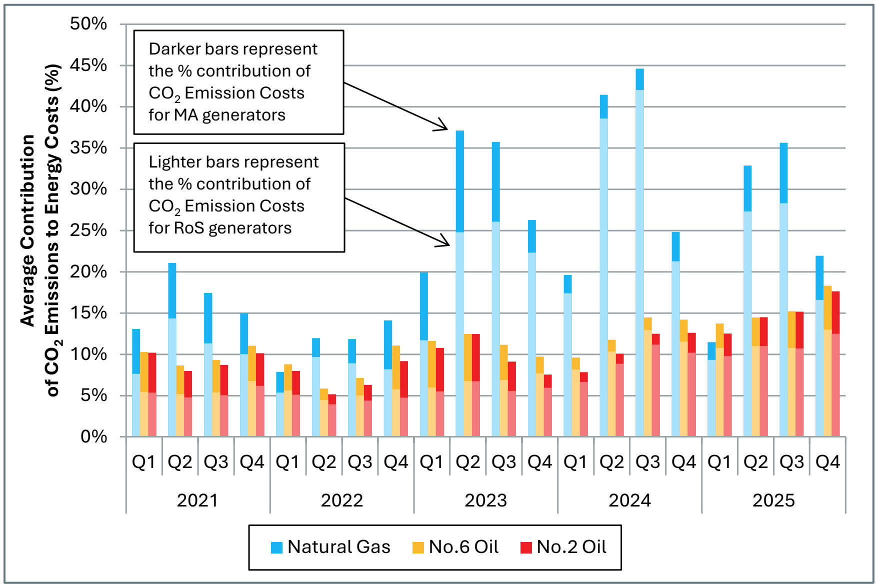
In 2025, RGGI compliance costs added $10.21/MWh to the production cost of an average natural gas combined-cycle unit, a slight increase from $9.59/MWh in 2024. MA EGEL compliance costs more than doubled over the same period, reaching $3.56/MWh for a combined-cycle unit. Despite increased emissions costs, those costs represented a smaller proportion of total generation costs for natural gas generators in 2025 compared with 2024, due to a larger rise in natural gas fuel costs (up 105% year-over-year). The contribution of emissions costs decreased 10 percentage points (from 27% to 17%) for natural gas generators participating only in RGGI, and about 9 percentage points (from 30% to 21%) for natural gas generators in Massachusetts that were subject to both carbon programs.

[147] Fuel, CO_2 emission, and variable operating and maintenance costs are considered when calculating the costs for each generator. Variable operating and maintenance costs represent a small percentage of costs for generators. CO_2 prices in $/short ton are converted to estimated $/MWh using average generator heat rates for each fuel type and an emissions rate for each fuel.

[148] IMM standard generator heat rates and fuel emission rates are used to convert $/ton CO_2 prices to $/MWh generation costs. The RGGI adder for a coal generator is about $22/MWh. Due to little remaining capacity, it is no longer shown in these exhibits.

The contribution of CO_2 emission costs to energy production costs at a quarterly level is detailed in Figure 4-13.

Figure 4-13: Estimated Average Percent Contribution of CO_2 Emission Costs to Energy Production Costs



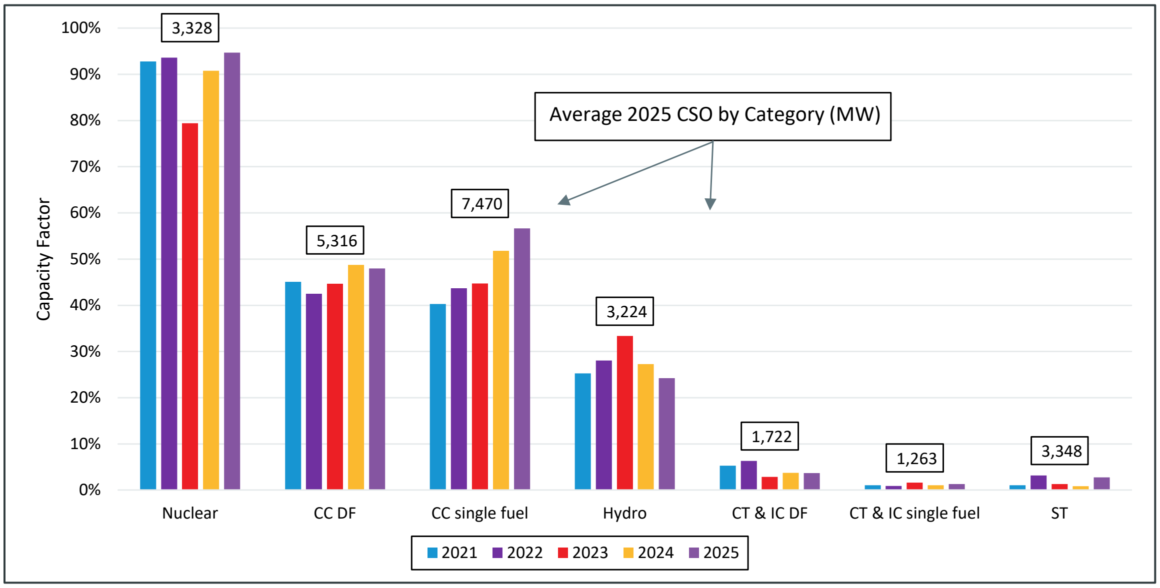
This graph illustrates how the share of total natural gas generator costs coming from emissions costs spikes in the second and third quarters of each year, when natural gas prices tend to be lower. In contrast, because oil prices have declined slightly over the past two years, the contribution of emissions costs to oil generator costs has increased in line with rising emissions costs.

4.2.2 Capacity Factors

Capacity factors provide a high-level view of the relative economics and physical capabilities of generators.[149] Average capacity factors by generator type are shown in Figure 4-14 below.

[149] For the purposes of this section, capacity factor is measured as the ratio of a generator's average hourly output relative to their total capacity supply obligation (CSO). Although this can result in high capacity factors for individual resources with a low portion of their capacity contracted through capacity supply obligations, at the fleet level the results represent the portion of the contracted capacity that is typically operating.

Figure 4-14: Capacity Factor by Generator Type



Hydro capacity factors fell to 24% from 27% in 2025 following drier conditions. Single-fuel combined-cycle capacity factors increased significantly in 2025, from 52% to 57%, primarily due to the retirement of the Mystic generators, which had two of the lowest four capacity factors of any single-fuel combined cycle units in 2023. Steam turbines also saw an increase in capacity factors, from about 1% to about 3% in 2025. Over half of steam turbine generation was in the winter months (about 30% in December and 25% in January) with June and July accounting for an additional third of steam turbine generation.

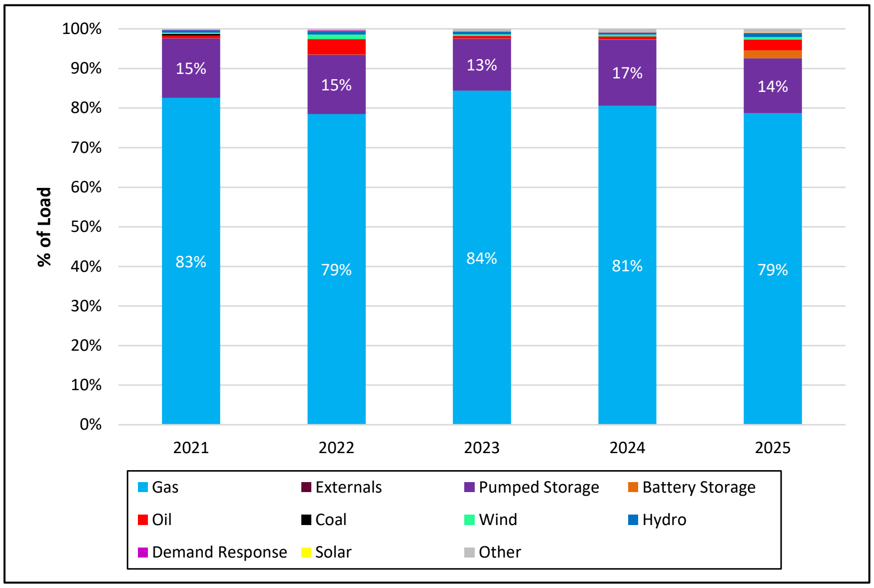
4.2.3 Marginal Resources

The price of energy is largely determined by the marginal resource (i.e., the resource that would provide the next increment of energy). Consequently, trends in marginal resources can provide important insights into changes in energy prices over time. Below, we present statistics on marginal resources by transaction and fuel type in the real-time energy market.[150]

The percentage of load for which each transaction type was marginal in the real-time energy market over the last five years is illustrated in Figure 4-15 below.

[150] The statistics presented in this section are calculated on a load-weighted basis. When more than one resource is marginal, the system is typically transmission-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.

Figure 4-15: Real-Time Marginal Resource by Transaction Type



Gas-fired generation set price for 79% of real-time load and pumped storage set price for 14% of load, consistent with averages over the last several years. Oil-fired generators were marginal for 3% of load, marking a higher share than the last two years and reflecting winter conditions that were relatively similar to Winter 2022.

Battery storage resources set price for 2% of load. Batteries have increasingly set price throughout 2025 as large battery facilities have come online and have an increasing share of the supply mix. In general, batteries charge when LMPs are low and discharge when LMPs are high. Therefore, batteries are frequently close to the marginal price of supply during daily peak periods.

4.2.4 Supply-Side Participation

Some resources are willing to clear in the energy market at any price (price-taking), while others offer supply at a specific price that is used in the market clearing engine to determine commitment and dispatch. The volumes of price-setting vs. non-setting price supply on the system have important implications for price formation. For example, if most supply cannot set price, there is a higher likelihood of low or negative LMPs.

In 2025, non-price-setting-supply made up 66% of total supply in the day-ahead energy market and 65% in the real-time energy market. Non-price-setting supply consists of offers from suppliers that are willing to sell at any price, as well as offers that cannot set price. Market supply may be insensitive to price for several reasons, including fuel and power contracts, hedging arrangements, unwillingness to cycle (on and off) a generator, or operational constraints. The remaining 34-35% of supply is considered price-setting supply (i.e., it is willing to sell at a specified offer price or higher and can set price).

There are three categories of *non-price-setting* supply: fixed imports, self-scheduled generation, and generation-up-to economic minimum.

- **Fixed imports** are scheduled to flow power into New England on the external interfaces regardless of price.

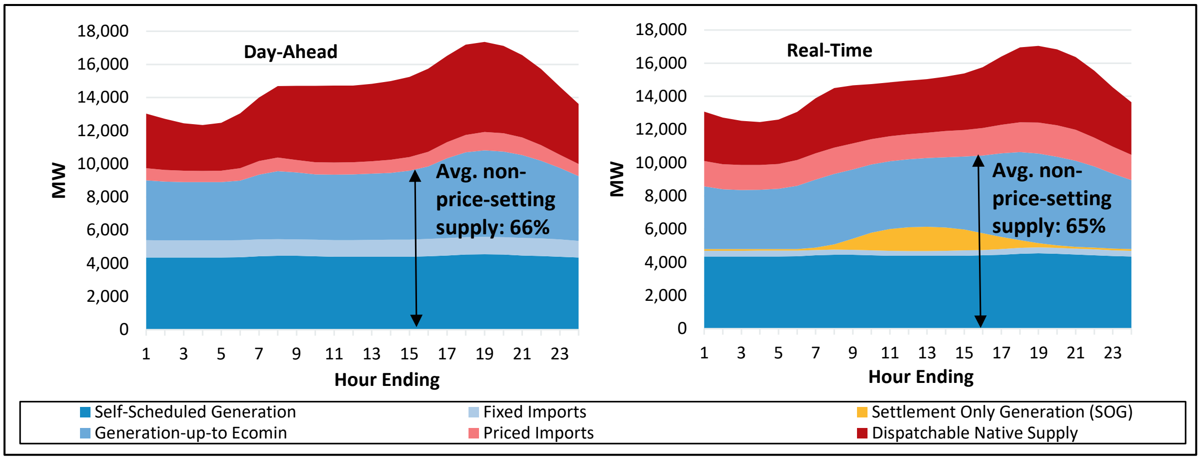
- **Self-scheduled generation** is offered into the energy market as must-run generation. Generators self-schedule at their economic minimum (EcoMin).[151]
- **Generation-up-to economic minimum** from economically-committed generators is the portion of output that is below EcoMin.[152]

There are two categories of *price-setting* supply that participate in price formation: dispatchable native supply and priced imports.

- **Dispatchable native supply** is energy from generators, demand response resources (DRRs), and virtual transactions (day-ahead market only) that is dispatched economically (based on its offer price). For generators and DRRs, this is energy delivered at levels within the resource's dispatchable range, above EcoMin.
- **Priced imports** include price-sensitive imports and up-to-congestion transactions.[153, 154]

An hourly average breakdown of price-setting and non-price-setting supply by category for the day-ahead and real-time markets in 2025 is provided in Figure 4-16 below.

Figure 4-16: Day-Ahead and Real-Time Supply Breakdown by Hour Ending, 2025



On average, non-price-setting supply made up 66% of total supply in the day-ahead market and 65% of total supply in the real-time market. These shares remained similar to 2024. Price-setting supply averaged 35% of total supply over all hours in the real-time market in 2025, with its share peaking in hours ending (HE) 18-22 at 37-38%.

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[151] The Economic Minimum (EcoMin) is the minimum MW output available from a generator for economic dispatch.

[152] For example, if a unit generating 150 MW has an EcoMin of 100 MW, then its generation-up-to EcoMin is the portion below 100 MW. Generation-up-to EcoMin does not participate in price formation, as the market software cannot dispatch it up or down.

[153] Up-to-congestion (UTC) transactions are external contracts in the day-ahead energy market that do not flow if the congestion charge is above a specified level. Real-time external transactions cannot be submitted as up-to-congestion contracts. Participants with real-time external transactions are considered willing to pay congestion charges.

[154] There are some nuances to the priced imports category in terms of price-setting ability. While priced imports regularly set price in the day-ahead market, they rarely set price in real-time market. This is because the tie lines are scheduled in advance of the delivery interval in real time and are given a small dispatchable range in the real-time dispatch and pricing algorithm. This prevents the market software from dispatching the tie lines far away from the scheduled amount determined by the transaction scheduling process.

In both markets, the daily ramp-ups in load are typically met by additional supply from *generation-up-to EcoMin* (as additional generators are committed) and *price-setting* supply. In the day-ahead market, the level of supply from *self-scheduled* generation (the largest component of unpriced supply) and *fixed imports* was reasonably stable over the course of an operating day. A majority of unpriced supply tends to be from nuclear generators whose production is stable throughout the day. By contrast, in the real-time market, average hourly self-scheduled generation was higher during midday due to output from settlement-only solar generators (SOGs).[155] In 2025, hourly SOG output averaged 531 MW, or 11% of total real-time self-scheduled generation. SOG generation is higher in the middle of the operating day, peaking at an average of 1,461 MW in HE 13. These smaller generators do not clear in the day-ahead market because they are not modeled in the market nor centrally dispatched by the ISO control room.[156]

Unpriced Supply and Price Formation Implications

Large volumes of non-price-setting supply can increase the likelihood of low or negative prices. This may become more common when combined with significant amounts of additional capacity from renewable generation (e.g., wind and solar) with low marginal costs. However, we generally find that energy price formation is robust under current levels of unpriced supply, with prices reflecting the marginal input costs of the highest cost resources dispatched to meet demand.

The combination of lower loads and large amounts of non-price-setting generation can bring about a sudden drop in prices, to low or even negative levels. However, the overall frequency of negative real-time prices at the Hub remains relatively low. Negative prices at the Hub occurred in 0.8% of five-minute real-time pricing intervals in 2025. Even in Maine, which tends to have a higher frequency of negative nodal prices at export-constrained pockets with wind generation, the zonal price was negative in only 1.5% of five-minute real-time pricing intervals in 2025. The frequency of negative LMPs is discussed further in Section 2.5.

The example shown in Figure 4-17 below illustrates low pricing at a time when a significant amount of non-price-setting supply combined with negative priced energy supply offers to result in low LMPs.[157]

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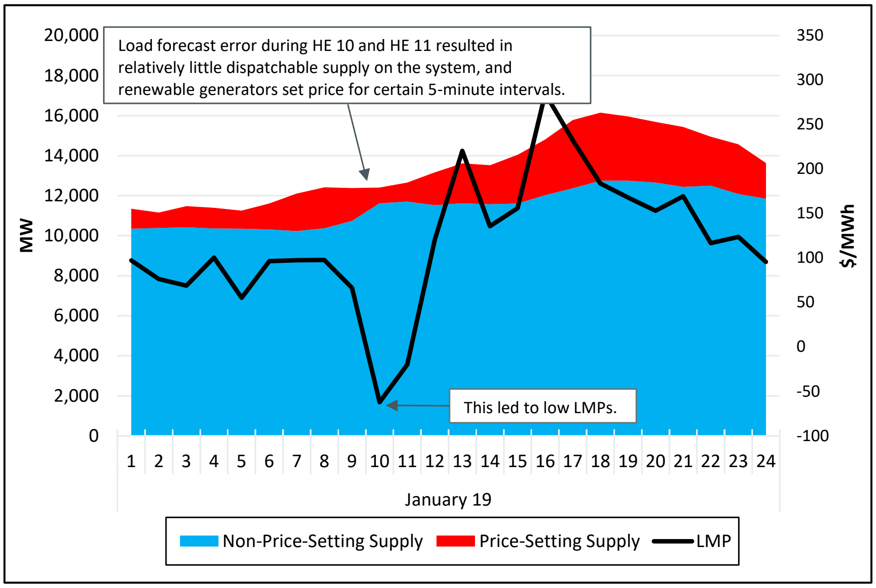
[155] See Section 1.6 for a discussion on solar generation and changing demand.

[156] SOGs are passive participants in the real-time energy market only.

[157] Unlike the figure above, this figure includes all imports in the fixed supply category for convenient illustrative purposes.

Figure 4-17: Priced and Unpriced Supply vs. Real-Time LMP, January 19, 2025



On January 19, load-serving entities cleared excess load in the day-ahead market due to warmer than forecasted temperatures. Real-time loads were lower than the ISO's load forecast, especially during HE 10 and HE 11. As a result, real-time generation needs were less than the amount that cleared in the day-ahead market, and the ISO only had to dispatch a small amount of price-setting generation throughout the morning. The small amount of economically dispatched generation offered into the market at low values, resulting in low prices. The five-minute Hub LMP ranged from -$99.49/MWh to $0.00/MWh from 9:00 am to 10:35 am, and the hourly price averaged -$66.11/MWh and -$20.00/MWh during HE 10 and HE 11, respectfully.

4.3 Demand-side Factors

This section explores key factors influencing demand levels and behavior in the energy markets. Section 4.3.1 analyzes the impact of weather and behind-the-meter solar generation on load. Section 4.3.2 takes a deeper look at the nature of demand-side participation.

Key Takeaways

Demand Trends: Average and peak load levels increased in 2025, with annual load rising from 13,299 MW in 2024 to 13,441 MW in 2025, just a 1% increase. Peak load reached 26,086 MW on June 24, 2025, the highest level since 2013. Weather-normalized load also increased modestly. Behind-the-meter (BTM) solar continued to lower wholesale load during daytime hours and shape intraday load profiles across all seasons, with growing impacts on both morning downward ramps and evening upward ramps.

Demand Bidding: Load Serving Entities (LSEs) continued to clear more demand in the day-ahead market relative to real-time load. Additionally, demand bidding remained mostly insensitive to prices with fixed-priced bids continuing to make up the largest share of day-ahead cleared demand. Virtual demand, exports and asset-related demand continued to provide important price-elasticity to the demand side.

4.3.1 Load and Weather Conditions

Net Energy for Load (NEL) averaged 13,441 MW in 2025, a 1% increase from 2024. The trends in New England's annual load levels are shown in Table 4-3 below.[158, 159]

Table 4-3: Average, Peak and Weather-Normalized Load

Demand (MW)	2021	2022	2023	2024	2025	% Change '24 to '25	Sparkline
Load (avg. hourly)	13,561	13,576	13,096	13,299	13,441	1%	
Weather-normalized load (avg. hourly)	13,419	13,514	13,132	13,236	13,394	1%	
Peak load (MW)	25,801	24,780	24,043	24,871	26,586	7%	
Minimum load (MW)	8,646	8,694	8,617	8,775	7,684	-12%	

Weather-normalized load averaged 13,394 MW, nearly identical to actual load, indicating that weather conditions were close to seasonal norms throughout the year. Peak load increased to 26,586 MW on June 24 during the PFP event, representing a 7% rise from 2024 and marking the highest level recorded since 2013.[160] Minimum load fell to 7,684 MW on April 20 during mild spring conditions, setting a new record low as strong behind-the-meter (BTM) solar output significantly reduced midday system demand, [161] with BTM solar systems lowering demand by an estimated 4,586 MW during the minimum-load hour.

Demand Profiles and Energy Prices

The connection between load levels and energy prices becomes particularly clear when examining hourly operating-day conditions. Figure 4-18 shows the average time-of-day profile for both day-ahead demand and real-time load compared to day-ahead and real-time LMPs, along with average hourly load reductions from behind-the-meter (BTM) solar generation. The figure is broken out into winter, summer, and rest-of-year averages to illustrate seasonal differences in load curves, prices, and solar generation.[162]

[158] In this analysis, load refers to *net energy for load* (NEL). NEL is calculated by summing the metered output of native generation, price-responsive demand and net interchange (imports – exports). It excludes pumped-storage demand.

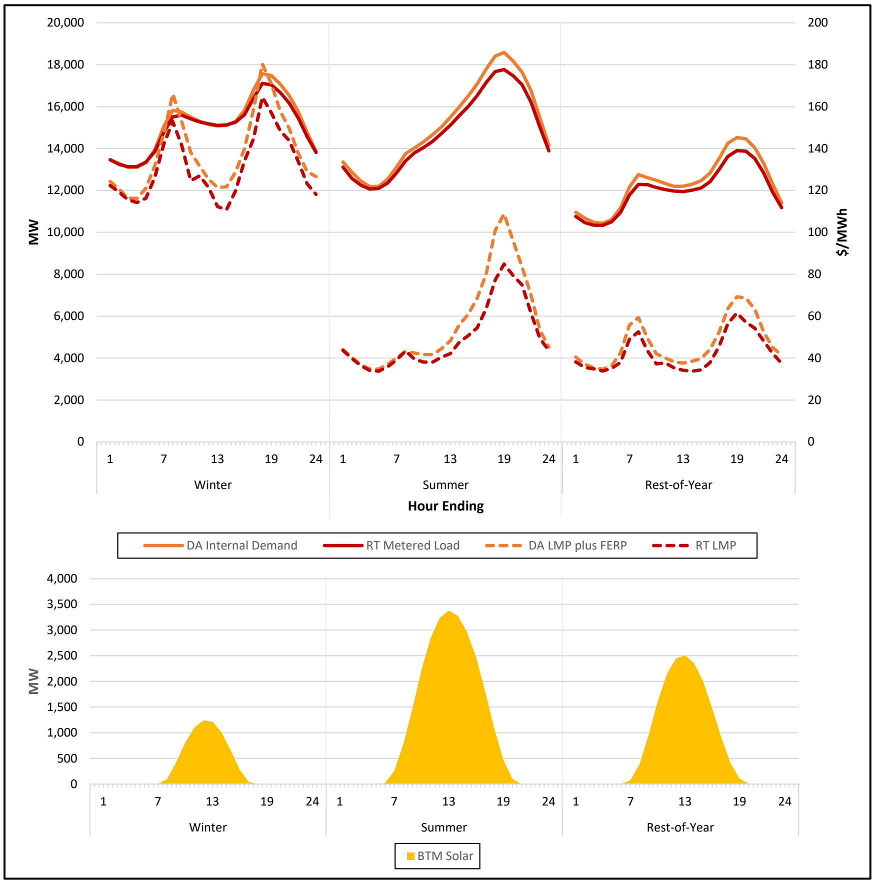
[159] Weather-normalized load estimates what load would be if monthly total heating degree days and cooling degree days were in line with historical averages. The estimate also factors in differences due to non-holiday weekdays and leap days.

[160] The region experienced exceptionally high electricity demand during a July 15–20, 2013 heat wave. The system reached a summer peak of 27,360 MW on July 19, 2013, marking the fourth-highest demand day ever recorded. ISO New England Inc., Internal Market Monitor, "*2013 Annual Markets Report*", May 6, 2014, https://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/2013/2013_amr_final_050614.pdf.

[161] For context, ISO New England has reported historically low system demand, including this new record low. ISO New England Inc., ISO Newswire, "*New England grid sees new record low for system demand*", April 22, 2025, https://isonewswire.com/2025/04/22/new-england-grid-sees-new-record-low-for-system-demand/

[162] Winter seasons include December, January, and February; summer seasons include June, July, and August.

Figure 4-18: Average Demand and LMP by Hour, 2025[163]



BTM solar generation continued to influence the wholesale load profile even in winter months in 2025, with an average of over 1,000 MW of BTM generation at noon and corresponding dips in midday load.[164] Summer months had both the highest load and ramps, with average peak load well over 18,000 MW. While summer BTM solar typically peaked well over 3,000 MW, peak loads did not typically fall midday in summer as air conditioning demand sharply increased. For “Rest-of-Year” peak loads typically occurred midday with over 2,500 MW of BTM generation.

Across all seasons, day-ahead and real-time prices follow load profiles, with lower LMPs during peak solar hours in winter and rest-of-year and sharply increasing evening LMPs in summer. Figure 4-18 also shows that day-ahead LMPs typically exceeded real-time LMPs as discussed in Section 4.1, and cleared demand typically exceeded real-time load as discussed further in Section 4.3.2.

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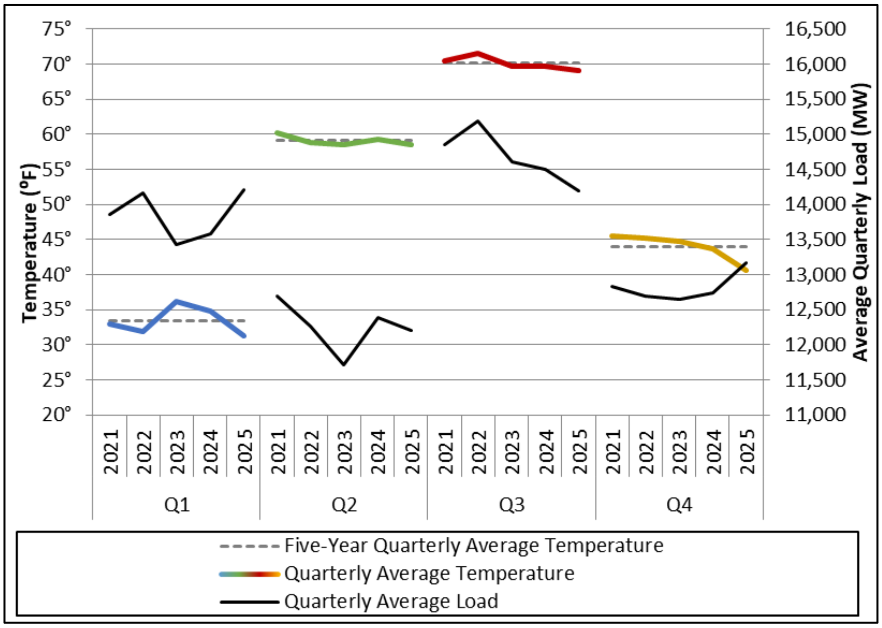
163 Day-ahead internal demand is equal to fixed demand + price-sensitive demand + virtual demand. This includes pumped-storage demand and excludes virtual demand at external nodes. Real-time load is the total end-use wholesale electricity load within the ISO New England footprint.

164 The ISO does not meter output from BTM solar installations or directly measure BTM capacity. For details on behind-the-meter estimation methods, see: ISO New England Inc., “*Load Forecast”* webpage, https://www.iso-ne.com/system-planning/system-forecasting/load-forecast/.

Impact of Weather

Weather is a significant driver of load in New England. Loads are significantly impacted by air conditioning demand in hot weather and electric heating demand in cold weather. Quarterly average and five-year average temperatures for 2021 through 2025 are illustrated in Figure 4-19 below.[165]

Figure 4-19: Seasonal vs. Five-Year Average Temperatures



Weather conditions in 2025 were colder than in 2024, contributing to higher average loads in the winter quarters (Q1 and Q4) and lower average loads in Q2 and Q3. Winter conditions in Q1 were 4°F colder than in 2024, with average temperatures just below freezing (31°F). As electrification of heating continues to expand, winter demand levels—and their sensitivity to temperature—are expected to rise. Summer conditions in Q3 were mild on average, although broadly consistent with 2024, with average hourly loads of approximately 14,200 MW. 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.[166]

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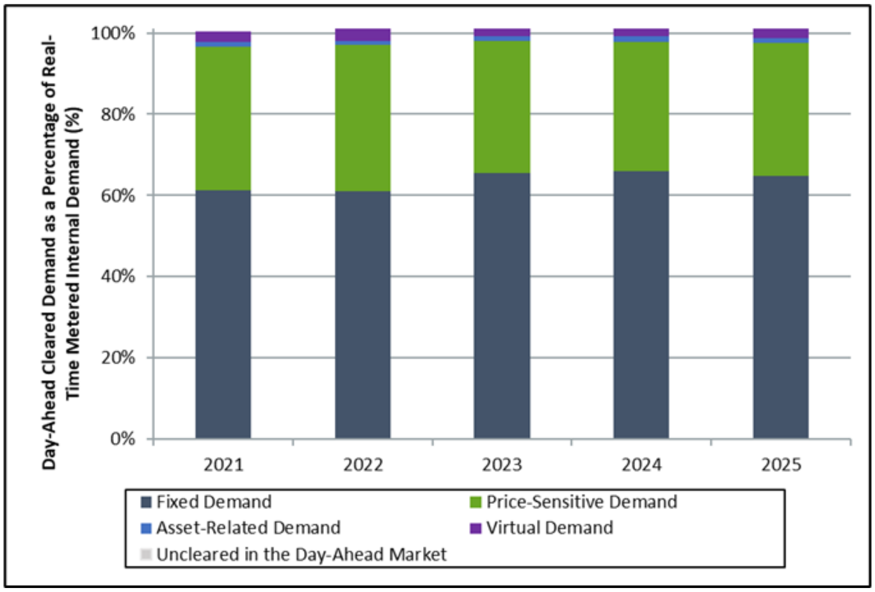
[165] As of July 27, 2023, the ISO calculates New England average temperatures based on new methodology and data collection that incorporates observations from 23 cities. ISO New England Inc., ISO Newswire, *"ISO-NE weather forecast improvements aid grid operations"*, July 27, 2023, https://isonewswire.com/2023/07/27/iso-ne-weather-forecast-improvements-aid-grid-operations/.

[166] ISO New England Inc., Internal Market Monitor, "*Summer 2025 Quarterly Markets Report",* November 12, 2025, 2025-summer-quarterly-markets-report.pdf

4.3.2 Demand Bidding

The quantity and pricing of bid-in demand in the day-ahead market have important implications for both price formation and system operations. Day-ahead cleared demand by bid type as a percentage of real-time load is shown below in Figure 4-20.[167]

Figure 4-20: Day-Ahead Cleared Demand as a Percentage of Real-Time Load by Bid Type



When real-time demand exceeds day-ahead cleared demand, higher cost resources may need to be dispatched to meet the energy gap, resulting in higher real-time energy prices relative to day-ahead prices. Demand activity can also directly influence price formation. In 2025 Fixed demand declined from 66.0% to 64.9%, while priced demand increased from 31.9% to 32.8%. Asset-related demand decreased slightly from 1.3% to 1.1%. The most notable change was in virtual demand, which increased from 2.6% to 3.7%, indicating a larger role for virtual activity in day-ahead demand outcomes in 2025.[168]

Participants cleared 102% of real-time load in the day-ahead market in 2025, continuing a pattern of modest over clearing observed in recent years. Day-ahead fixed demand, priced demand, and asset-related demand together accounted for nearly all of real-time load, indicating that over clearing continues to be driven primarily by virtual demand rather than shifts in underlying physical demand.[169]

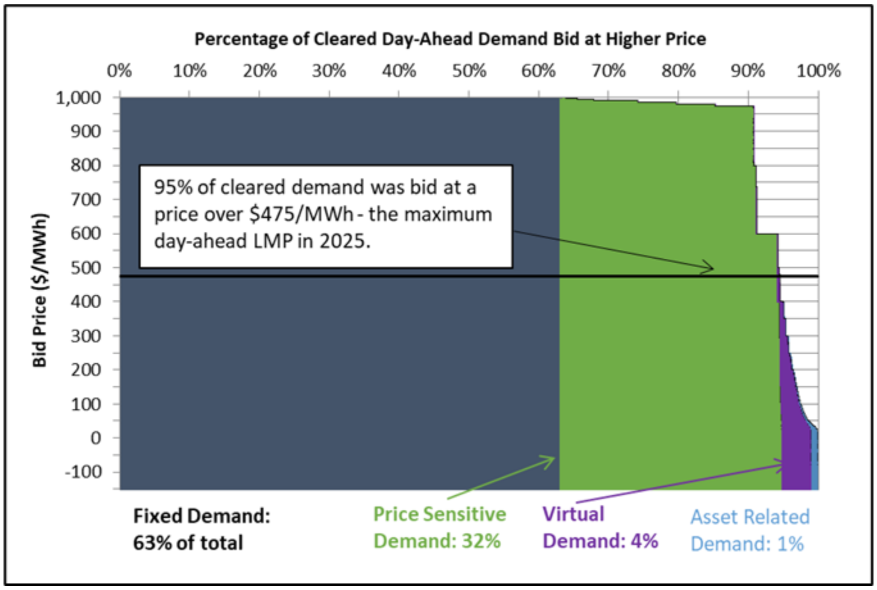
Aggregating cleared demand components by price provides additional insight into bidding behavior and the price sensitivity of demand. Figure 4-21 aggregates annual cleared demand by bid price.

[167] Real-time load is the total end-use wholesale electricity load within the ISO New England footprint. Real-time load is equal to Net Energy for Load – Losses.

[168] See Section 4.2.3 for a discussion of marginal resources and price-setting load.

[169] For more information on virtual demand, see Section 6.

Figure 4-21: Components of Day-Ahead Cleared Demand as a Percentage of Total Day-Ahead Cleared Demand



Internal demand in New England continued to exhibit very limited price responsiveness in 2025. Fixed demand represented 63% of total day-ahead cleared demand, consistent with prior years. Price-sensitive demand accounted for 32% of cleared demand; however, nearly all of these bids were submitted at prices well above expected day-ahead LMPs. As shown in Figure 4-21 95% of all cleared demand was bid at a price above expected LMPs. This bidding pattern indicates that load-serving entities were generally willing to reduce demand only under the highest price conditions.

Virtual demand represented 4% of cleared demand, while asset-related demand from storage and pumping accounted for 1%. Overall, the aggregate day-ahead internal demand curve remained steep around expected LMPs, confirming that internal demand remained largely price insensitive and similar to prior years.

4.4 System Reliability

The ISO is required to operate New England's wholesale power system to the reliability standards developed by the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC), and in accordance with its own reliability criteria.[170] The energy market may not always produce outcomes that satisfy these reliability criteria, in which case market operators may take out-of-market actions to ensure system reliability. This section of the

[170] These requirements are codified in the NERC standards, NPCC criteria, and the ISO's operating procedures. North American Electric Reliability Corporation (NERC), "*Reliability Standards*" webpage, http://www.nerc.com/pa/stand/Pages/default.aspx.

Northeast Power Coordinating Council Inc. (NPCC), "*Standards*" webpage, https://www.npcc.org/program-areas/standards-and-criteria.

ISO New England Inc., "*ISO Operating Procedures*" webpage, http://www.iso-ne.com/rules_proceds/operating/isone/index.html.

report analyzes these out-of-market actions.

Key Takeaways

In 2025, the day-ahead market generally procured sufficient energy to meet the ISO's load forecast, though there was a higher frequency of small positive energy gaps compared to prior years. These gaps primarily reflected the clearing of Energy Imbalance Reserve (EIR), a product introduced with the Day-Ahead Ancillary Services (DA A/S) market in March 2025. Along with cleared energy, EIR contributes to satisfying forecasted demand, and its increased use represents an intended feature of the updated market design rather than a deterioration in market outcomes.

Following the close of the day-ahead market, the ISO's Reserve Adequacy Analysis (RAA) evaluates whether cleared resources are sufficient to meet forecasted energy and reserve requirements. With the DA A/S market in place, reliance on post-market adjustments and additional commitments declined markedly. Consistent with this objective, no generator commitments originated from the initial RAA run in 2025, indicating improved alignment between day-ahead market outcomes and operational reliability needs.

Local reliability commitments and posturing continued to decline, extending a multi-year trend. The limited reliability commitments made in 2025 were predominantly in-rate, which helped contain reliability-related uplift payments.

Meanwhile, load forecasting accuracy remained stable relative to prior years, despite increasing complexity from continued growth in behind-the-meter solar generation. Ongoing investments by the ISO in forecasting tools have helped maintain forecast performance under these evolving system conditions. Because the load forecast is now a constraint in the day-ahead market with associated financial implications, continued investment in forecasting tools and methodologies remains particularly important for supporting efficient price formation and minimizing unintended cost impacts.

4.4.1 Reserve Adequacy Analysis and the Day-Ahead Energy Gap

The commitment and dispatch outcomes in the *financial* day-ahead market may not always reflect expected *physical* real-time conditions. For example, load-serving entities may clear less demand than the ISO's load forecast, resulting in less physical energy supply clearing in the day-ahead market than is expected to be needed in real time. When this happens, there is a day-ahead "energy gap," which we define here as (1) the expected real-time load less (2) the amount of day-ahead energy awards on physical resources (i.e., excluding virtual supply).

A key design change under the Day-Ahead Ancillary Services Initiative (DASI), which went into effect March 2025, was the explicit incorporation of the ISO's load forecast into the day-ahead market clearing process. The Forecast Energy Requirement (FER) constraint ensures that sufficient physical capability is procured in the day-ahead market to meet forecasted load (absent a violation of the constraint). This requirement may be satisfied through day-ahead energy awards from physical supply resources as well as awards of Energy Imbalance Reserve (EIR).[171] Consequently, while there can still be an "*energy* gap," there can no longer be a "*capability* gap" as the day-ahead market now clears sufficient physical capability (in the form of energy and EIR) to meet the load forecast.

After the day-ahead market is approved, the ISO performs the Reserve Adequacy Analysis (RAA) to evaluate day-ahead cleared supply against forecasted energy and reserve requirements.[172] If the day-ahead market did not clear enough *physical* supply to meet the ISO's forecasted demand and reserve requirements, the RAA may rely upon resources to operate at levels above their day-ahead schedules and, infrequently, may require additional generator commitments. This source of commitment should be less common with the DA A/S market in place, and, in fact, there were no commitments that originated from the first RAA run (i.e., the run that takes place shortly after the close of the re-offer period at 2PM the day prior to the operating day) in 2025.

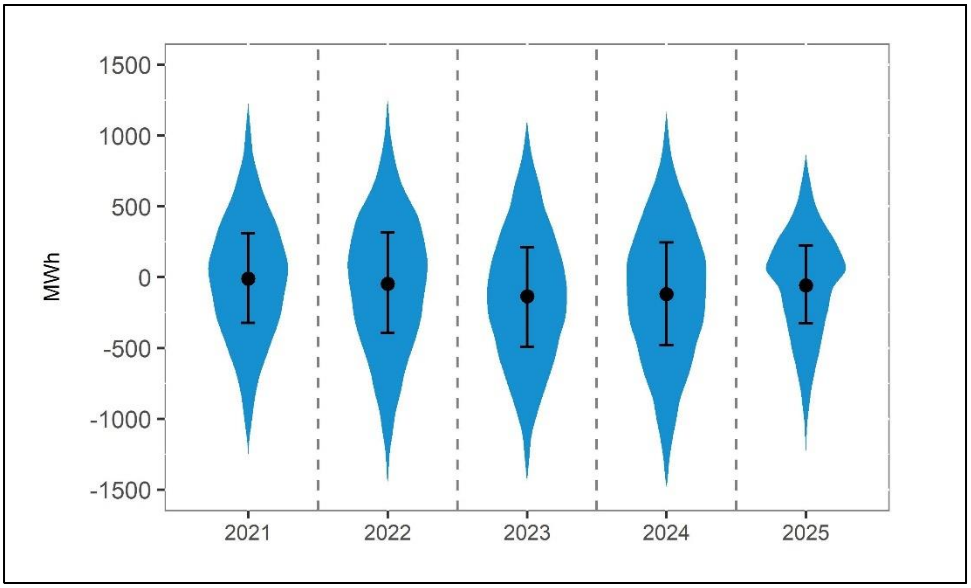
The day-ahead energy gap varied less widely in 2025 than in prior years and, on average, the day-ahead market continued to procure more energy than was expected to be needed in real-time. This can be seen in Figure 4-22 below, which shows the distribution of the day-ahead energy gap for each of the last five years.[173] The figure also shows, by year, the 25th and 75th percentiles (the black dashes), the interquartile range (the line between the dashes), and the mean (the black circle).

[171] For more information about Energy Imbalance Reserves, see Section 8.2.2.

[172] The RAA process is performed several times for each operating day, with the first RAA run taking place shortly after the close of the re-offer period at 2PM the day prior to the operating day. For more information about the RAA, see: ISO New England Inc., "*SOP-RTMKTS.0050.0010 - Perform Reserve Adequacy Analysis*", https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/sysop/rt_mkts/sop_rtmkts_0050_0010.pdf

[173] Figure 4-22 presents the day-ahead energy gap using a violin plot, which combines features of a boxplot and a density plot. The curves depict the distribution of the energy gap, where the widest sections of each curve represent the most-frequently observed levels. A negative value indicates that there was no day-ahead energy gap in a specific hour (i.e., the sum of the cleared physical day-ahead energy awards exceeded the load forecast).

Figure 4-22: Day-Ahead Energy Gap



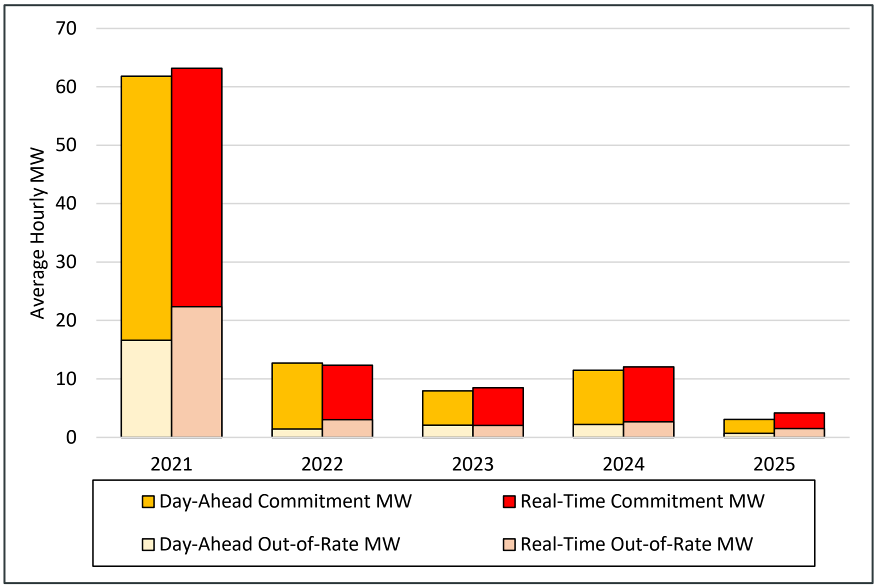
The average day-ahead energy gap in 2025 was -72 MWhs, which indicates that the quantity of cleared physical energy *exceeded* the load forecast on average. In 2025, the middle 50% of hourly observations fell between -334 MWh to 222 MWh, which represented a modest decrease compared to prior years. Notably, the curve for 2025 shows a higher frequency of observations at values slightly above 0 MWh, indicating that small energy gaps were more common in 2025 than in prior years. This is largely the result of the new FER constraint and EIR product. Given that EIR awards can now be used to meet the anticipated next-day load (along with day-ahead energy awards), the day-ahead market may deem it more efficient to satisfy energy gaps via EIR awards than to clear additional energy. During the period of March 2025 through December 2025, the hourly average volume of EIR awards was 125 MWh.

4.4.2 Reliability Commitments and Posturing

Reliability commitments include manual generator commitments for local second contingency protection, voltage support, or other special constraints. System operators direct such commitments for reliability purposes rather than generator economics. Consequently, reliability commitments are often out of merit and may negatively impact price formation for other online generators. Average hourly energy output (MW) from reliability commitments for 2021 through 2025 is shown in Figure 4-23 below.[174] The figure also specifies which portion of the output was out-of-rate, based on offer segments priced above the LMP.

[174] For more information on reliability commitments reviewed by the IMM, see: ISO New England Inc., "*Market Rule 1 Appendix A Market Monitoring, Reporting and Power Mitigation, Section III.A.5.5.6.1*", https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf.

Figure 4-23: Average Hourly Energy Output from Reliability Commitments



The total amount of reliability commitments decreased substantially in 2025, with an annual hourly average of under 10 MW of reliability commitments, about three quarters of which were local second contingency commitments. At a system level, reliability commitments declined significantly after 2021 when transmission upgrades in Maine and Southeastern Massachusetts (SEMA) were completed. Furthermore, the few reliability commitments were mostly in-rate, limiting reliability uplift payments. The local second contingency commitments occurred throughout the year and were generally in Maine or Southwest New England.

System operators may posture units—reducing their output below economic dispatch levels—to maintain operating reserves under stressed system conditions or to conserve limited stored fuel. When this occurs, resources are compensated through uplift payments for following operator instructions. In 2025, no resources were postured.

4.4.3 Load Forecast and Market Implications

The ISO's day-ahead load forecast, published around 9:30 am, is the last load projection prior to the close of the day-ahead market for the next operating day.[175] The load forecast was not a direct input into the day-ahead market up until March 2025, when DA A/S incorporated the load forecast as a constraint to be met in the market clearing engine. However, up to that point the ISO load forecast nonetheless informed Load Service Entities' (LSEs) submission of day-ahead demand bid quantities.[176, 177] Therefore, LSE day-ahead demand clearing relative to their real-time load generally aligns with the ISO forecast error. Consequently, the day-ahead load forecast error has

[175] Twice a day, the ISO produces a three-day load forecast that projects load for the current day and the following two days. The first forecast is typically released around 4:30am and the second, and typically final forecast, is published near 9:30am. ISO New England Inc., "*Three-Day System Demand Forecast*" webpage, https://www.iso-ne.com/markets-operations/system-forecast-status/three-day-system-demand-forecast

[176] Load Serving Entities (LSEs) may also rely on their own in-house or third-party forecasting tools to inform their day-ahead bidding strategy.

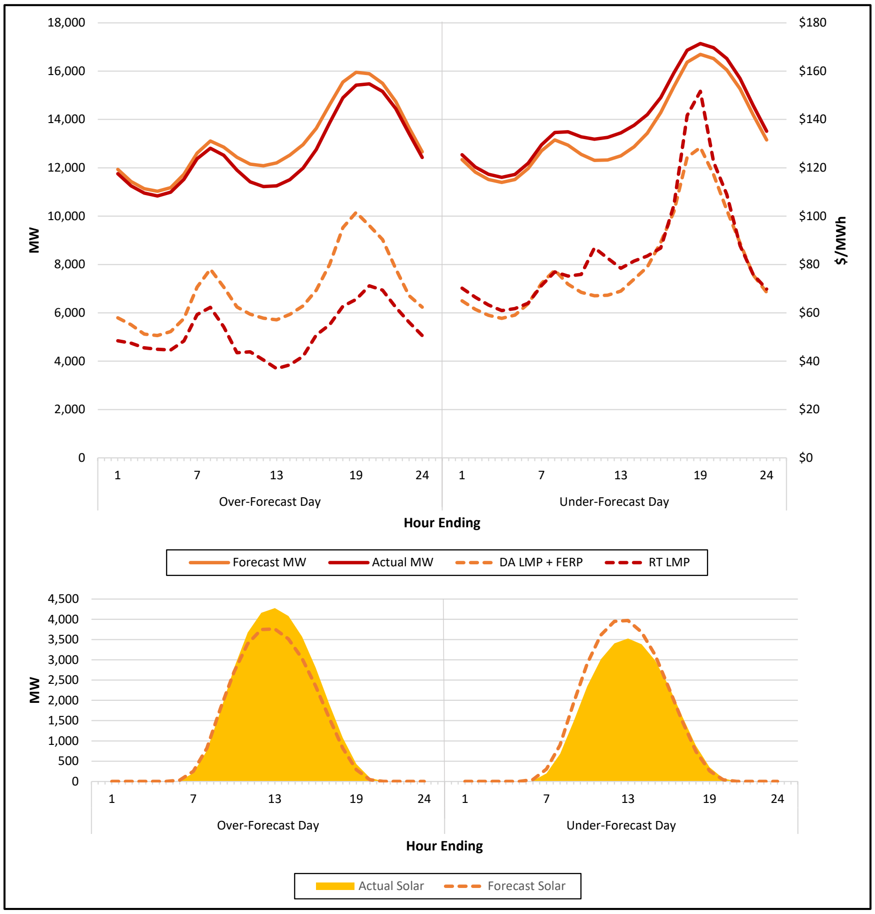
[177] Additionally, as mentioned in Section 4.4, the load forecast is used in the RAA process to finalize the ISO's next day operating plan.

implications for both generator commitments and price deviations between the day-ahead and real-time markets.

Load Forecast Accuracy

Trends in load forecasting accuracy are covered in Section 1.5 which concludes that the distribution of the load forecast error in 2025 was consistent with prior years. The continued growth in BTM[178] solar generation in recent years adds to the complexity of load forecasting, and the ISO has invested significantly in enhancing its load forecasting tools.[179] Figure 4-24 illustrates the relationship between solar forecast error, load forecasts, and LMP deviations by displaying the load curves of typical over- and under-forecast days, with load on the left axis, LMPs on the right axis, and solar forecasts below.[180]

Figure 4-24: Impact of BTM Solar on Load Forecast Error



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178 The ISO includes both behind-the-meter solar and front-of-the-meter settlement-only (SOG) solar in its operational solar forecasts.

179 In recent years, the ISO has made significant investments to better forecast BTM solar generation. For more information on ISO New England's investment in forecasting behind-the-meter solar generation, see: Energy Systems Integration Group, "*Building data intelligence for short-term load forecasting with behind-the-meter PV*", March 27, 2019, https://www.esig.energy/building-data-intelligence-for-short-term-load-forecasting-with-behind-the-meter-pv/.

180 The average over-forecast and under-forecast days in the graph are calculated from the days with the top 25% largest over- and under-forecast load deviations in 2024.

Over-forecast days, when the day-ahead load forecast is greater than actual real-time load, are typically driven in part by more load-reducing BTM and settlement-only solar generation than anticipated. This forecast error has a knock-on effect on LMPs, where the high day-ahead load forecast can result in more day-ahead unit commitments and higher LMPs and subsequent low LMPs in real time as units are dispatched down.

The opposite effects occur on under-forecast days, which are typically driven by less load-reducing solar generation than expected. Real-time LMPs are typically higher than day-ahead prices, driven by the costs of dispatching units up to meet unexpected demand, fast-start pricing as more units are committed to meet load, or reserve pricing as upward dispatch reduces available reserves.

4.5 Net Commitment Period Compensation (Uplift)

NCPC are make-whole payments made to generators, external transactions, and virtual transactions when they follow ISO dispatch instructions and experience revenue shortfalls or lost opportunity costs. NCPC payments can provide insight into unpriced energy costs, and higher levels of uplift may be symptomatic of price formation or missing product issues. In this section, we review NCPC in the context of total energy payments, provide a breakdown of payments by category, and show NCPC payments by generator type.

Key Takeaways

Net Commitment Period Compensation (NCPC) totaled $42 million ($0.35/MWh of load) in 2025, an increase of $7 million year-over-year, driven primarily by higher generation production and commitment levels. This increase was largely offset by higher energy prices (LMPs), resulting in NCPC declining as a share of total energy costs to 0.4%.

Approximately $31 million (75%) of NCPC payments occurred in the real-time market. Most payments were made to resources committed in economic merit order to meet load and reserve requirements, with uplift covering commitment and opportunity costs not fully recovered through LMPs during commitment and dispatch hours.

Overall, NCPC outcomes in 2025 did not indicate persistent or systemic price-formation concerns. However, consistent with last year's report, fast-start oil-fired generators—important for peak reliability and system flexibility—continue to rely on NCPC to recover a significant share (over 40%) of their operating costs. This reliance reflects a combination of out-of-merit operator-initiated commitments and operational constraints, such as minimum run times. The IMM will continue to monitor these drivers and their implications for price formation.

NCPC in the Context of the Energy Market Payments

Tracking NCPC payments relative to energy payments provides a high-level metric capturing reliance on compensation through make-whole payments rather than uniform market clearing prices, as well as the level of costs borne by payers of uplift, which can be difficult to predict and hedge. Energy and NCPC payments are summarized in Table 4-4 below.

Table 4-4: Energy and Uplift Payments

	2021	2022	2023	2024	2025
Energy Payments ($ millions)	$6,099	$11,712	$4,847	$5,620	$9,407
NCPC Payments ($ million)	$35.9	$53.1	$34.4	$34.7	$41.7
NCPC in $/MWh	$0.30	$0.45	$0.30	$0.30	$0.35

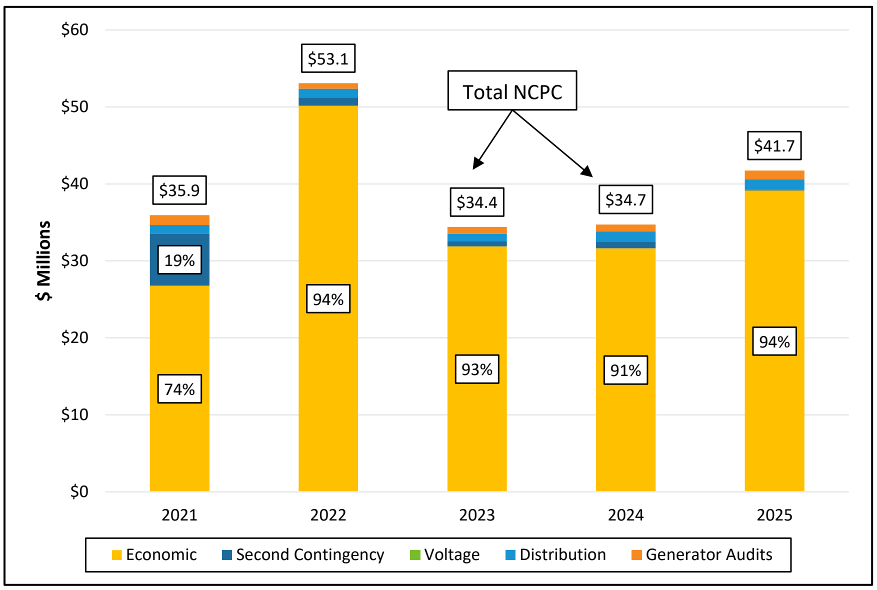
NCPC as % Energy Payments					
Day-Ahead NCPC	0.3%	0.1%	0.1%	0.1%	0.1%
Real-Time NCPC	0.3%	0.3%	0.6%	0.5%	0.3%
Total NCPC as % Energy Costs	**0.6%**	**0.5%**	**0.7%**	**0.6%**	**0.4%**

NCPC payments totaled $41.7 million in 2025, up from $34.7 million in 2024. The subsections below describe the drivers of increased uplift payments. As load was similar to 2024, NCPC payments increased to $0.35/MWh of load (up from $0.30/MWh in 2024). Despite this increase, NCPC payments grew at a lower rate than overall energy market payments. NCPC accounted for just 0.4% of energy market costs, the lowest share over the reporting period. The majority of NCPC continued to be incurred in the real-time market.

NCPC Payments by Category

Below, we sort NCPC payments into categories based on the underlying driver of the commitment or dispatch decision, including meeting system-wide first-contingency requirements (economic NCPC), local second-contingency, distribution or voltage requirements, and dual-fuel auditing requirements. Annual NCPC by category is shown in Figure 4-25 below.

Figure 4-25: Total Uplift Payments by Year and Category

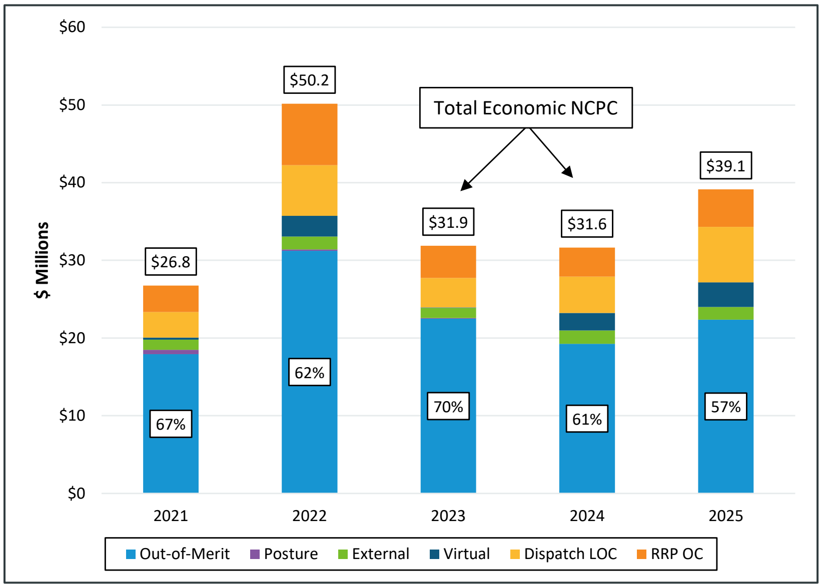


Economic (or First Contingency) NCPC continued to comprise the largest share of uplift payments at $39 million (94% of total). Economic payments drove the increase in overall NCPC as discussed below. Second contingency payments marked their lowest total in the reporting period (<$0.2 million), and distribution payments totaled $1.3 million. Audit uplift totaled just over $1 million.

Economic NCPC by Subtype

Economic NCPC payments contain sub-categories, including out-of-merit payments for unrecovered generation costs, posturing uplift, external transaction payments, and compensation for lost opportunity costs due to the dispatch or rapid-response pricing process. Economic NCPC by subtype is shown in Figure 4-26 below.

Figure 4-26: Economic Uplift by Sub-Category



Out-of-merit payments covering generators' operating cost shortfalls totaled $22 million, or 57% of total economic NCPC. Such payments increased by $3 million from 2024. As natural gas prices rose in 2025, gas-fired generator operating costs increased. Such increased operating costs can lead to higher out-of-merit payments in cases when LMPs do not fully cover generators' costs.

Real-time **fast-start commitments** are one such case when LMPs can fail to fully cover generators' operating costs. This might occur if prices fall while fast-start generators remain in their minimum run time, or if fast-start generation is committed to meet system reliability needs. Economic payments to real-time fast-start generators accounted for 53% of economic out-of-merit NCPC ($12 million).

Payments to **virtual transactions** increased to $3 million in 2025, continuing the increase from $50 thousand to $2 million in 2024. Payments to virtual and day-ahead external transactions increased due to relatively frequent congestion at external interfaces (see Section 5).[181] Such payments maximize total clearing (welfare) without creating additional NCPC charges for load, but rather is a transaction cost paid to the congestion relieving party.

Opportunity cost payments (dispatch and rapid-response pricing) totaled $12 million, up 42% from 2024. As LMPs increased in 2025, opportunity costs resulting from regular dispatch and fast-start pricing mechanics also increased. Additionally, battery storage generators incur higher opportunity costs in the dispatch process since they can respond immediately to ramping dispatch instructions that are sent in advance.

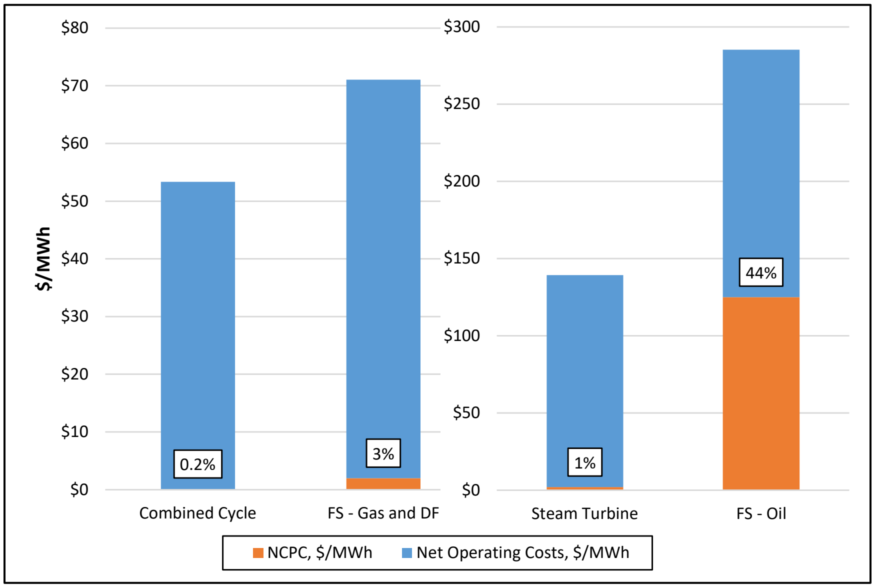
[181] For a numerical example of day-ahead virtual or external NCPC driven by congestion at external interfaces, see: ISO New England Inc., "*FAQs: Net Commitment-Period Compensation (NCPC)*" webpage, https://www.iso-ne.com/participate/support/faq/ncpc-rmr.

NCPC Reliance

As discussed above, high reliance on uplift payments for cost recovery might be indicative of poor price formation or might indicate other structural issues that lead to out-of-merit operation, such as out-of-market reliability commitments and dispatch.

Here, we define NCPC reliance as the share of total operating costs recovered through uplift payments.[182] Figure 4-27 below shows NCPC reliance for select fuel types. [183]

Figure 4-27: NCPC Reliance by Fuel Type



Combined cycle generators required uplift to recover less than 1% of their operating costs in 2025. While combined cycle operating costs increased in 2025 due to higher gas prices, NCPC reliance remained low as higher LMPs compensated generator operating costs. Dual-fuel units with fast-start capability relied on NCPC to recover 3% of their operating costs, and steam turbines relied on NCPC to recover 1% of their costs. By contrast, oil-fired fast-start units with high operating costs ($285/MWh) relied on NCPC to recover 44% of those costs ($125/MWh). Such units received $4 million in out-of-merit NCPC throughout 2025. Oil-fired fast-start generators are manually committed by system operators during relatively tight periods (particularly in the summer) to provide capacity or manage ramps and load forecast deviations. The resulting manual fast-start commitments are often either entirely out of merit or partially out of merit over the generator's

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[182] For the purposes of calculating NCPC reliance, operating costs (the denominator of NCPC reliance) are calculated as the sum of energy, startup, and no-load costs that are eligible for recovery through either energy market revenues or uplift. Offered costs may be negative, and resources that are self-scheduled are treated as if they have negative offered commitment costs. This calculation sums the maximum of each generator's offered operating costs and zero to only include positive operating costs. Additionally, this calculation includes all day-ahead and real-time incremental NCPC and NCPC costs for non-fast start generators, and only real-time NCPC and NCPC costs for fast-start generators. Day-ahead NCPC and costs for fast-start units are not included since day-ahead commitments for fast-start units are not binding. For more information on NCPC cost calculation rules, see ISO New England Inc., "*Section III Market Rule 1 Appendix F Net Commitment Period Compensation Accounting*", https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_f.pdf.

[183] In this figure, NCPC and net operating costs are expressed in $/MWh of real-time generation. Net Operating Costs represent the share of operating costs that can only be recovered through energy market revenues.

minimum run time, resulting in uplift for cost recovery. We continue to monitor these commitments and their implications for price formation.

In summary, NCPC payments increased in 2025 due to higher generator operating costs throughout the year. As increased operating costs were largely reflected in LMPs, NCPC rose in absolute terms but fell as a share of energy market payments. NCPC payments in 2025 did not indicate persistent price formation concerns.

4.6 Summary of System Events During 2025

System events, such as tight system conditions resulting from generator outages or higher than anticipated loads, can have a significant impact on energy market outcomes. Two events warrant mention in 2025: the June 24 and November 23 capacity scarcity conditions (shortage events). This section details the frequency of system events and abnormal conditions over the past five years and provides a summary of the shortage events.

Key Takeaways

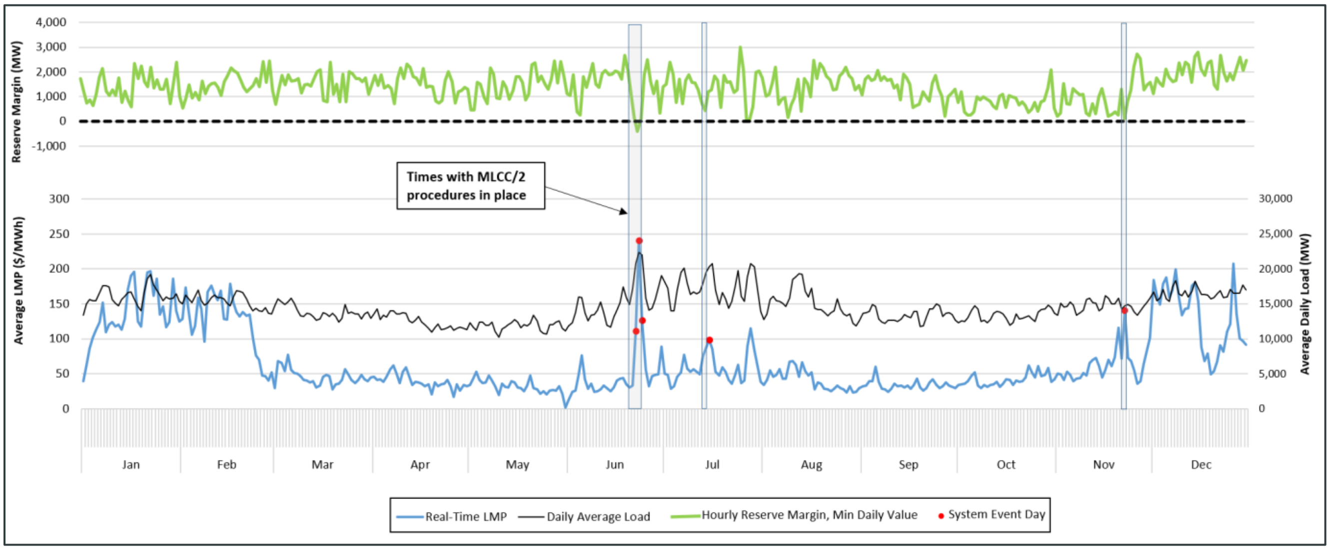
Overall, there were few instances of tight system conditions or scarcity pricing in 2025. These events were transitory in nature, and relatively small operating reserve deficiencies (compared to the requirement) were resolved within a few hours. During these periods, the markets provided transparent and strong price signals that incentivized supply resource performance.

Weather and unplanned supply outages were the main drivers behind notable system events over the last several years. Two reserve shortage events and three M/LCC 2 events occurred during 2025. The first shortage event occurred on June 24 and resulted from a combination of high loads and unplanned generator outages and reductions. The second event occurred on November 23 and resulted from generator outages around the highest loads of the day. These events both occurred simultaneously with M/LCC 2 events. The third M/LCC 2 event occurred in July when temperatures and loads were high.

Overall, these outcomes reflect a system that has had a healthy overall reserve margin with few periods of system stress in the past few years.

To provide context for the events covered in this section, Figure 4-28 below overlays the timing of the two events mentioned above and M/LCC2 (represented by the red dots) events on a series of average daily real-time LMPs and load levels. Also shown is the minimum total reserve margin (for an hour) for each day.

Figure 4-28: Pricing, Demand and Reserve Margin during System Events in 2025



The following metrics illustrate the frequency of abnormal system conditions and extreme market outcomes over the past five years:

- Number of OP-4 and M/LCC 2 Events
- Reserve Deficiency Events
- Frequency of Extreme Hub LMPs

OP-4 and M/LCC 2 Events

The ISO uses the following control room procedures to address issues and alert participants during times of tight or abnormal system conditions:

- **Master Local Control Center Procedure No. 2** (M/LCC 2, Abnormal Conditions Alert)[184]
- **Operating Procedure No. 4** (OP-4, Action during a Capacity Deficiency)[185]

The number of instances for each type of event is shown in Table 4-5 below.

Table 4-5: OP-4 and M/LCC 2 Event Frequency

Procedure	2021	2022	2023	2024	2025
# of OP-4 Events	0	1	1	2	2
# of M/LCC 2 Events	6	6	6	6	3

184 M/LCC 2 notifies market participants and power system operations personnel when an abnormal condition is affecting the reliability of the power system, or when such conditions are anticipated. The ISO expects these entities to take certain precautions during M/LCC 2 events, such as rescheduling routine generator maintenance to a time when it would be less likely to jeopardize system reliability. ISO New England Inc., "*Master/Local Control Center Procedure No. 2 (M/LCC2) Abnormal Conditions Alert*", https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/mast_satllte/mlcc2.pdf

185 OP-4 establishes criteria and guidelines for actions during capacity deficiencies. There are eleven actions described in the procedure that the ISO can invoke as system conditions worsen. ISO New England., "*ISO New England Operating Procedure No. 4 – Action During A Capacity Deficiency*", https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op4/op4_rto_final.pdf

The ISO implemented three M/LCC 2 events in 2025, down from six in the prior four years. In our assessment of the system events, detailed in the quarterly reports, we generally found that the market performed well during these periods. The table at the end of this section summarizes the high-level causes and outcomes of each system event in 2025.

Reserve Deficiency Events

Reserve deficiency events (i.e., periods when there are negative reserve margins) are indicative of stressed system conditions when there is not enough available supply capable of meeting the region's 10- or 30-minutes reserve requirements. During such events, reserve product and energy clearing prices reflect the reserve price cap associated with the deficient constraint, known as the applicable Reserve Constraint Penalty Factors (RCPFs). Below, Table 4-6 shows the number of hours during which each reserve margin was negative.

Table 4-6: Frequency of Negative Reserve Margins (System Level) [186]

Year	Hours of Negative Total30 Margins	Hours of Negative Total10 Margins	Hours of Negative Spinning Reserve Margins
2021	0.0	0.0	26.8
2022	1.4	0.1	48.1
2023	0.5	0.3	6.8
2024	2.2	1.1	3.7
2025	3.6	0.3	30.3

Overall, these outcomes reflect a system that has had a healthy reserve margin on average with few periods of system stress in the past few years. The Total30 and Total10 margins fell below zero in each of the last four years when tight system conditions led to capacity scarcity conditions under the Pay-for-Performance construct.

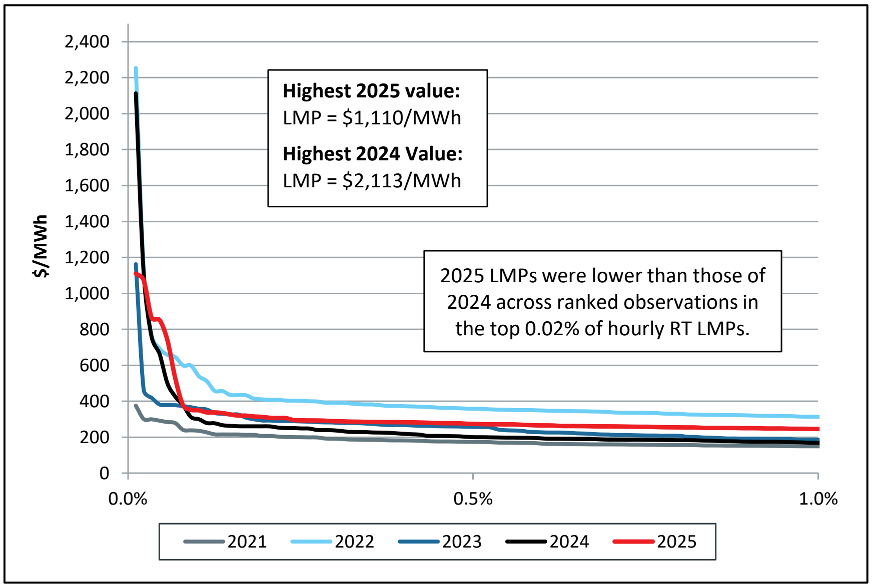
Shortages of ten-minute spinning reserves (with an associated RCPF of $50/MWh) occur more frequently reflecting demand for both energy and spinning reserves on committed dispatchable generation (mainly combined cycles). The spinning reserve shortages occurred across 46 days throughout the year in 2025 due to a variety of factors, such as tight system conditions caused by higher real-time loads or unplanned outages.

Frequency of Extreme Hub LMPs

High real-time LMPs can also be indicative of stressed system conditions, as higher-cost generation is required to meet load and reserve requirements. The duration curves in Figure 4-29 below show the top 1% of hourly average real-time LMPs ranked from highest to lowest over the past five years.

[186] The calculations in this table come from the LMP calculation processes in the real-time market software. The "Hours of Negative Total30 Margins" column does not include instances where only the replacement reserve margin is negative, because those instances are not associated with the $1,000/MWh RCPF.

Figure 4-29: LMP Duration Curves for Top 1% of Real-Time Pricing Hour



Real-time LMPs in 2025 were higher than those of 2024 across most ranked observations, consistent with the higher LMPs this year. The six highest hourly real-time LMP values occurred during the two shortage event days; however, the majority of the top 1% of LMPs (83%) occurred during winter months (January, February and December). Elevated energy prices during the winter were driven by high natural gas prices due to cold weather and pipeline constraints. There were no reserve deficiencies during these month.

The highest hourly price of the year ($1,110/MWh) occurred during HE 19 on June 24, when capacity scarcity conditions resulted in the RCPFs for the total thirty-minute reserve constraint ($1,000/MWh) being incorporated into LMPs for the entire hour.

Specific days that saw notable market and system outcomes in 2025 are summarized in Table 4-7 below.

Table 4-7: System Events In 2025

Date	Event Type	Driver	Market & System Summary
Jun 23-25	M/LCC 2 (Jun 23-Jun 25), OP4 Actions 1 and through 5 and Shortage Event (Jun 24)	Hot weather, high loads and generator outages and ambient derates	Loads were high due to hot weather. Multiple generator outages occurred throughout the day, while many thermal generators reduced maximum output due to hot weather. Capacity scarcity conditions for over t hours, and five-minute real-time LMPs peaked at $1,561/MWh.
Jul 16-17	M/LCC 2	Hot weather and high loads	High temperatures and loads led to high energy prices.
Nov 23	M/LCC 2, OP4 Actions 1 and 2, Capacity Shortage Event	Generator Outages	About 5,000 MW of generation was out-of-service; most of these outages were routine maintenance outages often taken during the shoulder months. 900 MW of generation went out-of-service in HE 18, leading to negative reserve margins. Capacity scarcity conditions for 30 minutes, and five-minute real-time LMPs peaked at $2,666/MWh.

4.7 Demand Response Resources

Demand Response Resources (DRRs) can participate in the day-ahead and real-time energy and ancillary services markets by reducing end-use consumption. The first subsection (4.7.1) analyzes how DRRs participate in the energy market[187] and the second subsection (4.7.2) analyzes their participation in the capacity market. The final section (4.7.3) reviews DRR compensation across all markets.

Key Takeaways

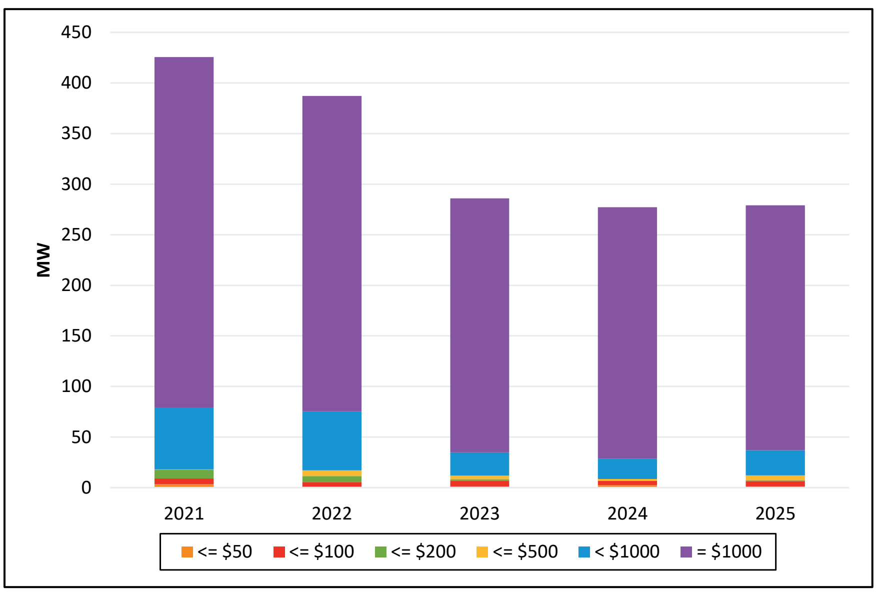
Similar to prior years, Demand Response Resources (DRRs) primarily served as capacity and operating reserve resources in 2025, generally only available for dispatch at very high offer prices. For example, 87% of DRR capacity was offered at $1,000/MWh in the real-time energy market in 2025. Given these high offer prices, dispatch of these resources occurred infrequently and at low quantities. DRRs mostly provided operating reserves during real-time operations; 5 MW of 10-minute reserves and 191 MW of 30-min reserves per hour on average in 2025.

The capacity market continues to provide DRRs with the majority of their overall market revenues; in 2025, DRRs received $11 million in capacity payments, which comprised 80% of their total market payments.

4.7.1 Energy Market Offers and Dispatch

By virtue of their high energy offer prices, most DRRs effectively function as reserve resources, providing energy only when prices are extremely high. Figure 4-30 below depicts average hourly demand reduction offer (i.e., energy offer) quantities in the real-time energy market by year and offer price category over the past five years.

Figure 4-30: Demand Response Resource Energy Offers in the Real-Time Energy Market

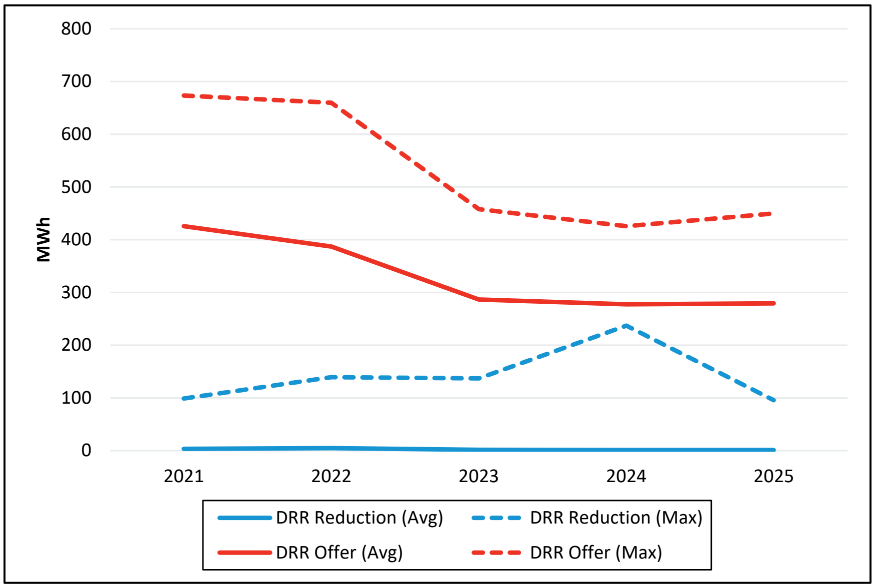


[187] Given the similarity of DRR participation across the day-ahead and real-time energy markets, this section uses only real-time energy offer and dispatch data to illustrate their participation in the ISO's energy markets.

Most DRRs offer their real-time energy at $1,000/MWh;[188] 87% of offered DRR capacity, on average, was offered at this value in 2025. In most hours, only the lower-priced energy offers ($200/MWh or less) have a reasonable likelihood of being dispatched in the real-time energy market; these offers averaged just 3% of hourly offered DRR capacity in 2025.

Given the offer price behavior of DRRs, the ISO dispatches relatively small quantities in the energy markets. Figure 4-31 below illustrates the reduction of DRRs in the real-time energy market relative to the resources' offered reductions over the past five years. The blue lines represent actual reductions, while the red lines indicate offered reduction capability.

Figure 4-31: Demand Response Resource Reductions in the Real-Time Energy Market



DRRs were dispatched to reduce consumption infrequently in 2025, averaging only 1.1 MWh of energy reductions. This is in line with average values over the study period. The highest observed DRR energy reduction values in 2025 occurred during the capacity scarcity conditions on June 24, 2025. Aggregate DRR reduction values reached nearly 100 MWh during this period of stressed system conditions. As a group, DRRs under-performed relative to their CSO during this scarcity event, which led to PFP charges of over $4 million.[189] These observations are reflective of the fact that DRRs are generally not relied upon as a form of energy supply during normal operating conditions. However, they do provide operating reserves in real time. In 2025, DRRs provided an hourly average of 5.3 MWh of ten-minute operating reserves and 190.8 MWh of thirty-minute operating reserves. These reserve designation values are very similar to those from 2024.

4.7.2 Capacity Market Participation

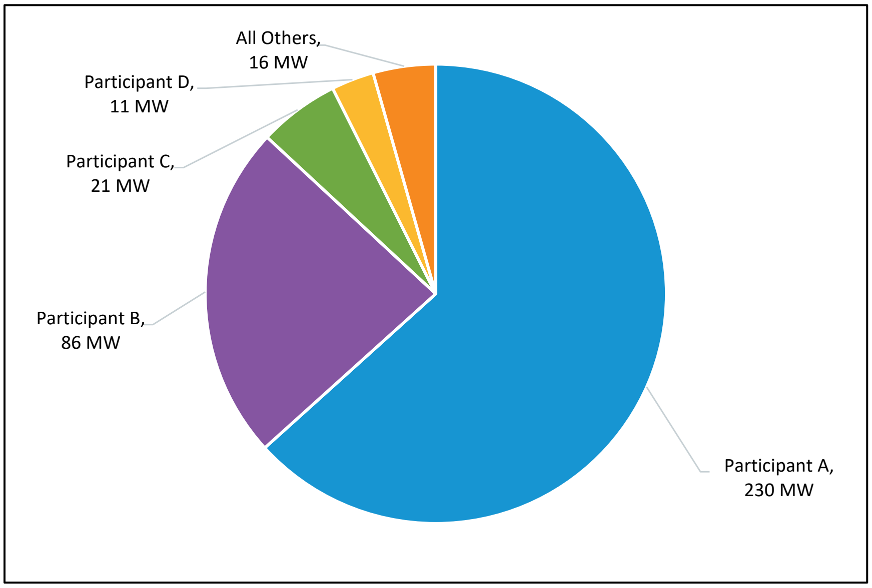
Active demand response participates in the Forward Capacity Market by aggregating one or more DRRs into Active Demand Capacity Resources (ADCRs). All active demand resources with capacity

[188] $1,000/MWh is the highest energy price offer that can be submitted without additional quantitative support provided by the participant and verification by the ISO. No DRR offered greater than $1,000/MWh during the study period.

[189] For more information about resource performance during the June 24, 2025, CSC event, see: ISO New England Inc., Internal Market Monitor, "*Summer 2025 Quarterly Markets Report*", November 12, 2025, https://www.iso-ne.com/static-assets/documents/100029/2025-summer-quarterly-markets-report.pdf.

market obligations are required to offer "physically available" capacity into the day-ahead and real-time energy markets.[190] Figure 4-32 indicates the total CSO for ADCRs in 2025 as well as the split by participant.[191]

Figure 4-32: CSO by Lead Participant for Active Demand Capacity Resources, 2025



In 2025, ADCRs had capacity supply obligations (CSOs) totaling approximately 364 MW. This continues the year-over-year trend of declining capacity market participation by ADCRs and is a reduction of 44 MW (11%) compared to 2024. The largest participant accounted for nearly two-thirds of the total ADCR capacity supply obligations in 2025, which was similar to the percentage held by the largest participant in 2024. Collectively, the two largest participants accounted for approximately 87% of ADCR capacity supply obligations in 2025.

4.7.3 Wholesale Market Compensation

The capacity market continues to be the key driver of DRR compensation with relatively modest levels of revenue coming from the energy and ancillary services markets. Figure 4-33 provides a summary of capacity,[192] energy, [193] and reserve payments to DRRs by year for the past five years.

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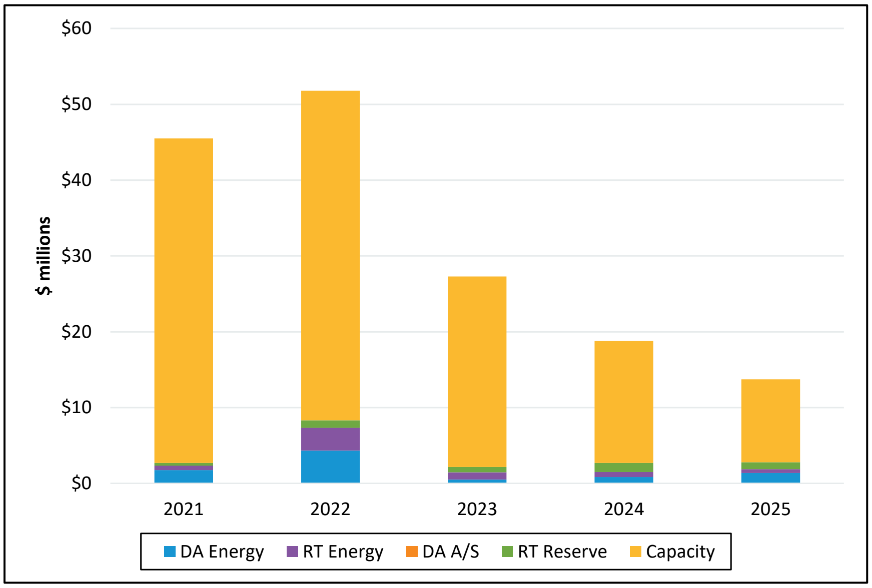
[190] To satisfy the ADCR's capacity supply obligation, DRRs mapped to an ADCR need to offer demand reductions into the energy market at an aggregate level consistent with the parent ADCR's capacity supply obligation.

[191] The CSO estimate indicates the average capacity supply obligation for the calendar year.

[192] The FCM compensation depicted in this figure is based the results of the primary FCA and does not account for any gains or losses that may have occurred as a result of CSO bilaterals or reconfiguration activities. The compensation does, however, account for Pay-for-Performance payments and penalties assessed to ADCRs.

[193] NCPC payments to DRRs are included within the DA and RT energy bars in this figure. Additionally, FER credits, which are credits paid to physical resources that have day-ahead energy awards, are also included within the DA energy bar.

Figure 4-33: Wholesale Market Payments to Demand Response Resources



In 2025, capacity market payments to DRRs totaled $11 million, accounting for 80% of all payments to DRRs. This reflects a decrease in capacity payments relative to prior years, largely as a result of the lower level of CSO held by DRRs. Meanwhile, payments for energy and reserves have remained relatively small. In 2025, total energy payments amounted to $1.7 million, which includes approximately $50 thousand in FER credits. Real-time reserve payments totaled $0.9 million in 2025, and DRRs received no day-ahead ancillary services payments in 2025.

Section 5
External Transactions

External transactions are energy market transactions that allow market participants to transfer power between New England and its neighboring control areas, and represent an important part of the overall supply and demand picture.[194] Transferring power between different control areas can help reduce total production costs across control areas by allowing power to flow from lower priced to higher priced control areas, and provide reliability benefits to the interconnected systems.

This section reviews trends in external transactions in the day-ahead and real-time energy markets. The first section (5.1) provides an overview of external transactions across all external interfaces, while the second section (5.2) looks specifically at the performance of Coordinated Transaction Scheduling (CTS) with New York.

5.1 External Transaction Trends and Drivers

This section on outcomes, trends and drivers of import and export (external) transactions is organized in three subsections: (5.1.1) overall flows between New England and its neighboring control areas, with a breakdown across the six interfaces[195], (5.1.2) the pattern of fixed bidding versus price-sensitive bidding, and (5.1.3) the drivers of uplift (NCPC) payments to external transactions.

Key Takeaways

Interchange Levels and Drivers: Real-time net interchange averaged 932 MW per hour (serving 7% of real-time load), which was the lowest level of net interchange since at least 2011. Net interchange continued to decrease as dry weather in Canada limited sales of hydro generation to New England and a nuclear generator in New Brunswick took an extended outage for the second consecutive year. Nearly 47% of total net interchange came from Canadian interfaces, a decrease from 60% in 2024 and 80% in 2023.

Contribution on High Priced Intervals: Despite falling over the last five years, net interchange continues to play a critical role in helping New England meet energy demand during periods when loads and energy prices increase. During hours where day-ahead energy prices were above $100/MWh, net interchange averaged nearly 2,700 MW per hour, in line with prior years. However, this relationship loosened late in the year as net interchange fell during Q4 2025, and New England imported an average of 1,421 MW during these high-priced intervals.

Priced vs. Unpriced: At the Canadian interfaces, most day-ahead transactions were priced during 2025. However, nearly all of these priced transactions were not re-offered in real time and

[194] A control area, or balancing authority area, is an area comprising a collection of generation, transmission and load within metered boundaries for which a responsible entity (defined by NERC to be a balancing authority) integrates resource plans for that area, maintains the area's load-resource balance, and supports the area's interconnection frequency in real time.

[195] There are currently seven external interfaces with the addition of the New England Clean Energy Connect in January 2026. This interface began non-commercial testing in November 2025. This section focuses on the six interfaces that were commercial during 2025.

therefore were effectively scheduled as fixed transactions in the real-time market. At the three New York interfaces, external transactions tended to be fixed in the day-ahead and priced in real time due to the mechanics of Coordinated Transaction Scheduling at New York North.

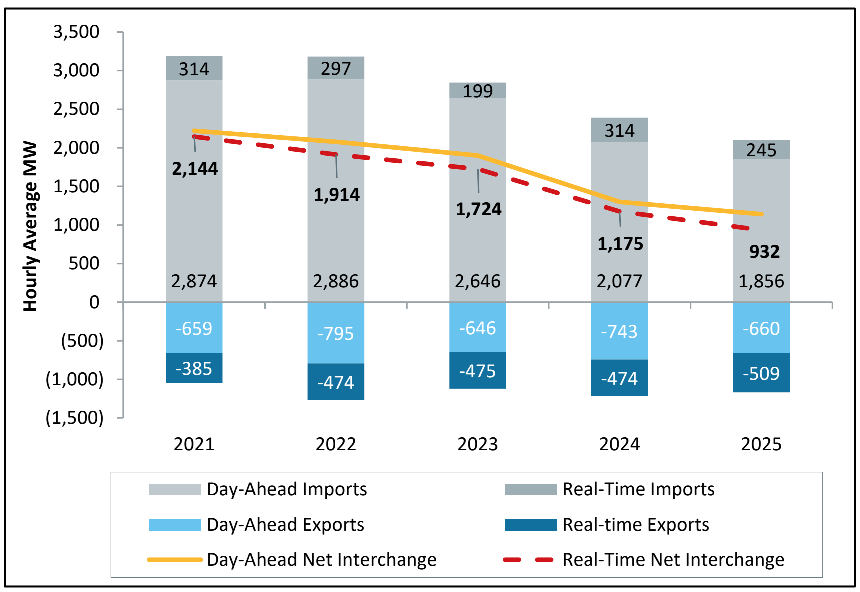
Uplift Payments and IMM Recommendation: External transactions received more uplift payments in the day-ahead market this year, largely due to increased payments to virtual transactions for relieving external congestion at the Highgate interface in the day-ahead market. In the real-time market, uplift payments decreased slightly compared to 2024 as price forecast error at non-CTS interfaces led to reduced clearing of out-of-merit external transactions.

We continue to recommend that ISO-NE review non-CTS external interface clearing rules to ensure participants are incentivized to offer external transactions that reflect expected quantities at the cost or value of the underlying energy (see Recommendation #2025-1 in the Executive Summary).

5.1.1 External Transaction Volumes

The average hourly system-wide net interchange from the day-ahead and real-time markets are shown in the line series of Figure 5-1 below. The bar series chart shows the hourly average imported volume (positive values) and exported volume (negative values), as well as the net interchange in both the day-ahead and real-time markets.[196]

Figure 5-1: Hourly Average Day-Ahead and Real-Time Pool Net Interchange



Net interchange continues to decrease between New England and its neighboring control areas. Real-time net imports averaged 932 MW per hour (or 7% of real-time load), the lowest volume of net interchange since at least 2011. In 2025, net interchange fell as dry weather continued in Quebec, and a nuclear unit in New Brunswick took an extended outage for the second consecutive

[196] The real-time import and export volumes are shown as the incremental additions to the amounts cleared in the day-ahead market.

year. Overall, day-ahead and real-time net imports fell by 158 MW and 243 MW on average, respectively.

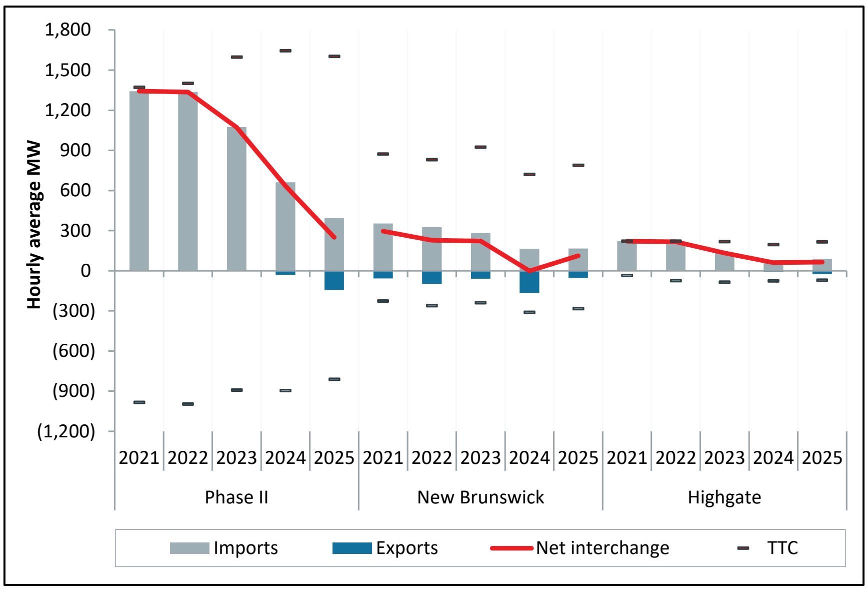
Despite falling over the last five years, net interchange still plays a critical role in helping New England meet energy demand during periods when loads and energy prices increase. During hours when day-ahead LMPs were at least $100/MWh, net interchange averaged over 2,700 MW per hour in 2025, broadly consistent with the prior four-year average. However, this relationship broke down late in the year. Net interchange during high-priced hours fell sharply in Q4 2025, when average interchange dropped to 1,421 MW—about 50% below the prior four-year average (~2,900 MW).

Day-ahead *net interchange* (orange) remained higher than real-time *net interchange* (red) during 2025. This was due to lower real-time net interchange at the New York North interface where real-time scheduled exports exceeded the volume of additional real-time imports across all interfaces. When net real-time interchange is lower, New England must commit additional real-time native generation which can lead to higher real-time prices.

A Breakdown of Flows across the Canadian Interfaces

Annual hourly average real-time net interchange volumes (red line), as well as the gross import and export volumes, are shown for each Canadian interface in Figure 5-2 below, along with the real-time total transfer capability (TTC) ratings for each interface.[197]

Figure 5-2: Real-Time Net Interchange at Canadian Interfaces[198]



Canadian exports into New England and neighboring regions have decreased steadily and significantly since 2022, driven by reduced hydro power generation in Canada. Nevertheless, Canada remains an import supplier of electricity to New England, providing 47% of New England's total net imports.

[197] The total transfer capability (TTC) rating is the MW amount of power that can be reliably transferred from one system to the other over the transmission interface.

[198] The New England Clean Energy Connect is not shown in the figure but is included in total net interchange numbers. The interface began testing in late 2025 and began commercial operation in January 2026.

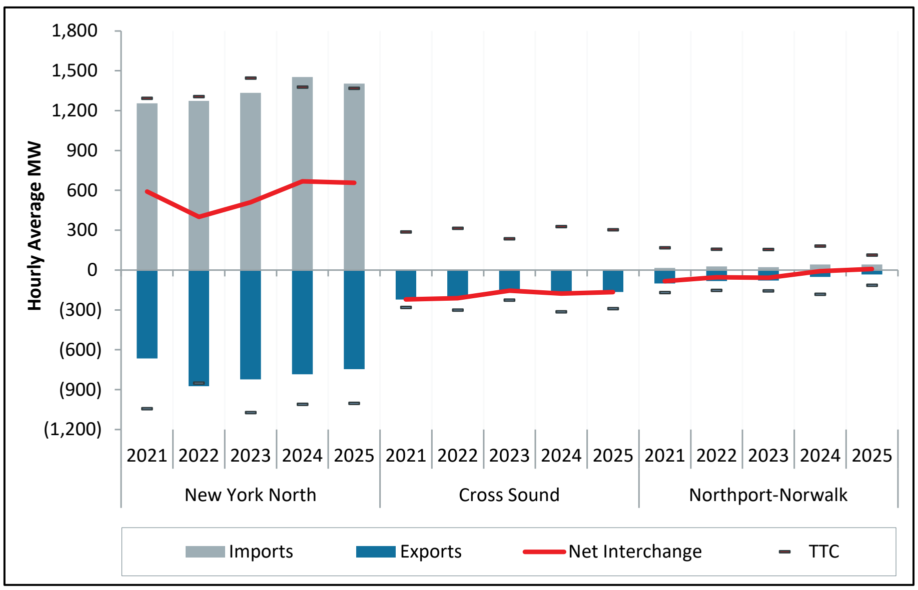
The net interchange between New England and Quebec saw another substantial fall in 2025 as dry weather persisted in Canada, limiting the amount of excess hydroelectric generation available to sell in New England.[199]. Phase II saw the highest net imports of any interface from 2021 to 2022, averaging 1,339 MW per hour, which was in line with historical norms. However, in 2025, net imports at Phase II averaged 250 MW per hour, 81% below average levels from 2021 and 2022. Historically, imports at the Highgate interface were close to the maximum import capability of the interface (225 MW) but have decreased in recent years. In 2025, net imports remained lower than normal, averaging just 65 MW per hour. Most import transactions over the Highgate interface in 2025 originated in IESO and were wheeled to New England through Quebec.

Net interchange with New Brunswick rebounded in 2025 but remained below historical levels. A large nuclear generator took a six-month outage (June 2025 to December 2025) for the second consecutive year, limiting the amount of generation and capacity in New Brunswick.[200] When the unit was in-service, New England was a net importer over this interface, averaging 189 MW per hour. During the outage, New England exported over 20 MW per hour, on average.

A Breakdown of Flows across the New York Interfaces

Real-time interchange volumes and capabilities for each of the three New York interconnections are shown in Figure 5-3 below.

Figure 5-3: Real-Time Net Interchange at New York Interfaces



On a net basis, New England imports power from New York over the New York North interface and exports power to Long Island via the Cross Sound Cable and Northport-Norwalk interfaces. Combining flows at all three interfaces, ISO-NE's net imports in 2025 averaged nearly 500 MW per hour (or 4% of total real-time load).

[199] For more information on Québec's reduction in exports, see: Hydro-Québec, " *Annual Report 2025"*, https://www.hydroquebec.com/data/documents-donnees/pdf/hq-rapport-annuel-2025-anglais.pdf.

[200] For more information on the outage of the New Brunswick nuclear generator, see: Énergie NB Power, "*Point Lepreau Nuclear Generating Station Returns to Operation",* Dec 15, 2025, https://www.nbpower.com/en/about-us/news-media-centre/news/2025/point-lepreau-nuclear-generating-station-returns-to-operation/.

At New York North, net interchange (red line) remained similar to levels in 2024, averaging 657 MW per hour. In the day-ahead market, prices remained close between New York and New England with New York prices just $0.28/MWh higher on average compared to about $0.70/MWh higher in 2024. External transactions may be willing to flow from New York to New England at a financial loss (based on spot energy price differences) to deliver on contracted energy or to sell Renewable Energy Certificates (RECs) at a higher price in New England.

New England typically exports power to Long Island over the Cross Sound Cable and Northport-Norwalk interfaces. In 2025, net exports to Long Island at Cross Sound Cable averaged 166 MW per hour, 11 MW lower than 2024. At Northport-Norwalk, *net imports* from Long Island averaged 8 MW after exporting an average of 9 MW per hour in 2024. The Northport-Norwalk interface was heavily reduced this year due to transmission work and was only at its full capability (200 MW) in about 10% of intervals.

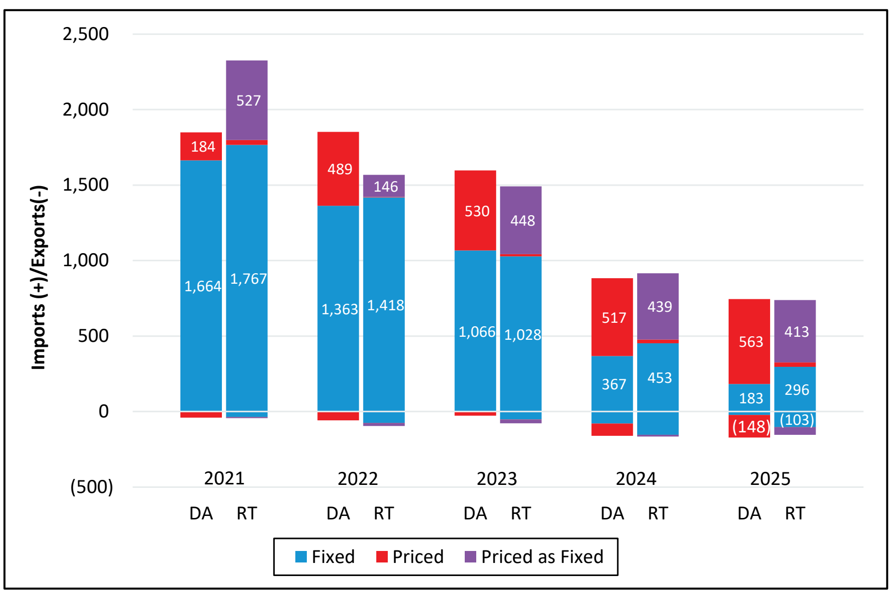
5.1.2 External Transaction Participation

In Section 4, we assess overall market supply and demand-side participation in terms of the extent to which supply offers or demand bids are price-taking (fixed) versus price-making (priced). This can have important implications for price formation in the energy markets. In this section, we present a similar analysis focusing on external transactions, which participate on both the supply and demand sides of the market (i.e., supply offers for imports and demand bids for exports).

Canadian Interfaces

The composition of transactions that *cleared* at the Canadian interfaces in the day-ahead and real-time markets by fixed, priced and "priced as fixed"[201] is shown in Figure 5-4 below.

Figure 5-4: Transaction Types by Market and Direction at Canadian Interfaces (Average MW per hour)



[201] A "priced-as-fixed" transaction is a real-time external transaction that was priced and cleared in the day-ahead market, but not reoffered in the real-time market. When day-ahead priced transactions are not reoffered in the real-time market, they are scheduled as fixed transactions.

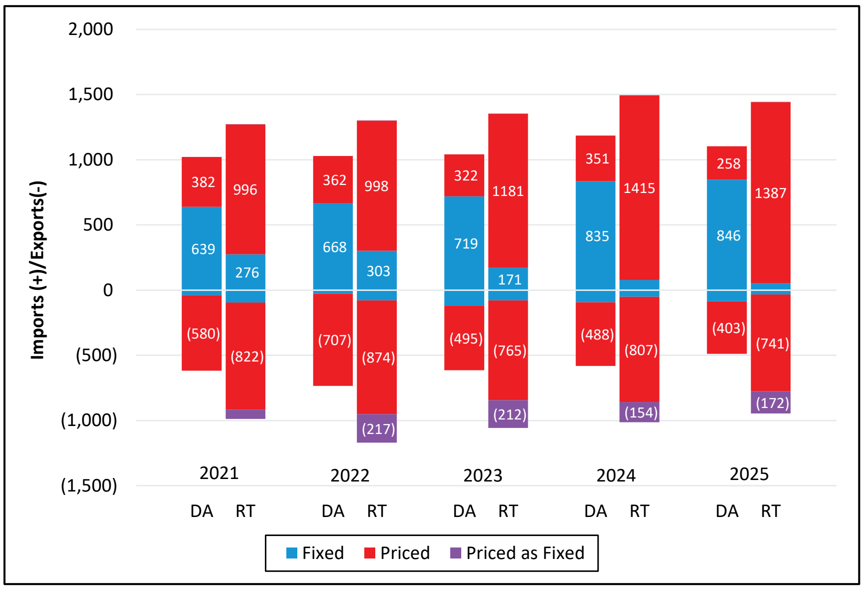
In the day-ahead market external transactions were predominantly fixed at Canadian interfaces prior to 2024. However, levels of fixed import transactions have fallen at Canadian interfaces in recent years in tandem with an overall decline in total import transactions. Day-ahead priced transactions remained relatively consistent over the last four years.

There continues to be very low levels of price-sensitive transactions in the real-time market. At the Canadian interfaces, most priced transactions were not reoffered in real time. Without these transactions being reoffered, nearly all real-time transactions are scheduled as fixed ("Priced as Fixed" label).

New York Interfaces

The composition of transactions that cleared at the New York interfaces in the day-ahead and real-time markets by fixed, priced and "priced as fixed" is shown in Figure 5-5 below.[202]

Figure 5-5: Transaction Types by Market and Direction at New York Interfaces (Average MW per hour)



Most day-ahead cleared import transactions at the New York interfaces were fixed while most exports were priced. In 2025, the composition of external transactions at New York interfaces remained similar to 2024 levels. Day-ahead price differences between New York and New England stayed relatively flat year-over-year, with New York prices averaging just $0.28/MWh higher than New England prices at New York North, the largest interface connecting New York and New England.

In real time, most transactions are priced due to the bidding mechanics of Coordinated Transaction Scheduling (CTS) at the New York North interface. Under CTS, all real-time transactions are evaluated based on price, although participants may offer prices as low as negative $1,000/MWh, which effectively schedules the import transaction as fixed. Most real-time import transactions that cleared in the day-ahead market continued to be price-insensitive at the

[202] Volumes not listed in the figure all averaged less than 100 MW per hour.

interface. Transactions can be fixed in real time at New York North, but these represent wheeled transactions which decreased this year.[203]

5.1.3 External Transaction Uplift (NCPC) Payments

External transactions are eligible to receive uplift (or NCPC) payments when revenues are not sufficient to recover their costs. These payments often occur in the real-time market when external transactions clear on an ISO price forecast but are unable to recover as-offered costs through actual settled prices. External transactions (or virtual transactions placed at external nodes) can also receive uplift in the day-ahead market for relieving congestion at non-CTS external interfaces since congestion is not captured in the LMP. These payments occur when a transaction that is out-of-the-money at the system price clears in the direction counter to the constraint (e.g., an export or virtual demand bid when the interface is import-constrained) allowing a counter-party to clear in excess of the interface limit.[204] These otherwise uneconomic transactions require uplift in the absence of congestion pricing.

The annual uplift credit totals at all external nodes in both the day-ahead and real-time markets are presented in Table 5-1 below.

Table 5-1: NCPC Credits at External Nodes

Year	Day-ahead credits ($million)	Real-time credits ($million)
2021	$1.0	$0.5
2022	$3.1	$1.2
2023	$0.1	$1.3
2024	$2.4	$1.6
2025	$3.9	$0.9

Typically, total uplift paid at external nodes is very small compared with other types of uplift (see Section 4.5)." In 2025, *day-ahead* uplift credits totaled $3.9 million, which was the second consecutive increase in day-ahead uplift credits. $2.8 million was paid to transactions at the Highgate interface for relieving the import-constrained interface. This interface often sees high uplift credits in the day-ahead market as participants compete for clearing priority at the interface by placing virtual demand bids to ensure they clear their full day-ahead import transaction. 90% of day-ahead uplift at Highgate was paid during January 2025 when higher energy prices led to increased competition for clearing priority at the interface.

[203] A wheeled transaction occurs when a participant flows power from one system to another over a third party's transmission lines. For example, a participant might use these transactions to flow power from PJM through New York and into New England.

[204] For example, consider an interface with an import TTC of 100MW and an LMP of $100/MWh. If there are 200MW of imports offered at $0/MWh, only 100MW can clear (due to the TTC), unless there is a transaction to offset the remaining 100MW of excess imports. If a 100MW export is offered at $50/MWh, it can provide counter-flow. The $50/MWh exports are willing to purchase the $0/MWh imports. However, because congestion is not captured in the LMP, the energy settlement for the export will result in a loss; the exports are only willing to pay $50/MWh and the LMP is $100/MWh. Therefore, these 100MW of exports must be paid $50/MWh to make them whole, for a total NCPC payment of $5,000. The NCPC charges are only levied to the participants importing over the interface. NCPC charges and credits are a transfer between participants creating the congestion to participants relieving the congestion.

Real-time uplift credits are driven by transactions scheduled out-of-rate due to price forecast error. In other words, transactions (at non-CTS interfaces)[205] were in-rate based on forecasted prices but were out-of-rate based on actual prices that are used in settlements. Accurate price forecasting of LMPs helps reduce NCPC paid to external transactions. In 2025, price forecast error improved and NCPC credits for external transactions fell to less than $1 million.

[205] At the CTS interface, out-of-rate transactions are not entitled to NCPC but also do not incur NCPC charges.

5.2 Coordinated Transaction Scheduling

This section provides an update on the assessment of how coordinated transaction scheduling (CTS) at the New York North interface is functioning. Specifically, we review CTS performance metrics against its high-level performance indicators, including scheduling efficiency, price convergence, and price forecast error. We continue to recommend the ISO assess enhancements to price forecasting to minimize forecast error, or changes to CTS mechanics to minimize the impact of price forecast error.[206]

> ***Key Takeaways***
>
> CTS produced similar outcomes to previous years. Price forecast error continues to dampen the positive impacts of CTS by creating financial risk for participants at the Roseton interface and is likely impacting bid and offer behavior. Specifically, participants often clear day-ahead transactions then offer hedged price-insensitive transactions in the real-time market. Lower price-sensitive offered capacity in real-time reduces the ability of the CTS engine to adjust flows as New England and New York price spreads fluctuate.
>
> On average, the CTS engine could have used 232 MW of unutilized capacity per hour to help converge prices before hitting the most limiting constraint (ramp- or transfer capability-constraint). The CTS engine was often unable to converge prices due to the unwillingness of participants to adjust to real-time price differences.
>
> We encourage ISO-NE to review its price forecasting tools and explore opportunities to improve forecast accuracy. Since price forecast error is unlikely to be completely eliminated, minimizing the impact of price forecast error through changes to CTS mechanics or settlement may better incentivize participants to offer at cost.

5.2.1 CTS Performance

We assess CTS performance against two measures of efficiency: the flow of power from the lower- to higher-cost region and degree of price convergence between New England and New York.

A summary of CTS power flows between the two control areas is shown in Table 5-2 below. The percentage of time power flowed into New England is shown in the *Net Flow* column.[207] The percentage of time the flow was directionally correct (i.e., power flowed from lower- to high-cost region, based on actual prices) is shown in the *Correct Flow* column.[208] The average New England price premium is shown for context, as a primary driver of flow direction. The correct flow and

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[206] A summary of this and other recommendations can be found in the executive summary of this report. For a more in-depth analysis of CTS outcomes, see: ISO New England Inc., Internal Market Monitor, *"2022 Annual Markets Report",* June 5, 2023, https://www.iso-ne.com/static-assets/documents/2023/06/2022-annual-markets-report.pdf.

[207] Fixed wheeling transactions at the New York North (NYN) interface are ignored in the analyses contained in this section. These transactions are not cleared in the CTS process. On average, in 2025 there were 20 MW of fixed-wheeling transactions net importing over the NYN interface in each interval.

[208] The prices used in this subsection are proxy prices that represent the marginal cost of energy on each side of the NYN interface. The NYISO pricing node is "N.E._GEN_SANDY PD" (Sandy Pond) and the ISO-NE node is ".I.ROSETON 345 1" (Roseton). Congestion pricing is removed from external prices to ensure we are better capturing the marginal cost of energy in each control area at the border. When the ramp or flow limit binds, the prices at the interface reflect the bids and offers that set price based on the forecast, and not necessarily the marginal cost of energy in each control area.

average price spreads including potential revenues from the Renewable Energy Certificate (REC) price spread (the difference between the New England and New York REC prices) are also shown to highlight other incentives participants are presented when flowing power across the NYN interface.[209]

Table 5-2: Summary of CTS Flows

Year	Net Flow (% of intervals) to ISO-NE	Correct Flow (% of intervals)	Correct Flow (% of intervals, accounting for REC spread)	Average New England Price Premium ($/MWh, without CTS Congestion)	Average New England Price Premium including REC spread ($/MWh, without CTS Congestion)	Average New England Price Premium ($/MWh, with CTS Congestion)[210]
2021	69%	56%	78%	$1.96	$20.03	($1.65)
2022	51%	57%	65%	($2.92)	$9.47	($4.09)
2023	68%	55%	70%	$2.04	$11.23	($0.91)
2024	81%	54%	68%	$2.15	$10.76	($1.03)
2025	83%	55%	77%	$3.01	$16.30	($2.52)

In 2025, power flowed into New England from New York 83% of the time and the average New England price premium was $3.01/MWh. However, CTS scheduling moved energy in the correct direction only 55% of the time on a 15-minute basis (i.e., from lower- to higher-cost region, based on the price without CTS congestion)—similar to the prior four years. When REC prices are included in the price spread, about 77% of the time power flowed in the correct direction. REC prices contributed about $13/MWh to the price spread between New England and New York on a per-MW basis.

Table 5-3 below shows a summary of price convergence between New York and New England and CTS price forecast error.

[209] Renewable Energy Certificate prices used in this analysis are the vintage prices from the date of flow. For example, for a transaction flowing on 2/10/2022, the vintage 2022 MA Class 1 REC price and 2022 New York Tier I REC price during the week of 2/5/2022-2/11/2022 is used to reflect the expected value of the RECs at the time of scheduling. In cases where the date falls before the first populated price (e.g., no 2020 NY Tier I REC price data was available before 1/2/2021) the first available price is applied in the analysis.

[210] The average New England price premium is shown in this table to highlight that although New England prices exceed New York prices (based on the "Average New England Price Premium without CTS Congestion" columns), participants are unable to capture that price spread due to the number of negatively-priced import offers. These negatively-priced import offers often set price, leading to a New York price premium once congestion, caused by these negatively-priced imports, is factored in.

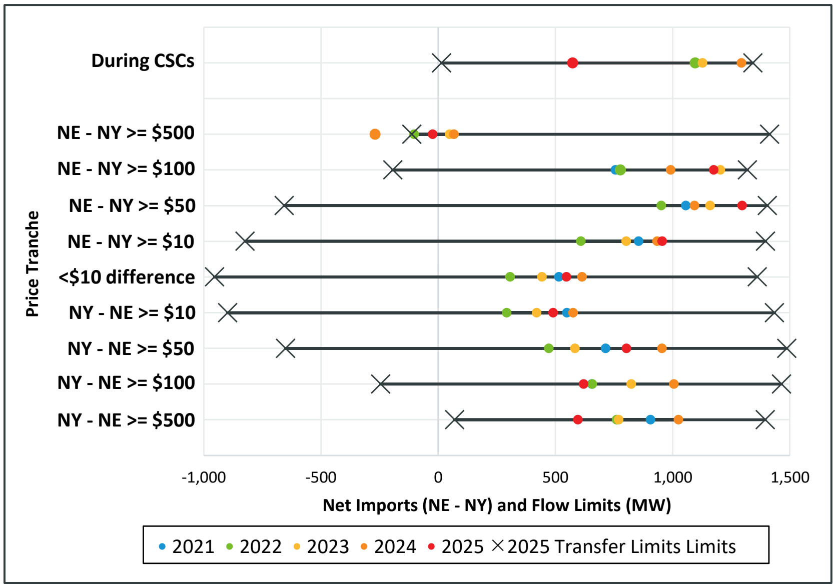
Table 5-3: Summary of Price Convergence and Forecast Error

Year	NY LBMP ($/MWh)	NE LMP ($/MWh)	Average Absolute Price Spread ($/MWh)	Average Absolute Price Spread as % of ISO-NE LMP (%)	Average Absolute Price Spread Forecast Error ($/MWh)	Average Absolute Price Spread Forecast Error as % of ISO-NE LMP (%)
2021	$41.07	$43.03	$12.76	30%	$10.78	25%
2022	$85.78	$82.86	$24.50	30%	$23.31	28%
2023	$32.63	$34.67	$11.98	35%	$10.10	29%
2024	$36.01	$38.15	$10.69	28%	$9.72	25%
2025	$60.61	$63.62	$18.16	29%	$14.77	23%

The average absolute price spread in 2025 was the highest since 2022, although the absolute price difference between New York and New England was 29% of the LMP, similar to previous years. This could indicate that, although the price differences were greater due to overall higher prices, the CTS engine helped converge prices about as efficiently as previous years. Despite the similar price spread outcomes, the CTS price forecast performed slightly better than in previous years. The average absolute price spread forecast error was 23%, compared with values above 25% in the previous four years.

Many variables impact the price spread between New York and New England (e.g., generator and transmission outages, interconnections with other areas, differences in scarcity pricing rules) so the price spread cannot be fully attributed to the efficiency of CTS solutions. Despite the improvement in price forecasts, CTS solutions did not efficiently utilize the New York North interface capacity to converge prices. On average, the CTS engine could have used 232 MW of unutilized capacity to help converge prices before hitting the most limiting constraint (ramp- or transfer capability-constraint). Figure 5-6 below, shows the average net flow of external transactions over the New York North interface, by price spread tranche. Additionally, the net flow of external transactions during capacity scarcity conditions (CSCs) is also shown in the line at the top. The × symbols on the line mark the 2025 import and export limits in the intervals shown. The red dots show the average scheduled net interchange in 2025.

Figure 5-6: Average NYN Flow by NE-NY Price Spread



In 2025, the CTS engine generally utilized more of the interface to converge prices. Most notably, when New England was experiencing a price premium less than $500/MWh, but greater than $10/MWh, the CTS engine imported more power than in past years (i.e. the red dot was further to the right). This does indicate that the CTS engine did a better job of converging prices at these times, but is due to a 20% decrease in export bids coupled with a 25% increase in import offers, rather than reductions in forecast error. Over half of cleared CTS transactions were offered at less than -$50/MWh, similar to 2024. These price-insensitive CTS transactions were often not exposed to real-time prices—and most (about 83%) were backed by a day-ahead transaction in 2025, similar to 87% in 2024. This may indicate that participants are unwilling to rely on the CTS engine to efficiently schedule transactions by submitting economic bids and offers or have other contracts that incent them to bring energy into New England.

During the two CSC events in 2025, New England scheduled about 600 MW of imports over the NYN interface. During the first event on June 24, which lasted three hours, the CTS engine scheduled an average of 540 MW of New England net imports per interval over the NYN interface with an average New England price premium of $615/MWh. The actual price difference was a *New York* price premium of $200/MWh, as NYISO was also resource deficient at the time. This actual price spread sent incentives for participants to export out of New England. During capacity scarcity conditions, participants that are net importers receive the pay-for-performance (PfP) rate of $9,337/MWh for each MW of net imports. Due to the difference in realized price for net importers and net exporters, different participants can be incentivized to import and export at the same time. The IMM has recommended that the ISO charge exports the PfP rate to align incentives for participants moving power between regions.

During the second 30-minute event, on November 23, NYN was importing power at the limit based on a forecasted $60/MWh New England price premium, on average, compared with the actual price difference of $1,916/MWh. Despite the large forecast error, CTS optimized flows as efficiently as was possible given the limits during the event.

Section 6
Virtual Transactions

Participants submit virtual demand bids and virtual supply offers to profit from, or limit exposure to, differences in day-ahead and real-time LMPs. Generally, profitable virtual transactions improve price convergence and help the day-ahead dispatch model to better reflect real-time conditions. In ISO New England, participants can submit virtual supply offers and demand bids at any pricing location on the system: the Hub, load zones, external interfaces, Demand Response Resource (DRR) aggregation zones, and the hundreds of generation and load nodes (network nodes). This section covers our assessment of virtual transaction participation in the day-ahead energy market, including the level of activity and profitability.

Key Takeaways

Average **cleared virtual supply** (1,054 MW per hour) increased to its highest level in the past five years, continuing an upward trend over the reporting period. While there are multiple drivers of participants' virtual supply offer behavior, the increased volume observed in the past several years is mainly due to the growing amount of solar and wind resources on the grid and their limited participation in the day-ahead market. Solar settlement-only generators (SOGs) are ineligible to participate in the day-ahead market, while modeled solar and wind generators (> 5 MW capacity) tend to offer high-priced energy in the day-ahead market due to uncertainty in real-time weather conditions, risk preferences, and outside commercial arrangements. Many virtual participants anticipate additional real-time generation from renewable resources and clear virtual supply in the day-ahead market in their place. These offers support more efficient day-ahead clearing outcomes and contribute to price convergence.

Average **cleared virtual demand** increased at all different location types and reached its highest level in the past five years (595 MW per hour). Clearing at external interfaces rebounded after having decreased in 2024, while several participants drove increased clearing of virtual demand at the Hub, load zone, and nodal level.

Profitability: Virtual demand incurred gross *losses* of $3.19/MWh in 2025, the highest level in the past five years. Virtual supply made a gross profit of $2.67/MWh, which was higher than the previous two years but in line with the first two years of the reporting period.

Overall, consistently higher day-ahead LMPs over the past five years have contributed to these outcomes. In addition, participants often place virtual supply offers in the middle of the day when solar output is high, and profit when that output puts downward pressure on real-time prices. By contrast, participants often place virtual demand bids for reasons other than price arbitrage, such as hedging physical positions or ensuring priority at external interfaces.

Uplift Charge Allocation: The total NCPC charge rate for virtual transactions in 2025 was $0.59/MWh, continuing a downward trend since 2022, when NCPC costs reached $0.91/MWh. NCPC credits for virtual demand increased in 2025 due to virtual demand relieving import congestion at external interfaces, while virtual supply received less NCPC credit compared to 2024. After accounting for NCPC charges and credits, virtual supply transactions were profitable ($2.16/MWh) while virtual demand transactions incurred losses of -$3.35/MWh.

IMM Recommendation on NCPC Charge Allocation: We continue to recommend that the ISO review the allocation of NCPC charges to virtual transactions to ensure the charges are consistent with principles of cost causation and don't pose an inefficient participation obstacle given the important role that virtual supply plays in converging and lowering day-ahead LMPs. The allocation of uplift and uncertainty regarding the charge can impact virtual supply offers and the day-ahead LMP which drives the vast majority of consumer costs.

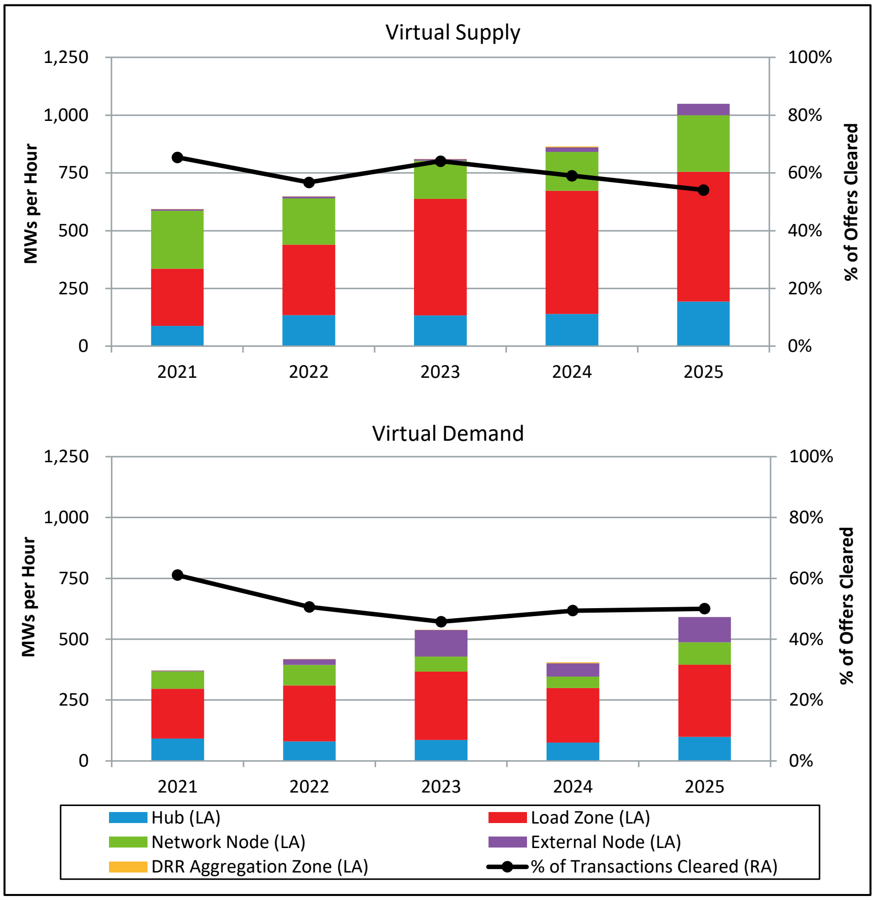
Review of the allocation of NCPC charges to virtual transactions is even more timely in the context of the new Day-Ahead Ancillary Services (DA A/S) market. This change strengthens the case for reassessing whether NCPC charges levied on virtual transactions are reasonable. Under DA A/S, sufficient physical supply is procured in the day-ahead market to meet the ISO's load forecast through the Forecast Energy Requirement (FER), regardless of virtual participation. As a result, virtual supply does not displace physical supply in the day-ahead market to meet the FER nor creates a physical shortfall that must be resolved in real time. Accordingly, traditional cost-causation arguments that attribute uplift to virtual supply deviations are materially less applicable under the current market design.

6.1 Virtual Transaction Volume

In 2025, the average quantity (in MW) of cleared virtual supply and demand per hour increased from 2024 and reached higher levels than in any of the previous four years, as shown in Figure 6-1 below.[211] The percentage of virtual supply offers that cleared declined slightly, while the percentage of virtual demand bids that cleared was about the same as in 2024.

[211] 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 6-1: Cleared Virtual Transaction Volumes by Location Type and Bid Type



Virtual Supply: Cleared virtual supply averaged 1,054 MW per hour in 2025, up 23% from 2024. This increase was consistent with an upward trend over the past several years and reflects, in large part, the growing amount of solar and wind resources on the grid; real-time solar and wind generation increased by a similar amount (24%) from 2024 to 2025. Virtual supply trends also reflect the limited participation of solar and wind generation in the day-ahead energy market.

Solar settlement-only generators (SOGs) are ineligible to participate in the day-ahead market, while modeled solar and wind generators (> 5 MW capacity) tend to offer high-priced energy in the day-ahead market due to uncertainty in real-time weather conditions, risk preferences, and power purchase arrangements.[212, 213] These offer patterns lead to higher volumes of renewable generation clearing in real-time than in the day-ahead market.

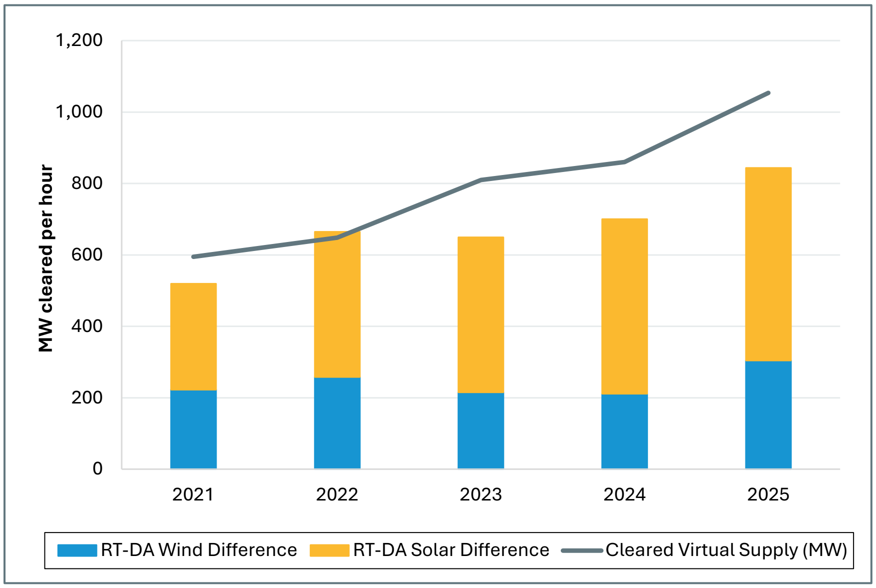
[212] Settlement-only generators are generating units that produce < 5 MW, are not centrally dispatched by the ISO New England control room, and are not monitored in real time. By the end of 2025, settlement-only photovoltaic and wind generators had an installed capacity of about 2,475 MW and 56 MW, respectively.

[213] ISO-NE defines a modeled asset as, "one or more generating units at a single location that is fully visible and controllable by ISO-NE's control room. Modeled generators bid into the Day-Ahead and/or Real-Time Energy Markets, contribute to price formation, and are therefore dispatched based on price." At the end of 2025, ISO-NE had about 1,200 MW and 1,750 MW of modeled photovoltaic and wind capacity, respectively.

In this context, virtual supply plays an important role in helping close the gap between day-ahead and real-time markets, partially offsetting limited renewable participation in the day-ahead timeframe and contributing to price convergence.

Figure 6-2 shows how the average hourly quantity of cleared virtual supply compared to the average hourly difference in real-time versus day-ahead front-of-the-meter wind and solar generation over the past five years.[214]

Figure 6-2: Cleared Virtual Supply, Solar, and Wind Volumes



In every year but 2022, the average volume of cleared virtual supply has exceeded the volume of SOG and modeled solar and wind generation that operated in real time but was not cleared in the day-ahead market. Within each year, there is considerable hourly and daily variation in the ratio of virtual supply volumes to solar and wind output, particularly during high-stress periods where the risk of high real-time price spikes tends to dampen willingness to clear virtual supply offers.

However, the overall annual trend indicates that virtual supply contributes to filling the gap between day-ahead and real-time renewable generation, and therefore supports more efficient day-ahead clearing outcomes. The fact that virtual supply volumes typically exceed the renewables gap, on an annual basis, demonstrates that participants also offer virtual supply to capture day-ahead and real-time price differences not related to renewable generation.

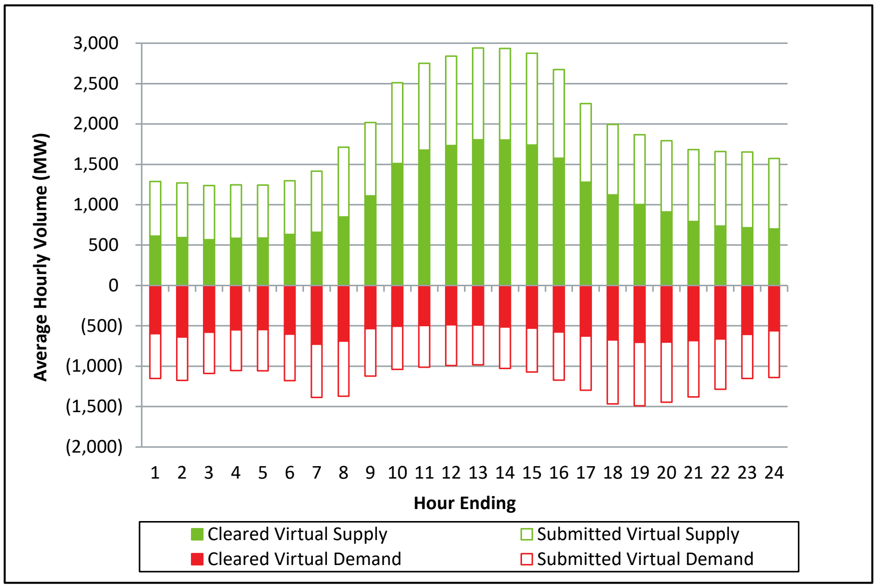
Virtual demand: As shown in Figure 6-1 above, cleared virtual demand averaged 595 MW per hour, a 194 MW or 48% increase from 2024. Volumes increased at all location types, reflecting multiple contributing factors. At external nodes, virtual demand volumes decreased from 2023 to 2024 but rebounded in 2025 due to increased clearing at the Highgate and New York North interfaces (up 35 MW/hr and 18 MW/hr, respectively, from 2024). Cleared virtual demand also increased at all other location types, driven by increases among a handful of participants.

Higher levels of virtual supply tended to be submitted and cleared during the middle part of the day, while higher levels of demand tended to be submitted and cleared during the morning and

[214] The figure does not include behind-the-meter (BTM) solar generation, which is factored into ISO-NE's load forecast and does not participate in either the day-ahead or real-time energy markets.

evening ramp periods. This can be seen in Figure 6-3 which shows the average hourly volume of submitted and cleared virtual transactions by time of day in 2025. Virtual supply is depicted as positive values, while virtual demand is depicted as negative values.

Figure 6-3: Average Hourly Submitted and Cleared Virtual Transaction Volumes by Time of Day, 2025



More virtual supply clears during the middle of the operating day than in the morning or evenings, reflecting the correlation between virtual supply volumes and output from solar generation. Between hours ending 9 through 17, cleared virtual supply averaged about 1,581 MW per hour compared to 737 MW per hour during the rest of the day.

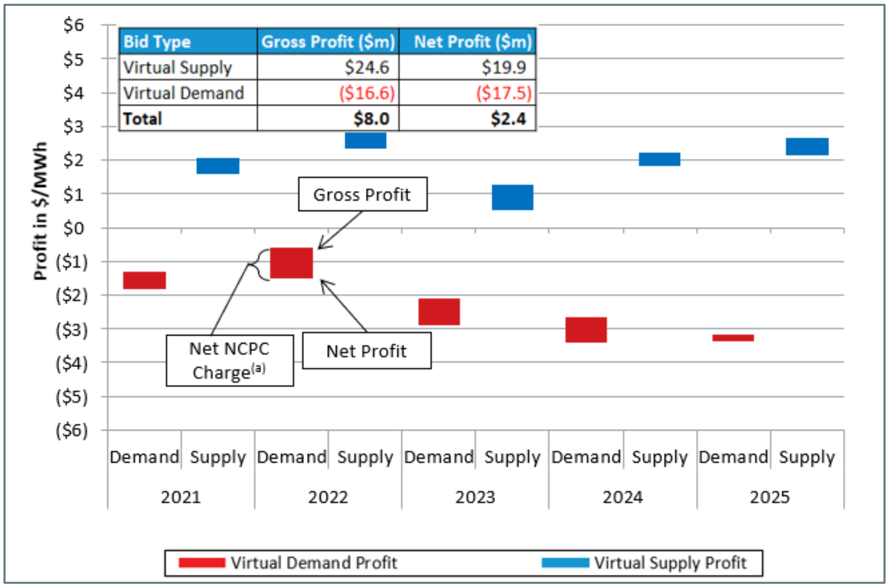
Meanwhile, the average volume of cleared virtual demand continues to be slightly higher during the morning and evening ramping periods, when loads are higher and prices tend to be more volatile in the real-time market.

6.2 Virtual Transaction Profitability

Virtual transactions profit from differences between day-ahead and real-time prices, while at the same time contributing to increased day-ahead and real-time price convergence. In this section we present virtual transaction profitability metrics at the system and location level and discuss the impact of NCPC charges on virtual transaction profitability.

Generally, profitable virtual transactions help ensure that day-ahead commitments more accurately reflect real-time requirements, bringing prices across the two markets closer together. This price-converging function is becoming increasingly important as low-marginal cost intermittent generation enters the market and tends to produce more energy in real time compared to the day-ahead market. However, transaction costs in the form of NCPC charges can turn otherwise profitable virtual transactions into unprofitable transactions on a net basis. Figure 6-4 illustrates the profitability of virtual transactions along with the impact of NCPC charges on profitability. The figure displays the average annual gross and net profit of virtual transactions since 2021.[215]

Figure 6-4: Average Annual Gross and Net Profits for Virtual Transactions



(a) Net NCPC charges are NCPC charges minus NCPC credits, which participants receive for virtual transactions that relieve congestion at external interfaces in the day-ahead energy market.

Virtual demand incurred a gross *loss* of $16.6 million, or $3.19/MWh, on average in 2025, the highest gross loss for virtual demand over the last five years. Virtual supply made a gross *profit* of $24.6 million, or $2.67/MWh, in 2025. Virtual supply profitability increased from 2024 ($2.21/MWh) and 2023 ($1.28/MWh), but was in line with average per MWh profits in 2022.

Over the five-year reporting period, virtual demand has lost money on an annual basis while virtual supply has remained consistently profitable. This is because real-time prices have tended to be lower than day-ahead prices, on average. Additionally, the systematic differences in profitability stem from the distinct motivations underlying virtual supply offers and virtual demand bids. Participants offering virtual supply to reflect real-time renewable generation submit more offers in the middle of the day when solar output is high. This is also the time of day when day-ahead prices are typically higher than real-time prices. In 2025 virtual supply offers that cleared between hours ending 9 and 17 accounted for 56% of total virtual supply volume but generated 90% ($22.2 million) of virtual supply's gross profit for the year.

By comparison, participants submitting virtual demand bids often do so to hedge against price risk in the real-time market.[216] Participants also clear high volumes of virtual demand at external

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[215] The bars are categorized by year and bid type with virtual demand shown in red and virtual supply shown in blue. The top of each bar represents gross profit, the bottom represents net profit, and the length of the bar represents the per-MWh net NCPC charge. The inset table shows profitability by bid type for 2025.

[216] While the introduction of the Day-Ahead Ancillary Services (DA A/S) market may motivate DA A/S sellers to hedge close-out exposure through virtual demand bids when performance risk is high, we do not observe a significant or material increase in cleared virtual demand attributable to DA A/S sellers in practice. To date, virtual demand activity appears broadly consistent with prior patterns and does not suggest a systematic shift in participation behavior by DA A/S providers.

interfaces, often to obtain scheduling priority of import transactions.[217] These strategies differ from purely speculative bidding that aims to profit from day-ahead and real-time price differences.

Another factor affecting virtual profitability is NCPC credits and charges.[218] Average NCPC charges for virtual supply decreased for the fourth straight year, averaging $0.55/MWh in 2025, while NCPC credits were smaller than in the prior year. In 2025, virtual supply remained profitable after subtracting net NCPC charges ($0.51/MWh), making a net profit of $2.16/MWh, on average. NCPC charges for virtual demand also decreased from prior years, averaging $0.66/MWh in 2025. NCPC credits allocated to virtual demand were higher than in 2024 as more virtual demand bids relieved congestion at external interfaces, particularly at Highgate.[219] Virtual demand lost $3.35/MWh, on average, after accounting for net NCPC charges ($0.17/MWh).

These NCPC charges can limit the ability of virtual transactions to converge prices by discouraging participation and leading participants to clear bids only when a higher day-ahead and real-time price divergence is expected. The IMM continues to recommend that the ISO review the allocation of NCPC charges to virtual transactions to ensure the charges are consistent with principles of cost causation.[220]

Review of the allocation of NCPC charges to virtual transactions is even more timely in the context of the new Day-Ahead Ancillary Services (DA A/S) market. This change strengthens the case for reassessing whether NCPC charges should be levied on virtual transactions. Under DA A/S, sufficient physical supply is procured in the day-ahead market to meet the ISO's load forecast through the Forecast Energy Requirement (FER), regardless of virtual participation. As a result, virtual supply does not displace physical supply in the day-ahead market to meet the FER nor does it create a physical shortfall that must be resolved in real time.

Accordingly, traditional cost-causation arguments that attribute uplift to virtual supply deviations are materially less applicable under the current market design.

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[217] For example, a participant with a large portfolio of generation assets may use virtual demand to hedge against higher real-time prices that might occur if one of their assets goes out of service in the real-time market after clearing in the day-ahead market.

[218] The ISO allocates the following NCPC charges to cleared virtual transactions: (1) **Real-time Economic NCPC**: all cleared virtual transactions (supply and demand) incur a charge to contribute towards the payment of real-time economic NCPC because they are considered real-time deviations; and (2) **Day-ahead Economic NCPC**: virtual demand bids are also charged day-ahead economic NCPC based on their share of day-ahead load obligation. This charge is typically much smaller because total day-ahead economic NCPC is divided among a much larger quantity of energy.

Virtual transactions can also incur NCPC charges associated with congestion at the non-CTS (coordinated transaction scheduling) external interfaces. Because these NCPC charges do not have a broad market impact or apply to virtual transactions at most locations, they are not considered in much detail in this report.

[219] For more information on NCPC credits at external interfaces, see Section 5.1.3.

[220] For more information on recommended market design changes, see the table in the Executive Summary.

Most Profitable Locations for Virtual Supply

Table 6-1 details the top 10 most profitable locations for virtual supply in 2025, after accounting for transaction costs and NCPC charges/credits (ranked by total net profit).[221]

Table 6-1: Top 10 Most Profitable Locations for Virtual Supply, 2025

Location	Location Type	Submitted MWh	Cleared MWh	Gross Profit ($k)	Net Profit ($k)	Gross Profit per MWh	Net Profit per MWh	# of Participants
.H.INTERNAL_HUB	Hub	2,696,192	1,692,453	$4,439	$3,530	$2.62	$2.09	40
.Z.SEMASS	Load Zone	944,118	727,188	$1,872	$1,470	$2.57	$2.02	21
.Z.MAINE	Load Zone	1,112,077	898,426	$1,892	$1,367	$2.11	$1.52	29
UN.BULL_HL 34.5BLHW	Gen Node	290,988	163,915	$1,280	$1,190	$7.81	$7.26	23
.Z.CONNECTICUT	Load Zone	583,951	410,089	$1,154	$930	$2.81	$2.27	21
.Z.NEMASSBOST	Load Zone	994,746	784,763	$1,322	$895	$1.69	$1.14	19
.Z.RHODEISLAND	Load Zone	560,812	447,574	$1,108	$860	$2.48	$1.92	17
.Z.NEWHAMPSHIRE	Load Zone	678,355	541,558	$1,076	$764	$1.99	$1.41	18
.Z.WCMASS	Load Zone	628,592	549,846	$1,073	$754	$1.95	$1.37	19
.Z.VERMONT	Load Zone	689,612	564,394	$968	$628	$1.72	$1.11	23

Nine of the top ten locations consisted of the Hub and all eight load zones. High total net profits at these locations were in line with the lower real-time prices at these locations, especially during the middle of the operating day.

The other location is associated with wind power generation in Northeast Maine, a region that is export-constrained. Because wind generators often do not offer their full capacity in the day-ahead market, or offer at high prices, virtual traders can profit when increased real-time wind generation leads to transmission congestion and lower real-time prices behind the export constraint.[222]

Most Profitable Locations for Virtual Demand

Table 6-2 details the 10 most profitable locations for virtual demand in 2025, after accounting for transaction charges and all relevant NCPC charges/credits (ranked by total net profit).

Table 6-2: Top 10 Most Profitable Locations for Virtual Demand, 2025

Location	Location Type	Submitted MWh	Cleared MWh	Gross Profit ($k)	Net Profit ($k)	Gross Profit per MWh	Net Profit per MWh	# of Participants
UN.OCEAN_ST13.8OS P2	Gen Node	6,271	3,046	$150	$142	$49	$47	3

[221] For more information about the additional charges for virtual transactions, see: ISO New England Inc., "*Section IV.A Recovery of ISO Administrative Expenses*, *Schedule 2 Energy Administration Service*", https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_4/section_iva.pdf.

[222] These locations tend to be riskier as well, given the difficulty of forecasting wind generation. For example, if a participant expects high wind output in the real-time market, they might clear virtual supply in the day-ahead market at a low price and expect to profit off negative real-time prices. However, if the wind generation does not meet day-ahead expectations, these locations will likely be unconstrained, and the participant would have to pay its day-ahead obligation back at a higher real-time price.

Location	Location Type	Submitted MWh	Cleared MWh	Gross Profit ($k)	Net Profit ($k)	Gross Profit per MWh	Net Profit per MWh	# of Participants
UN.BASELINE34.5DNEW	Gen Node	3,999	539	$28	$28	$52	$52	8
.I.SHOREHAM138 99	Ext Interface	229,851	11,973	$44	$28	$4	$2	7
LD.BUNKR_HL13.8	Load Node	21,402	16,794	$34	$21	$2	$1	13
.I.NRTHPORT138 5	Ext Interface	231,345	3,425	$10	$19	$3	$6	8
.I.SALBRYNB345 1	Ext Interface	164,781	1,894	$17	$16	$9	$8	7
UN.TUTTLEHL34.5ANTW	Gen Node	1,436	1,436	$18	$16	$13	$11	2
LD.JOHNSTON12.5	Load Node	3,270	2,852	$17	$15	$6	$5	5
LD.ELM_WEST13.8	Load Node	3,583	3,583	$13	$12	$4	$3	4
LD.CONGRESS13.8	Load Node	1,192	1,167	$12	$10	$10	$9	3

Three of the 10 most profitable locations were external interfaces. .I.SHOREHAM138 99 and .I.NRTHPORT138 5 are external proxy nodes for the two Long Island, New York interfaces, and .I.SALBRYNB345 1 is the external proxy node for the New Brunswick interface. At the Northport-Norwalk interface, about half of net profit came from uplift credits that a small number of participants received for relieving import congestion. [223] Typically, New England is a net exporter to Long Island via the Northport-Norwalk interface; however, in Q4 2025, New England was a net importer over this interface. Additionally, during Fall 2025 the Northport-Norwalk interface was frequently limited due to transmission work, which created more congestion at the interface than normal. Virtual traders were able to relieve some of that congestion in the day-ahead market and received uplift credit from importers for doing so.

The other seven most profitable locations consisted of generator and load nodes. Overall, none of the 10 nodes had more than 2 MWh of virtual demand clearing, on average.

[223] For more information on NCPC credits at external interfaces, see Section 5.1.3.

Section 7
Forward Capacity Market

The capacity auction for the delivery period 2028/29 delivery was delayed until 2028 as the Forward Capacity Market (FCM) shifts to a prompt-auction structure as part of the Capacity Auction Reforms (CAR) project.[224] In this section (7.1), we first discuss and provide our current thinking and recommendations on aspects of the CAR design, including comments on the Prompt-Deactivation component of the design ("CAR-PD") and benefits of the Seasonal-Accreditation component ("CAR-SA"). The CAR-PD phase of the reforms was recently approved by FERC.[225]

Finally, since no forward capacity auction occurred in 2025, we focus on secondary market activity and Pay for Performance (PfP) settlement outcomes. Monthly reconfiguration auctions for Capacity Commitment Periods (CCP) 15-16 and annual reconfiguration auctions for CCPs 16-18 were held during the year. Section 7.2 summarizes the outcomes of these reconfiguration auctions. Section 7.3 covers the PfP events on June 24 and November 23, which mark an increase in reserve deficiency hours and total PfP payments relative to prior years.

7.1 Capacity Auction Reforms

The Capacity Auction Reform (CAR) project is a multi-year initiative aimed at overhauling key aspects of the capacity market, including auction timing, seasonal procurement, and capacity qualification and exit (deactivation) rules. The project is split into two components: (1) the CAR-PD project encompasses the prompt-auction timeline and resource deactivation components and (2) The CAR-SA project encompasses the bi-annual seasonal auction and marginal resource accreditation components, including the implementation of a gas-specific resource constraint in winter months to better reflect limited natural gas availability to the power sector when pipelines are constrained.

The FERC approved tariff changes for CAR-PD in early 2026, and as part of this regulatory process, the IMM filed supportive comments on the CAR-PD design.[226] Section 7.1.1 below summarizes these comments. CAR-SA design work continued throughout 2025, and Section 7.1.2 outlines key design features of the proposal.

7.1.1 CAR: Prompt/Deactivations

The two primary components of the CAR-PD proposal are the replacement of the forward capacity auction construct (three years in advance) with a prompt (one month in advance) capacity auction, and associated changes to the resource deactivation process. Other key changes included moving from a descending clock auction to a sealed-bid auction format and the conforming changes to the buyer- and seller-side mitigation rules. While CAR-PD is intended as an intermediate step with changes that will carry through the final CAR design (incorporating both CAR-PD and CAR-SA), we support CAR-PD on its own merits as an improvement on existing capacity market rules.

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[224] For more details on the CAR project, see: ISO New England, "*Capacity Auction Reforms Key Project"* webpage, https://www.iso-ne.com/committees/key-projects/capacity-auction-reforms-key-project.

[225] Federal Energy Regulatory Commission, "*Order Accepting Tariff Revisions*, *194 FERC ¶ 61,249,* Mar. 30, 2026*,* Docket No. ER26-925-000, https://www.iso-ne.com/static-assets/documents/100033/er26-925-000.pdf.

[226] ISO New England Inc., Internal Market Monitor, "*Comments of the Internal Market Monitor of ISO New England",* January 20, 2026, Docket No. ER26-925-000, https://www.iso-ne.com/static-assets/documents/100031/er26-925-000_imm_comments_cars.pdf.

Benefits of Moving the Auction Timing: The prompt-auction structure reduces uncertainty in the capacity market. On the demand side, the capacity market relies on load forecasts, which were made more than three years in advance under existing Forward Capacity Auction (FCA) rules. Under the FCA, ongoing changes to the load forecast are reflected in Net ICR adjustments throughout three Annual Reconfiguration Auctions (ARAs), and these have shown significant variability to date. The prompt-auction design improves forecast certainty through reducing the load forecast window, enhancing market signals and eliminating the need for ARAs.

Prompt auctions similarly reduce uncertainty in supply. The CAR-PD design requires resources to be fully built before they can enter the auction. This eliminates unbuilt "phantom capacity" that might clear a forward capacity auction and fail to complete construction in time for the capacity commitment period, negatively impacting price formation. Additionally, the prompt timeframe should improve participants' expectations of the net going forward costs in their supply offers.[227]

Deactivation Process: The deactivation component of CAR-PD eliminates priced retirement bids in favor of unpriced, irrevocable deactivation notifications due one year before the commitment period. We observe that deactivation decisions are usually based on unit fundamentals and multi-year market outlooks rather than the single-year capacity clearing price implied by the priced retirement bid construct. The one-year notification due date balances the time necessary for the ISO to conduct reliability assessments for the deactivating resource and time for a market participant to form reasonable market expectations relatively near to the commitment period, with flexibility up until the binding one-year deadline.

While deactivations will be unpriced under CAR-PD, the IMM will continue to conduct market power reviews for deactivating resources. A conduct and portfolio benefits test will be applied to all deactivation notices. Should a resource fail these tests, the resource will still exit the market, but a proxy bid will be included in the auction in its place to preserve competitive price formation in the prompt auction.

Future Deactivation Mitigation Enhancements: During the design process, the IMM expressed a preference for adopting a market power charge as a more effective deterrent to uneconomic deactivations than the current and proposed proxy bid approach.[228] We continue to believe this option warrants further consideration. Because deactivations can affect market prices over multiple years—and are heavily influenced by the pace and nature of new entry—the proxy bid approach provides protection only for a single year. A well-designed market power charge would more directly discourage uneconomic deactivations and better protect market outcomes over time.

Future Seller-side Mitigation Enhancements: The IMM has recommended replacing the current Pivotal Supplier Test with a Conduct and Impact (C&I) framework for seller-side mitigation of existing resources offering capacity for a single delivery period. A C&I approach would more accurately assess market power, provide a more consistent and flexible mitigation framework, reduce reliance on rigid conduct thresholds, and offer a conceptual foundation for better

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[227] Net going forward costs represent the incremental costs of a resource taking on a CSO. ISO New England Inc., "*Market Rule 1 - Section 13 Forward Capacity Market*", Section III.13.1.2.3.2.1.2.A, https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf.

[228] ISO New England, Internal Market Monitor, " *IMM Feedback on Capacity Auction Reforms – Prompt & Deactivations",* June 10, 2025, https://www.iso-ne.com/static-assets/documents/100024/a03.3a_mc_2025-06-10-11_car-pd_imm_feedback.pdf.

alignment with buyer-side mitigation rules. While this recommendation was not adopted in for the CAR-PD phase, we continue to recommend that the ISO evaluate and adopt these changes in advance of the next capacity auction.[229]

Auction Format: The CAR-PD design includes a change to a sealed-bid auction and provides a number of improvements in terms of reducing administrative complexity, providing better alignment with the underlying economic issues that a prompt capacity procurement process is intended to address, and mitigating certain market power concerns. On the latter, the sealed-bid auction format addresses certain market power concerns that arise due to information release in the current descending-clock auction structure.

7.1.2 CAR: Seasonal/Accreditation

The ongoing CAR-SA project encompasses a shift to two seasonal capacity auctions (summer and winter) and a marginal resource accreditation approach.[230] The sections below outline these features at a high level.

Seasonality in Accreditation and Reliability Risk

The CAR-SA proposal includes a shift from one annual capacity auction to two seasonal capacity auctions, one for summer and one for winter. Each auction will be run independently with individual demand curves and supply offers. The primary purpose of the seasonal construct is to enable season-specific marginal resource accreditation; as discussed below, marginal accreditation can improve investment signals in the capacity market, and a seasonal context is necessary to reflect the different (and evolving) summer-winter load profiles and the value of different resource types in meeting summer and winter peaks.

Marginal Resource Accreditation

The resource accreditation reforms aim to align capacity market qualified supply with expected resource contributions toward system reliability by adopting a Marginal Reliability Impact (MRI) approach.[231] Current FCM rules generally qualify capacity based on audited resource performance, which can differ materially from the true reliability value provided by a resource if it is not fully available during stressed conditions, such as due to forced outages, gas pipeline limitation, and limited energy.

Shifting the capacity market toward MRI-based capacity improves market efficiency and cost-effectiveness, reducing the procurement of unreliable capacity and rewarding investment in resources that are best positioned to address system reliability needs.

Seasonality is a core consideration in marginal resource accreditation because seasonal conditions determine how effectively different resource types contribute to system reliability. For example, solar resources provide substantially more reliability value in summer, when daylight is abundant, than in winter, when daylight is limited and reliability events often occur during severe weather.

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[229] ISO New England Inc., Internal Market Monitor, "*2024 Annual Markets Report",* May 2025, Section 6, https://www.iso-ne.com/static-assets/documents/100023/2024-annual-markets-report.pdf.

[230] For more information on CAR-SA, see: ISO New England Inc., "*Capacity Auction Reforms: Seasonal/Accreditation (CAR-SA), Design Kickoff Discussion*", September 9, 2025, https://www.iso-ne.com/static-assets/documents/100027/a02.2a_mc_2025_09_09_10_introduction_car-sa_presentation.pdf.

[231] In this context, "system reliability" is defined by the one-day-in-ten-years reliability standard.

Also, short-duration energy storage resources, such as batteries, can provide significant reliability value during brief, high-risk reliability intervals; however, their contribution during prolonged stress events is inherently limited. Given the rapid growth of these technologies, it is increasingly important that resource accreditation accurately reflects their reliability attributes so that market compensation appropriately aligns with system needs.

Natural Gas Resource Constraint

Reliability risks in New England are particularly pronounced during winter periods due to the region's limited natural gas pipeline capability. Cold-weather conditions increase heating demand, which can constrain gas availability to generators at the same time winter peak loads and reliability events are most likely to occur. Looking ahead, projected growth in winter demand over the next decade is expected to further increase these risks (see Figure 2-5). As a result, it is increasingly important to explicitly model natural gas pipeline limitations and their impact on resource deliverability in the capacity market accreditation process, so that resource reliability contributions are accurately reflected and appropriately compensated.

In short, the physical natural gas constraint reduces the expected reliability contributions from gas-only generators in winter. To reflect this reality, the ISO's proposal models the limited gas system as a shared generation constraint for gas-only resources, conceptually and practically similar to a transmission export-constrained zone, which limits the generation behind the constraint in a shared manner.[232] This is because the gas constraint is a shared quantity among generators; on a day when the gas system is fully constrained, a gas-fired generator can only contribute to system reliability by consuming limited gas supplies and limiting reliability contributions from other generators.

Under this design, gas-only generators will face a gas demand curve that values the reliability contributions of gas-only generation at a lower level than other system generation, based on modeled gas system limits during expected shortage conditions. Gas-only units that clear based on this demand curve will receive a lower capacity clearing price than the rest of the system. Notably, gas-fired generators that firm up their fuel supplies are not included with the gas constraint, specifically dual-fuel generators that can switch to oil during winter conditions, and gas-only generators that sign firm contracts that confer priority access to gas regardless of system conditions.[233]

The gas constraint design will improve capacity market signals through aligning gas-only generator compensation with expected reliability contributions, and through limiting the impact of unreliable gas-only generation capacity on the market clearing prices. Gas generators will be incentivized to invest in firm fuel or dual-fuel capability through weighing the costs of such investments against their expected increase in capacity market compensation.

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[232] ISO New England Inc., "*CAR-SA: Gas Demand Curves Examples"* ,January 2026, https://www.iso-ne.com/static-assets/documents/100031/a04.1.a.iii_mc_rc_2026_01_13-14_follow_up_gas_demand_curve_examples.pdf.

[233] Since gas availability for electric generators (after heating demand) remains a limited quantity even if a portion of that gas is firm, the CAR-SA proposal will reduce the gas demand curve by the amount of demonstrated firm gas capacity at the time of the auction. Therefore, the gas-only demand curve will reflect the availability of non-firm gas for generation after both heating demand and demonstrated firm gas for generation are accounted. For more information, see: ISO New England Inc., "*Overview of Gas Design"* December 2025, https://www.iso-ne.com/static-assets/documents/100030/a04.1.a_mc_rc_2025_12_09-10_gas_constraint_design_cont..pdf.

7.2 Reconfiguration Auction Outcomes

This section provides a review of reconfiguration auction outcomes in 2025, with results spanning Capacity Commitment Period (CCP) 15 (2024/25) through CCP 18 (2027/28).

Key Takeaways

Overall traded volumes in secondary capacity auctions remain low relative to total contracted capacity, as most positions are established and held through the primary Forward Capacity Auctions (FCAs). Nevertheless, secondary auction clearing prices provide useful information about market participants' expectations. Notably, reconfiguration auction prices for the 2026/27 and 2027/28 capacity commitment periods were materially higher than the associated FCA clearing prices, suggesting tighter supply-demand fundamentals and potentially heightened expectations of future capacity scarcity conditions and Pay-for-Performance (PfP) exposure.

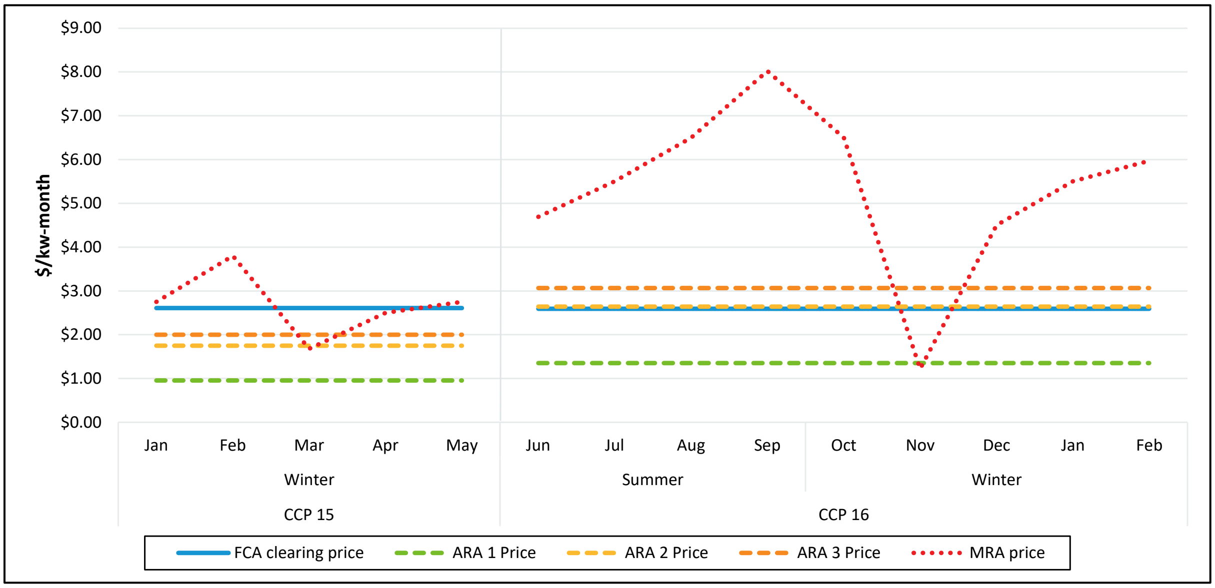
Annual Reconfiguration Auction (ARA) prices for CCPs 15 and16 were generally similar to or lower than FCA clearing prices. Reduced capacity prices were generally attributable to lowered Net ICR values as load forecasts shifted leading up to the commitment periods. In contrast, prices for ARA 2 of CCP 17 and ARA 1 of CCP 18 reached around $5/kW-month, marking a significant increase from each FCA. These prices were driven by tighter supply due to CSO terminations and higher prices for remaining supply.

Monthly Reconfiguration Auction (MRA) prices in CCP 15 were similar to the FCA 15 clearing price, but prices in CCP 16 were generally much higher than the FCA 16 price, peaking at $8/kW-month in September 2025. Clearing prices were driven by relatively tight supply availability in summer months and increased perceived PfP risk throughout the year.

7.2.1 Reconfiguration Auctions: CCP 14 and CCP 15

Monthly reconfiguration auctions covering the CCP 15-CCP 16 (2024/25 and 2025/26) period occurred throughout 2025. Figure 7-1 shows Monthly Reconfiguration Auction (MRA) rest-of-pool prices alongside Forward Capacity Auction (FCA) and Annual Reconfiguration Auction (ARA) rest-of-pool prices.

Figure 7-1: Reconfiguration Auction Prices for CCPs 15 and 16



Annual reconfiguration auction prices were generally near or below FCA clearing prices for CCPs 15 and 16 (June 2024 through May 2026), with falling Net ICR requirements following the forward auctions and closer to the delivery periods. Monthly reconfiguration auctions in the latter half of CCP 15 cleared at prices near the FCA 15 price with minimal price separation.

By contrast, MRAs throughout CCP 16 generally cleared at prices significantly higher than FCA 16, with significant price volatility. MRA prices averaged over $5/kW-month, with a peak of $8/kW-month in September 2025. Clearing prices throughout the summer of CCP 16 were influenced by limited supply. On average, only 500 MW of supply offers entered into the auctions, compared to 4,000 MW of demand. In other words, more resources were willing to offload obligations than resource willing to take on obligations.

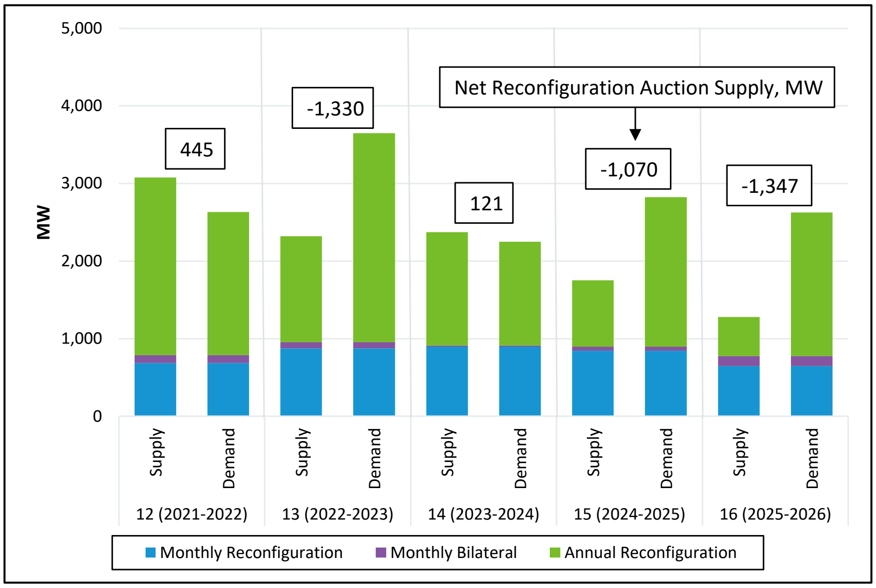
Capacity supply is typically tighter in summer as fossil fuel-fired generators have less qualified capacity due to high ambient temperatures, and therefore demand response resources make up the majority of MRA cleared supply. While a return to the relatively capacity-abundant winter period resulted in a low clearing price in November 2025, high supply offers and demand bids continued to drive high clearing prices through the rest of the year into 2026. Increased supply offers and demand bids may reflect a higher perceived risk of holding a CSO relative to prior years.

Traded volumes in reconfiguration auctions remained low as a share of total volumes acquired in FCAs. Figure 7-2 shows secondary auction volumes from CCP 12-CCP 16, with separate bars showing cleared supply and cleared demand.[234,235]

[234] The annual reconfiguration bars represent the volume of total capacity added or shed (whichever is greater) across all three ARAs for a commitment period. Volumes are calculated as annual averages. For example, MW traded in ARAs have a weight of 1, while MW traded in MRAs have a weight of 1/12.

[235] ARAs feature an updated Net ICR compared to the base auction. Demand represents a combination of an updated system demand curve and participant bids to shed CSO, while supply represents a price-taking component for CSO that is not participating in the ARA and a priced component for new supply offers. CSO can enter or exit the market on a net basis in an ARA, and this is the only reconfiguration type in which net entry or exit can occur.

Figure 7-2: Traded Volumes in Reconfiguration Auctions



Reconfiguration auction volumes averaged 8% of FCA auction volumes for CCPs 15-16. ARA volumes continued to make up the largest share of secondary auction volume as capacity left the market on a net basis throughout the ARAs in CCP 15-16 as Net ICR requirements fell. Decreased monthly reconfiguration auction volumes are associated with the limited capacity supply in Summer 2025. Bilateral trading accounted for 130 MW of capacity on average in CCP 16, up from only 50 MW in CCP 15.

7.2.2 Annual Reconfiguration Auctions: CCP 16 (2025/26), CCP 17 (2026/27), and CCP 18 (2027/28)

The final ARA for CCP 16, the second ARA for CCP 17, and the first ARA for CCP 18 occurred in 2025. Figure 7-3 shows the rest-of-pool clearing prices for the FCAs 16-18 alongside the ARAs that have occurred so far for each commitment period.

Figure 7-3: Annual Reconfiguration Auction Prices, CCP 16-CCP 18

The third ARA for CCP 16 cleared at $3.06/kW-month, higher than the $2.59/kW-month clearing price in FCA 16. Clearing prices rose despite a decline in the Net ICR (30,300 MW in ARA 3 compared to 31,645 MW in FCA 16).

The second ARA for CCP 17 and the first ARA for CCP 18 both cleared at roughly $5.00/kW-month, marking significant increases from both FCA clearing prices. While the clearing price of CCP 17 ARA 2 was influenced by a slight increase in Net ICR (30,600 MW, up by 300 MW), tighter supply was the primary driver of both outcomes. Increased supply prices were attributable to two factors; first, significant amounts of capacity were terminated between the FCA and ARAs (500 MW in CCP 17; 900 MW in CCP 18).[236] Notably, battery storage generators made up the majority of terminated CSO MW for CCP 17-18 (over 75%). Second, a heightened expectation of more PfP events likely contributed to increased offers for remaining incremental supply.

7.3 Pay-for-Performance Outcomes

Pay-for-Performance (PfP) is a two-settlement mechanism that credits or charges resources based on their performance in meeting energy and operating reserve requirements during periods when the system is deficient in Total 10- or 30-minute reserves. These periods are called Capacity Scarcity Conditions (CSCs).

Two distinct CSCs occurred in 2025, marking just the sixth and seventh occurrences since the PfP market rules were introduced in June 2018. The 2025 CSCs occurred on June 24 and November 23. The June 24 event was driven by high temperatures, peak system loads, and generation trips, while the November 23 event was driven by large generation trips on a comparatively normal operating day.[237] The two events totaled 3.6 hours, mostly driven by the historically long June 24 event. However, CSC hours were slightly under the ISO forecasting models' predictions of reserve deficiency hours for CCP 16 (2025/26).[238]

Key Takeaways

Two Capacity Scarcity Conditions (CSCs) occurred in 2025. The June 24 event was the longest CSC since the implementation of Pay for Performance (PfP) rules at just over 3 hours, while the November 23 event lasted only 30 minutes. The June 24 event was driven by the system annual peak load, and generator outages contributed to both events.

The PfP rate increased to $9,337/MWh for CCP 16 from $5,455/MWh in CCP 15, significantly impacting total credits and charges in the two-settlement system. PfP transfers totaled $114.3 million on June 24 and $32.3 million on November 23. Many resources reached monthly stop-loss limits on June 24, marking the first and only event in which the stop-loss construct

[236] For more information on termination of capacity supply obligations, see: ISO New England Inc., "*Market Rule 1 - Section 13 Forward Capacity Market*", Section III.13.3.4A., https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf.

[237] Detailed analysis of event drivers on both days is available in Section 4.6, and in the Summer and Fall 2025 Quarterly Markets Reports. ISO New England Inc., Internal Market Monitor, *"Internal Market Monitor Reports and other Materials"* webpage, https://www.iso-ne.com/markets-operations/market-monitoring-mitigation/internal-monitor.

[238] ISO New England., "*Operating Reserve Deficiency Information – Capacity Commitment Period 2024-2025",* December 7, 2021, https://www.iso-ne.com/static-assets/documents/2021/12/a00_pspc_2021_12_iso_memo_or_def_fca_16.pdf. FCA 16 cleared at 32,810 MW, a surplus of 1,165 MW over Net ICR (31,645 MW). At this level of capacity, the ISO forecast roughly 4-5 hours of reserve deficiencies.

significantly affected settled outcomes.

Notably, the balancing ratio exceeded 100% on June 24. The high balancing ratio indicated that system CSO was insufficient to meet load and reserve requirements during the event. Additionally, resources were required to produce more than their CSO to avoid receiving net PfP penalties. Forthcoming market rule changes will cap the balancing ratio at 100% to avoid financial obligations that exceed physical generating capabilities.

Capacity resource performance is assessed based on the energy delivered and operating reserves provided during CSCs relative to the resource's CSO and the system's balancing ratio—the fraction of total contracted capacity needed to meet load and reserve requirements.

The PfP rate is the price at which resources are compensated for providing energy or reserves above their CSO (after weighting by the balancing ratio). The rate increased to $9,337/MWh in CCP 16, a 70% increase from CCP 15 ($5,455/MWh). The higher rate contributed to large PfP settlements in 2025 relative to prior years. While the tariff continues to specify a rate of $9,337/MWh for upcoming CCPs, the ISO has recently proposed a reduction to $3,500/MWh, which would take effect immediately if accepted.[239]

Capacity market settlements for the June 24 PfP event are aggregated by fuel type in Figure 7-4, while Figure 7-5 shows settlements for the November 23 event.[240] The green and red bars show PfP credits or charges to resources with CSO by fuel type on a net basis. The yellow bars show PfP credits to resources with no CSO that provided energy or reserves during the event. Monthly base capacity payments are shown by fuel type for comparison.

[239] For current PPR, see: ISO New England Inc., "*Market Rule 1 - Section 13 Forward Capacity Market*", Section III. 13.7.2.5, https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf. For information on the proposed PPR update, see: ISO New England Inc., "*Pay-For-Performance Revisions: Performance Payment Rate (PPR) Proposed Change*", March 2026, https://www.iso-ne.com/static-assets/documents/100033/a03_mc_2026_03_10-12_pfp_revisions_ppr.pdf.

[240] In these figures, "DF" refers to dual-fuel assets and "CC" refers to combined-cycle generators. "ST – RFO" refers to steam turbine units burning residual fuel oil. Gas- or oil-fired units with fast-start capability are separated from similar units without fast-start capability. The "Other" category includes nuclear, coal, and wood or waste-fired units.

Figure 7-4: Pay-for-Performance Settlements, June 2025

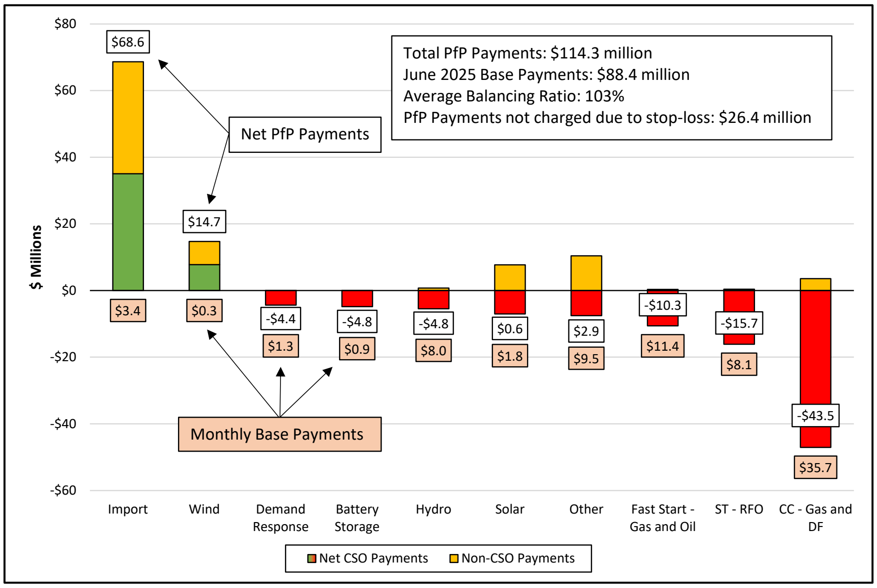
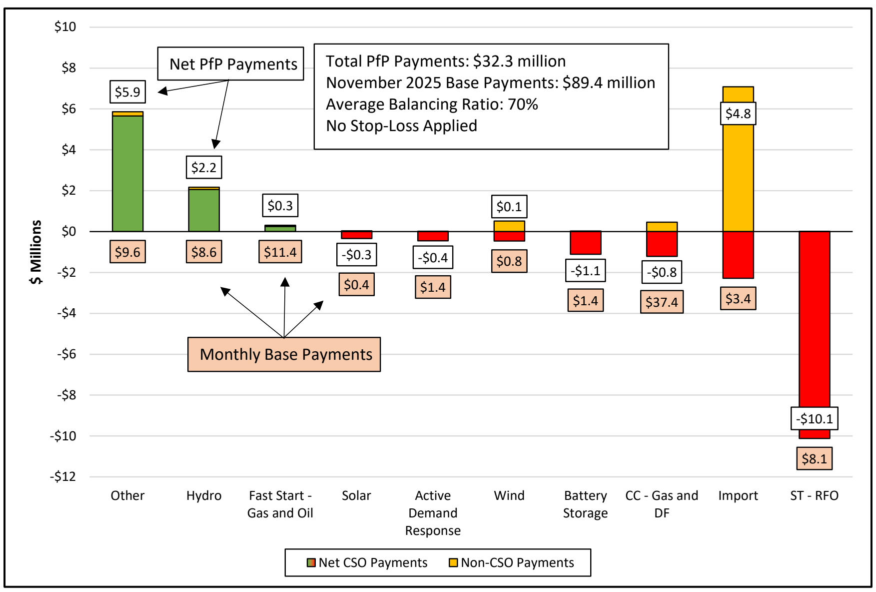


Figure 7-5: Pay-for-Performance Settlements, November 2025



Resource Performance: Aggregated across the year, imports were the best-performing resource type during shortage conditions due to their relative flexibility. Imports with and without CSO earned $69 million on June 24, and imports without CSO earned $7 million in credits on November 23.[241] While most resource types underperformed on June 24 due to the 103% average balancing ratio (discussed below), combined cycle units particularly struggled due to gas pipeline Operational Flow Orders and high ambient temperatures. Resource performance during the November 24 event was largely determined by resource availability in an unexpected and short-

[241] In contrast, imports with CSO faced $3.1 million in PfP charges in November. Imports as a group received $4.8 million in net credits during the event.

duration event, with flexible and already-online units performing well against a low balancing ratio and slower steam turbine units performing poorly since they were unable to come online in time.

Balancing Ratio: The balancing ratio averaged 103% on June 24 and 70% on November 23. The June 24 event marked the first and only time that the balancing ratio exceeded 100% since the implementation of PfP rules. The high balancing ratio indicated that system CSO was insufficient to meet load and reserve requirements,[242] and that resources were required to produce more than their CSO to avoid financial PfP penalties. Forthcoming market rule changes will cap the balancing ratio at 100% to eliminate financial obligations in excess of physical capabilities.[243] Additionally, exports occurred during both events and contributed to the reserve deficiency and to the high balancing ratio in June. The assessment of PfP charges to exports would have disincentivized export demand.[244]

Stop Loss Mechanism: The combination of the high PfP rate, high balancing ratio, and long event duration caused several resources to reach monthly stop-loss limits on June 24. The stop-loss construct resulted in $26.4 million in reallocations from over-performing capacity resources to cover shortfalls from under-performing capacity resources that reached stop loss limits. Notably, the stop-loss construct limits stop-loss charge exposure to capacity resources rather than reducing PfP credits to non-capacity resources. This is because the stop-loss mechanism functions as a mutual insurance fund for capacity resources, and this construct will continue under the balancing ratio changes. The November 23 event did not result in any additional resources reaching monthly or annual stop-loss limits.

[242] Weather on June 24 was unexpectedly extreme, and loads were estimated to be in-line with a 90/10 hotter-than-forecast day in the 2021 CELT report forecast for FCA 16.

[243] Federal Energy Regulatory Commission, "*Order Granting Complaint in Part and Denying in Part",* 194 FERC ¶ 61,052, Docket No. EL25-106-000, January 22, 2026, https://www.iso-ne.com/static-assets/documents/100031/el25-106-000_order_nepga_complaint_grant_in_part.pdf.

[244] For the IMM's recommendation on PfP treatment of exports, see: ISO New England Inc., Internal Market Monitor, "*2024 Annual Markets Report",* May 23, 2025, https://www.iso-ne.com/static-assets/documents/100023/2024-annual-markets-report.pdf.

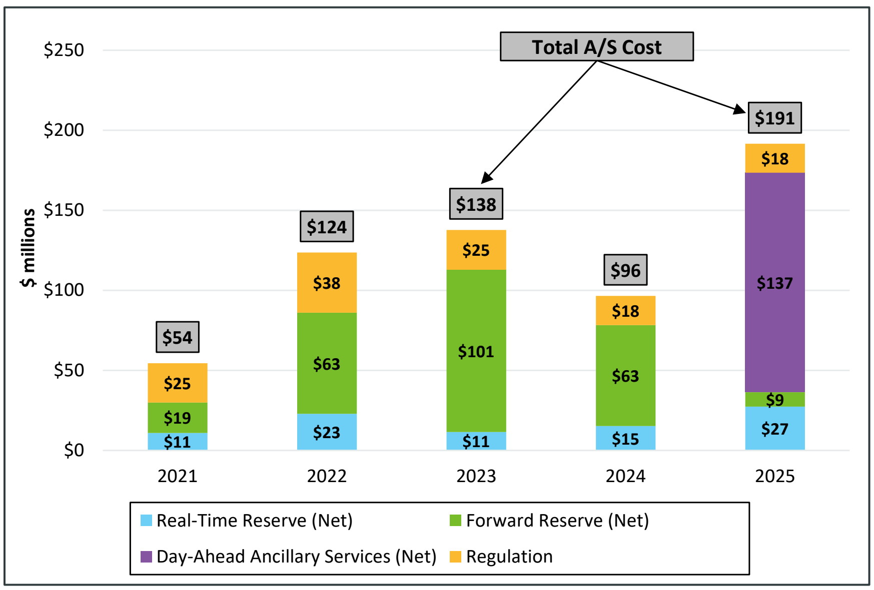
Section 8
Ancillary Services Markets

This section discusses the performance of ISO-NE's ancillary services markets. These markets are:

- **The real-time reserve market**: a *spot* market that procures and prices operating reserve capability (i.e., fast-start and fast-ramping capability) through a co-optimized process in the real-time energy market. (8.1).
- **The day-ahead ancillary services (DA A/S) market**: a *forward* market that procures and prices ancillary services capability (both operating reserve capability and the capability to meet the load forecast) through a co-optimized process in the day-ahead market (8.2).
- **The regulation market:** a *spot* market that procures and prices the capability of resources to alter their energy output over very short time intervals (minute-to-minute) in order to balance supply and demand and maintain system frequency in the real-time energy market (8.3).

Ancillary service market costs are shown by year in Figure 8-1 below. This figure also includes costs associated with the Forward Reserve Market (FRM), which sunset at the end of February 2025 coincident with the start of the DA A/S market.

Figure 8-1: Market-based Ancillary Service Costs by Year



Market-based ancillary services costs reached their highest level over the reporting period in 2025, totaling $191 million. This represented an increase of nearly 100% relative to 2024 costs ($96 million). The largest increase in costs came from the new DA A/S market, whose costs totaled $137 million in 2025. This increase was somewhat offset by a reduction in FRM costs. The FRM was eliminated at the end of February 2025 as it was incompatible with the new DA A/S market.

While not discussed in this section, the ISO does procure and compensate other ancillary services via non-market mechanisms. Two such ancillary services are: 1) *voltage service*, which helps the ISO maintain an acceptable range of voltage on the transmission system and 2) *blackstart service*, which is provided by generators that are able to start quickly without outside electrical supply and are therefore able to facilitate power system restoration in the event of a partial or complete system blackout. Voltage services costs totaled $16 million in 2025, which was nearly identical to the costs for this service in 2024. Meanwhile, blackstart services costs rose from $44 million in 2024 to $48 million in 2025.

8.1 Real-Time Operating Reserves

The following section reviews real-time operating reserve products and outcomes. The first subsection (8.1.1) presents the reserve requirements that the ISO maintains in the real-time energy market as well as the typical amount of reserve capability that is available in excess of those requirements. The second subsection (8.1.2) explores the frequency and magnitude of real-time reserve prices, including the frequency of reserve constraint penalty pricing, and summarizes the level of real-time reserve payments.

Key Takeaways

The system generally had ample reserve capability to satisfy reserve requirements throughout 2025, with two notable exceptions during a few days with reserve deficiencies resulting in Capacity Scarcity Conditions under the Pay for Performance rules. The average system reserve requirements in 2025 were effectively unchanged from 2024, and ten-minute spinning margins increased slightly in 2025 relative to 2024 as a result of newly commercial battery capacity.

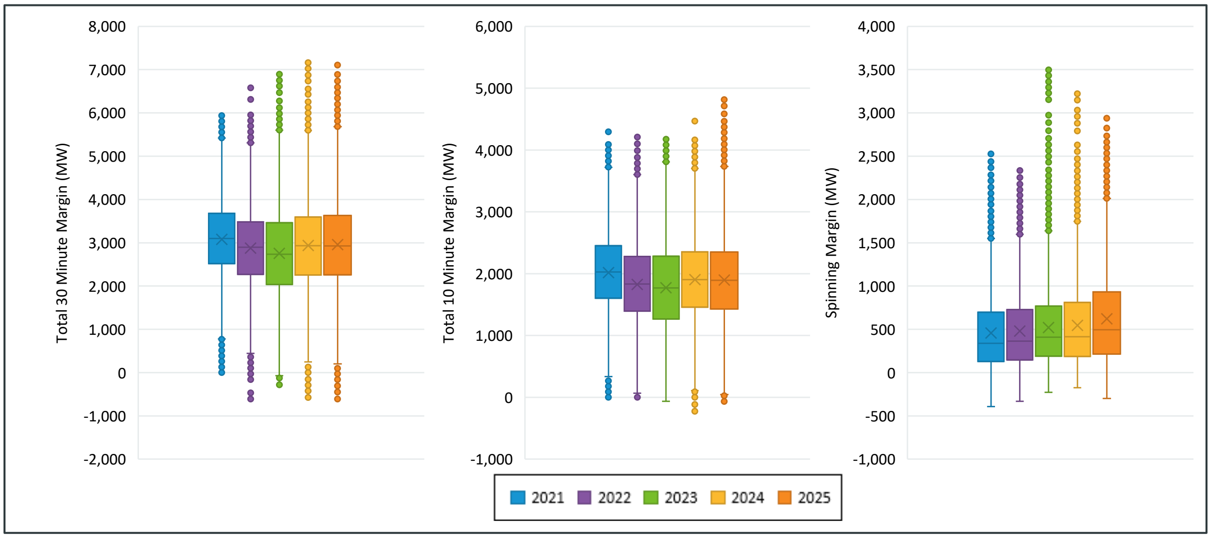
During 2025, net real-time reserve payments totaled $27.3 million, an 80% increase from 2024. A key driver of these increased payments was the sunsetting of the Forward Reserve Market with the implementation of day-ahead ancillary services. Total real-time credits before forward reserve adjustments only increased 3% year-over-year.

8.1.1 Reserve Requirements and Margins

There are three distinct reserve requirements determined by the North American Electric Reliability Corporation (NERC) and Northeast Power Coordinating Council Inc. (NPCC). Reserve requirements are based on the two largest contingencies on the system (commonly known as first and second contingencies). Figure 8-2 shows these system-level requirements, as well as the average reserves designated to satisfy these requirements.[245]

[245] There are also 30-minute local reserve requirements that are not shown or discussed below. These requirements bind infrequently, and thus are not impactful to system operations.

Figure 8-2: Average System Reserve Requirements and Designations



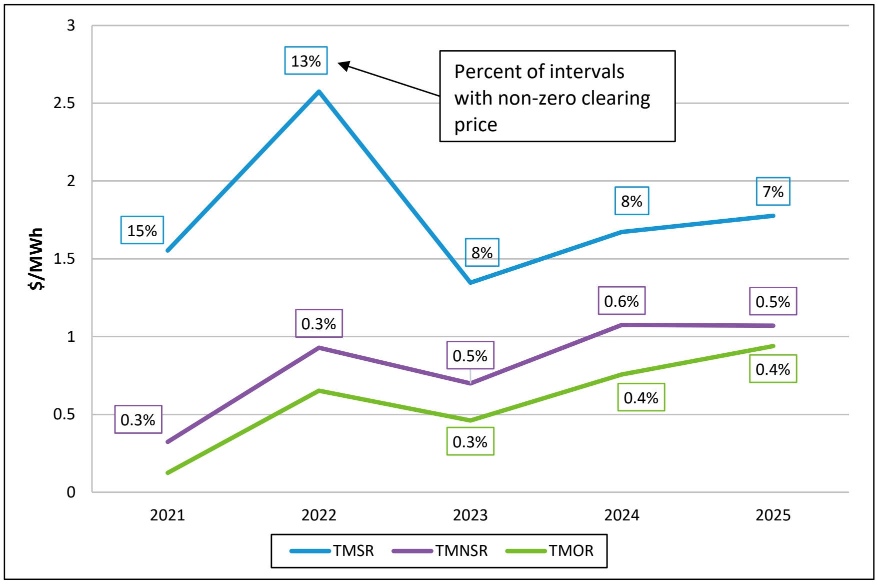
The reserve margin measures the reserve capability available in excess of reserve requirements (i.e., the distance between associated designation lines and bars in the figure above). Total ten-minute and thirty-minute reserve margins in 2025 were effectively unchanged from 2024. The spinning reserve margin increased from 546 MW to 624 MW on average year-over-year, driven by contributions from new battery assets that went commercial in 2025. These assets contributed ~70 MW more per hour to the spinning reserve margin in 2025 than in 2024. In most intervals, the system carries plentiful total-10 and total-30 reserves, with only outlier values dipping below the requirement (i.e. the dots below 0). Spinning reserve margins fall below 0MW more often, due to the lower penalty factor—the market software will only pay a maximum of $50/MWh to ensure the requirement is met, compared with $1,500/MWh for the total-10 minute requirement and $1,000/MWh for the total-30 requirement.

On average, there has been a healthy surplus of reserve capability on the system compared to the requirements, though there were noteworthy periods during 2025 when the region experienced deficiencies of reserves. These instances are included in the discussion of system events in Section 4.6.

8.1.2 Reserve Prices and Payments

Reserve prices occur when there is an opportunity cost of providing reserves rather than energy; in other words, when the market clearing engine re-dispatches resources to maintain reserve requirements. This is an infrequent occurrence in New England, which has a large fleet of offline fast-start resources. Most of the time such re-dispatch is not necessary and, because reserve constraints are not binding, reserve clearing prices are $0/MWh. Figure 8-3 below shows both the frequency of non-zero reserve prices and the average value of reserve prices for all products at the system level.

Figure 8-3: Reserve Price Frequency and Average Value

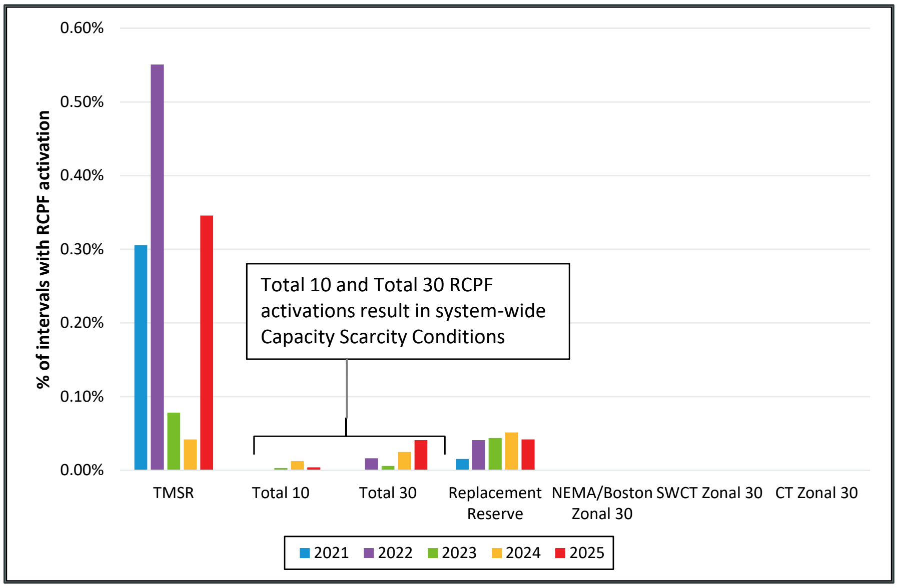


The frequency of non-zero reserve pricing, as indicated by the data labels in the figure above, was consistent with that observed in 2024. Average reserve prices, however, were higher on average in 2025 than in 2024 for the TMOR and TMSR products. This outcome indicates that when reserve constraints did bind, the re-dispatch necessary to maintain reserve requirements was costlier in 2025 than in 2024 (i.e., those resources ‘held down’ to provide reserves incurred greater opportunity costs, on average). A key contributor to higher average reserve prices in 2025 were the Capacity Scarcity Conditions that occurred during June and November. There were about 3.5 hours of CSCs in 2025 (driven primarily by the TMOR RCPF), compared with 2.3 hours in 2024.

Reserve Constraint Penalty Factors (RCPFs)

RCPFs for reserve constraints are “activated” and impact reserve prices when there is insufficient reserve capability to meet the reserve requirements, or when the cost of re-dispatch to satisfy those requirements exceeds RCPF values. The percentage of five-minute intervals during which the RCPF for each reserve constraint was activated is shown in Figure 8-4 below.

Figure 8-4: Reserve Constraint Penalty Factor Activation Frequency



The most significant RCPF activations of 2025 were the total 30-minute reserve requirement RCPFs, which triggered Capacity Scarcity Conditions in June and November. The total 10-minute RCPF ($1,500/MWh) was active for only 20 minutes, and the total 30-minute RCPF ($1,000/MWh) was active for 215 minutes. This level of activation is the highest observed in the last five years. These instances are included in the discussion of system events in Section 4.6.

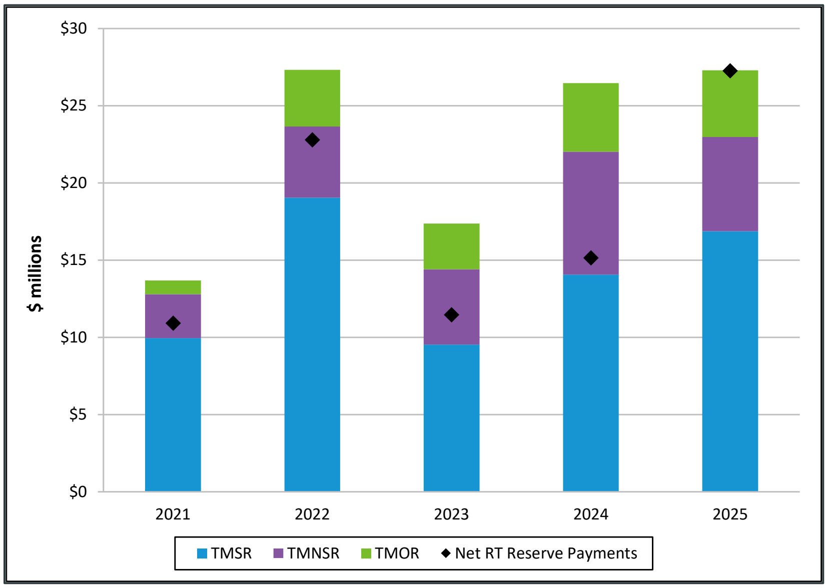
The RCPF for the TMSR requirement ($50/MWh) activated for 30 hours in 2025, compared with 4 hours in 2024. This RCPF tends to activate more frequently than the RCPFs of other reserve constraints due to its relatively low value.

Reserve Payments

Real-time reserve payments are made to resources designated to provide operating reserves in intervals when reserve clearing prices are non-zero. Total real-time reserve payments are relatively small compared to overall energy market and capacity market payments.

Figure 8-5 below shows the total payments made for real-time reserves over the past five years, as illustrated by the stacked bars. The black diamond shows total net real-time reserve payments, and is reflective of the elimination of real-time reserve credits to forward reserve resources to ensure these resources are not double-compensated.

Figure 8-5: Real-Time Reserve Payments



Total gross real-time reserve payments in 2025 totaled $27.3 million. With the implementation of DA A/S in March 2025, the Forward Reserve Market was sunset, resulting in only $26 thousand of forward reserve payment adjustments (the difference between the black dot and the top of the green bar), compared with $11 million in 2024.

The most notable changes in 2025 relative to 2024 are the increase in TMSR payments, driven by the higher magnitude of TMSR pricing discussed above, and the offsetting decrease in TMNSR payments, which stem primarily from the decrease in TMNSR RCPF activations.

Fast-start pricing has had a significant impact on real-time reserve payments, increasing payments by over 119% in 2025. An assessment of the impact of fast-start pricing is provided in Section 4.1 of this report.

8.2 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 December 31, 2025.[246, 247]

As a result of our ongoing analysis of DA A/S market outcomes and discussions with market participants, the IMM released a memo on February 4, 2026, that contained three recommended

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

[247] For more detailed analysis of the DA A/S market at a quarterly level see the following three IMM Quarterly Reports:

ISO New England Inc., Internal Market Monitor, "*Spring 2025 Quarterly Markets Report*", July 16, 2025, https://www.iso-ne.com/static-assets/documents/100025/2025-spring-quarterly-markets-report.pdf,

ISO New England Inc., Internal Market Monitor *"Summer 2025 Quarterly Markets Report",* November 12, 2025, https://www.iso-ne.com/static-assets/documents/100029/2025-summer-quarterly-markets-report.pdf,

ISO New England Inc., Internal Market Monitor "*Fall 2025 Quarterly Markets Report*", February 4, 2026, https://www.iso-ne.com/static-assets/documents/100032/2025-fall-quarterly-markets-report.pdf .

changes to improve the cost-effectiveness of the day-ahead market.[248] The IMM's recommendations are to:

1) Increase the Strike Price to better reflect the short-run marginal costs of resources providing ancillary services.

2) Reduce the Forecast Energy Requirement (FER) to account for renewable generation.

3) Review and potentially lower the non-performance factor (NPF) applied to operating reserve requirements.

Additionally, the IMM plans to publish a report in May 2026 that will provide a comprehensive evaluation of the competitiveness and performance of the DA A/S market during its first year.

Key Takeaways

Flexible Response Services (FRS) capability consistently exceeded requirements. While FRS requirements remained steady throughout the year, offered capability showed seasonal fluctuations, declining during the shoulder seasons (spring and fall), when resources tend to take their planned outages, and rising in summer and winter.

Only small amounts of Energy Imbalance Reserve (EIR) typically cleared, although volumes fluctuated based on market conditions. October had the highest level of average EIR clearing due to high generator outages and reduced net interchange, while July had the lowest level.

DA A/S products accounted for a relatively small share of total Energy and Ancillary Services (E&AS) costs in 2025, amounting to a net settlement of $137.2 million, or about 2% of overall costs.

Based on its analysis, the IMM has recommended three changes to the DA A/S market and will further evaluate the market's first year in a comprehensive report planned for May 2026.

8.2.1 Flexible Response Services

Under the Day-Ahead Ancillary Services (DA A/S) market, the ISO procures a set of operating reserve capabilities designed to ensure sufficient fast-starting and fast-ramping resources are available to respond quickly to large, unexpected supply losses. These capabilities are procured in the DA A/S market as Flexible Response Services (FRS). The FRS requirements align closely with those in the real-time market and include 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:

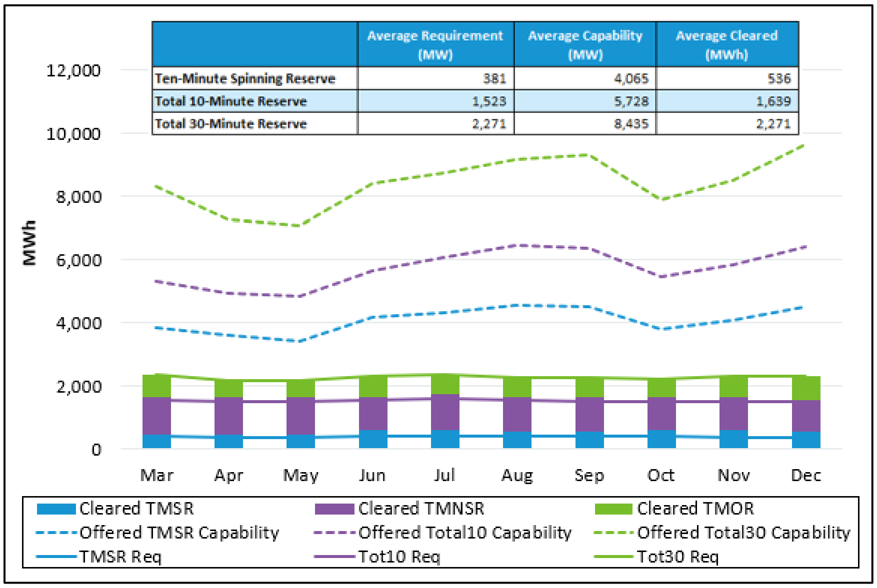
- ten-minute spinning reserve (TMSR)
- ten-minute non-spinning reserve (TMNSR)
- thirty-minute operating reserve (TMOR)

Overall, offered FRS capability has remained well above FRS requirements. This can be seen in Figure 8-6, which shows the average hourly FRS requirements, offered capability, and the cleared

[248] ISO New England Inc., Internal Market Monitor, *"Recommended Changes to the Day-Ahead Ancillary Services Market"*, February 4, 2026, https://www.iso-ne.com/static-assets/documents/100032/2026_02-imm-memo-with-daas-recommendations.pdf

awards, by month.[249] This figure also includes hourly averages over the entire period (March 2025 – December 2025) in the inset table.

Figure 8-6: FRS Requirements, Offered Capability, and Cleared Awards



	Average Requirement (MW)	Average Capability (MW)	Average Cleared (MWh)
Ten-Minute Spinning Reserve	381	4,065	536
Total 10-Minute Reserve	1,523	5,728	1,639
Total 30-Minute Reserve	2,271	8,435	2,271

On average, offered TMSR capability exceeded the TMSR requirement 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. The FRS requirements, which are based on the projected first and second contingencies, did not change much during the year. However, the offered capability displayed a seasonality, with participation declining in the spring and fall (when resources tend to undertake planned outages) and then rising in the summer and winter.

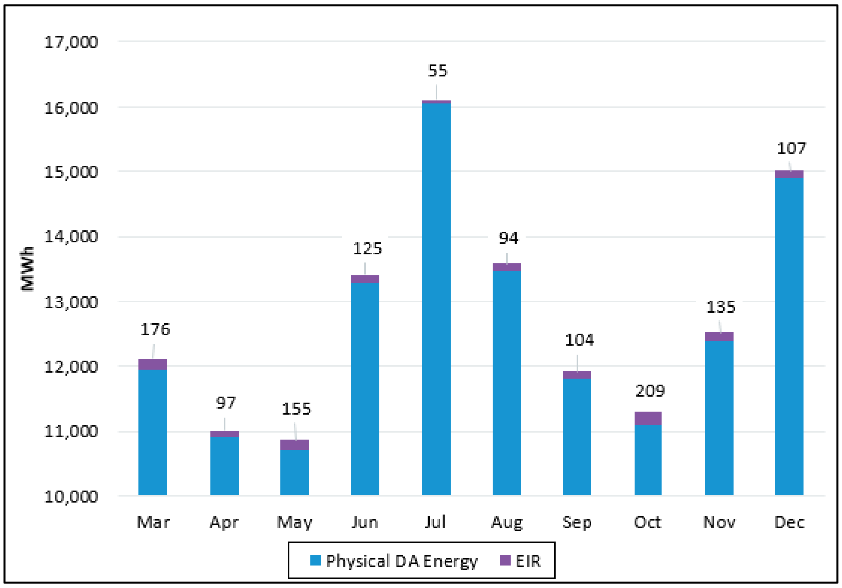
8.2.2 Energy Imbalance Reserves

The other ancillary service procured in the DA A/S market is reserve capability used to help meet the load forecast. Physical supply resources that can provide 60-minute reserve capability are compensated through a new ancillary service product called Energy Imbalance Reserve (EIR). This product is procured by the market clearing engine to meet the Forecast Energy Requirement (FER) constraint, which may be satisfied by a combination of day-ahead energy awards on physical resources and EIR awards. Physical resources with day-ahead energy awards and resources cleared for EIR are both paid the FER Price, as each contributes to satisfying the FER constraint.

Generally, only small amounts of EIR clear as day-ahead energy awards to physical suppliers satisfy the majority of the FER demand. This can be seen in Figure 8-7, which shows the average hourly cleared FER supply by month over the period March 2025 to December 2025.

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

Figure 8-7: Cleared Awards to Satisfy the Forecast Energy Requirement



The average hourly volume of EIR cleared during the period of March 2025 through December 2025 was 125 MWh. However, EIR clearing did vary by month depending on the dynamics of both the supply and demand sides of the market. October had the highest level of EIR clearing on average (209 MWh), which was related to high levels of generator outages and reduced net interchange. Meanwhile, the lowest level of EIR clearing occurred in July (55 MWh on average) when generation outage levels were low, resulting in higher levels of day-ahead energy awards that could cost-effectively satisfy the FER constraint.

8.2.3 Settlements

The four DA A/S products are paid an initial credit at the applicable DA A/S clearing price and incur a closeout charge whenever the real-time Hub LMP exceeds the strike price. For the purposes of calculating the settlement value of the DA A/S market, we sum the initial credit and the closeout charge to calculate a final *net* payment/charge.

DA A/S products represented a relatively small percentage of overall energy and ancillary services (E&AS) costs in 2025.[250] This can be seen in Table 8-1, which shows the initial credit, closeout charge, and *net* settlements for the DA A/S products for the period from March 2025 through December 2025.

[250] Total energy and ancillary services costs include day-ahead and real-time energy, reserve, regulation, and NCPC costs.

Table 8-1: DA A/S Settlements ($ millions)

DA A/S	Credit	Closeout	Total
DA TMSR (net)	$65.2	-$28.7	$36.5
DA TMNSR (net)	$123.8	-$59.8	$64.0
DA TMOR (net)	$65.5	-$33.2	$32.3
EIR (net)	$10.0	-$5.5	$4.5
Total (net)	**$264.5**	**-$127.2**	**$137.2**
		Total E&AS Costs:	$7,125
		% Total E&AS Cost:	2%

DA A/S credits totaled $264.5 million over this period, while closeout charges amounted to -$127.2 million. The net settlement was $137.2 million, which represented 2% of E&AS costs over this *ten-month* period.

8.3 Regulation

In this section, we examine the participation, outcomes, and competitiveness of the regulation market. Specifically, we review the amount of regulation capability needed by the ISO (8.3.1), and regulation clearing prices and payments (8.3.2).

Key Takeaways

Regulation requirements were stable in both 2024 and 2025, averaging about 93 MW per hour, with the highest needs during morning and evening ramps. Battery storage and other Alternative Technology Regulation Resources (ATRRs) increased their share of the market, supplying more than 80% of cleared regulation capacity in 2024 and increasing to 86% in 2025.

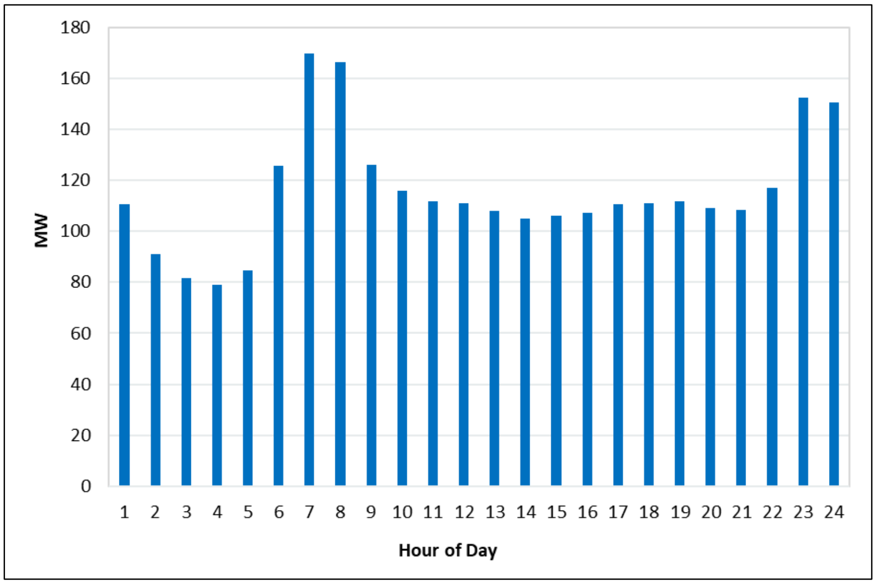
System frequency performance remained strong, with no BAAL violations in 2025, indicating sufficient regulating capability and performance. Regulation capacity clearing prices declined from $15.30/ MWh in 2024 to $12.21/ MWh in 2025, while service prices stayed constant at $0.08 per mile.

Total regulation payments fell slightly from $18.2 million to $18 million, reflecting low system stress. Throughout this period, the market remained competitive, and the growing role of battery storage improved efficiency by lowering costs and maintaining reliable frequency control.

8.3.1 Regulation Requirements, Resource Mix, and Performance

The regulation *requirement* in New England varies throughout the day and is typically highest in the morning and the late evening. The higher regulation requirement during these hours is the result of greater load variability (load ramping up in the morning and down in the evening). The average hourly regulation requirement by hour of day for 2025 is shown in Figure 8-8 below.

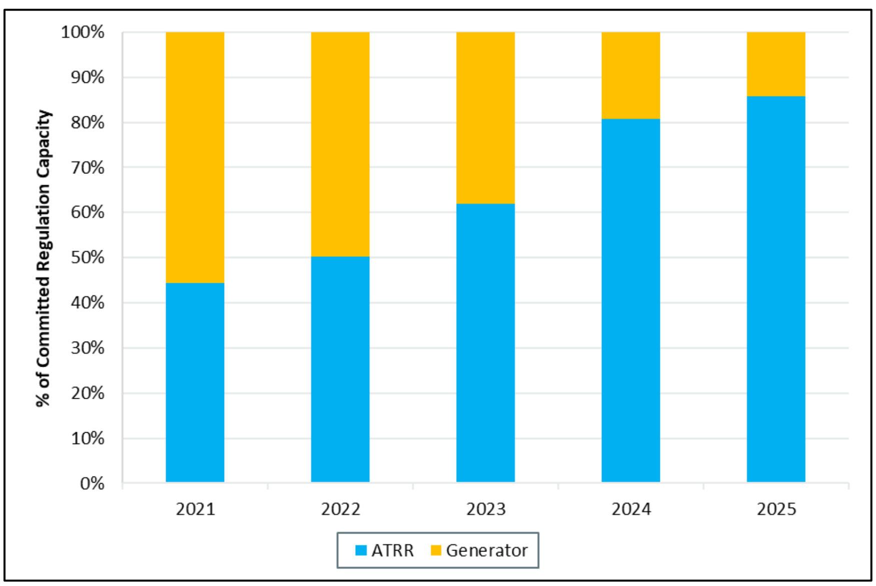
Figure 8-8: Average Hourly Regulation Requirement, 2025



The average hourly regulation requirement in 2025 was 93.4 MW, nearly unchanged from the 93.5 MW requirement in 2024. Regulation service is supplied by two types of resources: traditional generators and Alternative Technology Regulation Resources (ATRRs). Most ATRRs consist of battery energy storage systems that can provide regulation exclusively or operate as multi-use assets by charging, discharging, or doing both while participating in the energy market.

The regulation market resource mix for 2021 to 2025 is shown in Figure 8-9 below.

Figure 8-9: Regulation Resource Mix



The *resource mix* for regulation has changed significantly. In 2021, ATRRs (blue shading) provided 44% of cleared regulation capacity. By 2025, ATRRs provided 86%. This change follows continuing increases in the installed capacity of battery resources. Regulation capacity available from ATRRs has increased from 88 MW to 468 MW over the period. The change in resource mix also supports the finding that battery resources are lower-cost regulation resources (i.e., have lower-cost regulation market offers), as these ATRRs have increasingly displaced traditional generators in the merit order for regulation market commitment.

8.3.2 Regulation Prices and Payments

Regulation Clearing Prices (RCP) are based on the regulation offer of the highest-priced generator providing the service. There are two types of regulation clearing prices: "service" and "capacity."[251] Clearing prices for the past five years are shown in Table 8-2 below.[252]

Table 8-2: Regulation Prices

Year	Regulation Capacity Clearing Price ($/MW per Hour)			Regulation Service Clearing Price ($/Mile)		
	Min	Avg	Max	Min	Avg	Max
2021	0.00	19.23	732.93	0.00	0.21	10.00
2022	0.00	30.96	2,979.80	0.00	0.27	10.00
2023	0.00	23.48	2,048.15	0.00	0.13	10.00
2024	0.00	15.30	3,812.42	0.00	0.08	10.00
2025	0.00	12.21	4,051.16	0.00	0.08	10.00

Regulation capacity prices decreased by 20% in 2025, reflecting a decline in offer prices as lower-cost ATRRs continued to make up a larger share of the regulation mix. Regulation service prices, on the other hand, showed no change compared to 2024. In 2025, the average service price was $0.08/mile.

The absence of change in the average regulation service price indicates that system conditions did not produce the higher mileage intensity, ramping volatility, or increased opportunity-cost exposure that typically raises service prices. Regulation mileage patterns, dispatch behavior, and storage state-of-charge dynamics were comparable to the prior year, resulting in a consistent price formation environment and an unchanged annual average. By contrast, the Average Regulation Capacity Clearing Price dropped from $15.30 to $12.21/MWh; the lower average, alongside still-elevated upper-tail outcomes, is consistent with continued clearing of low- or zero-priced ATRR capacity in most hours.

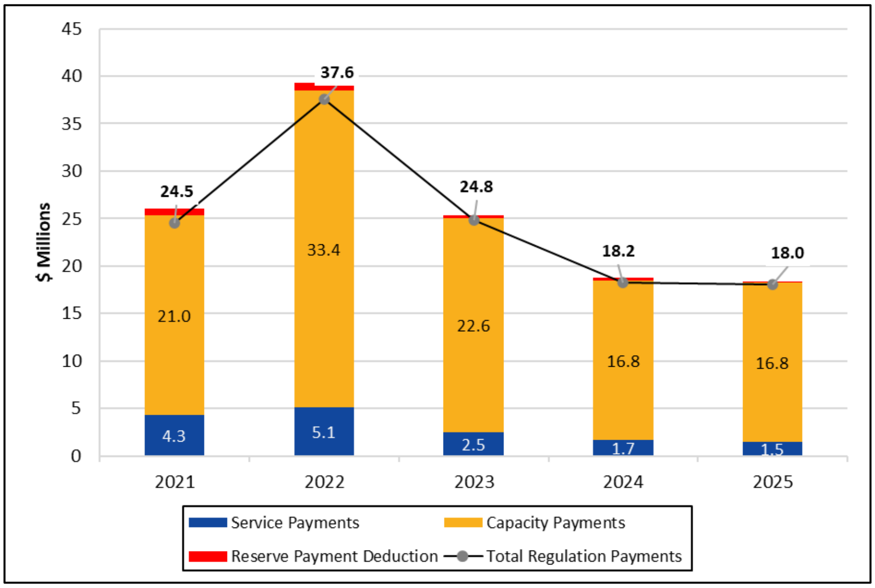
[251] The service price represents the direct cost of providing the regulation service (also known as regulation "mileage"). Mileage represents the up and down movement of generators providing regulation and is measured as the absolute MW variation in output per hour. These direct costs may include increased operating and maintenance costs, as well as incremental fuel costs resulting from the generator operating less efficiently when providing regulation service. The capacity price may represent several types of costs, including: (1) the expected value of lost energy market opportunities when providing regulation service, (2) the value of intertemporal opportunities that would be lost from providing regulation, (3) elements of fixed costs such as incremental maintenance to ensure a generator's continued performance when providing regulation, and (4) fuel market or other risks associated with providing regulation.

[252] The prices in the table are simple average prices for each year.

Regulation Payments

Compensation to generators providing regulation includes a Regulation Capacity Payment, a Service Payment, a Make-Whole Payment, and an operating reserve adjustment.[253] Annual regulation payments over the past five years are shown in Figure 8-10 below.[254]

Figure 8-10: Regulation Payments



Regulation payments saw just a 1% year-over-year decline in 2025, from $18.2 million in 2024 to $18.0 million in 2025. This slight reduction reflects continued easing in both capacity and service components, driven by lower clearing prices and fewer high-mileage intervals, though the scale of these changes resulted in only a small shift in total annual payments.

Capacity payments, which consistently represent the majority of total regulation payments, showed no change between 2024 and 2025, remaining at $16.8 million, as lower-cost ATRRs continued to dominate the regulation mix. Service payments decreased 13%, from $1.7 million in 2024 to $1.5 million in 2025, indicating that fewer hours required high-mileage performance or that mileage-related opportunity costs were less pronounced. As a result, capacity payments accounted for 92% of total regulation payments in 2025, while service payments represented only 8%.

As energy storage capacity continues to grow in New England—including the addition of larger-scale facilities—and as the regulation market remains relatively saturated, batteries are

[253] The operating reserve adjustment represents a deduction to regulation payments. Under certain circumstances, part of a regulation resource's regulating range may overlap with the resource's operating reserve range. Since generators do not actually provide operating reserves within the regulating range, reserve compensation needs to be deducted from the resource's market compensation. The reserve payment deduction represents the MW quantity overlap of the regulating range and operating reserve range, multiplied by the operating reserve price.

[254] The reserve payment deduction is shown as a negative value in the exhibit; the positive values represent total payments (prior to reserve payment deductions) for the regulation capacity and service (mileage) provided by regulation resources during the period. The make-whole payment is included in capacity payment totals, since it represents an uplift payment when the capacity payments do not fully compensate resources for energy market opportunity costs.

expected to play an increasing role in the energy market. In this environment, battery strategies are likely to increasingly shift toward energy price arbitrage, alongside Massachusetts Clean Peak Energy Program (CPEC) operating strategies.

Section 9
Transmission Congestion and Financial Transmission Rights

This section covers trends in transmission congestion and financial transmission rights (FTRs), ISO-administered tools for managing or taking positions on congestion risk.

Key Takeaways

Congestion: In 2025, congestion revenue totaled $75 million, representing 0.8% of total energy costs. Congestion revenue increased on a yearly basis due to both higher LMPs and more frequent congestion. Temporary transmission work drove most of the increased congestion in 2025, notably including outages in April-May surrounding interconnection work for the New England Clean Energy Connect (NECEC) line that began operation in early 2026.
Overall, levels of transmission congestion are relatively low in New England compared to other ISO markets due to the significant amount of reliability-driven transmission investment over the past decade.[255]

Financial Transmission Rights: The average number of FTR MWs held in 2025 (35,000 MWs per hour) increased 4% from the prior year. FTRs were fully funded in 2025, meaning there was sufficient revenue collected through the energy markets' congestion revenue fund to pay FTR holders.
FTR positions earned $34 million in profits throughout 2025, reversing a trend of negative or low profitability since 2022. Profits were driven by a more congested system (due in part to transmission work in Maine to accommodate the NECEC line) and high LMPs, leading to high positive target allocations. The Roseton interface reflected 57% of all FTR purchase costs and 25% of positive target allocations throughout the year. While profits at this location were small, they were profitable for the first time since 2021, contributing to the increase in total FTR profits.

9.1 Transmission Congestion

Below, we examine transmission congestion in New England over the past five years, beginning with overall congestion revenues and then assessing where congestion has emerged across the system.

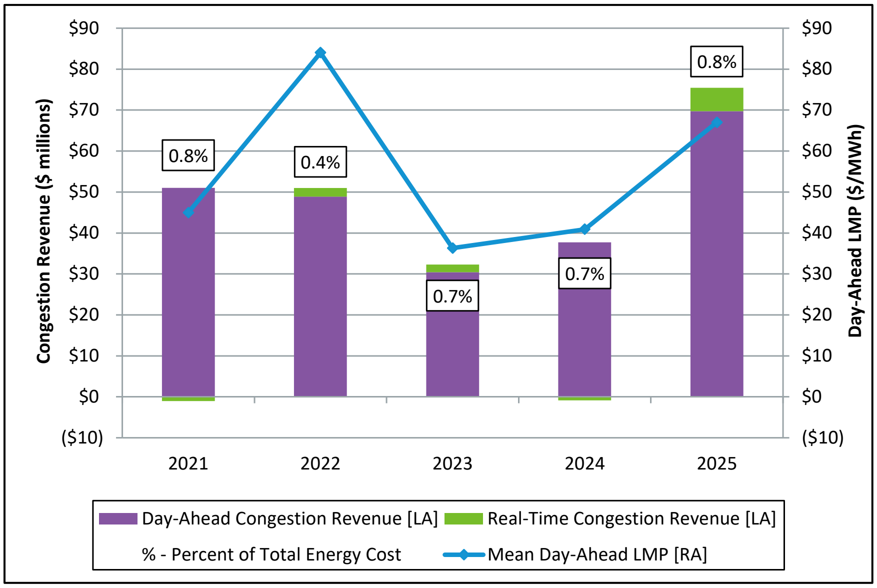
[255] Potomac Economics' (the External Market Monitor for ISO-NE) *2024 Assessment of the ISO New England Electricity Markets* showed that ISO-NE had the lowest congestion rate between 2022-2024 ($0.33/MWh) among a set of RTOs that included ERCOT, ISO-NE, MISO, NYISO, and PJM. However, ISO-NE had the highest transmission rate in 2024 ($24/MWh) of these RTOs. See Figure 2 in its *2024 Assessmen*t. Potomac Economics, "*2024 Assessment of the ISO New England Electricity Markets"*, June 2025, https://www.potomaceconomics.com/wp-content/uploads/2025/06/ISO-NE-2024-EMM-Annual-Report_Final.pdf.

Congestion Revenue

Congestion revenue represents the difference between what load pays for energy and what generation receives for energy as a result of transmission congestion.[256] A feature of New England's locational energy market is that load pays for energy at the price where it is *consumed,* and generation is paid at the price where it is *produced*. This means that, when there is a binding transmission constraint limiting the production of less expensive generation, load will often pay more for the energy than generation receives for the energy. This resulting congestion revenues form the basis for Auction Revenue Rights (ARRs), which are auctioned through FTRs and ultimately fund payments to the FTR holders as discussed further in Section 9.2.

Over the last five years, congestion revenue has been small relative to total energy market payments and typically moves in line with energy prices. This can be seen in Figure 9-1 below.[257]

Figure 9-1: Average Day-Ahead Hub LMP, Congestion Revenue Totals as Percent of Total Energy Cost



Total day-ahead and real-time congestion revenue was $75 million in 2025, representing 0.8% of energy market costs. Congestion revenue is typically correlated with day-ahead energy prices. For export constraints, this occurs because export-constrained zones (such as Maine) often feature inexpensive renewable energy, driving up congestion revenue as Hub LMPs increase relative to low export-constrained LMPs. Conversely, import-constrained zones often require relatively expensive fossil fuel-fired generation, and high input fuel prices raise price differences and congestion revenue relative to hub generation.

Congestion revenue more than doubled relative to 2024, reflecting both higher LMPs and an increase in the frequency of binding transmission constraints, as discussed below. Most

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[256] For an exact definition of day-ahead and real-time congestion revenue, see: ISO New England Inc., "*Section III Market Rule 1 Standard Market Design*", Section III.3.2.1(i), https://www.iso-ne.com/static-assets/documents/2014/12/mr1_sec_1_12.pdf.

[257] The percentages in the figure are the total congestion revenue each year (i.e., the day-ahead congestion revenue plus the real-time congestion revenue) expressed as a percent of total energy market costs. Additionally, the designation 'LA' in the legend indicates that the value is measured by the y-axis on the left side, while 'RA' indicates that the value is measured by the y-axis on the right side.

congestion revenue accrued in the day-ahead market ($70 million) since this market accounts for the majority of transaction settlement, while net congestion revenue associated with real-time deviations totaled $6 million in 2025.

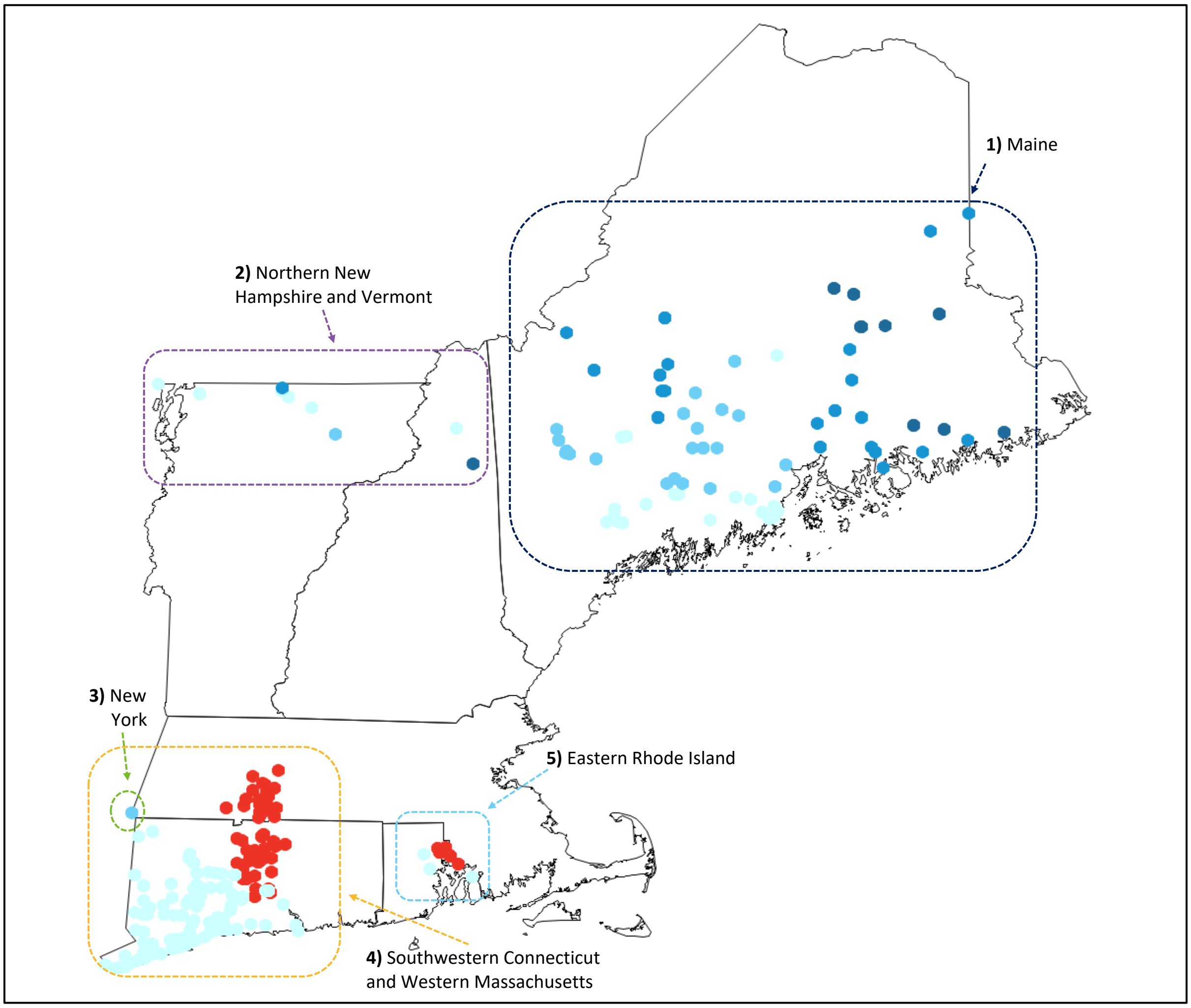
Congested Areas in New England

The New England pricing nodes and areas most affected by transmission congestion in the day-ahead market in 2025 are shown in Figure 9-2 below.[258] Locations that are "upstream" of a binding transmission constraint have a negative congestion component, while locations that are "downstream" of a binding constraint have a positive congestion component.[259]

[258] In order to highlight the constrained areas, this figure only includes nodes that had an average day-ahead congestion component in 2025 of greater than or equal to $0.20/MWh or less than or equal to -$0.20/MWh.

[259] More specifically, a negative congestion component occurs when a location has a positive shift factor to a binding constraint. In simple terms, a shift factor measures how an injection of energy at a location impacts the flow of energy over a transmission constraint. In other words, locations with a positive shift factor indicate that an injection of energy at that location would *exacerbate* transmission congestion. Conversely, a positive congestion component occurs when a location has a negative shift factor to a binding constraint. In other words, locations with a negative shift factor indicate that an injection of energy at that location would *alleviate* transmission congestion.

Figure 9-2: New England Pricing Nodes Most Affected by Congestion, 2025



Many of the congested areas in New England in 2025 were relatively small geographic areas where transmission capacity limited the ability to export power to the rest of the system. Several areas in Figure 9-2 have been highlighted and each of them is discussed in detail below:

1) **Maine**: The Maine area features low loads, high amounts of renewable generation, and interconnections with the New Brunswick control area. Congestion can occur as inexpensive energy in Maine flows to the rest of the system over limited transmission, resulting in periodic congestion of interfaces that include Orrington South ("ORR-SO"), Rumford Export ("IRMF-E"), and Keene Road Export ("KR-EXP"). Notably, congestion patterns in Maine increased relative to prior years due to transmission work in certain months. Transmission work to accommodate the NECEC line occurred in April-May, leading to frequent congestion over Orrington South and Coopers Mill-South ("COMI-S"). Additionally, the Rumford Export interface bound frequently in October due to transmission line outages.

2) **Northern New Hampshire and Vermont**: Northern New Hampshire and Vermont also feature high amounts of intermittent generation, and imports over the Highgate tie line. Constrained interfaces in this area include Kingdom Wind Generation ("KCW"), Sheffield

Generation ("SHEF"), and Sheffield-Highgate ("SHFHGE"). Overall congestion patterns in this area were similar to prior years.

3) **New York**: The lines between New York and New England may become congested when line limits are reduced or price differences between New York and New England strongly incentivize flows in one direction. For example, in cold weather, New York typically has lower energy prices than in New England due to gas pipeline availability, and the New York-New England ("NYNE") interface binds due to imports reaching line limits.

4) **Southwestern Connecticut**: The Southwestern Connecticut region contains several large, efficient gas-fired generators. The local 115-kV transmission system occasionally limits exports to the rest of the system, resulting in local export congestion around the generating units and import congestion in Connecticut and Western Massachusetts. The Berlin 1771 line bound relatively frequently in 2025, particularly in December.

5) **Eastern Rhode Island**: Similar to the Southwestern Connecticut region, the Eastern Rhode Island area occasionally experiences congestion due to generation patterns over the local 115-kV system. This can occur in winter months due to gas-fired generator locations; gas generators on the west side of the constraint can be less expensive than those on the east side, since the east-side generators are located on the relatively constrained and expensive G-lateral of the Algonquin pipeline. This can create transmission constraints when more generators are committed on the west side of the constraint since they are less expensive. The Hartford Avenue E105 line was the most frequent binding constraint for this area in 2025.

9.2 Financial Transmission Rights

The assessment of financial transmission rights (FTRs) activity and performance is structured as follows: (9.2.1) FTR auction volumes, (9.2.2) FTR funding, and (9.2.3) FTR profitability at a market level. Given their outsized impact on FTR market outcomes, special attention is given to FTR paths that source from .I.ROSETON 345 1 ("Roseton"), which is ISO-NE's external node for trading across the New York - New England ("NYNE") interface.[260]

9.2.1 FTR Volume

The volume of FTRs held by participants reflects several factors, most notably expectations about the magnitude and frequency of day-ahead congestion. When participants anticipate greater congestion than in prior years, they may acquire additional FTR MWs to hedge expected price differences. Conversely, expectations of lower congestion are likely to result in reduced FTR purchases.

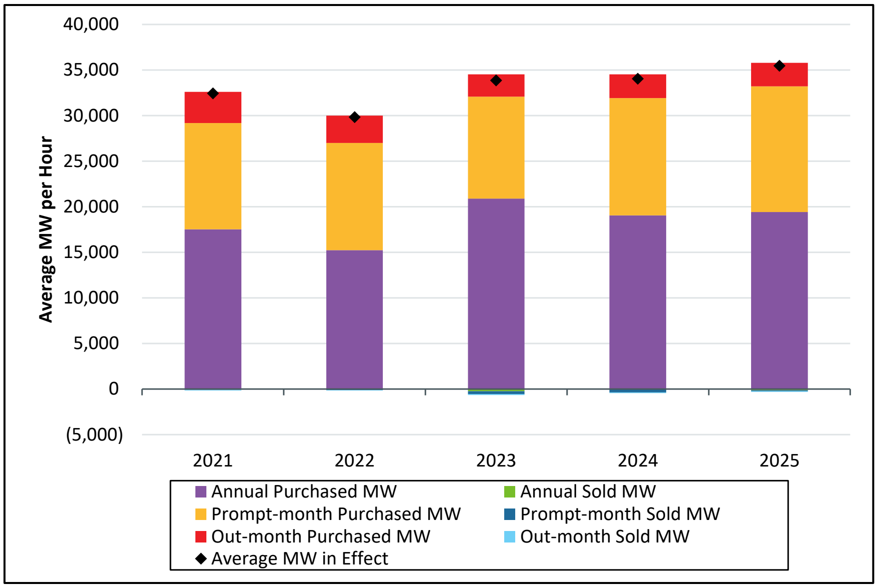
Another important factor is the set of transmission limits that the ISO uses in the auctions it conducts to award FTRs. The ISO performs a market feasibility test in each FTR auction that ensures that the awarded set of FTRs respects the transmission system's physical and operational

[260] I.ROSETON 345 1 is represented by area 3 in Figure 9-2 above.

limits.[261] Essentially, these limits restrict the MW volume of FTRs that can be purchased in FTR auctions, which helps ensure that the congestion revenue collected from the energy market will be sufficient to pay FTR holders.

Figure 9-3 shows the average MW volume of FTRs in effect each hour by year (black diamonds) for the past five years.[262] This figure also shows the average hourly MW volume of FTRs purchased and sold by auction type (i.e., annual, prompt-month, or out-month) during each year.[263] FTR purchases are depicted as positive values, while FTR sales are depicted as negative values.

Figure 9-3: Average FTR MWs in Effect per Hour by Year



Market participants held roughly 35,000 MWs of FTRs per hour in 2025, a 4% increase from 2024. The increase in held FTR MWs was driven by increased purchases both in annual auctions (19,000 MW) and prompt-month auctions (14,000 MW). Out-month FTR purchases averaged 3,000 MW, unchanged from 2024. FTR holders continued to sell very few FTR positions in any auction throughout 2025. Discussed below, FTRs were more profitable in 2025 than in 2024, driving increased participation, particularly in prompt-month auctions.

9.2.2 FTR Funding

FTR funding refers to the ability to pay FTR holders the full value of their positive target allocations. Positive target allocations arise when the congestion component at the sink location (point of

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[261] This test is performed to increase the likelihood of revenue adequacy, which means that there is sufficient congestion revenue collected in the energy market and from FTR holders with negative target allocations to fully compensate all FTR holders with positive target allocations. This is further discussed in Section 9.2.2.

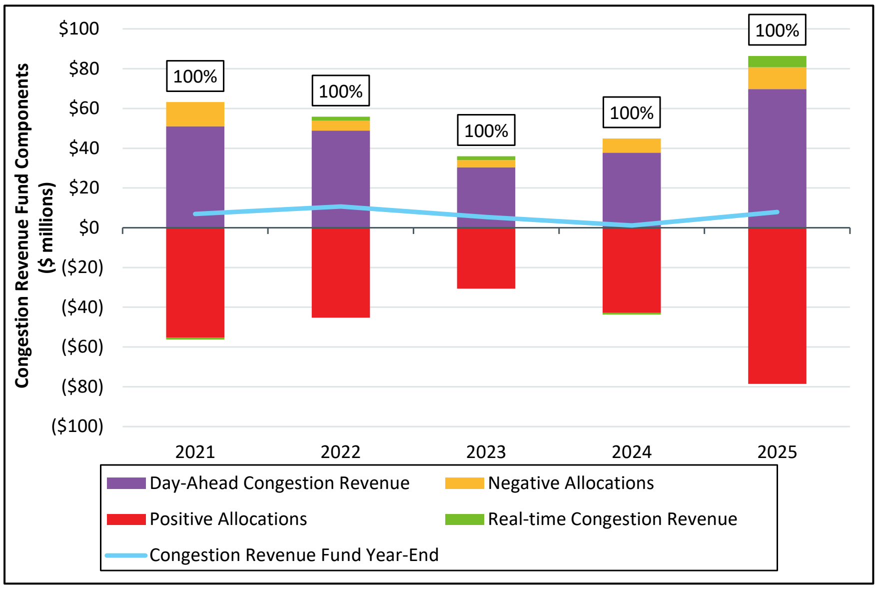
[262] The averages are hourly-weighted MW volumes. This weighting accounts for the fact that there are more off-peak hours than on-peak hours in a year. The volume of FTRs in effect each year represents the hourly-weighted average MW volume of FTRs purchased less the hourly-weighted average MW volume of FTRs sold.

[263] An *annual* auction refers to an auction where participants purchase (or sell) FTRs whose term is one calendar year, while both *prompt-month* and *out-month* auctions refer to auctions where participants purchase (or sell) FTRs whose term is one month. P*rompt-month* refers to the monthly auctions for FTRs that are in effect for the month immediately after when the auction takes place, while *out-month* refers the monthly auctions for FTRs that are in effect for any other month remaining in the calendar year (excluding the prompt-month).

delivery) of an FTR path is larger than the congestion component at the source location (point of injection). When there is sufficient revenue to pay all the positive target allocations, FTRs are said to be *fully funded*. Fully funding FTRs is an important aspect of a well-functioning FTR market because it gives market participants confidence that they will receive the full value of their FTRs.

FTRs were fully funded in 2025 and have been in each of the last five years, as can be seen in Figure 9-4 below. The graph shows, by year, the different components of the congestion revenue fund ("CRF"), including: congestion revenue from the day-ahead and real-time energy markets and positive and negative target allocations.[264] The balance in the CRF at the end of each year is shown by the blue line.[265]

Figure 9-4: FTR Funding and Congestion Revenue Fund Components by Year



Day-ahead congestion revenue totaled $70 million in 2025, up 85% from 2024 following higher average LMPs and more congested average conditions. Real-time congestion revenue reached $6 million. While day-ahead and real-time congestion revenue alone were not sufficient to cover positive target allocations ($79 million), negative target allocations ($11 million) covered the revenue shortfall. Consequently, FTRs were fully funded at the end of year, and the $8 million surplus was distributed proportionately to entities that paid congestion costs during the year.[266]

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[264] The CRF is used to pay FTR holders with positive target allocations. This fund collects money from three sources: (1) day-ahead congestion revenue, (2) real-time congestion revenue, and (3) the holders of FTRs with negative target allocations. For more information about transmission congestion revenue and FTR funding, see: ISO New England Inc., "*Section III Market Rule 1 Standard Market Design*", Section III.5, https://www.iso-ne.com/static-assets/documents/2014/12/mr1_sec_1_12.pdf.

[265] The CRF balance is defined here as the $\sum$[day-ahead congestion revenue + real-time congestion revenue + abs(negative target allocations) – positive target allocations]. Note that this does not include surplus interest throughout the year. For the final settled CRF values, see: ISO New England Inc., *"2025 FTR Monthly Summary"*, https://www.iso-ne.com/static-assets/documents/100020/2025_monthly_summary.pdf.

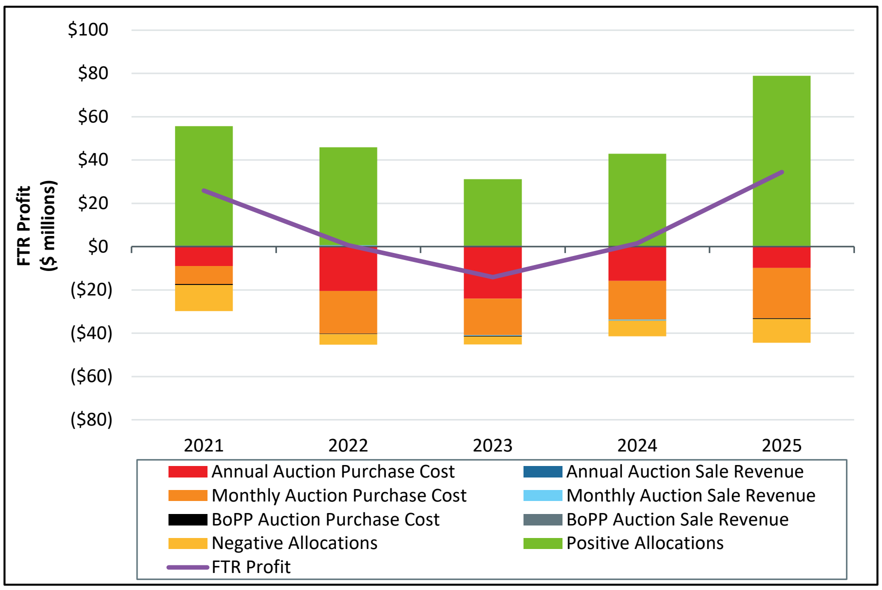
[266] For more information about the distribution of excess congestion revenue see: ISO New England., "*Section III Market Rule 1 Standard Market Design*", Section III.5.2.6, https://www.iso-ne.com/static-assets/documents/2014/12/mr1_sec_1_12.pdf.

9.2.3 FTR Profitability

Overall profit in the FTR market is measured as the sum of the positive target allocations and the revenue from FTR sales, minus the negative target allocations and the cost of FTR purchases. In a competitive FTR market, one would not expect to see excessive (risk-adjusted) profits or losses sustained over numerous years. Prolonged periods of high profitability would likely spur the entry of new participants (or at least an increase in FTR bid prices among existing participants), raising the cost to purchase FTRs and reducing FTR profitability. Conversely, prolonged periods of losses might motivate existing participants to exit the market (or at least decrease their FTR bid prices), lowering the cost of purchasing FTRs and increasing FTR profitability.

As a group, FTR holders were profitable in 2025. Figure 9-5 below shows total profit (purple line) as well as each of the different profit components. In this figure, FTR sales revenue and positive target allocations are shown as positive values (as they increase FTR profitability), while FTR purchase costs and negative target allocations are shown as negative values (as they reduce FTR profitability). Further, this figure classifies purchase costs and sales revenues by auction type (i.e., annual, prompt-month, or out-month).

Figure 9-5: FTR Costs, Revenues, and Profits



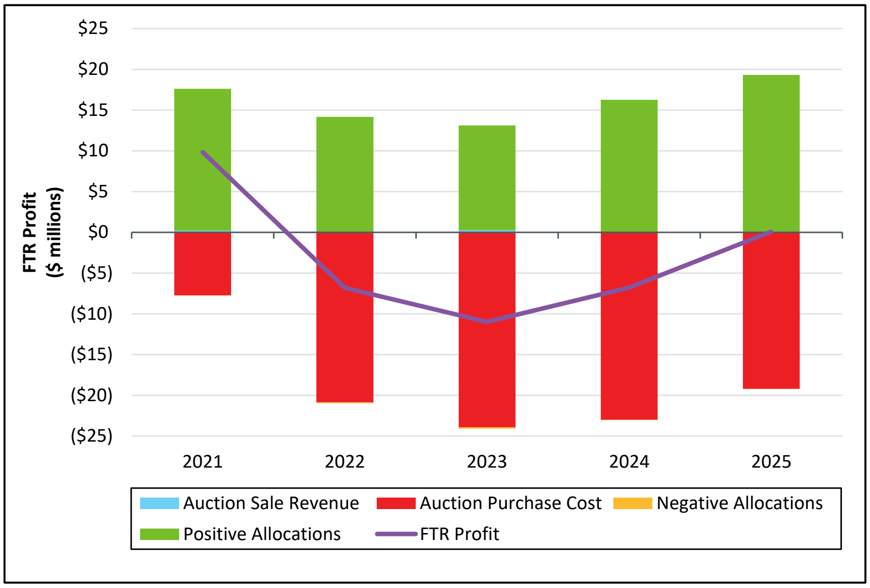
FTR profits totaled $34 million in 2025, the highest over the five-year period. Profits were driven by a more congested system (due in part to transmission work in Maine to accommodate the NECEC line) and high LMPs, leading to high positive target allocations ($79 million). Annual auction purchase costs fell to $10 million from $16 million in 2024. Conversely, monthly purchase costs increased to $23 million, up from $18 million in 2024. The increase in monthly purchase costs reflected increased volumes in prompt-month auctions.

Congestion on the New York – New England Interface

Changes in profitability of FTRs that source from Roseton can contribute significantly to overall FTR market outcomes. This is partly because the NYNE interface tends to be one of the most frequently binding transmission constraints in the day-ahead market. Many of the participants that purchase FTRs that source from Roseton also import power over the New York North interface and use these FTRs to hedge against negative congestion pricing in the day-ahead market. To provide some perspective, the purchase costs for FTRs sourcing from Roseton represented 57% of all the FTR auction purchase costs in 2025, while the positive target allocations for FTRs sourcing from Roseton represented 25% of all positive target allocations.

FTRs sourcing from Roseton were modestly profitable in 2025. This can be seen in Figure 9-6 below, which shows the total annual profits (purple line) for these FTRs over the last five years. This figure also shows the associated purchase costs, sale revenues, and positive and negative target allocations.

Figure 9-6: FTR Profits and Costs for FTRs Sourcing from Roseton



FTRs sourcing from Roseton generated $76 thousand in profit on a net basis in 2025. While such profits were modest, this reversed a trend of unprofitability since 2022. Profitability increased from 2024 despite the NYNE interface binding less frequently (6% of hours in 2025, compared to 11% of hours in 2024). Positive target allocations over NYNE ($19 million) increased, indicating larger price separation between the Roseton node and the rest-of-system in 2025 relative to 2024. At the same time, auction purchase costs ($19 million) fell 17% year-over-year.

Section 10
Market Design and Rule Changes

This section provides an overview of the major market design and rule changes that were recently implemented[267] or are being considered or planned for future years.[268] The section also summarizes notable long-term studies that will have market and operational implications for the future grid.

10.1 Major Design Changes Recently Implemented

The following subsections provide an overview of changes recently implemented.

10.1.1 Day-Ahead Ancillary Services Initiative

The Day-Ahead Ancillary Services Initiative (DASI) went live on February 28, 2025, for the operating day of March 1, 2025. This initiative created a day-ahead ancillary services (DA A/S) market that procures and transparently prices specific ancillary services needed for system reliability. Prior to the creation of the DA A/S market, there was no day-ahead reserves market. Instead, ISO-NE procured reserves on a forward basis via the Forward Reserve Market (FRM). The FRM was retired co-incident with the start of the DA A/S market.

The DA A/S market is covered in more detail in Section 8.2.

10.2 Major Design or Rule Changes in Development or Implementation for Future Years

The following market design or rule changes have been (i) completed and the planned implementation date is in the future or (ii) are currently being assessed or are in the design phase.

10.2.1 Capacity Auction Reforms – Prompt Deactivation

On December 30, 2025, ISO-NE filed revisions to its Tariff referred to as the Capacity Auction Reforms – Prompt Deactivation (CAR-PD).[269] This set of reforms proposes major changes to the ISO's capacity market by replacing the primary auction in the Forward Capacity Market, which is held more than three years before the capacity delivery period, with a prompt auction held about one month before the delivery period. Under this new approach only commercial, deliverable resources may participate, eliminating the complexities associated with non-commercial entry. Other reforms in CAR-PD include replacing the descending-clock auction with an administratively simpler sealed-bid format and reducing that retirement notice requirement from four years to one year.

Several design features remain, including monthly settlements, cost allocation rules, and Pay-for-Performance. Existing methods for determining qualified capacity largely stay in place, with some improvements enabled by the shorter timeline. Market power mitigation rules also remain mostly unchanged and changes are conforming in nature with the reduced timeframe. Overall, the reforms

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[267] ISO New England Inc., " *Implemented Key Projects"* webpage, https://www.iso-ne.com/committees/key-projects/implemented.

[268] ISO New England Inc., "*Key Projects"* webpage, https://www.iso-ne.com/committees/key-projects.

[269] ISO New England Inc., "*ISO New England Inc., Revisions to ISO New England Inc. Transmission, Markets and Services Tariff to Establish a Prompt Capacity Market and Deactivation Framework, FERC filing",* Docket No. ER26-925-000, December 30, 2025, https://www.iso-ne.com/static-assets/documents/100030/car-pd_filing.pdf.

are expected to improve the accuracy of auction inputs, enhance supply participation, and support more efficient capacity and reliability outcomes. The transition had broad stakeholder support, and while the ISO plans additional reforms for the 2028/29 auction cycle, the CAR-PD package stands on its own merits.

More information about this topic can be found in Section 7.1.1.

10.2.2 Capacity Auction Reforms – Seasonal Accreditation

The changes associated with seasonal accreditation represent the second set of major reforms that the ISO is undertaking to modernize its capacity market. Referred to as Capacity Auction Reforms – Season Accreditation (CAR-SA), this set of reforms aim to ensure that procured capacity better reflects each resource's actual contribution to resource adequacy. By procuring capacity in separate summer and winter auctions, the market can more accurately reflect seasonal reliability needs and the changing performance of resources across seasons. The reforms also support the system's long-term sustainability by aligning investment incentives with how resources contribute to reliability as system conditions evolve. This initiative is currently in stakeholder discussions, and the ISO aims to file the reforms with FERC by the end of 2026.[270]

More information about this topic can be found in Section 7.1.2.

10.2.3 FERC Order 2222, Distributed Energy Resources

On September 17, 2020, FERC issued Order 2222, which found that existing ISO/RTO market rules were unjust and unreasonable because they contained barriers to the participation of distributed energy resources aggregations (DERAs).[271] The purpose of Order 2222 is to remove these barriers and allow DERAs to provide all services that they are technically capable of providing. Specifically, the order outlined 11 directives for ISOs/RTOs to follow, including allowing participation of DERAs in the energy, ancillary services, and capacity markets and allowing DER aggregators to register DERAs under one or more participation models.[272]

The ISO developed new rules to integrate aggregated distributed energy resources, then worked through several rounds of FERC feedback and compliance filings to refine those rules over the next few years. By late 2025, FERC had accepted the final updates, allowing these resources to participate more fully in the region's energy and capacity markets. The ISO Tariff now permits

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[270] ISO New England Inc., "*Capacity Auction Reforms Key Project*" webpage, https://www.iso-ne.com/committees/key-projects/capacity-auction-reforms-key-project.

[271] A Distributed Energy Resource (DER) is any resource located on the distribution system, any subsystem thereof or behind a customer meter that is capable of providing energy injection, energy withdrawal, regulation, or demand reduction. Federal Energy Regulatory Commission, "*FERC Order No. 2222: Fact Sheet*" webpage, September 28, 2020, https://www.ferc.gov/media/ferc-order-no-2222-fact-sheet.

[272] A "participation model" refers to rules created for a specific type of resource that has unique physical and operational characteristics. For example, a generator is a type of participation model in ISO-NE. ISO New England Inc., "*Revisions to ISO New England Inc. Transmission, Markets and Services Tariff to Allow for the Participation of Distributed Energy Resource Aggregations in New England Markets; Docket No. ER22-983-000*" February 2, 2022, p. 5, footnote 7, available at https://www.iso-ne.com/static-assets/documents/2022/02/order_no_2222_filing.pdf.

DERAs to participate in its energy and ancillary service markets effective on November 1, 2026, and its capacity market effective for the 2028-29 Capacity Commitment Period (CCP 19).

10.3 Additional Notable Studies

The following subsection provides an overview of additional notable studies that are not part of any planned market design or implementation work.

10.3.1 2025 Regional System Plan

On December 8, 2025, the ISO published the final version of its 2025 Regional System Plan (RSP25), a comprehensive biennial system planning analysis that provides a 10-year view of New England's grid.[273] The report highlights that demand for electricity is projected to grow significantly between 2025 and 2034, driven mostly by states' clean-energy and electrification policies. These policies are advancing the transition toward renewable generation while increasing adoption of electric vehicles and electric heating, reshaping both the level and timing of electricity consumption.

RSP25 also outlines how the power grid will need to adapt to these changes, including managing the rapid growth of behind-the-meter solar, which will push daytime electricity use to new lows on mild, sunny days. It identifies emerging long-term transmission needs and ongoing regional efforts to prepare the grid for more renewable energy, such as projects aimed at increasing transfer capability through Maine and supporting new generation in northern New England. While not a blueprint for future resource development, RSP25 serves as a broad planning tool that helps policymakers, utilities, and stakeholders anticipate challenges and coordinate investments to ensure continued reliability as the region moves toward cleaner energy.

[273] ISO New England Inc., *"2025 Regional System Plan"*, December 8, 2025, https://www.iso-ne.com/static-assets/documents/100030/final_2025_rsp.pdf

Acronyms and Abbreviations

Acronyms and Abbreviations	Description
°F	degrees Fahrenheit
AC	alternating current
ACE	area control error
ADCR	Active Demand Capacity Resources
AMR	Annual Markets Report
ARA	annual reconfiguration auction
ARD	asset-related demand
ART	Annual Reconfiguration Transaction
AS	ancillary service
BAA	balancing authority area
BAAL	Balancing Area ACE Limits
BAL-001-2	NERC's *Real Power Balancing Control Performance Standard*
BAL-003	NERC's *Frequency Response and Frequency Bias Setting Standard*
bbl	barrel (unit of oil)
Bcf	billion cubic feet
BTM	behind-the-meter
Btu	British thermal unit
C4	market concentration of the four largest competitors
CAR	Capacity Auction Reform
CARPD	Capacity Auction Reform: Prompt and Deactivation
CARSA	Capacity Auction Reform: Seasonal and Accreditation
CC	combined cycle (generator)
CCP	capacity commitment period
CDD	cooling degree day
CMR	Code of Massachusetts Regulations
CO_2	carbon dioxide
CONE	cost of new entry
CPS 2	NERC *Control Performance Standard 2*
CSC	Cross Sound Cable *or* capacity scarcity condition
CSO	capacity supply obligation
CT	State of Connecticut, Connecticut load zone, Connecticut reserve zone
CT	combustion turbine
CTL	capacity transfer limit
CTS	Coordinated Transaction Scheduling
DAGO	day-ahead generation obligation
DALO	day-ahead load obligation

Acronyms and Abbreviations	Description
DARD	dispatchable asset related demand
DASI	Day-Ahead Ancillary Services Initiative
DA A/S	Day-Ahead Ancillary Services
DDBT	dynamic de-list bid threshold
DDG	do-not-exceed dispatchable generators
DDT	dynamic de-list threshold
Dec	decrement (virtual demand)
DFC	dual fuel commissioning
DG	distributed generation
DLOC	dispatch lost opportunity costs NCPC
DNE	do not exceed
DOE	US Department of Energy
DR	demand response
EGEL	Electricity Generator Emissions Limits (program)
EIA	US Energy Information Administration (of DOE)
EIR	Energy Imbalance Reserve
EMM	External Market Monitor
EMOC	Energy Market Opportunity Cost
EMOF	Energy Market Offer Flexibility
EPA	Environmental Protection Agency
ERS	external reserve support
ETU	Elective Transmission Upgrade
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
FER	Forecast Energy Requirement
FERC	Federal Energy Regulatory Commission
FRM	Forward Reserve Market
FRS	Flexible Response Services
FSP	Fast-Start Pricing
FTR	Financial Transmission Right
GT	gas turbine
GHG	greenhouse gas
GW	gigawatt
GW-month	gigawatt-month
GWh	gigawatt-hour
GWSA	Global Warming Solutions Act
HDD	heating degree day
HE	hour ending
HQ	Hydro-Québec

Acronyms and Abbreviations	Description
HQICCS	Hydro-Québec Installed Capacity Credit
IBT	internal bilateral transaction
ICE	Intercontinental Exchange, Inc.
ICR	Installed Capacity Requirement
ICT	Interim Compensation Treatment
IEP	Inventoried Energy Program
IMAPP	Integrating Markets and Public Policy
IMM	Internal Market Monitor
Inc	increment (virtual supply)
ISO	Independent System Operator, ISO New England
ISO tariff	*ISO New England Transmission, Markets, and Services Tariff*
kW	kilowatt
kWh	kilowatt-hour
kW-month	kilowatt-month
kW/yr	kilowatt per year
L	symbol for the competitiveness level of the LMP
LA	left axis
LCC	Local Control Center
LEG	limited-energy generator
LMP	locational marginal price
LNG	liquefied natural gas
LOC	lost opportunity cost
LOLE	loss- of-load expectation
LS/ERI	Lower SEMA/Eastern RI Import interface
LSE	load-serving entity
LSCPR	local second-contingency-protection resource
LSR	local sourcing requirement
M-36	*ISO New England Manual for Forward Reserve*
MA	State of Massachusetts
MAPE	mean absolute percent error
MassDEP	Massachusetts Department of Environmental Protection
MCL	maximum capacity limit
MDE	manual dispatch energy
ME	State of Maine and Maine load zone
M/LCC 2	Master/Local Control Center Procedure No. 2, *Abnormal Conditions Alert*
MMBtu	million British thermal units
MOPR	Minimum Offer Price Rule
MRA	monthly reconfiguration auction

Acronyms and Abbreviations	Description
MRI	marginal reliability impact
MW	megawatt
MWh	megawatt-hour
N-1	first contingency
N-1-1	second contingency
NCPC	Net Commitment-Period Compensation
NECEC	New England Clean Energy Connect
NEL	net energy for load
NEMA	Northeast Massachusetts, Boston load zone
NEMA/Boston	Northeast Massachusetts/Boston local reserve zone
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Corporation
NH	State of New Hampshire, New Hampshire load zone
NHME	New Hampshire-Maine Import interface
NICR	net Installed Capacity Requirement
NNE	northern New England
No.	Number
NPCC	Northeast Power Coordinating Council
NY	State of New York
NYNE	New York-New England interface
NYISO	New York Independent System Operator
OATT	*Open Access Transmission Tariff*
OP 4	ISO Operating Procedure No. 4
OP 7	ISO Operating Procedure No. 7
OP 8	ISO Operating Procedure No. 8
ORTP	offer-review trigger price
PER	peak energy rent
PFP	pay-for-performance
PJM	PJM Interconnection, L.L.C.
pnode	pricing node
PPR	pay-for-performance penalty rate
PRD	price-responsive demand
PROBE	Portfolio Ownership and Bid Evaluation
PST	pivotal supplier test
PTO	Participating Transmission Owners
PURA	Public Utilities Regulatory Authority
PV	photovoltaic
Q	quarter

Acronyms and Abbreviations	Description
RA	reconfiguration auction
RA	right axis
RAA	reserve adequacy assessment
RCA	Reliability Coordinator Area
RCP	regulation clearing price
RCPF	Reserve Constraint Penalty Factor
RFP	Requests for Proposals
RGGI	Regional Greenhouse Gas Initiative
RI	State of Rhode Island, Rhode Island load zone
RMCP	reserve market clearing price
RNL	regional network load
RNS	regional network service
RoP	rest of pool
RoS	rest of system
RRP OC	rapid-response pricing opportunity costs NCPC
RSI	Residual Supply Index
RTDR	real-time demand response
RTLO	real-time load obligation
RTO	Regional Transmission Organization
RTR	renewable technology resource
SCR	special-constraint resource
SEMA	Southeast Massachusetts load zone
SENE	southeastern New England
SMD	Standard Market Design
SWCT	Southwest Connecticut
THI	Temperature-Humidity Index
TMNSR	10-minute non-spinning reserve
TMOR	30-minute operating reserve
TMSR	10-minute spinning reserve
TPRD	transitional price-responsive demand
TTC	total transfer capability
UDS	unit dispatch system
US	United States
UTC	up-to-congestion
VT	State of Vermont and Vermont load zone
WCMA	Western/Central Massachusetts
WRP	Winter Reliability Program
WTI	West Texas Intermediate

Acronyms and Abbreviations	Description