2025 Assessment of the ISO New England Electricity Markets

Prepared By:

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External Market Monitor
for ISO-NE

June 2026

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PREFACE

Potomac Economics serves as the External Market Monitor for ISO-NE. In this role, we are responsible for evaluating the competitive performance, design, and operation of the wholesale electricity markets operated by ISO-NE.[1] In this assessment, we provide our annual evaluation of the ISO's markets for 2025 and our recommendations for future improvements. This report complements the Annual Markets Report, which provides the Internal Market Monitor's evaluation of the market outcomes in 2025.

We appreciate the Internal Market Monitor and other ISO staff for providing the data and information necessary to produce this report.

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[1] The functions of the External Market Monitor are listed in Appendix III.A.2.2 of "Market Rule 1."

Executive Summary

ISO-NE operates competitive wholesale markets for energy, operating reserves, regulation, financial transmission rights ("FTRs"), and capacity to satisfy New England's electricity needs. These markets provide substantial regional benefits by coordinating resource commitment and dispatch so the lowest-cost supplies reliably satisfy short-term demand. They also establish transparent, efficient price signals that govern long-term investment and retirement decisions.

ISO-NE's Internal Market Monitor ("IMM") produces an annual report that provides an excellent summary of market outcomes and trends during the year, including:[2]

- Real-time energy prices increased about 70 percent from 2024 to 2025, primarily because natural gas prices rose 105 percent. Higher load levels, lower imports from Quebec, and higher CO_2 emissions allowance prices also contributed to the increase in energy prices.
- Average load rose about 1 percent, while peak load increased 7 percent to 26.6 GW. However, average summer load fell by 3 percent year-over-year, which reflects continued growth in behind-the-meter solar generation that reduces the apparent load during daylight hours. However, it contributed relatively little at the peak because the peak load hour has shifted later in the day to hour-ending 19 in 2025.
- The capacity clearing prices were $2.61 and $2.59 per kW-month in the 2024/25 and 2025/26 Capacity Commitment Periods ("CCP"), respectively. Capacity prices rise to $3.58 per kW-month in the 2027/28 CCP, largely because of the effects of inflation on FCA demand curve parameters and market participants' offers.

This report is intended to complement the IMM's report by comparing key market outcomes with those in other RTO markets, assessing market competitiveness, and evaluating specific market design and operational issues. This year's report also evaluates residential retail rates and highlights affordability challenges in New England. Where appropriate, we recommend measures to address these issues and ensure the markets continue to provide efficient price signals, support reliable system operations, and adapt effectively as system needs evolve.

Cross-Market Comparison of Key Market Outcomes

ISO-NE faces unique challenges that distinguish it from most other RTOs and affect the structure and performance of its markets. In particular, ISO-NE is at the end of several interstate pipelines whose aggregate capacity to deliver gas to the region's gas utilities and gas-fired generators is limited. In addition, ISO-NE operates a network with far less congestion than other RTOs, which affects its competitive performance, operating needs, and reliability. In Section I of this report, we compare several key outcomes in the ISO-NE markets with those in other RTO markets.

2 See ISO New England's Internal Market Monitor 2025 Annual Markets Report, available at https://www.iso-ne.com/markets-operations/market-monitoring-mitigation/internal-monitor.

Energy Prices	In recent years, ISO-NE had the highest average energy prices among ISO markets in the Eastern Interconnect because of higher natural gas prices and CO_2 emissions allowance costs.
Capacity Prices	ISO-NE capacity prices remained relatively stable over the past three years at below $3.0 per kW-month. NYISO had the highest capacity costs because peaking-resource retirements from air permit limitations and reduced capacity imports tightened supply. Capacity prices also increased significantly in MISO and PJM in 2025 because of market reforms, demand growth, and recent generator retirements.
Congestion	ISO-NE experiences significantly less congestion than other ISOs, with average congestion costs of roughly $0.40 per MWh of load over the past three years – just 9 to 20 percent of the levels in other RTO markets. This reflects large transmission investment, primarily to address conservative local reliability planning criteria. As a result, transmission rates exceeded $29 per MWh in 2025, more than double the average rates in other RTO markets. Other markets have accelerated transmission investment in recent years, primarily to increase the deliverability of renewable generation to consumers.
Uplift Costs	ISO-NE generally incurs higher market-wide uplift costs, adjusting for its size, than MISO and NYISO because it is subject to higher fuel costs and its real-time unit commitment model often schedules fast-start resources poorly. However, the introduction of the day-ahead ancillary services markets lowers ISO-NE's market-wide uplift and this report recommends improvements in the real-time unit commitment model to achieve further reductions.
Virtual Trading	Virtual trading levels in ISO-NE have been significantly lower than those in NYISO and MISO, adjusting for size, primarily because ISO-NE over-allocates real-time Net Commitment Period Compensation ("NCPC") charges to virtual transactions and other real-time deviations. Addressing this issue is valuable because virtual trading plays an important role in aligning day-ahead and real-time market outcomes, especially as the generation mix evolves.
External Transactions	The Coordinated Transaction Scheduling ("CTS") process with NYISO has performed much better than other CTS processes between other eastern RTOs, largely because ISO-NE and NYISO do not impose fees on CTS transactions and forecast prices better. However, much larger savings could likely be achieved by transitioning to a 5-minute real-time adjustment process, which we are recommending in other areas.
Shortage Pricing	ISO-NE has employed the most aggressive shortage pricing among U.S. RTOs, primarily through the Pay-for-Performance ("PFP") framework rather

than the energy market. In June 2025, ISO-NE increased its shortage PFP rate to $9,337 per MWh. Together with its operating reserve demand curves, this rate produces the highest shortage pricing of any centrally-dispatched wholesale market. The PFP framework creates outsized risks from modest shortages that generally do not raise substantial reliability concerns. To address this issue, we recommend that ISO-NE vary the penalty rate with the size of the shortage and cap it at a reasonable Value of Lost Load ("VOLL").

Energy Affordability Challenges

In recent years, rising electricity costs and their impact on consumers have received significant attention nationwide. Average retail rates for residential customers in New England were 28.9 cents per kWh in 2025, 67 percent higher than the US average (Section II.A). Residential retail rates rose by 12 percent in inflation-adjusted terms from the 2016-2019 period to 2025. Section II discusses trends in New England residential electricity rates over the past decade and the impact of the ISO-NE markets on retail rates.

Figure ES-1: Changes in Retail Rate Components, 2016-2019 to 2024-2025

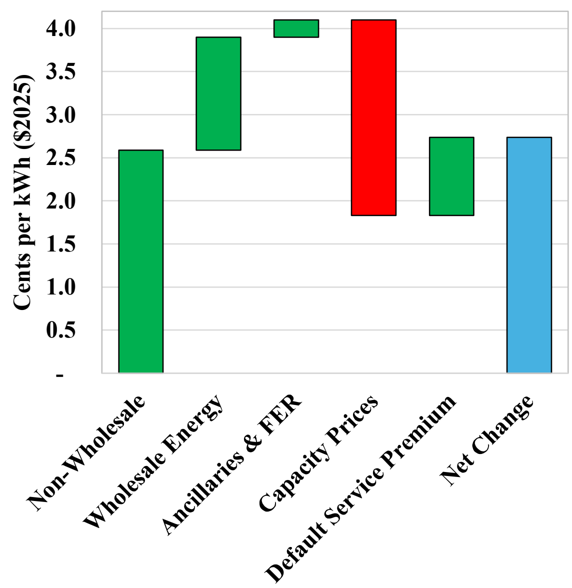


Figure ES-1 summarizes the factors driving the rise in residential retail rates. Non-wholesale costs drove most of the increase, including regulated transmission and distribution charges, renewable and energy efficiency programs, and other non-wholesale costs.

Total wholesale costs were relatively flat from 2016 to 2025, but the individual components diverged: wholesale energy prices and ancillary services costs rose, while capacity prices fell.

The primary causes of rising wholesale energy prices were natural gas prices and CO_2 allowance prices (Section II.B). Since 2022, forward gas prices in New England have increased significantly, and the premium over upstream areas has grown, reflecting a higher likelihood that pipeline constraints will cause extreme spot prices. Regional Greenhouse Gas Initiative ("RGGI") and Massachusetts CO_2 allowance prices have also risen dramatically and now account for a large share of generators' costs (e.g., about 24 to 30 percent of combined cycle generator production costs in 2025).

Wholesale market prices averaged 30 percent of the residential retail rate, while investor-owned utilities' (IOUs') supply rates for 'default service' averaged 44 percent of residential retail rates. [3]

[3] Most residential load in New England is supplied under fixed-price default service rates. IOUs procure default service through RFPs conducted months in advance where power generators offer to supply 100 percent of the capacity, energy, and ancillary service needs of a group of utility customers in each hour.

Figure ES-1 shows that over the period, the premium on IOUs' default service over wholesale market components increased by about 0.9 cents per kWh. Even after adjusting for distribution losses and the additional cost of satisfying variable load at a fixed rate under the RFP requirements, we estimate that IOUs' default service prices carry an average premium of 16 percent above wholesale market prices. Suppliers participating in IOUs' default service RFPs likely require significant risk premiums to meet utilities' full-service requirements at fixed rates because they face both market price risk and quantity risk for the load served. Additionally, states tightly prescribe RFP requirements and timing in ways that may limit the pool of competitive bidders and result in higher premiums over wholesale prices.

In Section II.C, we estimate generator profits in the ISO-NE markets relative to residential retail rates. Overall, we estimate that net revenues of fossil fuel (gas and oil) generators built more than 20 years ago exceeded fixed operating costs and capital recovery for maintenance by roughly 0.5 cents per kWh of ISO-NE load (about 2 percent of the retail rate) in 2023-2025. Generators may earn revenues above their fixed operating costs through the ISO-NE markets, which incentivizes: (a) ongoing capital investment needed to keep generators in a reliable condition and (b) new generating facilities even when wholesale prices are below levels that would allow full recovery of the investment in the initial 20 years of operation.

In Section II.D, we review recent nationwide evidence that the economic life of combined cycle and combustion turbine units exceeds the 20 years often assumed in Net CONE studies. This finding is consistent with the estimated profitability of older units in New England. Considering generators' residual value after 20 years in future Net CONE studies would reconcile the market's long-term investment signals with the marginal value of new resources and reduce rate pressure if capacity prices rise.

Finally, we discuss policy actions to reduce retail rates while maintaining competitive, efficient markets, including:

- Permitting new pipeline infrastructure, which would require cooperation from New York State and the federal government;
- Permitting of new dual fuel generation capacity or retrofitting gas-only units to be dual fueled;
- More flexible forward-contracting requirements for IOUs to expand the pool of potential suppliers; and
- Consider long-term residual value in the Net CONE used to set the capacity demand curve.

Clean Energy Transition

State programs in New England have driven investment in wind and solar resources, with roughly 370 MW of solar, 120 MW of wind, and 420 MW of storage added to ISO-NE in 2025. However, intermittent renewables remain a much smaller share of total generation than in major

RTO markets with high wind and solar penetration. In our 2024 Assessment of the ISO-NE Markets, we described strategies MISO and ERCOT have developed to address operational issues caused by high levels of intermittent generation, including rising output uncertainty, greater ramp needs, and challenges maintaining voltage levels and transmission security.

New England's shortage pricing and PFP rules provide strong incentives for flexible resources to manage net load fluctuations as intermittent output grows. Additional changes will help ISO-NE prepare for a grid with greater renewable penetration:

- *Marginal Capacity Accreditation*: The capacity market must accurately value the marginal reliability value of each resource type so that clean energy investment is directed to the most valuable projects and the market sends adequate signals to retain needed dispatchable generation. Therefore, we recommend that ISO-NE adopt marginal capacity accreditation (Rec. #2020-2) and move to a prompt seasonal auction structure (Rec. #2020-1). The ISO's Capacity Auction Reform ("CAR") projects address both recommendations.[4]
- Increasing reliance on intermittent resources and battery storage will create dispatch challenges that a short-term dispatch model cannot always solve efficiently, such as ramping conventional units in advance of net load ramps and optimizing energy storage dispatch. ISO-NE should develop a look-ahead dispatch model to optimize scheduling and price-setting across multiple time steps. Therefore, we recommend (#2023-1) that ISO-NE evaluate the potential benefits and costs of a look-ahead dispatch model that would optimize multiple hours into the future.

Lastly, we recommend treating Energy Efficiency as a load reduction in the capacity market rather than as a supply resource (Recommendation #2020-3). This would address gaming opportunities we have identified in ISO-NE and other RTO markets that allow EE to participate in the capacity market as supply. It would also be much less administratively burdensome and create more efficient incentives to invest in EE technologies.[5] Bother PJM and MISO recently filed changes with FERC to stop allowing EE to be sold as supply in its capacity market, noting that this shifts costs from EE beneficiaries to other consumers.[6]

Competitive Assessment

Based on our evaluation of ISO-NE's wholesale electricity markets in Section III of this report, we find little evidence that suppliers exercised market power in New England, either at the system level or within individual sub-regions. However, recent and one pending acquisition,

4 These include the Capacity Auction Reform: Prompt/Deactivation ("CAR-PD") and Capacity Auction Reform: Seasonal/Accreditation ("CAR-SA") projects.

5 See our 2020 Assessment of the ISO-NE Markets, available here.

6 See comments of PJM Interconnection and Monitoring Analytics in FERC Docket ER24-2995.

along with reduced imports from Canada and generator retirements, have increased indications of potential structural market power in the form of rising pivotal supplier frequencies since 2022. To ensure the market power mitigation measures remain effective, we support the Internal Market Monitor's recommendation #2023-1 to *review mitigation thresholds and reference level methodologies, eliminate mitigation exemptions for non-capacity resources, and extend mitigation to export-constrained area*.

We also continue to recommend revisions to the current energy mitigation process to address an inefficiency identified in our 2022 annual report (Recommendation #2022-2a). Specifically, we recommend that the ISO implement hourly conduct and impact tests to ensure it does not impose mitigation when a resource's conduct or prevailing competitive conditions no longer warrants it.

In addition, we find that market power mitigation in the day-ahead ancillary services ("DA A/S") market has occurred more frequently and in higher volumes than expected, often during low-to-moderate-load conditions when market power concerns are not typically most acute. Given these results and the tight mitigation thresholds, we find that the current mitigation measures warrant reassessment. Therefore, we continue to recommend that ISO-NE evaluate the current conduct and impact threshold levels and revise them as needed to ensure they limit the exercise of market power without interfering with competitive behavior (Recommendation #2024-2).

The ISO's proposed market reforms to address recommended improvements to DA A/S that are described in Section III help address Recommendation #2024-2 by reducing how often competitive DA A/S offers are mitigated. In particular, the proposal to apply a $3 per MWh floor to the Impact Test Threshold ("ITT") directly addresses these concerns by reducing mitigation caused by overly stringent thresholds, especially for smaller suppliers. After implementing these reforms, we will assess whether the rules still need further revision to avoid mitigation of competitive DA A/S offers.

Initial Observations on the Performance of the Day Ahead Ancillary Services Markets

The DA A/S markets have generated higher costs than expected in their first year of operation. The IMM estimated $974 million or a 9% rise over the prior market. It estimated that 75 percent of the incremental costs are due to fundamentals and roughly 25 percent to participation and offers. We find this evaluation reasonable and will be providing more detailed comments on the performance of the day-ahead ancillary services markets after the IMM releases its full report on the first year of operation.

However, we believe these costs overstate the net effect on consumers overall for two reasons:

- DA A/S revenues will be included in the energy and ancillary service revenue offsets used to develop the net CONE for the capacity demand curve. Higher revenues from this market will ultimately lower capacity prices and offset the estimated cost increase.

- The IMM estimates do not consider that increased commitments in the day-ahead market will lower real-time LMPs. Lower expected real-time LMPs will lower day-ahead LMPs as participants arbitrage the two markets. This offsets the estimated cost increase.

Nonetheless, we do believe that the relatively low strike price in the DA A/S market contributes to higher costs. Hence, we strongly support the ISO's reform to raise the strike price. More broadly, we find that the DA A/S markets have improved the performance of the ISO markets overall, lowering uplift costs and improving generator availability. While there are opportunities for improvements, the introduction of these markets have been highly beneficial.

Resource Commitments and Operating Reserve Pricing

Efficient resource commitment and pricing are important to ensure reliability cost-effectively. Accordingly, this report evaluates: (a) day-ahead commitments for local second contingency protection requirements; (b) incentives and eligibility criteria for receiving Forecast Energy Requirement ("FER") payments; (c) the accuracy and efficiency of the Real-Time Unit Commitment ("RTUC") model; and (d) operating reserve pricing in the real-time fast-start pricing logic.

Day-Ahead Commitments for Local Reserve Requirements. In Section IV.A, we find that day-ahead commitments satisfy local second contingency requirements that market prices do not reflect. Although such commitments have become less frequent, relying on out-of-market NCPC payments to satisfy these requirements does not efficiently compensate other resources that help meet them. Accordingly, we recommend defining local operating reserve requirements in the day-ahead and real-time markets to satisfy these reliability needs through the competitive market rather than out-of-market actions (Recommendation #2019-3).

Eligibility to Receive FER Payments – In Section IV.B, we discuss imports scheduled day-ahead that receive FER payments even when they are not available in real time. These day-ahead scheduled transactions are not obligated to be available in real time, so they do not provide a service comparable to other resources that receive FER payments. Over time, these incentives could reduce the effectiveness of the DA A/S market in supporting system reliability.

Real-Time Unit Commitment Model Performance. The RTUC model is a key operational tool that ISO-NE uses to schedule resources while maintaining system security and reliability during the operating day. Its primary outputs include startup and shutdown recommendations for fast-start resources and DARD pumps (i.e., pumped storage resources), which ISO-NE passes to the Unit Dispatch System (UDS) for execution.

Section IV.C indicates that RTUC frequently over-forecasts the need to commit fast-start resources. While we identify several contributors, RTUC over-forecasting was primarily caused by operator load adjustments and frequently led RTUC to "recommend" committing uneconomic fast-start generation. As a result, real-time NCPC uplift exceeded $10 million in 2025 and accounted for 65 percent of all real-time economic NCPC paid to internal resources. To improve fast-start commitment efficiency, we recommend that ISO-NE address the causes of price divergences between the RTUC and real-time dispatch models (Recommendation #2024-1).

Excessive Real-Time Reserve Prices. Section IV.D identifies an inefficiency in the fast-start pricing logic that tends to overstate reserves and energy pricing under certain system conditions. Specifically, the pricing model fails to recognize unscheduled capacity below generators' economic minimums. This reduction in supply can cause it to set inefficiently high prices. We recommend that the ISO modify the fast-start pricing logic to use the full capability of online resources for energy or reserves so reserve prices more accurately reflect the cost of maintaining operating reserves (Recommendation #2022-1).

Pay-for-Performance Incentives during Capacity Shortage Conditions

Capacity shortage events have been relatively infrequent since ISO-NE implemented Pay-for-Performance in 2018, occurring only five times over the past three years. These events generally lasted 30 minutes to three hours, with average 10-minute and 30-minute reserve shortages of less than 250 MW. Section V.B evaluates the PFP rules and outcomes.

Although none of these events posed a significant risk of firm load shedding in New England, settlement amounts over the past three years were substantial:

- Suppliers incurred more than $230 million in performance charges, most of which came from available combined cycle or steam units that were offline because the day-ahead market had not committed them.
- The total price for imports or resources performing above their Capacity Supply Obligations ("CSOs") was as high as $12,000 per MWh, including the $9,337 per MWh penalty rate in 2025.

These prices and associated settlements vastly exceed the reliability value of energy during these events and create substantially inefficient incentives for ISO New England participants.

One key inefficiency is the inconsistent settlement treatment of imports and exports. Applying the PFP rate to importers but not exporters is a significant flaw that distorts incentives to schedule imports and exports. During these five events, ISO-NE curtailed few scheduled exports and allowed 700 to 1800 MW of scheduled exports to flow which led to additional PFP charges for other suppliers. To correct these inefficient incentives, we recommend that the ISO:

- Revise the PFP rules to charge exporters at the PFP rate during Capacity Scarcity Conditions (Recommendation #2022-3). The ISO recently proposed revising the PFP framework to charge System-Backed Exports, which addresses our recommendation and we fully support this rule change.

- Modify the PFP rates to levels consistent with a reasonable estimate of VOLL that escalate as reserve shortages deepen (Recommendation #2018-7). The ISO recently proposed reducing the PFP rate from the current formula-based value of $9,337 per MWh to a fixed rate of $3,500 per MWh, which partially addresses our recommendation. However, we continue to recommend that the ISO implement a graduated stepwise PFP structure that aligns incentives more closely with the severity of reserve shortages and the associated reliability risk.

Unavailable Qualified Capacity under Peak Summer Conditions

The Qualified Capacity ("QC") values for generators with combustion turbines do not adequately reflect ambient conditions during periods with the greatest reliability risks because these values generally assume milder temperature, humidity, and barometric pressure conditions than the conditions that drive planning reliability needs (see Section IV.A). We also observed additional derates under peak summer conditions related to the effect of ambient conditions on cooling equipment. Together, these factors caused available capacity to be 680 MW less than qualified capacity during summer peak conditions in 2025. Therefore, we recommend that the ISO monitor generators' compliance with forced-derating reporting rules and reassess how it accounts for ambient conditions in the calculation of Qualified Capacity after the CAR project is completed (#2024-3).

In addition, we identified generators that experienced partial derates during the June 2025 PFP event and did not promptly report them to the ISO. Consequently, the PFP settlement treated much of this capacity as operating reserves and produced a net benefit of $6 million for these generators. Monitoring compliance with generators' obligations to report unit status is particularly important when operating reserves are compensated at a marginal rate above $10,000 per MWh (as we recommend in #2024-3).

Table of Recommendations

Although we find that the ISO-NE markets have generally performed competitively and efficiently, we identify several opportunities for improvement and make recommendations that we list in the following table.

This table references the location of our analyses and discussions supporting each recommendation and we indicate those we believe will deliver the greatest benefits. Several recommendations were first made in prior annual reports. Rather than repeat all prior analyses and discussions, we often cite the most recent annual report containing the relevant discussion.

Recommendation Number and Description		High Benefit[7]	Current/ Planned Efforts	Report Reference
Reliability Commitments and NCPC Allocation				
2010-4	Modify allocation of "Economic" NCPC charges to make it consistent with a "cost causation" principle.			III of 2018 Report
Energy and Operating Reserve Markets				
2024-1	Evaluate and address causes of the price divergences between RTUC model and the real-time dispatch.			IV.B
2023-1	Evaluate benefits and costs of a look-ahead dispatch model to optimally manage fluctuations in net load and the use of storage resources.	✓		II of 2024 Report
2022-1	Allow fast-start pricing model to utilize the full capability of online units for energy or reserves.			IV.D
2019-3	Define a full set of local operating reserve requirements in the day-ahead and real-time markets.			IV.A
Energy & Ancillary Services Market Mitigation				
2024-2	Evaluate the appropriateness of the current conduct and impact threshold levels for reserves in the DAM.			III.E
2022-2a	Implement hourly conduct and impact tests in the automated energy mitigation procedure in RT.			III.D
Capacity Market				
2024-3	Enforce compliance with forced derate reporting requirements and reassess the adjustments for ambient conditions to determine Qualified Capacity.			V.A
2022-3	Charge exporters the PFP rate during reserve shortages.		SBE Filing Plan 2026-Summer	V.B
2021-1	Replace the forward capacity market with a prompt seasonal capacity market.	✓	CAR-PD Filing Approved, CAR-SA Filing Plan 2026-Q4	V.B of 2023 Report
2020-2	Improve capacity accreditation by a) accrediting all resources consistent with their marginal reliability value, and b) modify the planning model to accurately estimate marginal reliability values.	✓	CAR-SA Filing Plan 2026-Q4	V.A of 2023 Report
2020-3	Account for energy efficiency as a reduction in load instead of as a supply resource in the FCM.			V of 2020 Report
2018-7	Modify the PPR to rise with the reserve shortage level, and do not implement the planned increase in the PPR.	✓	$3,500 PPR Filing Plan 2026-Summer	V.B

[7] Recommendation will likely produce considerable efficiency benefits.

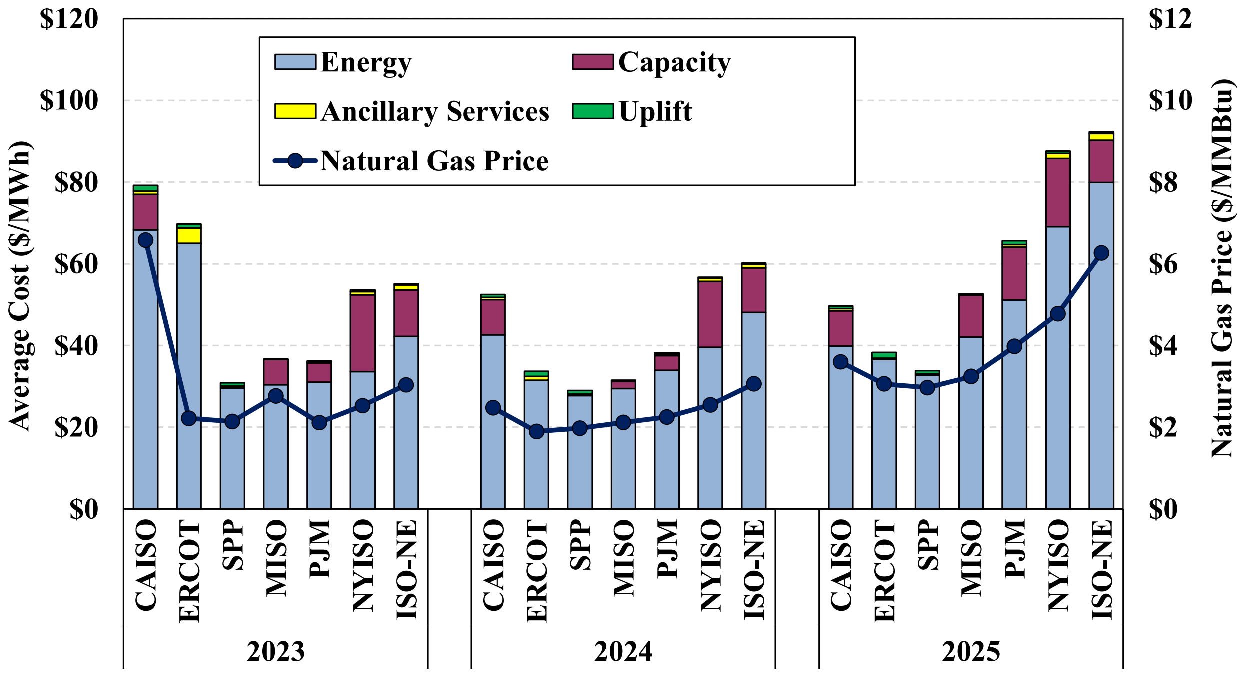
I. Comparing Key ISO-NE Market Metrics to Other RTOs

The 2025 Annual Markets Report by the Internal Market Monitor ("IMM") provides descriptive statistics and useful summaries of outcomes in the ISO-NE markets. It also discusses these outcomes and the factors that led to changes in 2025. In this section, we complement that discussion by comparing New England market outcomes and investment incentives with those in other RTO markets.

A. Market Prices and Costs

While US RTOs have converged to similar energy and ancillary service market designs, including Locational Marginal Pricing ("LMP"), some market rules still vary substantially across RTOs. In addition, the existence and design of capacity markets are far less consistent. Many factors affect market prices and costs across RTOs, including the types and vintages of generation assets, state policies supporting specific technologies, fuel market dynamics, and differences in transmission network capability. Figure 1 shows the "all-in price" of electricity to compare overall prices and costs across RTOs.[8]

Figure 1: All-In Prices in RTO Markets
2023 – 2025



8 These include only wholesale market costs and not, for example, transmission or distribution service charges. Section II of this report provides a more detailed analysis of how New England's retail rates are affected by ISO-NE market costs, forward contracting, and other factors.

The all-in price metric comprehensively measures the wholesale market cost of serving load. It equals the load-weighted average real-time energy price plus capacity, ancillary services, and bid production cost guarantee costs (referred to industry-wide as "uplift costs") per MWh of real-time load across each system. We also show the average natural gas price because it is the principal driver of generators' marginal costs and energy prices in most markets.

Energy Costs: Figure 1 shows persistent differences in prices and costs across these markets that reflect differences in fuel prices, resource mixes, and market design.

Energy prices and natural gas prices were strongly correlated in ISO-NE, NYISO, PJM, and MISO, where natural gas-fired generation frequently set market prices across broad areas. From 2024 to 2025, energy prices in these markets increased by 43 to 75 percent, consistent with increases in natural gas prices. ISO-NE had the highest energy prices among these markets, primarily because natural gas prices at New England pipeline delivery locations were higher than in other regions. This pattern was most pronounced during winter months, when pipeline constraints tightened gas supplies and drove gas prices sharply higher.

In contrast, the relationship between energy prices and natural gas prices was weaker in ERCOT, SPP, and CAISO. In ERCOT, high energy prices often occurred during summer months despite relatively low natural gas prices. In prior years, this was partly because ERCOT did not jointly optimize the real-time scheduling on ancillary services and energy, which was remedied in late 2025. Average energy prices were especially elevated in 2023 because ERCOT implemented a new reserve product poorly in June 2023, resulting in frequent artificial shortage pricing. However, ERCOT prices have declined over the past two years as large-scale additions of solar and storage resources significantly reduced the frequency of shortage conditions.

The weaker correlation between energy and gas prices in SPP and CAISO reflects their significantly higher penetration of wind and solar resources. In these markets, intermittent renewable and hydroelectric resources more often set market clearing prices, which reduces the influence of natural gas prices on energy prices. By contrast, natural gas-fired generation sets clearing prices in more than 75 percent of pricing intervals in ISO-NE, NYISO, and MISO. In addition, CAISO remains the only major market that has not implemented fast-start pricing, so energy prices remain below efficient levels when fast-start resources are committed to maintain system reliability and balance supply and demand.

Other key factors affecting energy costs in New England include:

- *Rising Carbon Emission Costs.* ISO-NE energy prices are affected more than most other regions by the state greenhouse gas compliance costs.
    - In 2025, compliance added an average of $14 to $19 per MWh to the costs of gas-fired combined-cycle generators in Massachusetts and $10 to $13 per MWh in the other five New England states in the Regional Greenhouse Gas Initiative ("RGGI").

 - Generators in NYISO and several PJM states are also subject to RGGI compliance costs. ERCOT, MISO, and SPP have no such programs. CAISO's greenhouse gas (GHG) allowance cap-and-trade system raised combined-cycle generators' costs by an average of $14 to $19 per MWh.

- *Low Levels of Transmission Congestion*. Although we do not show the most congested locations in neighboring markets, some import-constrained locations in those markets have energy prices substantially higher than those in New England, contributing to higher system-wide average prices. Conversely, the unusually low levels of transmission congestion in New England tend to reduce system-wide average energy prices. We discuss congestion levels in more detail in the next subsection.

Capacity Costs: The figure shows that capacity costs in New England remained relatively stable over the past three years. Since 2023, New England has experienced substantial capacity surpluses, resulting in capacity prices below $3.0 per kW-month, despite winter reliability issues that led to the out-of-market retention of the Mystic generating facility. The sustained low prices led 760 MW of retirement bids from units with on-site fuel supplies to clear in FCA18. After ISO-NE transitions to a prompt, seasonal market with marginal capacity accreditation, prices and market incentives are expected to improve. This change will facilitate better investment, retirement, and fuel supply decisions by market participants.

New York. NYISO had the highest capacity costs among the seven markets over the past three years. Capacity prices rose dramatically after 800 MW of peaking generation retired in 2023 because of air permit limitations and after capacity imports from neighboring control areas fell. NYISO also implemented marginal capacity accreditation beginning with the 2024/25 capability year. However, this change did not significantly affect prices immediately because NYISO's resource adequacy model already included many of the factors driving accreditation values. NYISO is developing capacity market and resource adequacy model enhancements focused on winter reliability risk, which will affect prices and accreditation values in future years.

PJM. Capacity prices in PJM cleared at very low levels in 2023 and 2024, generally below $2.0 per kW-month. These low prices reflected large capacity surpluses and were likely below the going-forward costs of many existing units, leading to retirements. In part, the surpluses resulted from low development costs that supported new capacity entry over the past decade. However, PJM's capacity auction for the 2025-26 period cleared at much higher prices, ranging from $8.2 to $14.2 per kW-month. The sharp increase reflected rapid datacenter-driven load growth, recent retirements, and a new marginal capacity accreditation approach that significantly discounted the capacity contributions of many resource classes compared to prior auctions.

MISO. MISO has made major market design changes in recent years, including implementing a seasonal capacity market and capacity accreditation changes in 2023 and a sloped, reliability-based demand curve in 2025. Capacity prices increased sharply to roughly $6.5 per kW-month (annualized) in the 2025-26 auction as the region continues to be affected by recent retirements.

CAISO. The California PUC also implements a resource adequacy program to ensure sufficient capacity for reliable grid operations, with an effective planning reserve margin requirement of 20 to 22.5 percent. Suppliers and load serving entities ("LSEs") negotiate capacity contracts bilaterally, so there is no uniform clearing price. The capacity cost component in Figure 1 represents the soft offer cap of the capacity procurement mechanism in CAISO for backstop capacity procurement. The CPUC adopted a Local Capacity Requirement Reduction Compensation Mechanism (LCR RCM) to encourage development of preferred resources and energy storage resources in local capacity areas.[9] Weighted-average Resource Adequacy (RA) contract prices have risen dramatically in recent years, from approximately $7 per kW-month for 2022-2023 delivery to roughly $25 per kW-month for 2025-2026 delivery. This increase likely reflects tightening capacity conditions in California, including generator retirements, growing resource adequacy requirements, and declining planning reserve margins.

ERCOT and SPP. These are "energy-only" markets (i.e., no capacity market), although SPP enforces a 12 percent planning reserve requirement.

Uplift Costs: The last cost component shown in Figure 1, although difficult to discern, is the average uplift cost per MWh of load in each region. Although this amount is small, it is important because market participants cannot easily hedge it and because it tends to occur when market requirements are not fully aligned with the system's reliability needs or when prices are otherwise not fully efficient. We discuss uplift in more detail in Subsection C.

B. Transmission Congestion

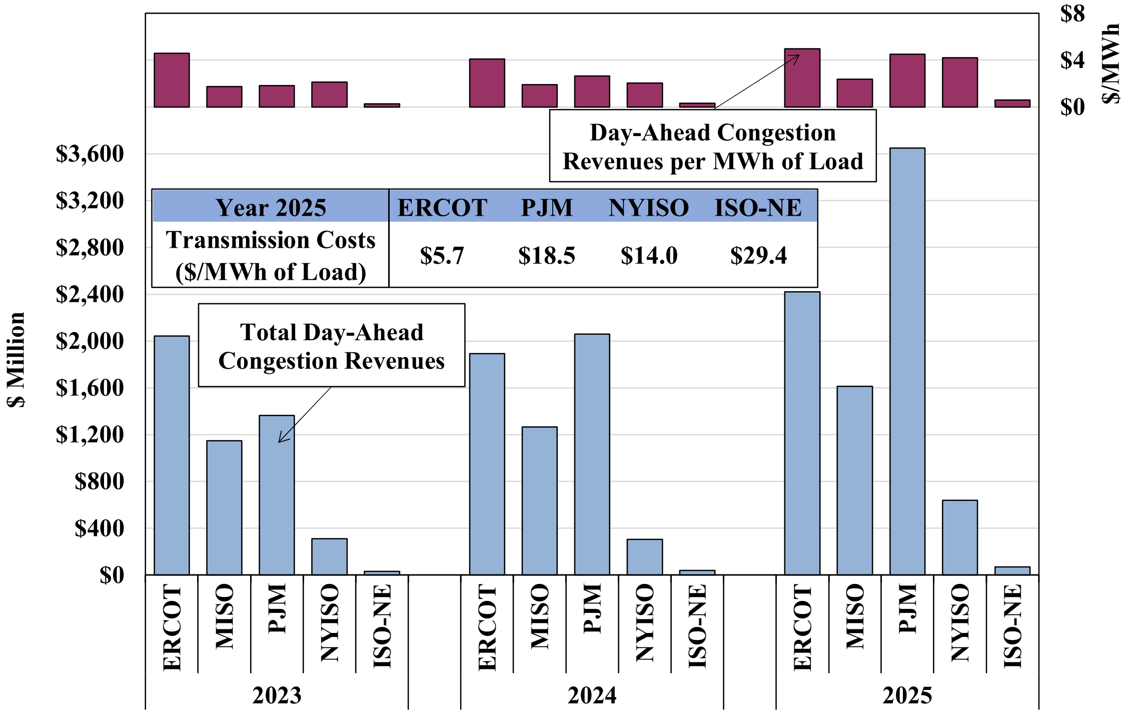
A principal objective of the day-ahead and real-time markets is to commit and dispatch resources efficiently to control power flows on the transmission system and manage transmission congestion. Figure 2 shows day-ahead congestion revenues across several U.S. RTOs. To compare markets of different sizes, the top panel normalizes total day-ahead congestion revenues by actual load.

Figure 2 shows that ISO-NE experienced far less congestion than other RTOs, averaging $0.39 per MWh over the past three years. In contrast, congestion levels per MWh of load in the other RTOs were four to ten times higher. The low level of congestion in New England reflects substantial investments in transmission infrastructure over the past two decades to address reliability needs and support local transmission security. These investments produced transmission rates of over $29 per MWh in 2025, more than double the average rates in the other RTO areas shown in the figure. [10]

9 See CPUC Decision (D.) 20-12-006.

10 The annual average transmission rate for MISO is not reported, as reliable data are not available.

Figure 2: Day-Ahead Congestion Revenues
2023-2025



Transmission rates in other RTO areas are significantly lower than in New England, despite substantial investments to support renewable integration:

- ERCOT has invested more than $5 billion in transmission expansion to alleviate congestion between wind resources in western Texas and load centers in eastern Texas.
- MISO has invested more than $15 billion in transmission to integrate renewables and approved more than $35 billion through its Long Range Transmission Planning process.
- NYISO and New York state have invested $7.5 billion and approved another $8.5 billion in transmission projects since 2019 to deliver renewable energy to downstate load centers and support offshore wind development. This increase in transmission investment is largely responsible for the $6 per MWh rise in average transmission charges since 2021.

Transmission expansion in these markets has primarily focused on improving the deliverability of renewable resources. By contrast, ISO-NE's transmission expansion over the past two decades has been driven largely by local reliability requirements. Under ISO-NE's reliability planning process, transmission needs are identified based on a conservative criterion requiring the system to withstand the simultaneous loss of the two largest contingencies under a 90th-percentile peak load scenario. This planning criterion is more stringent than those used by the other three RTOs. From 2002 through March 2026, New England invested more than $13 billion in transmission to maintain reliability, with $0.3 billion more planned through 2034.[11]

[11] See *RSP Project List and Asset Condition List – March 2026 Update*, Planning Advisory Committee Meeting, March 24, 2026.

In general, transmission investment is economic when the marginal value of reduced congestion and capacity benefits exceeds its costs. Capacity benefits include the avoided costs of maintaining generating capacity to satisfy planning reliability needs and the value of improved reliability. Congestion reduction benefits are small because average congestion costs in New England have been approximately $0.39 per MWh of load over the past three years. Transmission costs totaled $3.4 billion in 2025, compared to just $1.2 from the entire capacity market, so much of the existing transmission is likely uneconomic, and additional transmission investment would likely be uneconomic in the near term. Nonetheless, prior investments have significantly reduced local reliability Net Commitment Period Compensation ("NCPC") costs and better prepared the system to integrate renewable resources in the future.

C. Uplift Charges and Cost Allocation

Net Commitment Period Compensation (NCPC) costs, often called "uplift costs" across the industry, typically account for a small share of wholesale market costs. However, they are important because they usually arise when market requirements do not fully align with actual system reliability needs or when prices are otherwise inefficient.[12] This undermines the economic signals that govern behavior in the day-ahead and real-time markets in the short term, as well as investment and retirement decisions in the long term. Therefore, we monitor the market for potential inefficiencies by examining the causes of NCPC payments. Table 1 summarizes total day-ahead and real-time NCPC charges in ISO-NE over the past three years, along with comparable 2025 uplift charges in NYISO and MISO.

To allow meaningful comparisons despite differences in ISO size, the table also shows these costs per MWh of load. Because RTOs differ in the extent to which they make reliability commitments in the day-ahead horizon versus real time, the table also includes a total of day-ahead and real-time uplift at the bottom.

Local Reliability Uplift

Table 1 shows that local reliability NCPC uplift remained relatively low over the past three years, averaging less than $2 million annually and accounting for less than $0.02 per MWh of load. Minimal supplemental commitments in constrained load pockets reflect new resource additions and ongoing transmission upgrades in key areas. As a result, ISO-NE's local reliability uplift was considerably lower than in other RTOs, particularly NYISO.

12 For example, if the market clearing price is $50 per MWh and the operator schedules a 100 MW resource outside of the market at a cost of $55 per MWh so that it does not set the market clearing price, it could lead to NCPC charges of $500 (= 100 MW × $5 per MWh). However, if load is 20,000 MW, the total amount of underpricing of transactions will total $100,000 (= 20,000 MW × $5 per MWh). So, even small amounts of NCPC charges can be an indicator of a significant market inefficiency.

By contrast, NYISO continues to incur substantial local uplift. This is primarily because it must commit significant generation capacity for local second contingency protection within New York City load pockets. In addition, NYISO frequently dispatches oil-fired peaking resources on Long Island out-of-merit in real time to support local voltage requirements during the summer months. NYISO's energy and reserve market models do not fully reflect these local reliability requirements. Consequently, they produce inefficient prices, higher uplift costs, and weaker investment incentives for resources that could support local reliability more efficiently.

Table 1: Summary of Uplift by RTO

		ISO-NE			NYISO	MISO
		2023	**2024**	**2025**	**2025**	**2025**
Real-Time Uplift						
Total	**Local Reliability ($M)**	$1.0	$1.3	$1.3	$9	$2
	Market-Wide ($M)	$25	$27	$30	$47	$28
Per MWh of Load	**Local Reliability ($/MWh)**	$0.01	$0.01	$0.01	$0.06	$0.00
	Market-Wide ($/MWh)	$0.22	$0.23	$0.26	$0.31	$0.04
Day-Ahead Uplift						
Total	**Local Reliability ($M)**	$0.7	$0.9	$0.2	$13	$24
	Market-Wide ($M)	$4	$6	$10	$13	$25
Per MWh of Load	**Local Reliability ($/MWh)**	$0.01	$0.01	$0.00	$0.09	$0.03
	Market-Wide ($/MWh)	$0.03	$0.05	$0.09	$0.08	$0.04
Total Uplift						
Total	**Local Reliability ($M)**	$1.6	$2.2	$1.5	$22	$26
	Market-Wide ($M)	$29	$33	$40	$60	$53
Per MWh of Load	**Local Reliability ($/MWh)**	**$0.01**	**$0.02**	**$0.01**	**$0.14**	**$0.04**
	Market-Wide ($/MWh)	**$0.26**	**$0.28**	**$0.35**	**$0.39**	**$0.08**
	All Uplift ($/MWh)	**$0.27**	**$0.30**	**$0.36**	**$0.54**	**$0.11**

Market-Wide Uplift

Unlike local reliability uplift, ISO-NE has typically incurred higher market-wide uplift costs than the other two markets after adjusting for size. ISO-NE introduced day-ahead reserve markets in March 2025, which helped reduce market-wide NCPC costs. However, these costs rose from 2024 to 2025 because of high levels in January and February 2025. In previous years, ISO-NE's market-wide NCPC costs were generally more than double the average cost per MWh of load in NYISO and MISO, which we do not expect to be the case in the future. The day-ahead reserve markets provide additional market revenues, reducing the need for day-ahead NCPC. It also reduces the need for supplemental commitments, lowering real-time NCPC uplift payments.

Despite this reduction, several factors kept uplift costs in New England high:

1) Although all three RTOs have provisions for compensating resources when their scheduled output deviates from their most profitable output level, ISO-NE's rules offer compensation under a broader set of circumstances than those in MISO and NYISO. Examining these differences may help identify best practices across markets.

2) ISO-NE also experienced higher levels of real-time economic NCPC payments to fast-start units committed in economic merit order than NYISO and MISO. These payments accounted for approximately 65 percent of uplift in this category over the past two years. Section IV.C analyzes several of the factors contributing to these uplift payments.

Uplift Allocation and Virtual Trading

Beyond differences in uplift costs, their allocation also varies significantly across RTOs. ISO-NE allocates real-time "Economic" NCPC charges to real-time deviations, including virtual transactions, although such deviations do not directly cause most of these charges. Over the past three years, fast-start resources accounted for more than 60 percent of real-time Economic NCPC payments. Uneconomic real-time commitments in response to forecast errors often drive these payments. Real-time deviations such as virtual transactions typically play little or no role in causing this uplift. By contrast, virtual load can reduce NCPC costs by increasing day-ahead commitments and reducing the need for fast-start resources in real time.

Table 2 shows the average volume of virtual supply and demand cleared in the three eastern RTOs we monitor, expressed as a percentage of total load. It also reports the gross profitability of these transactions, measured as the difference between the day-ahead and real-time energy prices that settle the virtual positions. These profitability figures do not account for uplift costs allocated to virtual transactions, which the table shows separately in an additional column.

Table 2: Scheduled Virtual Transaction Volumes and Profitability

Market	Year	Virtual Load		Virtual Supply		Uplift Charge Rate
		MW as a % of Load	Avg Profit	MW as a % of Load	Avg Profit	
ISO-NE	2022	3.1%	-$1.75	4.8%	$3.23	$1.02
	2023	4.2%	-$2.09	6.3%	$1.28	$0.83
	2024	3.1%	-$2.64	6.6%	$2.21	$0.75
	2025	4.5%	-$3.19	8.0%	$2.67	$0.63
NYISO	2025	6.1%	$3.39	7.7%	$1.25	< $0.1
MISO	2025	15.5%	-$0.30	15.5%	$1.49	$0.16

Table 2 shows that virtual trading is profitable overall, which suggests that it improves price convergence between the day-ahead and real-time markets. The table also shows that virtual trading activity increased in 2025 relative to prior years as uplift charge rates declined. However, virtual trading activity in ISO-NE remains lower than in the other RTOs, averaging about 11 percent of load, compared to 14 to 31 percent in the other two RTOs. This disparity arose in part from the over-allocation of NCPC charges to real-time deviations in New England. These allocations discourage virtual participation, reduce day-ahead market liquidity, and ultimately impair market performance.

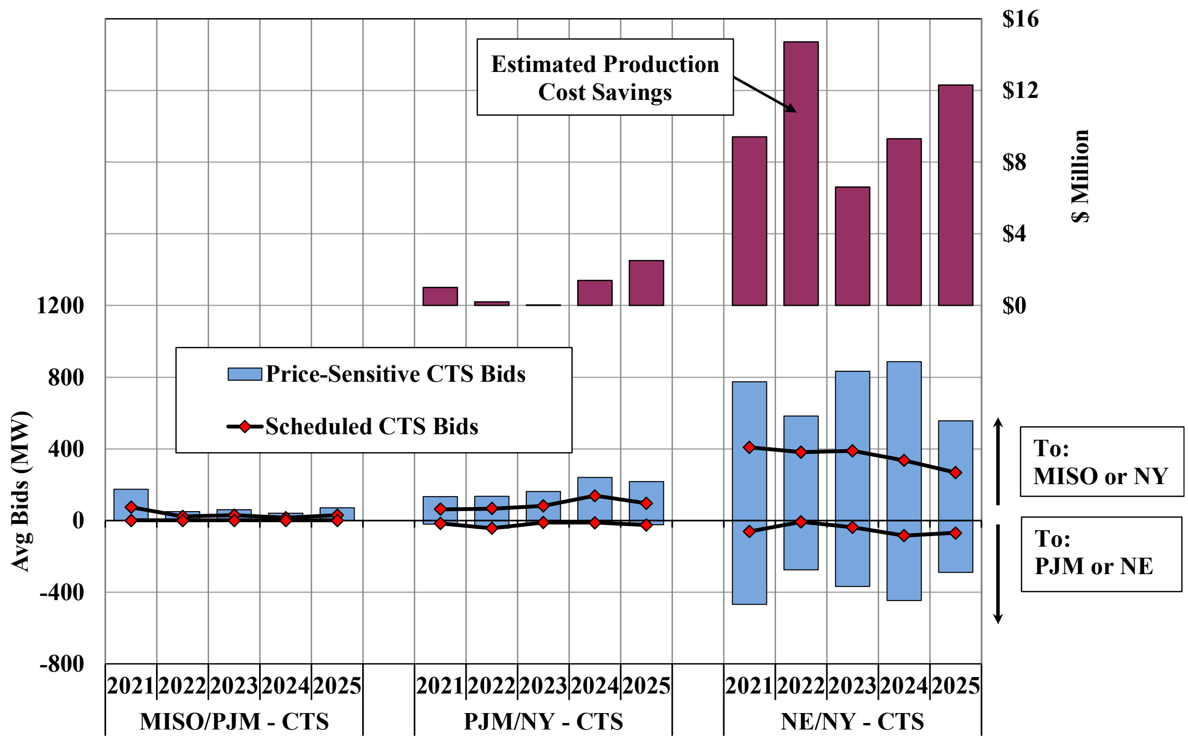
We continue to recommend that the ISO modify the allocation of Economic NCPC charges to align with "cost causation" principles. Specifically, the ISO should stop allocating NCPC costs to virtual load and other real-time deviations that do not cause real-time economic NCPC costs (Recommendation #2010-4).

D. Coordinated Transaction Scheduling

Coordinated Transaction Scheduling ("CTS") is a vital process in which neighboring RTOs exchange real-time market information to schedule external transactions more efficiently. CTS optimizes use of the interface between markets, lowering costs and improving reliability in the region. As intermittent generation increases, CTS will play an even more critical role in helping RTOs balance supply and demand efficiently. Figure 3 compares CTS performance in the NE-NY process with the PJM-NY and MISO-PJM processes.

The lower panel in Figure 3 shows annual average quantities of price-sensitive CTS bids and schedules over the past five years.[13] Positive numbers indicate transactions from neighboring markets to the NYISO or MISO markets, while negative numbers indicate transactions from neighboring markets to the PJM or New England markets. The upper panel shows CTS market efficiency gains measured by production cost savings, excluding estimates for the PJM-MISO process because of very limited participation.

Figure 3: CTS Scheduling and Efficiency
2021 – 2025



[13] CTS bids in the price range of -$10 to $10 per MWh are considered price-sensitive for this evaluation.

Figure 3 shows significantly higher CTS participation at the NE/NY interface than at the PJM/NY and MISO/PJM interfaces. Substantial transaction fees at the PJM/NY and MISO/PJM interfaces discourage scheduling, while the NE/NY interface imposes no transaction fees. This pattern shows that transaction charges can impede efficient scheduling by discouraging CTS participation.

The estimated production cost savings from the NE/NY CTS process exceeded $52 million over the past five years, compared to $5 million at the PJM/NY interface.[14] In addition to higher participation levels, more accurate price forecasting also contributed to higher savings at the NE/NY interface. ISO-NE's forecasting approach is more granular: it incorporates a supply curve with seven interchange levels, while PJM forecasts a single price at a fixed interchange level. Better forecast accuracy could further increase the cost savings from the CTS processes.

However, forecasting improvements may be limited because forecasts are produced roughly 40 minutes in advance. As an alternative, we evaluated a process for MISO and PJM that adjusts interchange every five minutes based on updated real-time prices. The estimated savings from such a real-time process are significantly larger than those achieved under current CTS processes, suggesting that a similar enhancement may warrant consideration for the New England and New York interface.

E. Net Revenues for New Entrants

A well-functioning wholesale market establishes transparent, efficient price signals that guide investment and retirement decisions. The New England states have set ambitious policy goals to decarbonize the electricity sector and implemented several programs to encourage development of clean energy resources. Efficient market incentives will help the states meet their goals at the lowest cost. This remains true even for projects primarily motivated by state and federal incentives because wholesale prices still play a significant role in most projects' profitability.

This subsection compares investment incentives in ISO-NE with those in other markets by estimating the net revenue new resources would have earned from wholesale markets and applicable state and federal incentives. Figure 4 shows the estimated net revenues for new combustion turbine ("CT") and combined-cycle ("CC") generators, while Figure 5 shows the net revenues for land-based wind, offshore wind, and solar PV units from wholesale market products and state and federal incentives.[15] The figures also show the estimated annual net revenue these new investments would need to be profitable (i.e., the "Cost of New Entry" or CONE) in 2024 and 2025.

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14 Production cost savings are calculated relative to our estimates of scheduling that would have occurred under the previous hourly scheduling process, which we proxy based on the advisory schedules in NYISO's RTC model that are determined 30 minutes before each hour.

15 See Appendix A for the assumptions used for this analysis. The CT chosen for each market is the most economic: a F Class Frame CT in MISO and ERCOT and a H Class Frame CT in NE and NY.

Figure 4: Estimated Net Revenues of CT and CC Units in ISO/RTO Markets
2024 – 2025

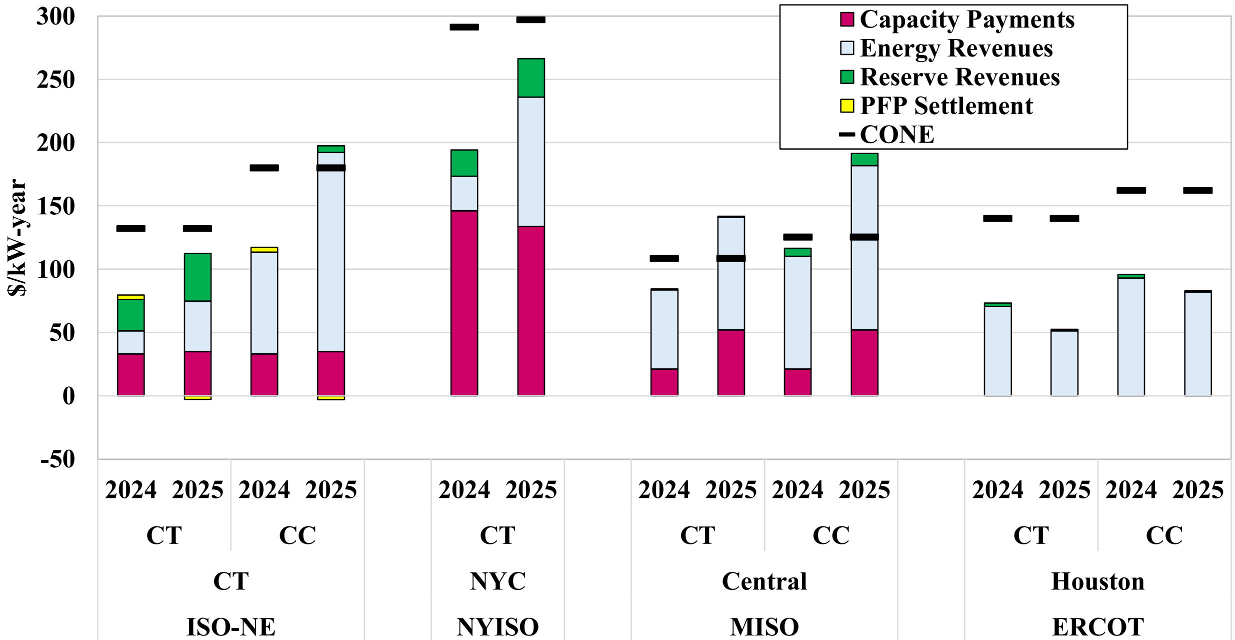
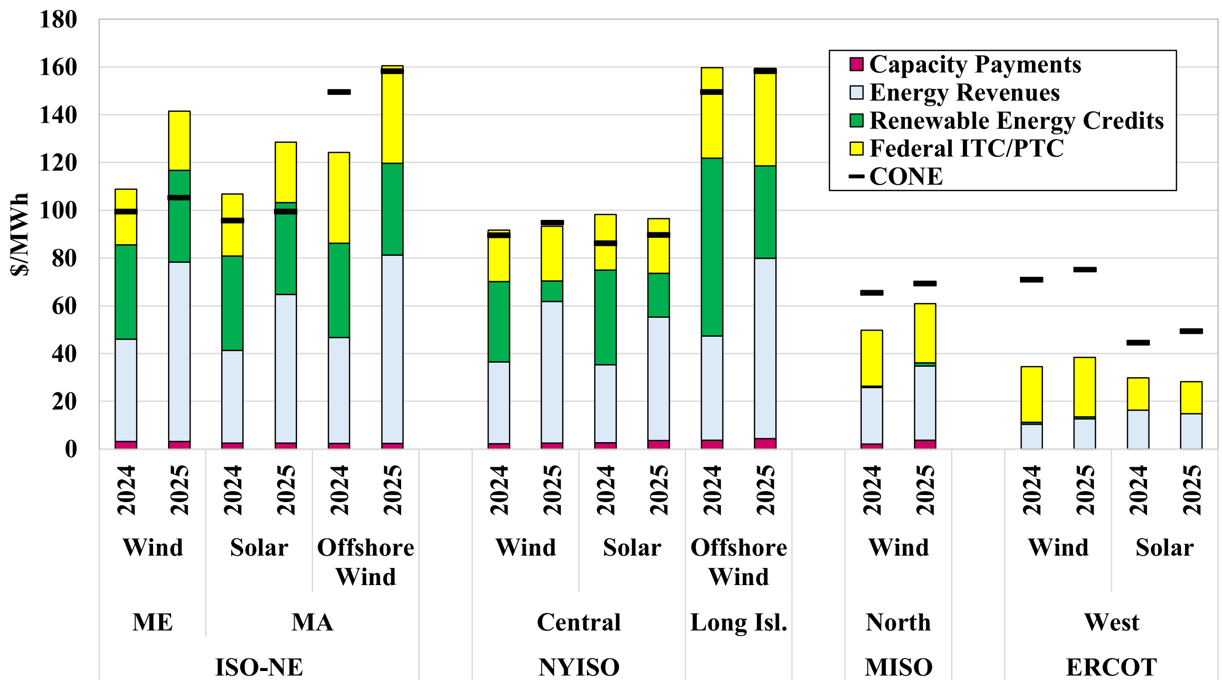


Figure 5: Estimated Net Revenues of Renewables in ISO/RTO Markets
2024 – 2025



Incentives for New Combustion Turbines and Combined Cycles

Net revenues of fossil generators increased markedly in most regions in 2025. In ISO-NE, 2025 net revenues exceeded the estimated Cost of New Entry for CCs. In MISO, they exceeded the estimated Cost of New Entry for both CTs and CCs. Figure 4 provides the following insights on incentives to invest in CTs and CCs in each market:

- *New England*. Net revenues of a new CT have remained below Net CONE because they rely heavily on capacity prices, which have been low in recent years. However, CT revenues rose in 2025 because of generally higher market spark spreads and the introduction of the day-ahead ancillary services ("DA A/S") markets in March 2025, which raised reserve market revenues for new flexible CTs. Revenues of a new CC also increased substantially in 2025 because of rising energy prices, payment of the Forecast Energy Requirement ("FER") shadow price to units that sell day-ahead energy as part of the DASI initiative, and higher winter gas prices in 2025, which created opportunities for a new unit built with dual fuel capability.
- *New York*. Net revenues of a new CT in New York City were below CONE despite comparatively high capacity prices because the region had nearly a 6 percent capacity surplus. New York City generally has higher prices than other areas because of its very high CONE. New York recently raised capacity requirements in New York City to better align them with transmission security requirements. Net revenues for a new CT would likely have been above CONE in 2024 and 2025 if those requirements had been used. We did not evaluate the economics of a new CC in New York because state policy has been to deny permits for new fossil generators.
- *ERCOT*. Net revenues of CT and CC units in ERCOT were much lower than in other markets in 2024 and 2025. ERCOT does not have a capacity market, so peaking units derive net revenues in tight market conditions from a higher frequency of scarcity pricing hours. Large-scale entry of solar and storage resources, along with very conservative market operations that lead to over-commitment of resources, significantly reduced the frequency of price spikes, resulting in lower net revenues.
- *MISO*. MISO held its first auction with a sloped demand curve in 2025, along with other changes to its capacity market structure and parameters. Those changes resulted in significantly higher clearing prices, which were sufficient to justify investment in new CT and CC capacity.

Although shortage pricing is an important component of expected revenues in both ISO-NE and ERCOT, ISO-NE settles a large share of it through its Pay For Performance ("PFP") framework. Compared with very strong conventional shortage pricing, this approach alters the financial risks to consumers and suppliers under extreme conditions in at least five ways:

i. The performance payments are a transfer from underperforming to overperforming resources. Hence, there is no direct increase in consumer payments.[16]

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[16] Although the PFP framework does not result in direct increase in consumer costs from higher prices during shortage events, it should increase capacity prices as capacity suppliers raise their offers in the FCM.

ii. ISO-NE has stop-loss provisions that limit the losses a capacity resource could incur monthly and annually because of poor performance in PFP events.[17] These provisions limit generators' financial risk while generally maintaining strong incentives to perform during shortages. Aside from PFP, the operating reserve demand curves can set energy and reserve clearing prices above $2,500 per MWh.

iii. The stop-loss provisions can also limit the compensation for generators that perform well during sustained shortages, which may weaken the incentives that PFP provides.

iv. The expected frequency of shortages in New England is lower by design because the capacity market produces a higher reserve margin than an energy-only market like ERCOT.

v. Under PFP, ISO-NE prices very small shortages of 30-minute reserves, which are difficult to forecast, much more aggressively than ERCOT or any other market. This increases participants' risk and is inefficient to the extent that these modest shortages raise only small reliability concerns.

Hence, the risk profile for suppliers and consumers, as well as the likelihood of shortage events, differs considerably in ISO-NE from that in a typical energy-only market.

Incentives for New Wind and Solar Projects

Investment in land-based renewables is driven by several factors, including resource potential (which affects the levelized cost of energy because projects in areas with greater annual output require a lower price per unit), wholesale market prices, transmission and interconnection bottlenecks, the availability of federal and state incentives or mandatory contracts, markets for voluntary PPAs, and the ease of land acquisition and permitting. Figure 5 shows the following:

- *New England and New York*: Net revenues of land-based wind and solar projects in New England and New York appear to justify investment because of relatively high market prices and generous state subsidies.
  - Federal and state incentives accounted for more than half of total revenues in these regions for all renewables examined.[18] Offshore wind projects have much higher costs than land-based renewables, but higher-priced OREC contracts in New York and utility PPAs in New England incentivize them.
  - However, siting, permitting, and transmission challenges in these states have caused actual investment in utility-scale renewables to fall far short of state goals despite the apparent financial incentives. In 2025 and early 2026, about 400 MW of solar PV participating in the ISO-NE markets entered service, along with 180 MW of land-

17 The monthly stop-loss limit caps the loss to the capacity obligation times the FCA starting price. The annual stop-loss limit caps loss to three times the resource's maximum monthly potential net loss.

18 The figure reflects NYSERDA Tier 1 Index REC prices for recently built projects in NY and MA Class I REC prices in New England. Prices of class I RECs for utility-scale renewables vary depending o the amount supplied relative to procurement requirements, while New York has adopted an 'Index REC' framework where higher energy prices reduce REC payments to renewables

based wind generation in Maine (where there are fewer challenges to siting new wind generation). Offshore wind projects originally contracted in the 2010s have recently begun to enter service in New England and New York, although many contracts have stalled or been canceled amid cost overruns and a volatile federal permitting environment.

- *MISO and ERCOT*: Land-based wind and solar investment has historically been stronger in MISO and ERCOT, where resource potential is better than in New England and New York, even though MISO and ERCOT lack highly priced REC programs. LMPs in MISO, and particularly in ERCOT, have fallen to very low or negative levels at times of day when renewable generation is highest because of high penetration in some areas.

Recent changes in federal law will eliminate key subsidies for wind and solar projects that are not in service by the end of 2027 or under construction as of July 4, 2026. These subsidies account for a large share of wind and solar revenues in all markets, and eliminating them will significantly challenge project economics absent a major increase in REC prices.

II. ENERGY AFFORDABILITY IN NEW ENGLAND

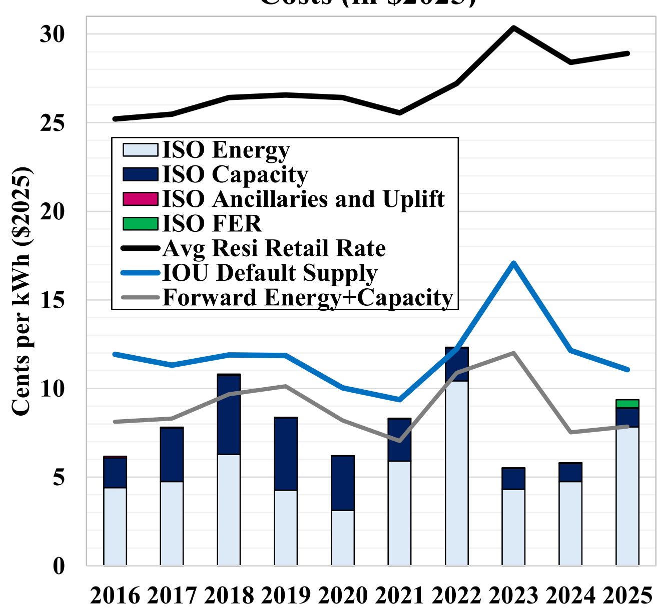
In recent years, rising electricity costs and their effects on consumers have received significant attention nationwide. This section examines long-term trends in residential electricity rates in New England and the role of the ISO-NE markets. Retail rates include cost-of-service elements (such as regulated transmission and distribution charges) and wholesale costs passed through to consumers. This section evaluates:

- How major components of retail and wholesale rates changed over the past decade. We find that non-wholesale costs rose while ISO-NE prices remained largely flat, with higher energy prices offset by lower capacity prices (in subsection A). Premiums associated with utility supply RFPs also contribute meaningfully to retail rates.
- Forward energy prices, which comprise most of consumers' supply costs, finding that gas pipeline constraints into New England and rising carbon allowance costs caused them to increase (in subsection B).
- Generator profit levels produced by the ISO-NE markets, which are significant for some older units but have little overall effect on retail rates (in subsection C).
- Indications that Net CONE should be adjusted to reflect that the economic life of most generators exceeds 20 years (in subsection D).
- Rate design and policy choices that would help reduce retail rates (in subsection E).

A. Long-Term Trends in Retail and Wholesale Rates

Figure 6 compares average New England residential retail rates with wholesale market prices from 2016 through 2025.[19] All values are in inflation-adjusted 2025 dollars. The stacked bars show ISO-NE market prices weighted by typical residential class load shapes for energy, FER, and reserves, and by annual load factors for FCA capacity prices. In 2025, Figure 1 shows separately the effect of paying the FER price to DAM energy suppliers separate from the energy component of the day-ahead LMP.

Figure 6: Residential Retail and Wholesale Costs (in $2025)



The blue line in Figure 6 shows average residential default supply service rates, sometimes called standard service, for

[19] Retail rate and IOU supply cost data are derived from EIA Form 861 data and publicly filed or posted supply rates of IOUs in New England.

investor-owned utilities (IOUs) in New England. As of 2024, IOUs supplied approximately 60 percent of residential load, while municipal or competitive load-serving entities (LSEs) supplied the rest. The default supply rates shown in Figure 6 exclude costs for renewable energy credits that are sometimes bundled with supply on retail bills. The gray line shows average forward prices for ISO-NE Mass Hub traded 3 to 9 months before delivery, weighted by residential load shapes, plus FCA capacity prices.[20]

Figure 6 shows that retail rates are rising in real terms, driven mainly by non-wholesale costs and IOU supply costs. The provide the following observations from this analysis:

Retail versus Wholesale Rate Observations:

- *New England retail rates are rising faster than inflation* – Residential retail rates in New England increased by approximately 12 percent in real 2025 dollars over the period shown, from 25.9 cents per kWh on average in 2016-2019 to 28.9 cents in 2025. New England residential retail rates were 56 percent higher than the US average in 2016-2019 and 67 percent higher in 2025.
- *Non-wholesale components account for most of the retail rate increases* – The non-wholesale component of retail rates has risen over the past decade. The difference between inflation-adjusted retail rates and IOU supply costs rose from 14.2 cents per kWh in 2016-2019 to 18 cents in 2025, an increase of almost 4 cents (or **27** percent).
- *T&D costs are the largest single driver of non-wholesale cost increases* – Non-wholesale market costs include transmission and distribution costs, renewable and energy efficiency programs, low-income ratepayer support, and other taxes and surcharges. Transmission and distribution cost recovery is the largest component of residential bills and was generally the largest source of rate increases. Regional Network Load charges that ISO-NE allocated to recover regulated high-voltage transmission costs rose from 3.1 cents per kWh in 2016 to 4.1 cents in 2025 (in real dollars weighted by residential load factor).

ISO-NE Supply Cost Observations:

- *ISO-NE all-in prices have risen modestly* – Annual all-in prices can be volatile, but they have been relatively flat over time, averaging 8.0 cents per kWh in 2016–2021 and 8.3 cents per kWh in 2022–2025.
- *ISO-NE costs have shifted from capacity to energy* – While overall prices were flat, capacity costs fell and energy prices rose. Average capacity prices fell by 1.8 cents per kWh, from 3.1 cents in 2016–2021 to 1.3 cents in 2022–2025. Average energy prices rose by 2.2 cents per kWh, from 4.8 cents per kWh in 2016–2021 to 7.0 cents per kWh in 2022–2025, primarily because of higher gas and CO_2 emission allowance prices.
- *Day Ahead Ancillary Services account for a small portion of retail rates* – Ancillary services prices (including the Forward Reserve Auction prior to March 2025 and Day Ahead Ancillary Services thereafter) generally accounted for a small share of rates. FER

[20] Forward prices in this section are obtained from NYMEX and Amerex using S&P Capital IQ.

payments to energy suppliers, introduced in March 2025, increased residential-weighted wholesale prices by 0.5 cent per kWh in 2025.

Observations on IOU Supply Costs:

- *IOU supply costs are significantly higher than ISO-NE wholesale prices* – On average, ISO-NE market prices equaled 30 percent of the residential retail rate during 2016–2025. IOU default service supply rates equaled 44 percent of retail rates.
- *IOU supply costs incorporate distribution losses and forward prices* – Utilities' default service rates differ from ISO-NE prices because IOUs procure supply forward and incur distribution losses, typically about 10 percent. New England states require utilities to procure the full supply needs of their residential full-service customers at fixed rates through RFPs, which typically procure most supply several months to a year in advance.[21] Hence, these rates are driven primarily by forward expectations for the cost of energy, capacity, and ancillary services.
- *The Ukraine war led to a temporary spike in IOU supply costs* – IOU default service rates were relatively flat, averaging 11.7 cents per kWh in 2016-2019 and 11.6 cents per kWh in 2024-2025. The outbreak of the Ukraine conflict in 2022 sharply and temporarily increased forward energy prices, resulting in IOU costs of 17.1 cents per kWh in 2023, compared to ISO market costs of 5.5 cents per kWh.
- *IOU supply costs show a consistent premium over wholesale energy forward prices*– IOU default service rates exceed average ISO-NE market prices and financial futures.
  - After adjusting for assumed 10 percent distribution losses, ancillary service and balancing energy costs, and residential class hourly load shape, default service rates were 16 percent higher on average than forward energy and capacity prices from 2016 to 2025. They were 26 percent higher from 2023 to 2025.[22]
  - Suppliers participating in IOUs' default service RFPs likely require significant risk premiums to meet utilities' full-service requirements at fixed rates because they are exposed to both market price risk and quantity risk for the amount of load served. However, state governments tightly prescribe the requirements and timing of the RFPs in ways that may limit the pool of competitive bidders and result in higher premiums over wholesale prices.

Overall, recent increases in residential retail rates were driven primarily by non-wholesale costs. ISO-NE energy prices (including the FER) have risen in recent years, but lower capacity prices offset these increases as they fell from historically high levels in the late 2010s to historically low levels in recent years. Utility supply procurement practices in New England add a large

[21] For an example IOU supply RFP, see National Grid's "Request for Power Supply Proposals to Provide the Following Services: Default Service in Massachusetts for the period August 1, 2026 – July 31, 2027, issued March 27, 2026, available here.

[22] For purposes of this comparison, we adjusted forward energy prices for 10 percent assumed distribution losses, a 7.5 percent factor reflecting higher average day-ahead prices when weighted by a residential load shape compared to peak and off-peak averages, $0.4 cents per kWh ancillary service costs, and 1 percent balancing energy costs.

premium above ISO-NE market prices in exchange for greater price certainty, and these premiums have risen in recent years as spot prices have become more volatile. The following subsection discusses the factors driving forward energy prices, the main component of IOU supply costs paid by consumers.

B. Drivers of Hedged Wholesale Costs

Load-serving entities (including IOUs and competitive suppliers) enter into forward hedges and supply contracts on behalf of their end-users. Their prices are driven by forward expectations of ISO-NE prices and risk at the time of contracting.

Figure 7 shows how changes in commodity price forwards (fuel and emissions) have contributed to forward power prices. All values are in real 2025 dollars per MWh. The black lines show average around-the-clock forward prices for ISO-NE day-ahead LMPs traded three to nine months ahead of each delivery month. The stacked bars show (1) forward natural gas prices with the same trade dates as the power forwards and (2) forward CO_2 emissions allowance prices, including RGGI and Massachusetts' emissions allowance program.

Gas and allowance prices converted to dollars per MWh using a 7.5 MMBtu per MWh heat rate comparable to older combined cycle units in ISO-NE. For gas forwards, the figure shows the portion of the Algonquin Citygates price that exceeds the TETCO M3 index, indicating the impact of pipeline constraints into the northeast U.S. ("Northeast"). The difference between the stacked bars and the black lines is correlated with combined cycle margins, but it excludes other cost items such as VOM expenses and gas delivery costs.

Figure 7: Forward Prices of Power, Gas and Emissions Allowances ($2025)
2016 - 2026

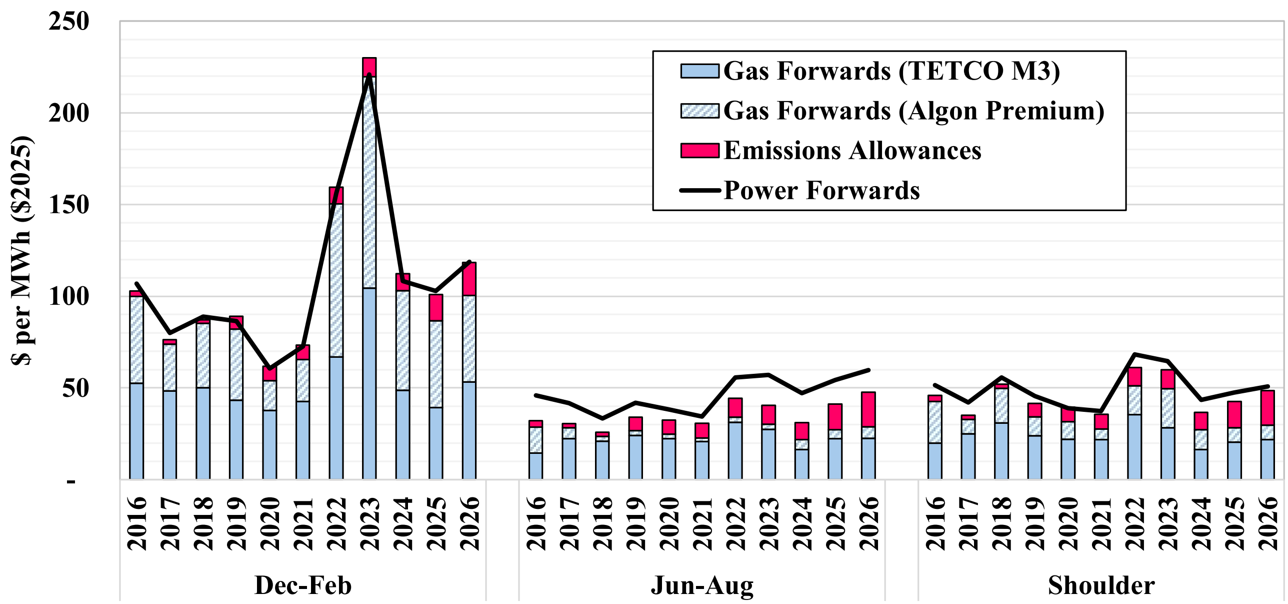


Figure 7 shows a number of key trends:

- Higher forward gas prices have been a primary driver of rising forward power prices since 2022. Average forward power prices for winter months rose by $58 per MWh between 2016-2021 and 2022–2026. Average forward prices for summer and shoulder months rose by $15 and $10 per MWh, respectively. This excludes costs associated with the FER price in 2025 and 2026, which are not reflected in forward LMPs. Gas pipeline constraints into the Northeast, with the average winter premium over TETCO M3 forwards rising from $31 per MWh in 2016-2021 to $70 per MWh in 2022-2026.
- Because forward markets price the risk of gas price spikes, pipeline constraints drive higher consumer costs even in mild winters. For example, 2023 had notably low ISO-NE market prices (see Figure 6) but historically high supply costs due to the impact of the Ukraine war outbreak in the preceding year on forward gas prices.
- Emissions allowance prices also increased steadily during this period. RGGI costs rose from approximately $3 per MWh in 2016 to $11 per MWh in 2026, and Massachusetts allowance prices, implemented in 2018, added over $7 per MWh in 2026 for Massachusetts units.
- Gas-fired generator margins have increased in the Northeast as nuclear generation and Canadian hydro imports have fallen. All-hours implied forward generator margins for a 7.5 heat rate unit rose by $1.9 per MWh in Massachusetts and $4.1 per MWh elsewhere between 2016-2021 and 2022-2026 (excluding the impact of the FER, which is not currently included in financial future settlement definitions but averaged $4.8 per MWh in March through December of 2025).

Overall, the energy component of wholesale supply rates has risen in recent years primarily because of higher forward pricing of natural gas (which reflects the expected value of price spikes caused by pipeline congestion) and rising costs of RGGI and Massachusetts carbon allowances. The large and growing gas price premium in New England results from pipeline projects' inability to obtain permits in New England and New York (which most pipeline projects must cross to reach New England from supply regions). Permitting more on-site dual fuel capability for natural gas resources would also mitigate costs and improve winter reliability.

To a lesser extent, forward spark spreads have also risen, although suppliers participating in IOUs' default service RFPs may earn higher profits than forward spark spreads imply. The following subsection analyzes how profits that generators earn from the ISO-NE market and financial futures markets contribute to retail rates in New England.

C. Impact of Generator Profits on Affordability

This subsection examines whether rising generator profits in the ISO-NE and financial futures markets have significantly driven higher electricity costs in New England. By comparing estimated net revenues and fixed costs across major fossil generation technologies, we assess how much recent market outcomes have increased producer profitability and contributed to retail rates. This analysis considers returns from hedging energy and fuel prices at market rates but excludes premiums above ISO-NE revenues for suppliers that participate in IOUs' default service RFPs.

Figure 8 and Figure 9 show estimated net revenues and fixed costs for fossil generators in ISO-NE from 2023 to 2025. We estimated revenues for several unit types comprising approximately 19 GW of summer capacity in ISO-NE: newer CCs (2010s vintage), older CCs (mainly late 1990s and early 2000s), small older CCs (plants with total capacity of about 300 MW or less), steam turbines, newer CTs (mostly late 2000s and 2010s vintage, many of which are dual fuel), and older CTs (many of which are oil fired).[23] We considered the following revenues and costs:

- *Capacity revenues*. Reflect FCA prices net of PFP settlements based on average performance by technology type. In years when clearing prices varied by location, we show a capacity-weighted average price.
- *Energy and reserve revenues*. Estimated using a model that simulates day-ahead and real-time market commitment with historic prices for LMPs, reserves, FER, natural gas, and emissions allowances (including RGGI and Massachusetts cap and trade, where applicable). Reserve revenues are based on the Forward Reserve Auction prior to March 2025 and on Day Ahead Ancillary Services thereafter. We model gas prices using the Algonquin Citygate index plus an adder of $0.10 per MMBTU in summer and $0.50 per MMBTU in winter.
- *Hedge settlement revenues*. Estimated assuming a generator hedges a portion of its expected output by selling forward power and buying forward gas and allowances. We calculate settlements based on the difference between average forward prices three to nine months ahead of the delivery month and spot prices. In winter months with high forward gas prices, we assume dual fuel units sell some forward power without an accompanying forward gas purchase. This locks in the expected value of periods when gas prices exceed oil prices.[24]
- *Fixed costs*. Fixed costs for existing units reflect going-forward costs (including fixed O&M, administrative, site leasing and property tax, and periodic maintenance capex). For newer units (those built less than twenty years ago, mostly during the 2010s), fixed costs include amortization of the original capital investment. Although we do not know the actual fixed costs of individual generators, these estimates generalize by technology type based on our monitoring work in multiple US ISO/RTO markets.

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23 This includes approximately 2.5 GW of newer CCs, 6.8 GW of large older CCs, 3.5 GW of small older CCs, 1.2 GW of newer CTs, 1.6 GW of older CTs, and 3.1 GW of steam turbines.

24 For hedge settlements, we assume that generators cover a portion of expected monthly peak and off-peak generation through forward sales of energy and purchases of gas and emissions allowances. We assume that generators hedge less than their full expected output to preserve market upside and manage outage risk, with the quantity varying based on the expected monthly capacity factor with a maximum of 75 percent of expected output. In winter months with high forward gas prices, we assume that dual fuel generators buy forward a proportionally smaller quantity of gas compared to their forward power sales in order to secure expected revenues from oil firing.

Figure 8: Net Revenues and Costs of Combined Cycle Generators
2016 - 2025

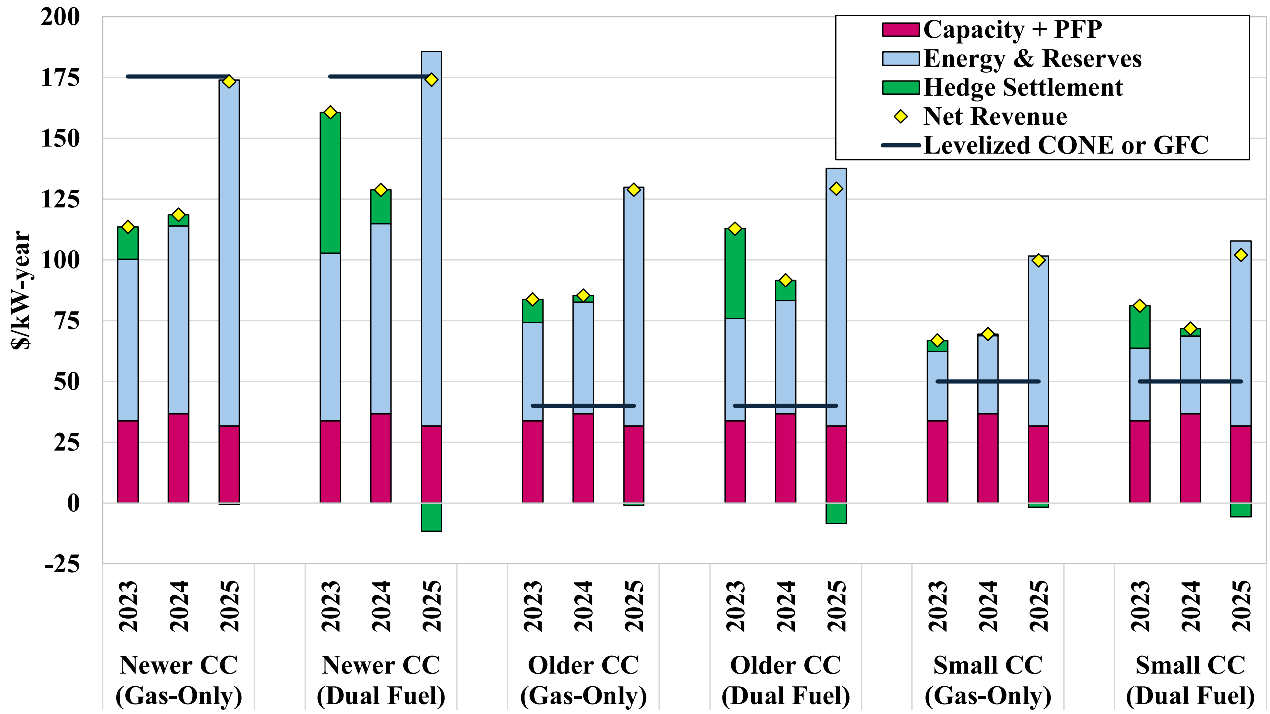
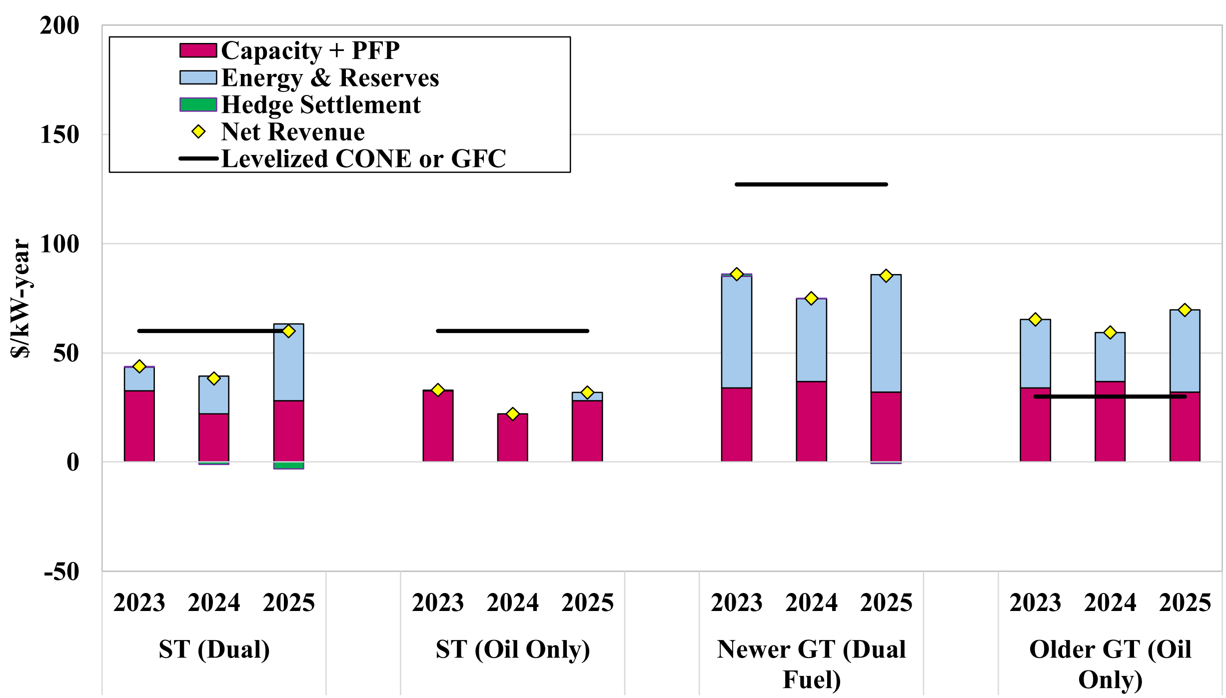


Figure 9: Net Revenues and Costs of Steam Turbine and Combustion Turbine Generators
2016 - 2025



Our analysis of net generator revenues shows the following:

- Net revenues exceed going-forward costs for many older combined-cycle and combustion turbine units. Revenues for newer units were often near or below their fixed costs, which include recovery of investment costs. Some newer units benefited from seven-year lock-in of relatively capacity rates secured in the late 2010s (not shown). By contrast, older steam turbine units appear to earn relatively little revenue, and some of these resources have cleared retirement offers in recent Forward Capacity Auctions.
- Dual-fueled combined-cycle units earned an estimated $12 to $19 per kW-year more than gas-only CCs over the three-year period. Dual-fuel generators earn additional revenues by burning oil during winter gas price spikes. Periods of extreme forward power and gas price uncertainty, such as in winter 2023 following the outbreak of the Ukraine war the preceding year, also allow dual-fuel units to lock in substantial forward margins.

Overall, although some existing generators likely earn revenues far exceeding their GFCs, fossil-fuel generator profits are a small component of retail rates. Based on the estimates in Figure 8 and Figure 9, total fossil generator profits divided by ISO-NE load were about 0.5 cents per kWh in 2023-2025 (about 2 percent of the residential retail rate). We did not assess the profits of nuclear and renewable facilities, many of which sell power under long-term contractual arrangements with states or utilities.

Generator profits reward capital investment and risk-taking by investors who are also exposed to losses when market conditions are unfavorable. Although fossil generator profits overall make up a small share of retail rates, their impact may rise if market conditions tighten in the future. Therefore, it is important to assess the adequacy of the market power mitigation measures on an ongoing basis as supply margins tighten.[25] In addition, it is worth considering whether elements of the wholesale market design that affect overall generator profits are appropriately calibrated. The following subsection discusses evidence that ISO-NE's capacity market demand curves do not adequately consider the long-term value of generator investments, which can lead to inflated estimates of the net cost of new entry.

D. Evidence on Economic Life of Fossil Generators

Estimates of the net cost of new entry ("net CONE") for a fossil fuel-fired generator are often based on the assumption that it will have a 20-year economic life. However, as shown in the previous subsection, when capacity margins are small, market revenues significantly exceed the GFCs of most existing generators that are more than 20 years old. This reflects that most generators still have significant residual value at the end of their first 20 years of operation. This subsection reviews information from recent transactions about the residual value of existing generation assets and how this is likely to affect the cost of new entry.

25 See discussion of the market power mitigation measures in Section III.E.

Several major M&A transactions involving portfolios composed primarily of gas-fired generators in the US RTO markets were completed or announced in 2025 and early 2026. Tight market conditions driven by load growth and recent generator retirements likely drove these deals. Although many of the assets were outside New England, their valuations provide insight into the market value of older gas-fired generators under rising demand.

Table 3 summarizes recent transactions, including the share of each portfolio consisting of gas CC and CT units, the age of the generators purchased, and the purchase price per kW of capacity. All ten transactions consisted primarily of CC and CT assets, and in many cases, all or most of the portfolio consisted of generators over 20 years old. These generators retained significant value after more than 20 years, with older generator portfolio valuations ranging from 31 to 52 percent of the capital cost of the FCA18 Net CONE unit capital cost.

Table 3: Summary of Recent Gas-Fired Portfolio Transactions in US Wholesale Markets[26]

Transaction Close	Buyer	Seller	Primary Markets	Total Capacity (GW)	Percent Gas CT	Percent Gas CC	Price per kW	Average Age of CC and CT (Years)	Percent of CC/CT over 20 Years Old
Jun-25	Capital Power	LS Power	PJM	2.1	46%	54%	1,060	15	46%
Jun-25	Partners Group	Avenue Capital	CAISO	1.9	35%	63%	1,128	22	80%
Sep-25	CPS	ProEnergy	ERCOT	1.6	100%	0%	865	3	0%
Oct-25	Vistra	Lotus	PJM, ISO-NE, NYISO	2.5	8%	92%	760	24	87%
Nov-25	Talen Energy	Caithness / BlackRock	PJM	2.9	0%	100%	1,343	4	0%
Jan-26	Constellation	Calpine	ERCOT, CAISO, PJM, ISO-NE	27.4	5%	87%	969	23	81%
Jan-26	NRG	LS Power	PJM, ERCOT, NYISO	12.7	48%	35%	1,024	24	84%
2026 (expected)	LS Power	Constellation	PJM	4.4	0%	84%	1,139	20	61%
2026 (expected)	Talen Energy	ECP	PJM	2.7	19%	81%	1,296	23	100%
2026 (expected)	Vistra	Cogentrix	PJM, ERCOT, ISO-NE	5.1	20%	80%	789	19	57%

ISO-NE has historically assumed a 20-year economic life for the proxy unit used to set the capacity market demand curves. This creates an upward bias in the estimated Net CONE, which would be lower if the estimate considered the residual value the unit retains after 20 years.

26 Purchase prices and lists of assets in each portfolio are from publicly reported details. Since capacity amounts are not reported in uniform units in the trade press (e.g. nameplate vs. net capacity), we show the average summer and winter net capacity for each portfolio based on EIA data and calculate the price per kW based on the publicly reported total purchase price. NRG's acquisition of assets from LS Power also included the CPOWER demand response platform in addition to the generation portfolio shown.

Figure 10: Residual Value Impact on 20-Year CONE Estimate

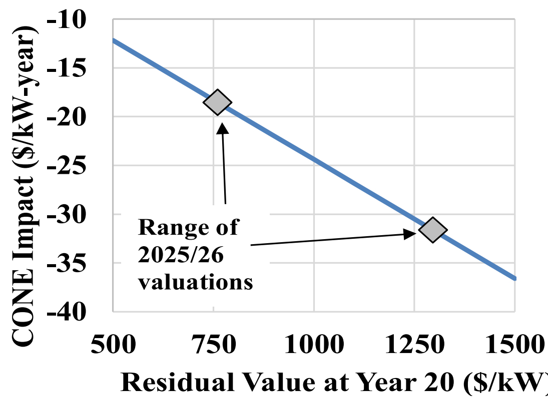


Figure 10 estimates the range of potential residual value impacts on Net CONE based on capacity sold in recent deals. Table 1 reports seven deals where the average age of capacity was between 19 and 24 years and the residual value ranged from $760 to $1,296 per kW. The figure shows how these residual valuations would affect the annualized CONE of a generator built 20 years earlier. A more thorough assessment of residual value might consider valuation adjustments applicable to the proxy unit technology (many of the recent portfolios include CCs), location, and future market expectations that are less favorable than those underlying recent transactions. We recommend that Future Net CONE studies consider residual value.

E. Conclusions

This section summarizes trends in residential retail rates in New England and analyzes how wholesale prices have contributed to them. Although residential rates have risen by almost 14 percent in real terms since 2021, the primary drivers have been non-wholesale market costs, including regulated transmission and distribution. Wholesale market costs have been relatively flat with energy cost increases caused by gas infrastructure constraints, fuel costs and emissions allowance costs have been offset by falling capacity costs.

Most residential customers in New England pay electric supply rates that IOUs lock in through RFPs conducted months in advance. These rates are driven mainly by forward energy price expectations, although they routinely exhibit a substantial premium over the prices of financial futures for ISO-NE products. Although some generators may earn net revenues through these RFPs and the ISO-NE markets that exceed their going-forward costs, the total impact on residential retail rates is very small. This suggests that competitive discipline in the ISO-NE markets has helped constrain retail rate increases over time.

Our analysis suggests that the following actions by ISO-NE and policymakers could slow or reverse rising electricity rates:

- **Permitting natural gas transport and/or storage infrastructure**. Although environmental policy considerations and the need for cooperation from New York State policymakers make this complex, gas infrastructure improvements would likely reduce electricity market prices more than any other single factor. They would do so by reducing New England's gas price premium, which generators pass through to wholesale prices.
- **Permitting dual-fuel generation capacity**. This is one of the lowest-cost means to address winter reliability concerns with little emissions impacts. New dual-fuel generation is likely economic without subsidies, particularly as capacity prices rise from

recent lows. Generation that is profitable without subsidies lowers consumer costs by adding additional supply in the capacity market and during fuel-constrained winter storm conditions. The capacity accreditation enhancements in the Capacity Auction Reform: Seasonal/Accreditation ("CAR-SA") project may create long-term economic incentives to retrofit existing gas-fired generation with oil-fired capability if such projects can be permitted.[27] The back-up oil capability would produce negligible emissions since it would rarely be utilized, but would substantially improve winter reliability.

- **Changes to forward contracting practices**. Over the past decade, IOUs' supply costs have exceeded the prices of financial futures that settle against ISO-NE prices by 16 percent. Our experience in the New York market, where utilities use a combination of physical and financial hedges to cover part but not all of their supply costs, suggests that alternative strategies may produce lower average rates than the mandatory full-service procurements that are common in New England.
- **Include Residual Value Estimate in Net CONE**. The Net CONE values used in the capacity market have historically assumed that investments must be fully recovered in twenty years. However, evidence after ~25 years of US RTO markets suggests that modern CT and CC units continue to have substantial value after twenty years. Reflecting this in capacity market Net CONE would result in more reasonable prices by recognizing units' long-term revenue potential. It also highlights one benefit to consumers of non-discriminatory capacity pricing that treats existing and new generation on equal terms.

27 The costs to upgrade an existing gas-fired unit to dual fuel capability (including combustion and fuel storage) are significant but lower than construction of a new plant. A 2016 Department of Energy study estimated the cost of field-installed dual fuel modifications for a gas turbine at $54,000 per MW (approx. $75,000 per MW in 2025 dollars). See "ISO New England Dual Fuel Capabilities to Limit Natural Gas and Electricity Interdependencies", April 22, 2016, DOE/NETL-2015/1701, available here.

III. Competitive Assessment of the Energy & Reserve Markets

This section evaluates the competitive performance of the ISO-NE energy market in 2025. Although LMP markets generally increase economic efficiency, they can also reveal incentives to exercise market power in areas with limited generation resources or transmission capability. Market power in wholesale electricity markets is often dynamic and exists only in certain areas under particular conditions. The ISO employs market power mitigation measures to prevent suppliers from exercising market power under these conditions. Although these measures have generally been effective, it is still necessary to evaluate the competitive structure and conduct in the ISO-NE markets because participants may still have incentives to exercise market power below mitigation thresholds.

In this section, we identify the geographic areas and market conditions with the greatest potential for market power abuse based on our analysis. We use a methodology developed in prior assessments of ISO-NE's competitive performance to identify competitive concerns.[28] This section addresses five main areas:

- Mechanisms sellers use to exercise market power in LMP markets;
- Structural market power indicators to assess competitive market conditions;
- Potential economic and physical withholding;
- Market power mitigation in the real-time market; and
- Market power mitigation in the day-ahead ancillary services market.

These evaluations allow us to assess the competitive performance of the ISO-NE markets.

A. Market Power and Withholding

In electricity markets, supplier market power is the ability to profitably raise prices above competitive levels by withholding generating capacity, either economically or physically.

- **Economic withholding** occurs when a supplier offers a resource at prices above competitive levels, thereby reducing its output or otherwise raising market clearing prices.
- **Physical withholding** occurs when a supplier does not offer some or all of a resource's available and economic output into the market to raise clearing prices above competitive levels. For example, a supplier can implement this strategy by "derating" a generating unit (i.e., reducing its maximum operating limit).

Although many suppliers can influence prices through economic or physical withholding, not all can do so profitably. Withholding is profitable only when the gains from selling the remaining supply at elevated prices exceed the lost profits from the withheld output. In other words, the

[28] See, e.g., Section VIII, 2013 Assessment of Electricity Markets in New England, Potomac Economics.

price increase must outweigh the opportunity cost of foregone sales. Larger suppliers, which have a greater share of total market capacity, are generally more likely to have both the ability and the incentive to withhold resources profitably. In addition to supplier size, several factors affect the potential to exercise market power:

- **Sensitivity of clearing prices to withholding**: Prices can be highly sensitive to withholding during high-load conditions or in congested local areas;
- **Forward contracts:** These reduce a supplier's incentive to raise market prices;[29] and
- **Information availability**: Access to timely, accurate market information can help suppliers anticipate when the system is most vulnerable and time withholding strategies more effectively.

B. Structural Market Power Indicators

This subsection examines structural aspects of supply and demand that affect market power. Market power is most likely in areas with small capacity margins, particularly import-constrained areas. Accordingly, this subsection analyzes the three main import-constrained regions and all of New England using the following structural market power indicators:

- **Supplier Market Share:** The market shares of the largest suppliers determine the possible extent of market power in each region.
- **Herfindahl-Hirschman Index (HHI):** This standard measure of market concentration is calculated by summing the squares of each participant's market share.
- **Pivotal Supplier Test:** A supplier is pivotal when some of its capacity is needed to meet demand and reserve requirements. A pivotal supplier can unilaterally raise spot market prices by raising its offer prices or by physically withholding generating capacity.

The first two structural indicators focus exclusively on the supply side. Although they are often used to analyze other industries, they are less useful in electricity markets because they ignore how inelastic electricity demand affects competition.

The Pivotal Supplier Test is a more reliable way to evaluate the competitiveness of electricity markets because it recognizes the importance of both supply and demand. Whether a supplier is pivotal depends on its size and the amount of excess supply (above demand) held by other suppliers. When one or more suppliers are pivotal, the market may be vulnerable to market power abuse, but not all pivotal suppliers have market power. Suppliers with market power must have both the ***ability*** and ***incentive*** to raise prices. A supplier must also foresee when it will be pivotal to exercise market power. This becomes easier when a supplier is pivotal more often. Finally, a supplier must also have a way to benefit from the higher prices (e.g., other resources or contracts that would receive the inflated price).

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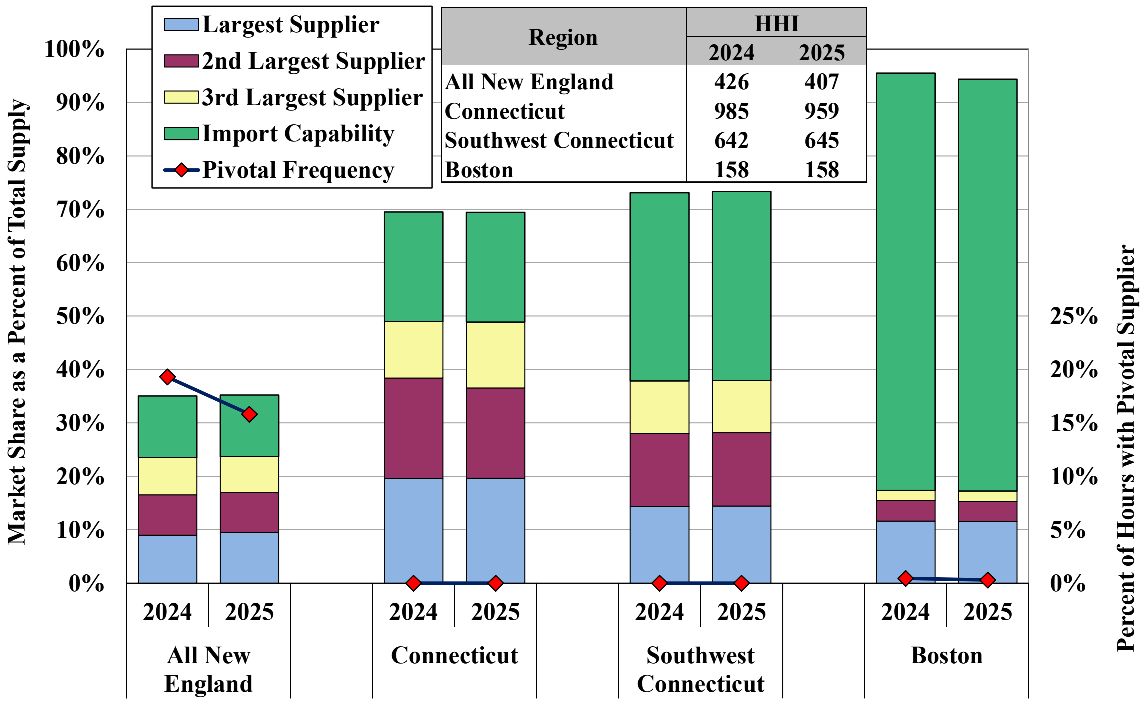
29 When a supplier's forward power sales exceed the supplier's real-time production level, the supplier is a net buyer in the real-time spot market, and thus, benefits from low rather than high prices. However, some incentive to withhold may still exist because spot prices will eventually affect prices in the forward market.

Figure 11 shows three structural market power indicators for four regions over the past two years. The stacked bars show the market shares of the three largest suppliers and the import capability in each region. Smaller suppliers hold the remaining supply in each region.

Figure 11: Structural Market Power Indicators
2024 – 2025



Region	HHI 2024	HHI 2025
All New England	426	407
Connecticut	985	959
Southwest Connecticut	642	645
Boston	158	158

The import capability and market shares are based on public ISO-NE data, and the inset table shows the HHI for each region.[30][31] We assume imports are highly competitive and treat their market share as zero in the HHI calculation. The red diamonds indicate the portion of hours when one or more suppliers were pivotal in each region. We exclude potential withholding from nuclear units because they have limited flexibility and because withholding them would be costly given their low marginal costs.

Figure 11 shows that the market concentration of internal generation remained relatively stable across all regions from 2024 to 2025. Although asset ownership changed over the past two years, these shifts did not significantly affect the top suppliers' market shares in each region. Market concentration varied significantly across the four regions. In Boston, import capability accounted for 78 percent of total supply, including internal generation and imports. By contrast,

30 The market shares of individual firms are based on information in the monthly reports of Seasonal Claimed Capability (SCC), available at: https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/seson-claim-cap. In this report, we use the generator summer capability in the July SCC reports from each year.

31 The import capability shown is the transmission limit from the latest Regional System Plan, available at: https://www.iso-ne.com/system-planning/system-plans-studies/rsp. The *Capacity Import Capability* is used for external interfaces, and the N-1-1 Import Limits are used for reserve zones.

in all New England, the three largest suppliers each held relatively small, comparable market shares below 10 percent, while import capability accounted for 11 percent of total supply.

Market concentration, as measured by the HHI, remained low in 2025, with values below 1,000 in all regions. For context, the U.S. Antitrust Agencies and FERC typically consider HHI values above 1800 highly concentrated when evaluating the competitive effects of mergers. However, low HHI values do not necessarily eliminate market power concerns. Pivotal supplier analysis assesses these concerns more accurately, indicating that:

- There were almost no hours with a pivotal supplier in Southwest Connecticut and Connecticut.
- In Boston, pivotal supplier frequency remained very low at just 0.3 percent of hours in 2025, even after two large combined-cycle units retired in 2024. These infrequent instances generally coincided with minimal congestion into the Boston area.
- Across New England, at least one supplier was pivotal in 16 percent of hours.[32]

The persistently low pivotal supplier frequency and minimal congestion in Boston over the past two years were mostly attributable to transmission upgrades that greatly increased import capability. This result underscores the importance of import capability into constrained areas for providing competitive discipline.

Across New England, the pivotal supplier frequency fell modestly from 2024 to 2025 because of several factors:

- *Load levels* – This reduction occurred mostly in the summer months, when average load fell by 3 percent year-over-year even as peak load increased by 7 percent. This pattern reflects continued growth in behind-the-meter solar, which significantly reduced net load in the summer but contributed relatively little at the peak because the peak load hour shifted later in the day (to hour-ending 19 in 2025).
- *New supply patterns* – Net imports from Quebec continued to decline in 2025, partly because of lower rainfall and reduced hydroelectric output.[33] Quebec became a net importer from New England in the last three months of 2025, a pattern not seen in previous years. This was partially offset by higher imports from New Brunswick, higher output from intermittent renewable generation because of new capacity additions, and higher nuclear generation because of fewer maintenance and forced outages.
- *Day-ahead ancillary services market* – ISO-NE implemented the DA A/S market in March 2025, which incentivized suppliers to be available, particularly during tight system

32 The pivotal supplier results are conservative for "All New England" compared to those of the IMM partly because of the differences in: (a) treatment of nuclear generation; (b) supply availability assumptions; and (c) frequency of pivotal evaluation. See the memo, "Differences in Pivotal Supplier Test Results in the IMM's and EMM's Annual Market Assessment Reports", NEPOOL Participants Committee Meeting, Dec. 7, 2018.

33 Our pivotal supplier analysis is based on actual import schedules, which is conservative because it may underestimate the amount of competitive supply available in a given hour. This is due to the presence of additional unused import capability that is offered into ISO-NE's real-time market but not scheduled.

conditions. This market design change contributed to an increase in average surplus capacity in the real-time market by 175 MW year-over-year and the associated reduction in pivotal supplier frequency.[34]

Together, these shifts in supply, demand, and market design contributed to the decline in pivotal supplier frequency. The next subsection examines supplier conduct across New England.

C. Economic and Physical Withholding

Suppliers with market power can exercise it through economic or physical withholding. We measure potential withholding using the following metrics:

- **Economic withholding:** we estimate an "output gap" for units that produce less output because they raised their economic offer parameters (start-up, no-load, and incremental energy) significantly above competitive levels. The output gap is the difference between a unit's capacity that would be economic at the prevailing clearing price and its actual output.[35]
- **Physical withholding:** we focus on short-term deratings and outages because they are more likely to represent strategic physical withholding. Withholding through a long-term outage would be more costly because it would cause larger lost profits in hours when the supplier does not have market power.

The following analysis shows the output gap and short-term physical deratings relative to load and supplier size because market power is most likely when load is high (and excess supply held by competitors is low) for larger suppliers. Correlating conduct with load and supplier size helps test whether the output gap and short-term physical deratings rise when the exercise market power is more likely to be successful.

Because the pivotal supplier analysis raises potential competitive concerns throughout New England, Figure 12 shows the output gap and short-term physical deratings by load level for the region. It calculates the output gap separately for:

- **Offline quick-start units** that would have been economic to commit in the real-time market, considering commitment costs; and
- **Online units** that can economically produce additional output.

Our short-term physical withholding analyses examine:

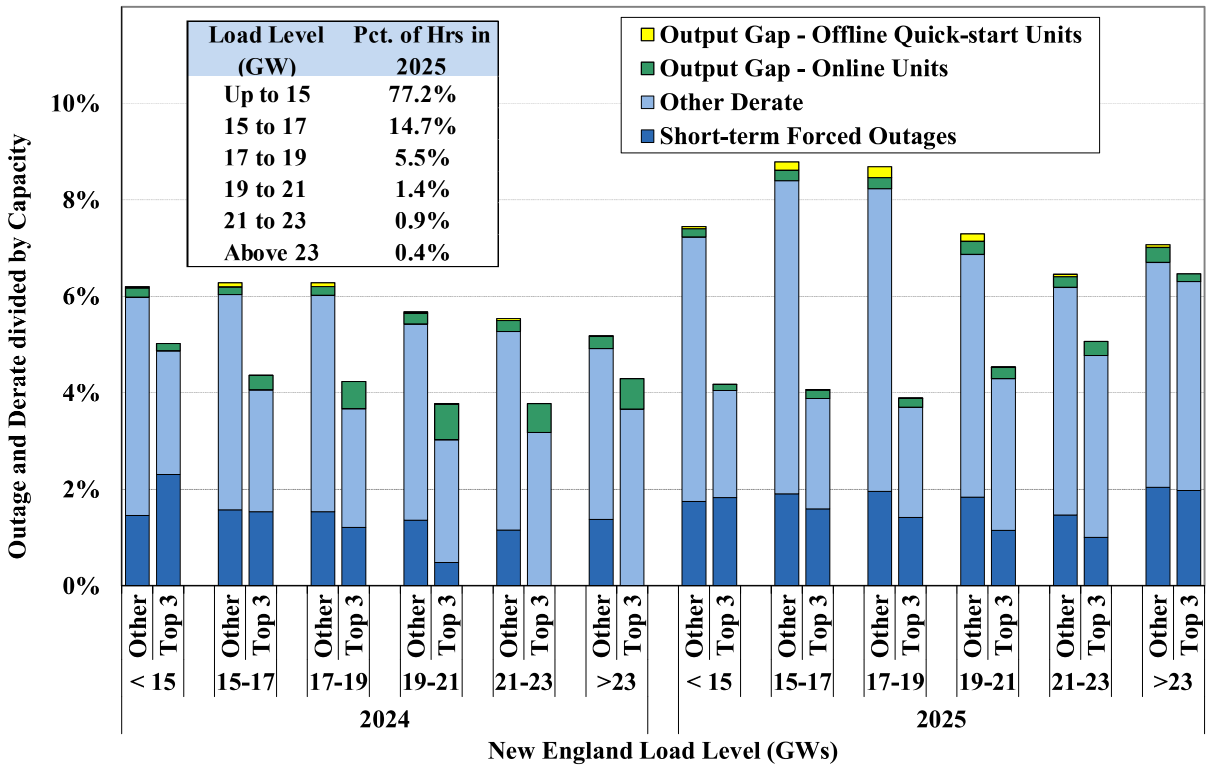
- **Short-term forced outages** that usually last less than one week; and
- **Other derates**, including reductions in a unit's capability not logged as forced or planned outages. These can result from ambient temperature changes or other legitimate factors.

34 Surplus capacity is defined as the headroom from online resources, along with available offline quick-start resources, after accounting for energy and ancillary services requirements.

35 To identify clearly economic output, the supply's competitive cost must be less than the clearing price by more than a threshold amount - $25 per MWh for energy and 25 percent for start-up and no-load costs.

Figure 12 shows these metrics as a percentage of suppliers' portfolio size and distinguishes the largest suppliers from other suppliers over the past two years. The analysis compares the three largest suppliers, which collectively owned and/or controlled approximately 27 percent of internal generating capacity in both years, with all other suppliers.

Figure 12: Average Output Gap and Deratings by Load Level and Type of Supplier
All New England, 2024 – 2025



The figure shows that the "Other Derate" category was usually higher than the other categories. This category includes instances when suppliers offered and operated some combined-cycle capacity in configurations with reduced capability during off-peak hours. This operationally efficient practice generally does not raise competitive concerns. In addition, high ambient temperatures and humidity during summer peak load hours often reduce the capacity ratings of thermal resources and contribute to this category of derates. The overall output gap and deratings in 2025 were modest relative to total system capacity.

The output gap and short-term deratings generally declined as load levels increased. The output gap was particularly low during the highest load hours (above 23 GW), when prices were most sensitive to withholding. Although short-term forced outages, including "Other Derate", rose modestly during these periods, the increase was largely associated with heat waves. High temperatures during these events reduced thermal unit capacity ratings and increased mechanical failure rates. In addition, the largest suppliers generally exhibited lower levels of output gap and short-term deratings than smaller suppliers, especially at higher load levels. Together, these patterns support the conclusion that supplier behavior, particularly among large suppliers, was consistent with competitive conduct when market conditions were most critical.

Overall, these results indicate that the energy market was competitive in 2025, with no significant evidence of withholding intended to raise market clearing prices.

D. Market Power Mitigation in the Real-Time Market

Mitigation measures limit market power abuses while minimizing interference when the market is workably competitive. ISO-NE uses a conduct-and-impact test framework to determine whether to mitigate a participant's supply offers (including incremental energy offers, start-up offers, and no-load offers). It imposes mitigation only when suppliers' conduct exceeds well-defined thresholds above a unit's reference levels and the effect on market outcomes exceeds specified impact thresholds. This framework ensures that mitigation is used only when necessary to address market power, while allowing high prices during legitimate shortage periods.

In import-constrained areas, the market can be substantially more concentrated, requiring more restrictive conduct and impact thresholds than those used market-wide. The ISO uses two structural tests (i.e., Pivotal Supplier and Constrained Area Tests) to determine which of the following mitigation rules apply: [36]

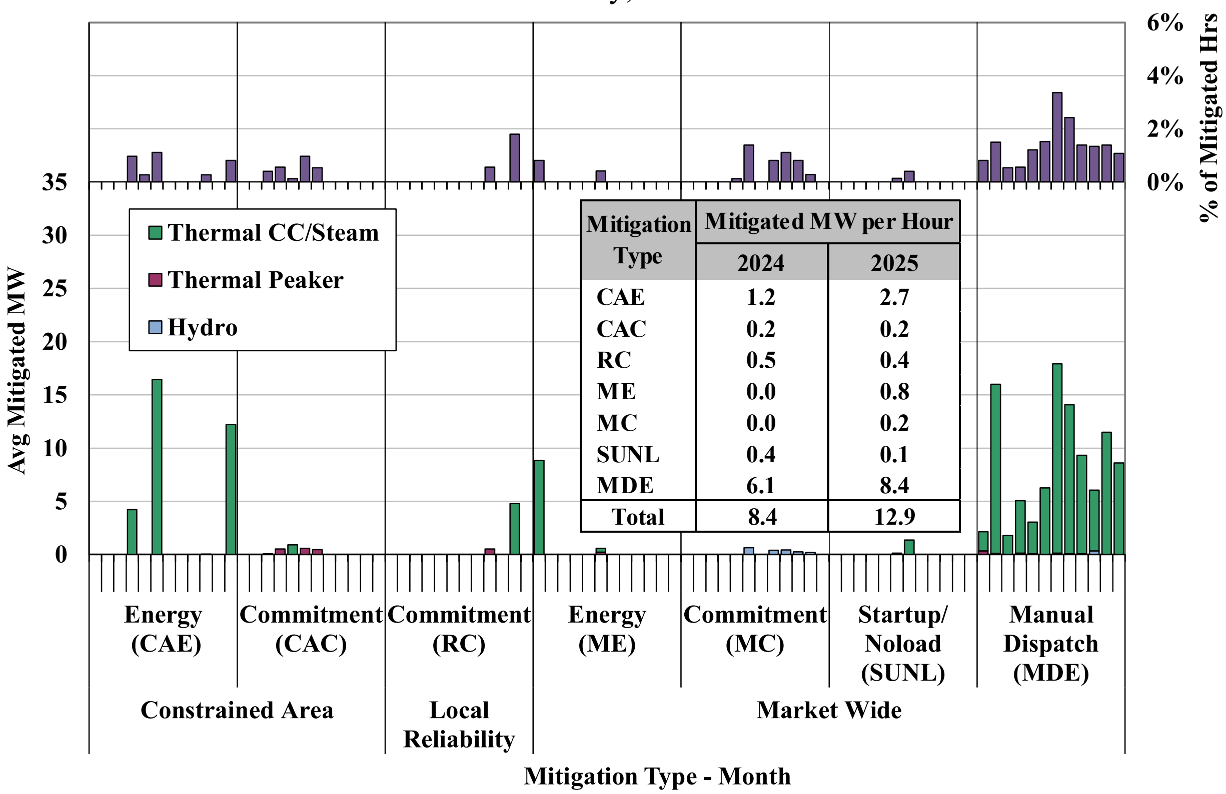
- **Market-Wide Energy Mitigation (ME):** ME mitigation evaluates the incremental energy offers of online resources. It is applied to any resource whose Market Participant is a pivotal supplier.
- **Market-Wide Commitment Mitigation (MC):** MC mitigation evaluates commitment offers (i.e., start-up and no-load costs). It is applied to any resource whose Market Participant is a pivotal supplier.
- **Constrained Area Energy Mitigation (CAE):** CAE mitigation is applied to resources in a constrained area.
- **Constrained Area Commitment Mitigation (CAC):** CAC mitigation is applied to a resource committed to manage congestion into a constrained area.
- **Local Reliability Commitment Mitigation (RC)**: RC mitigation is applied to a resource committed or kept online for local reliability.
- **Start-up and No-load Mitigation (SUNL):** SUNL mitigation is applied to any resource committed in the market.
- **Manual Dispatch Mitigation (MDE):** MDE mitigation is applied to resources dispatched out of merit above their Economic Minimum Limit levels.

There are no separate impact tests for SUNL mitigation, MDE mitigation, or the three types of commitment mitigation (i.e., MC, CAC, and RC). Consequently, suppliers are mitigated if they fail the conduct test in any of these five categories. This approach is reasonable because this

[36] See Market Rule 1, Appendix A, Section III.A.5 for details on these tests and thresholds.

mitigation normally affects only uplift payments, which increase as offer prices rise. Therefore, it is unnecessary to determine whether an offer that failed the conduct test affected the payment to the generator. When a generator is mitigated, all offer cost parameters are set to their reference levels for the entire hour. Figure 13 examines the frequency and quantity of mitigation in the real-time market in each month of 2025. This analysis excludes mitigation changes made after the automated mitigation process, which constitute a very small share of overall mitigation.

Figure 13: Frequency of Real-Time Mitigation by Mitigation Type and Unit Type
Monthly, 2025



The upper portion of Figure 13 shows the share of hours affected by each type of mitigation. If multiple resources were mitigated in the same hour, the figure counts only one hour. The lower portion shows the average mitigated capacity per month (i.e., total mitigated MWh divided by total hours in each month) for each type of mitigation and for hydroelectric units, thermal peaking units, and thermal combined cycle and steam units. The inset table compares the average annual amount of mitigation for each type over the past two years.

Mitigation has been infrequent in recent years, occurring in approximately 2.6 percent of all hours in 2025, up modestly from 2024. In 2025, more than 70 percent of real-time market mitigation was for manual dispatch energy and local reliability commitment. This high proportion is expected because local reliability areas raise the greatest market power concerns and are mitigated under the tightest thresholds. Likewise, units manually dispatched for energy are selected outside the normal economic evaluation of offers, so competition does not necessarily discipline their offers. These two mitigation categories typically affect only NCPC payments and have little effect on energy or ancillary service prices. Most MDE mitigation was on combined-cycle units that operators typically instructed to provide regulation service or dispatched manually to address transient network issues.

Effective mitigation depends on accurate generator cost estimates (i.e., “reference levels”). High reference levels allow suppliers to inflate prices and/or NCPC payments above competitive levels. Low reference levels may lead to mitigation below cost and inefficiently suppress prices. Estimating costs accurately is challenging for certain generators, including:

- **Energy-limited hydroelectric and battery storage resources:** Their costs consist almost entirely of opportunity costs (the trade-off between producing more now and producing or not charging later), which are difficult to reflect accurately.
- **Oil-fired resources during tight gas supply periods:** These units become economic when gas prices rise above oil prices. However, with limited on-site oil inventory, suppliers may raise offer prices to conserve oil for periods with potentially higher LMPs.
- **Gas-fired resources during tight gas supply periods:** Volatile winter natural gas prices create fuel cost uncertainties that can be difficult to reflect accurately in offers and reference levels. The requirement to determine day-ahead market offers and reference levels by 10 am the prior day exacerbates this uncertainty.

Recognizing opportunity costs appropriately in resources’ reference levels reduces inappropriate mitigation of competitive offers, conserves limited fuel supplies and improves scheduling efficiency for fuel-limited resources. ISO-NE uses a model to estimate opportunity costs for oil-fired and dual-fuel generators with short-term fuel supply limitations and include them in reference prices. The model estimates opportunity costs by forecasting each fuel-limited unit’s profit-maximizing generation schedule over a rolling seven-day period and the opportunity cost adder (“Energy Market Opportunity Cost” or “EMOC”) required to limit generation accordingly.

Market-wide energy mitigation has been rare in recent years. Before 2025, it last occurred on December 24, 2022, when nine resources in one Lead Market Participant’s portfolio were inappropriately mitigated over multiple hours. This significantly affected market outcomes on this day. Our 2022 report identified several aspects of the mitigation measures that resulted in inefficient outcomes.[37] Although the ISO has addressed two issues raised in that report, we continue to recommend that it implement the following revision to the real-time energy mitigation process (Recommendation #2022-2a):

a) Implement hourly conduct and impact tests: Mitigate resources only in hours when they fail both conduct and impact tests.

Although we have consistently observed competitive outcomes in the real-time market, changes in the New England market could increase the potential for market power over time. Recently-

37 See *2022 Assessment of The ISO New England Electricity Markets*, Potomac Economics, June 2023.

announced acquisitions have increased or will increase the sizes of the largest portfolios. Generator retirements, increased load growth, and reduced imports from Canada have reduced capacity margins. In addition, the ISO is proposing changes under the CAR-SA project that will reduce the share of fossil-fuel generators with Capacity Supply Obligations ("CSOs") during the winter. This change will reduce the share of installed capacity that is not subject to the physical withholding mitigation measures. Because of these changes, it would be appropriate to evaluate the adequacy of the market power mitigation thresholds. Therefore, we support the Internal Market Monitor's recommendation:

> #2023-1 to *Review mitigation thresholds and reference level methodologies, eliminate mitigation exemptions for non-capacity resources, and extend mitigation to export-constrained areas*.

E. Market Power Mitigation under Day-ahead Ancillary Services Markets

Launched on March 1, 2025, the DA A/S markets enhance the ISO's ability to satisfy the reliability needs by procuring ancillary services in the day-ahead market. The ISO introduced four new day-ahead ancillary service products. Three of these, Ten-Minute Spinning Reserves ("TMSR"), Ten-Minute Non-Spinning Reserves ("TMNSR"), and Thirty-Minute Operating Reserves ("TMOR"), are Flexible Response Services ("FRS") and align with the real-time reserve products used to manage system contingencies. The fourth product, Energy Imbalance Reserves ("EIR"), ensures that physical suppliers clear sufficient energy and EIR to satisfy forecasted load in the day-ahead market. The day-ahead market co-optimizes scheduling of all four products with energy and clears them using marginal-cost pricing.

DA A/S schedules are settled as call options on energy based on real-time clearing prices, giving generators not scheduled for energy in the day-ahead market stronger incentives to be available in the real-time market. For each hour of the day-ahead market, participants submit a single maximum quantity amount of ancillary services they are willing to provide across all four eligible products. They may also submit up to separate prices for each reserve product.

Like energy offers, DA A/S offers are subject to mitigation measures that prevent the exercise of market power. The mitigation framework includes the following components:

- **Conduct Test:** The conduct test identifies reserve offers that exceed a threshold, which equals the sum of: (a) the greater of either twice the expected close-out cost or $2 per MWh, and (b) 1.5 times the avoidable input cost to cover the day-ahead reserve schedule.
- **Price Impact Test:** If at least one offer fails the conduct test, the impact test evaluates whether the conduct-failing offers materially affected day-ahead market prices. If the impact test identifies a sufficiently large effect on one or more day-ahead market prices, all conduct-failing offers are mitigated to their calculated Benchmark Levels.[38]

[38] The price impact threshold is 150 percent of median of the hourly difference between conduct test thresholds and Benchmark Levels across all available resources with DA A/S offers.

- **Benchmark Levels:** The estimated close-out cost of reserves (estimated using the Gaussian Mixture Model which runs initially at 5:30 AM and again at 10:30 AM using updated inputs such as load forecasts) and estimated avoidable input costs.
- **Ex Ante Consultation with the IMM:** Participants may consult the IMM and submit analytically supported override requests so the IMM can consider their specific cost expectations.

This mitigation structure is designed to deter exercises of market power and support efficient pricing, while allowing offer flexibility for legitimate cost deviations and reasonable variations in risk tolerances associated with selling these option-based ancillary services. Mitigating offers that reflect these factors is unwarranted and undermines market performance. Therefore, ongoing evaluation of the mitigation framework is necessary to ensure its effectiveness.

Our analysis of mitigation outcomes during the initial implementation of DA A/S markets indicated that mitigation occurred far more frequently than in the energy market. In addition, each mitigation instance typically involved a substantial volume of reserve offers and disproportionately affected smaller suppliers that are unlikely to possess market power.[39] Mitigation also frequently occurred during low- to moderate-load conditions rather than during tight system conditions, when market power concerns were typically most acute.

We found that one primary reason for the relatively frequent market power mitigation is the small size of the mitigation thresholds. The threshold formulas described above are based in part on the expected close-out costs for the option-based reserve products. Because the expected close-out costs are frequently near or below $1 per MWh and the avoided input costs are generally low or zero, participants can begin to violate the conduct threshold by offering more than $2 per MWh. However, actual close-out costs have been volatile and frequently above $20 per MWh. Hence, this conduct threshold is likely to interfere with competitive participants reflecting reasonable assessments of risk and legitimate risk preferences. Similarly, the impact threshold in this case can be as low as $1.50 per MWh, which is likely too low to warrant market power mitigation. As a result, the mitigation framework appears overly sensitive, mitigating competitive conduct rather than the exercise of market power.

Based on these findings, we recommended that ISO-NE evaluate its current conduct and impact thresholds used in the DA A/S markets and, if necessary, revise them to avoid overly aggressive mitigation that may unduly burden smaller suppliers without addressing actual market power concerns (Recommendation #2024-2).

[39] See Figure 12 in our 2024 Assessment of the ISO New England Electricity Markets.

IMM Recommendations and ISO-NE Proposed Changes

In February 2026, the IMM issued recommendations to improve the efficiency of the DA A/S market design.[40] These recommendations addressed inefficiencies observed during the market's first year, including issues with price formation, procurement levels, and incentive alignment. Key recommendations included:

- **Adjusting the Forecast Energy Requirement** to better reflect the expected contribution of front-of-the-meter renewable resources;
- **Increasing the Strike Price**, including consideration of a floor aligned with the short-run marginal cost of key suppliers; and
- **Reassessing the Non-Performance Factor (NPF)** used in reserve requirements to reflect improved generator performance.

The ISO has supported these recommendations and proposed corresponding changes to the DA A/S design, including:[41]

- A downward adjustment to the FER demand quantity to reduce over-procurement when intermittent renewable generators schedule less than their forecasted output in the day-ahead market;
- Implementation of a strike price floor based on the estimated marginal cost of an efficient combustion turbine; and
- A targeted revision to the mitigation framework to address issues the IMM's and EMM's analyses identified.

We support these changes because they address inefficiencies in the current design while maintaining appropriate incentives for performance and participation. In particular, introducing a floor on the Impact Test Threshold ("ITT") would help address the concern underlying Recommendation #2024-2. The ISO proposes a minimum ITT of $3 per MWh to prevent the threshold from becoming excessively stringent in low-price conditions. Under the current design, the ITT can fall to very low levels when expected closeout costs are small, increasing the likelihood of mitigation when market power is unlikely to be a concern. This issue was a key driver of the frequent mitigation of smaller suppliers during the initial implementation of DA A/S markets.

Overall, the ISO's proposed changes address the IMM's and EMM's findings and should improve price formation efficiency, reduce unnecessary costs, and maintain appropriate performance incentives. These adjustments are incremental but meaningful improvements to the DA A/S market design and we support them.

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40 See memo *Recommended Changes to the Day-Ahead Ancillary Services Market* to ISO New England from David Naughton, Executive Director, Internal Market Monitor, dated February 4, 2026.

41 See memo *Adjustments to the Day-Ahead Ancillary Services Market* to NEPOOL Participants Committee from Rosendo Garza, NEPOOL Counsel, dated June 9, 2026.

F. Competitive Performance Conclusions

Overall, we find little evidence that suppliers exercised market power in New England, either at the system level or in sub-regions. Our evaluation of participant conduct also indicates that the markets performed competitively, with no evidence of market power abuse or manipulation in 2025. However, recent and one pending acquisition, along with reduced imports from Canada and generator retirements, have increased indications of potential structural market power in the form of rising pivotal supplier frequencies since 2022. To ensure the market power mitigation measures remain effective, we support the Internal Market Monitor's recommendation #2023-1 to *review mitigation thresholds and reference level methodologies, eliminate mitigation exemptions for non-capacity resources, and extend mitigation to export-constrained area*.

We also continue to recommend revisions to the current energy mitigation process to address an inefficiency identified in our 2022 annual report (Recommendation #2022-2a). Specifically, we recommend that the ISO implement hourly conduct and impact tests to ensure it does not impose mitigation when a resource's conduct or prevailing competitive conditions no longer warrants it.

In addition, we find that market power mitigation in the DA A/S market has occurred more frequently and in higher volumes than expected, often during low- to moderate-load conditions when market power concerns are not typically most acute. Given these results and the relatively tight mitigation thresholds, we find that the current mitigation measures warrant reassessment. Therefore, we continue to recommend that ISO-NE evaluate the appropriateness of its current conduct and impact threshold levels and revise them as needed to ensure they limit the exercise of market power without interfering with competitive behavior (Recommendation #2024-2).

Finally, the ISO's proposed market reforms to address recommended improvements to DA A/S that are described in the Section help address Recommendation #2024-2 by reducing how often competitive DA A/S offers are mitigated. In particular, the proposal to apply a $3 per MWh floor to the ITT directly addresses these concerns by reducing mitigation caused by overly stringent thresholds, especially for smaller suppliers. After implementing these reforms, we will assess whether the rules still need further revision to avoid mitigation of competitive DA A/S offers.

IV. ASSESSMENT OF RESOURCE COMMITMENT AND PRICING ISSUES

To maintain system reliability, sufficient resources must be available to satisfy load and operating reserve requirements during the operating day, both systemwide and in local areas. The day-ahead market is designed to incentivize market participants to make resources available at the lowest cost. Satisfying reliability requirements in the day-ahead market is more efficient than waiting until after it clears because this allows less flexible resources with long start-up notification times to compete more effectively with fast-start resources to satisfy the system's energy and reserve needs at the lowest cost.

Before March 2025, the day-ahead market did not economically schedule all resources needed to satisfy the system's requirements because it lacked the operating reserve products required in real time. Instead, the day-ahead market process included commitment constraints that allowed the ISO to maintain reliability in key local areas in response to both the first- *and* second-largest contingencies; and satisfied system-level operating reserve requirements. However, the day-ahead market did not compensate resources for satisfying these requirements, so resources were not necessarily obligated to take the steps necessary to be available.

In March 2025, the ISO improved the day-ahead market's ability to satisfy New England's needs by introducing system-level operating reserve requirements. However, commitment constraints are still used to satisfy local reliability needs, resulting in commitments whose costs are not reflected in ISO-NE's market pricing. Hence, ISO-NE provides NCPC payments to cover the revenue shortfall when these resources do not recoup their full as-bid costs.

Although total NCPC costs are small relative to overall market costs, they are important because they usually occur when market requirements do not align with the system's reliability needs or when prices are otherwise inefficient. This alignment is key to efficient short-term performance incentives and long-term investment incentives. Efficient incentives for flexible, low-cost providers of operating reserves will become increasingly important as intermittent renewable generation penetrates further.

After the day-ahead market, ISO New England runs the Real-Time Unit Commitment ("RTUC") model to determine which resources may need commitment to satisfy the system's needs. The RTUC model needs accurate input data to identify the need for real-time commitments and to avoid inefficient commitments that tend to increase NCPC costs.

This section includes subsections that evaluate: (a) day-ahead commitments for local second contingency protection requirements; (b) scheduling patterns in the DA A/S markets; (c) the accuracy and efficiency of the RTUC model; and (d) pricing of operating reserves in the real-time fast-start pricing logic. The final subsection summarizes our conclusions and recommendations.

A. Day-Ahead Commitment for Local Second Contingency Protection

Most reliability commitments for Local Second Contingency Protection (LSCP) occur in the day-ahead market. Although these commitments may be justified for reliability, the day-ahead market pricing software still does not enforce the underlying local requirements, even after implementing new day-ahead reserve markets. As a result, these commitments lead to inefficient prices and concomitant NCPC uplift. Unlike most other RTOs, ISO-NE incurs most of its NCPC charges for local reliability commitments in the day-ahead rather than real-time market.

Table 4 summarizes day-ahead market commitments for local second contingency protection over the past three years, showing:

- The number of days in each year with such commitments;
- The number of hours in each year with such commitments;
- The average capacity (i.e., the Economic Max of the unit) committed over these hours;
- The amount of NCPC uplift charges incurred;
- The NCPC uplift charge rate (that is, NCPC uplift per MWh of committed capacity); and
- The implied marginal value of local reserves not reflected in market clearing prices, aggregated over the year.

The table below shows these values for each import-constrained area with LSCP commitments in the day-ahead market. The implied marginal reserve values are additive for areas nested within a broader import-constrained area.[42]

Table 4: Day-Ahead Commitment for Local Second Contingency and NCPC Charges
2023 – 2025

Year	LSCP Region	# LSCP Days	#LSCP Hours	Average LSCP Capacity per Hour (MW)	DA NCPC (Million $)	Average Uplift Rate ($/MWh)	Implied Marginal Reserve Value ($/kW-Year)
2023	NH-to-Maine	5	47	229	$0.1	$8.15	$0.73
	Lw. SEMA & East RI	3	23	213	$0.1	$13.54	$0.44
	NE West-to-East	25	202	322	$0.5	$7.17	$1.84
2024	Rhode Island	1	12	154	$0.1	$32.77	$0.38
	North East NE	7	89	408	$0.4	$12.26	$1.13
	NE West-to-East	26	216	369	$0.4	$4.63	$1.11
2025	NH-to-Maine	2	30	257	$0.05	$6.08	$0.18
	Lw. SEMA & East RI	1	2	333	$0.03	$42.81	$0.09
	NE West-to-East	10	63	404	$0.09	$3.39	$0.28

Day-ahead commitments for local second contingency protection have declined notably in recent years, primarily because of reliability transmission upgrades in areas with these needs. In 2025,

42 For example, the NE West-to-East interface defines an import-constrained region that includes Central Mass, SE Mass, NEMA/Boston, Rhode Island, New Hampshire, and Maine. So, the implied marginal reserve value for a unit in Maine would be $2.57/kW-year in 2023 ($0.73 of NH-to-Maine plus $1.84 of NE West-to-East).

the table shows that these commitments were limited to fewer than 100 hours over 13 days, mostly in the broader region east of the New England West-to-East interface. Most occurred during periods when planned transmission outages reduced transfer capability across the West-to-East interface, highlighting the continued sensitivity of local reliability commitments to transmission system conditions.

Although the frequency of these commitments and the associated total uplift costs have declined substantially, the uplift cost per MWh of committed capacity remained significant in 2025. It ranged from approximately $3.4 per MWh in the broader region east of the New England West-to-East interface to $42.8 per MWh in Lower SEMA and East Rhode Island. These outcomes continue to raise two efficiency concerns:

- Units receiving NCPC payments are typically higher-cost, less flexible resources that systematically receive more revenue than flexible, low-cost resources that generally do not require them.
- Operating reserve prices paid to other resources that help satisfy the same local reliability requirement do not reflect the costs of resources committed for local reliability.

These inefficiencies distort market incentives in favor of higher-cost, less flexible units and suppress prices for other resources. Therefore, although commitments for local second contingency protection have become relatively infrequent, relying on out-of-market NCPC payments to satisfy these requirements continues to produce inefficient price signals. Incorporating these local reliability requirements into a day-ahead operating reserve market would improve the efficiency and transparency of energy and reserve prices, align compensation more closely with reliability value, and further reduce the need for out-of-market commitments. Therefore, we continue to recommend (see #2019-3) that the ISO define local operating reserve requirements in the day-ahead and real-time markets to satisfy these reliability needs through the competitive market rather than through out-of-market actions.

B. Day-ahead Ancillary Services Scheduling Patterns

Before the ISO introduced DA A/S products, out-of-market commitments were needed when load was under-scheduled in the day-ahead market. To satisfy these reserve requirements through the market, the ISO introduced the FER as part of the original DA A/S market design. Now, the ISO procures additional EIR to cover any gap between the FER and the amount of scheduled physical energy resources. Accordingly, the market clearing price for EIR equals the FER price, which is paid to scheduled physical energy resources because they also contribute to satisfying the FER. Virtual supply does not contribute to satisfying the FER, so it does not receive the FER price.

In principle, physical energy resources are paid the FER price because they are expected to be available to satisfy forecasted needs the following day. Physical resources scheduled in the day-ahead market do not receive the FER price if they do not submit an offer in the real-time market.

This provision reduces the likelihood that resources could receive the FER price without being available. However, we have observed strategies that allow suppliers to schedule day-ahead energy and collect FER payments even though they were unavailable in the real-time market.

For example, one market participant simultaneously scheduled day-ahead imports and virtual load positions of equal quantities at the same location. In real time, the participant submits an import offer that is usually unavailable because the source control area has not scheduled the export component of the transaction. Under the current settlement design, when the source control area schedules the real-time import:

- The import receives the DA LMP plus the FER price,
- The virtual load pays the DA LMP minus the RT LMP, so
- The net payment to the participant = FER price + RT LMP

When the real-time import is *not* scheduled by the source control area:

- The import is paid the DA LMP plus the FER price minus the RT LMP,
- The virtual load pays the DA LMP minus the RT LMP, so
- The net payment to the participant = FER price

Ultimately, this strategy allows the participant to receive the FER price regardless of whether the import is available to New England in real time. Even when the import flows in real time, it results from the source control area's real-time export bid evaluation process rather than the participant meeting a clear obligation associated with its day-ahead import schedule in ISO -NE.

FER and EIR mechanisms were introduced to ensure that the ISO procures sufficient dependable supply in the day-ahead market to satisfy forecast energy requirements and improve real-time reliability. However, under the current rules, import schedules can receive FER-related compensation without a corresponding requirement to remain consistently available in real time. As a result, the ISO may compensate transactions that schedule financially in the day-ahead market but do not reliably provide operational capability when system conditions tighten.

The core problem is the lack of a clear performance obligation on the participant that schedules a day-ahead import. The ISO effectively treats day-ahead import schedules as satisfying the system's Forecast Energy Requirement even though the associated supply need not be available in real time.[43] Consequently, the day-ahead market solution may overstate the quantity of dependable supply available to the system during stressed operating conditions.

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43 This scheduling pattern also reveals an issue with the representation of the import transfer limit in the day-ahead market. Virtual load is treated as reducing import flows similar to export transactions. As a result, the day-ahead market solution may schedule more than the feasible amount of imports, thereby reducing the amount of EIR scheduled below what would be needed if the day-ahead net imports were limited by the interface transfer limit.

If day-ahead imports receive FER payments but need not be available, the ISO may under-procure EIR from resources that would be available in real time. Import transactions that receive FER compensation but are not subject to equivalent real-time performance obligations may displace resources capable of providing dependable capacity in the day-ahead clearing process. Over time, this could reduce the DA A/S market's effectiveness in maintaining reliability without resorting to out-of-market actions.

C. Resource Scheduling Efficiency by RTUC

RTUC is a key operational tool that ISO-NE uses to schedule resources while maintaining system security and reliability in the operating day. RTUC runs every 15 minutes (at :05, :20, :35, and :50 of each hour) and typically uses an 85-minute look-ahead period.[44] It evaluates near-term forecast conditions and commits fast-start resources to ensure reliability and reserve adequacy. RTUC produces startup and shutdown recommendations for fast-start resources and DARD pumps (i.e., pumped storage resources), which the Unit Dispatch System (UDS) then executes.[45]

While the vast majority of unit commitment decisions are made in the day-ahead market or earlier, RTUC gives the ISO additional flexibility to commit non-dispatchable resources in the operating day. As New England attracts more investment in intermittent renewable generation, balancing supply and demand throughout the operating day will become increasingly challenging without RTUC's additional flexibility. Efficient commitment of peaking resources in the operating day can reduce ramping demands on dispatchable resources and help maintain system reliability.

Because RTUC commits fast-start resources in anticipation of supply shortfalls or system stress, evaluating the efficiency of these commitment decisions is important. This subsection examines the conditions under which forecasting inaccuracies lead to uneconomic commitment of fast-start resources and analyzes the key drivers of RTUC forecast errors.

Uneconomic Commitment of Fast-Start Resources by RTUC

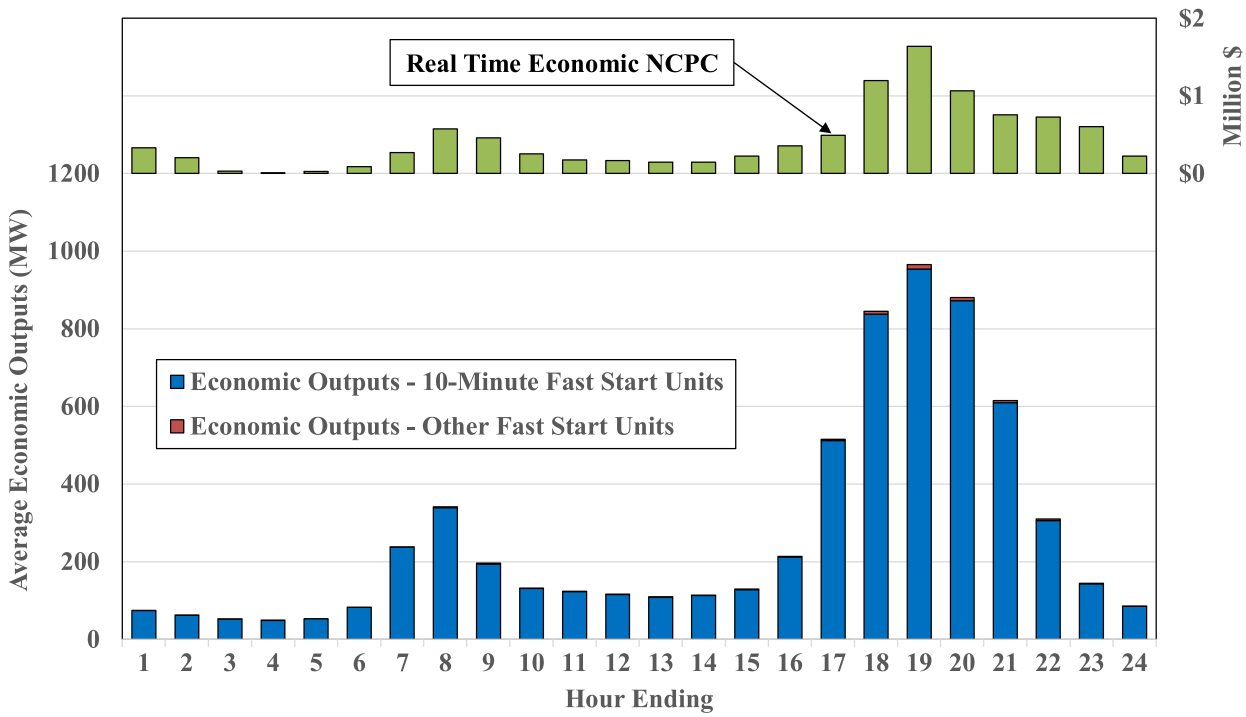
Figure 14 shows the average economically scheduled output from fast-start generators by hour in 2025. These values exclude output associated with self-scheduling, out-of-market commitments, and dispatch. The figure shows fast-start generators that can start and synchronize within 10 minutes separately from other fast-start resources.

44 Each RTUC run typically includes six look-ahead intervals, with the first interval covering 10 minutes and the remaining intervals each spanning 15 minutes. However, operators have the flexibility to extend the look-ahead period by adding additional 15-minute intervals as necessary.

45 UDS depends on RTUC for fast start resource commitment decisions. When RTUC is active, UDS cannot independently commit or de-commit fast start resources or DARD pumps. It can only dispatch fast start units that RTUC has committed.

The upper portion of the figure shows the corresponding real-time economic NCPC uplift payments to these resources and highlights periods when RTUC has the greatest effect on real-time market outcomes. Although these uplift payments are small relative to the overall wholesale market, they indicate periods when RTUC may be committing fast-start resources inefficiently.

Figure 14: Economic Outputs from Fast-Start Generators and Associated RT NCPC Uplift
By hour, 2025

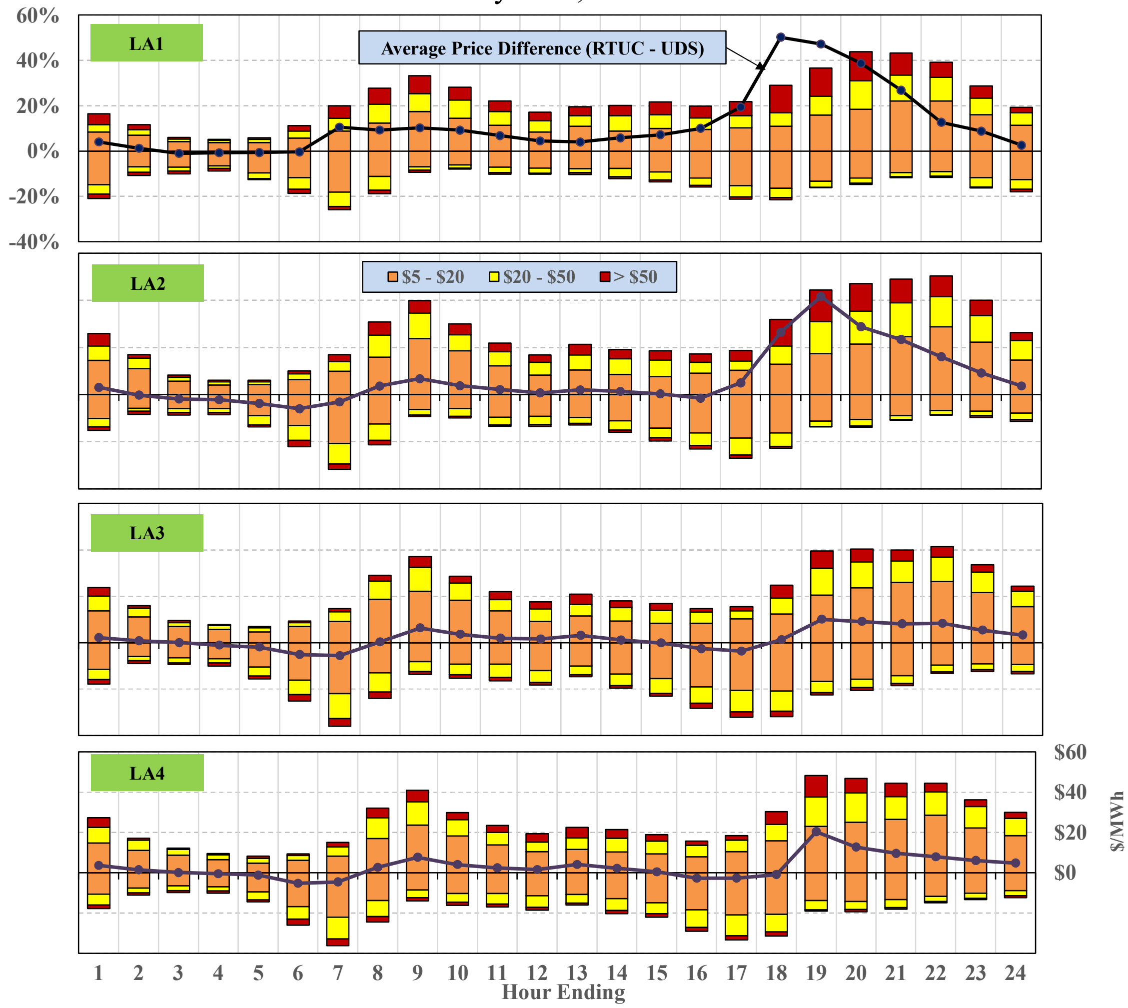


The figure shows several key insights:

- In 2025, fast-start generators incurred over $10 million in real-time economic NCPC uplift, accounting for nearly 65 percent of such uplift to internal resources. This share is significantly higher than typically observed in other RTOs. For instance, NCPC payments to economically committed fast-start units in ISO-NE were 80 percent higher in $ per MW-start than make-whole payments to comparable units in NYISO.
- Notably, 99 percent of the economic output from fast-start resources originated from units that can start and synchronize within 10 minutes, while these units account for only 90 percent of fast-start capacity. This indicates that 10-minute fast-start units are utilized more heavily than other fast-start units.
- Approximately 60 percent of economic starts occurred during the evening peak period (hours ending 17 to 21). This period also accounted for 51 percent of the associated real-time economic NCPC uplift payments. These results indicate that the ISO routinely relies on fast-start resources to satisfy the daily peak in net demand (load minus renewable energy) and manage changing system conditions during the evening ramp period.

These findings are consistent with the 2024 results. Elevated make-whole payments to economically committed fast-start units are generally associated with over-forecasting system needs in the operating day. To evaluate potential drivers of over-forecasting, the next analysis compares RTUC forecasts of real-time systemwide LMPs with UDS LMPs in Figure 15.

Figure 15: Price Forecasting by RTUC vs. UDS LMPs
By hour, 2025



The figure has four panels, each representing a different RTUC forecast horizon. Look-Ahead (LA) periods One through Four correspond to forecast windows ranging from less than 15 minutes (LA1) to one hour out (LA4), in 15-minute increments. The stacked bars summarize the frequency, direction, and magnitude of differences between RTUC and UDS prices; positive values indicate hours when RTUC prices exceeded UDS prices. The black line in each panel shows the average hourly difference between RTUC and UDS prices.

Figure 15 shows that the average hourly differences between RTUC and UDS prices were generally close to zero in most hours across all four forecast horizons. However, during morning and evening peak hours, RTUC prices were consistently higher than UDS prices across all four forecast horizons. The differences were especially pronounced in Look-Ahead periods One and Two, when average RTUC prices exceeded average UDS prices by as much as $50 per MWh in hour ending 18. Figure 15 highlights several issues with RTUC performance:

- RTUC frequently committed fast-start resources inefficiently during evening peak hours. When actual real-time prices were lower than forecasted prices, these units often operated at a loss and required substantial real-time economic NCPC payments to cover their costs. This finding is consistent with the patterns observed in Figure 14.
- If market participants perceive a systematic bias in RTUC commitments, it may weaken their incentives to offer at marginal cost. For instance, if fast-start resources frequently receive NCPC payments that depend on their offer prices, they may be incentivized to offer above marginal cost.
- Although less pronounced, an upward bias is also evident in LA3 and LA4 forecasts. These forecasts generally use the same inputs as the CTSPE model that forecasts prices for transactions scheduling with NYISO.

Drivers of Price Over-Forecasting in RTUC

This subsection evaluates the factors contributing to the inconsistencies between RTUC and UDS prices discussed above. It quantifies each factor's contribution using the metric described below and distinguishes between factors that tend to reduce or exacerbate the inconsistencies.

Inconsistencies between RTUC and UDS prices can cause inefficient scheduling decisions. This inefficiency stems from two related discrepancies: (a) differences in MW levels between RTUC and UDS (e.g., forecasted vs. actual load); and (b) differences in price levels between the RTUC forecast price and the actual UDS price. To capture these effects, we define an inconsistency metric for each generator, external transaction, or load i:

$$Metric_i = (NetInjection_i^{RTUC} - NetInjection_i^{UDS}) \times (Price_i^{RTUC} - Price_i^{UDS})$$

Using the example above, the following shows how the metric is calculated for each input/resource:

- Load Forecast: $Metric_{Load} = +100\,MW \times (\$50 - \$70) = -\$2{,}000$

  This negative value indicates that the load under-forecast was a "detrimental" factor that increased the divergence between forecasted and actual prices.
- High-Cost Generator used in UDS:

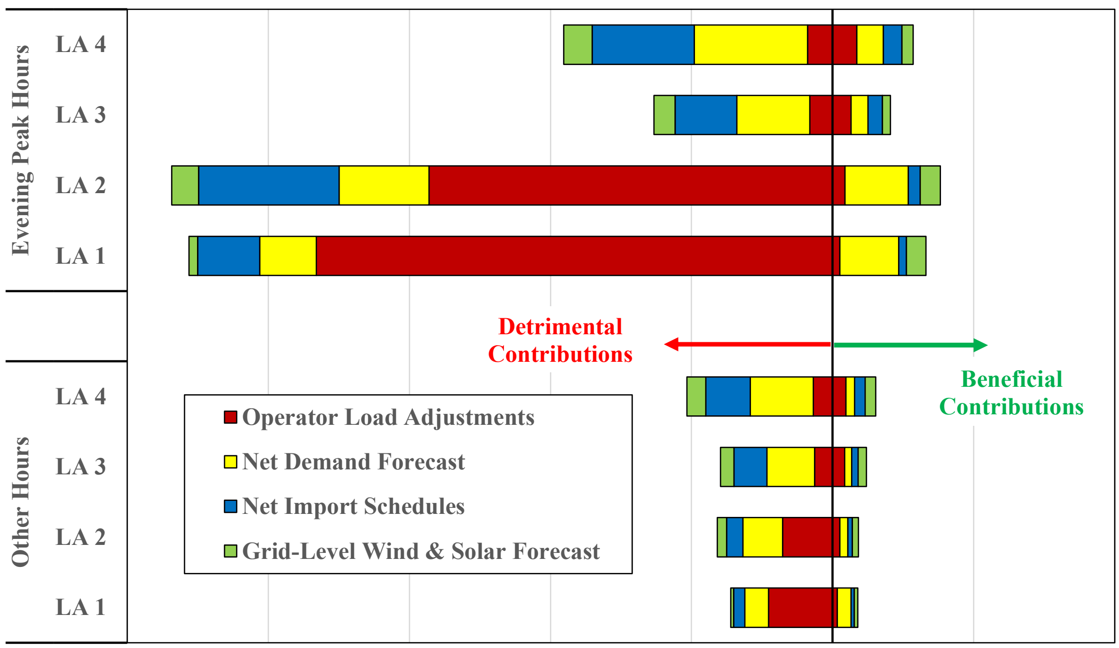
  $$Metric_{High-Cost\ Generator} = -100\,MW \times (\$50 - \$70) = +\$2{,}000$$

  This positive value shows that the generator's contribution was "beneficial" because it helped meet the unexpected load and mitigate the price gap.
- Foregone Fast-Start Unit: $Metric_{Fast-Start\ Unit} = 0\,MW \times (\$50 - \$70) = \$0$

  The zero value reflects that the fast-start unit itself did not cause the divergence. Rather, the load under-forecast caused its absence from the RTUC commitment.

This metric differentiates between "detrimental" factors that increase price divergences between RTUC and UDS and "beneficial" factors that reduce them. Flexible resources, such as fast-ramping units, generally act as beneficial factors that alleviate differences between forecast and actual real-time schedules, while inaccurate forecasts of inputs determined outside the model (e.g., load forecast) tend to be detrimental. Figure 16 evaluates inconsistency metric values for four key factors that contributed to RTUC-UDS price differences in 2025: (i) net demand (demand minus behind-the-meter solar) forecast; (ii) operator load adjustments; (iii) scheduled net imports; and (iv) grid-scale wind & solar forecasts.

Figure 16: Factors Contributing to RTUC Price Forecast Errors
2025



The figure presents the cumulative detrimental and beneficial metric values for each factor over the year. To highlight impacts during peak periods, the analysis compares evening peak hours (HE 17 to 21) with all other hours. In addition, it disaggregates the results across the four RTUC forecast horizons to show how each factor's contribution varies by look-ahead interval. For comparability, the figure displays hourly average metric values for each group rather than absolute totals. It does not show the actual metric values because this analysis focuses on each factor's relative significance in driving price inconsistencies rather than on exact magnitudes.

Like the 2024 findings, Figure 16 shows several key insights into the drivers of RTUC and UDS price divergences in 2025:

- **Overall Impact Primarily Detrimental** – Although all four factors sometimes reduced price divergence, their net impact over the year was primarily detrimental.
- **Minor Impacts for Grid-Level Wind and Solar** – Forecast errors associated with grid-scale wind and solar had small effects relative to the other three factors. This is expected

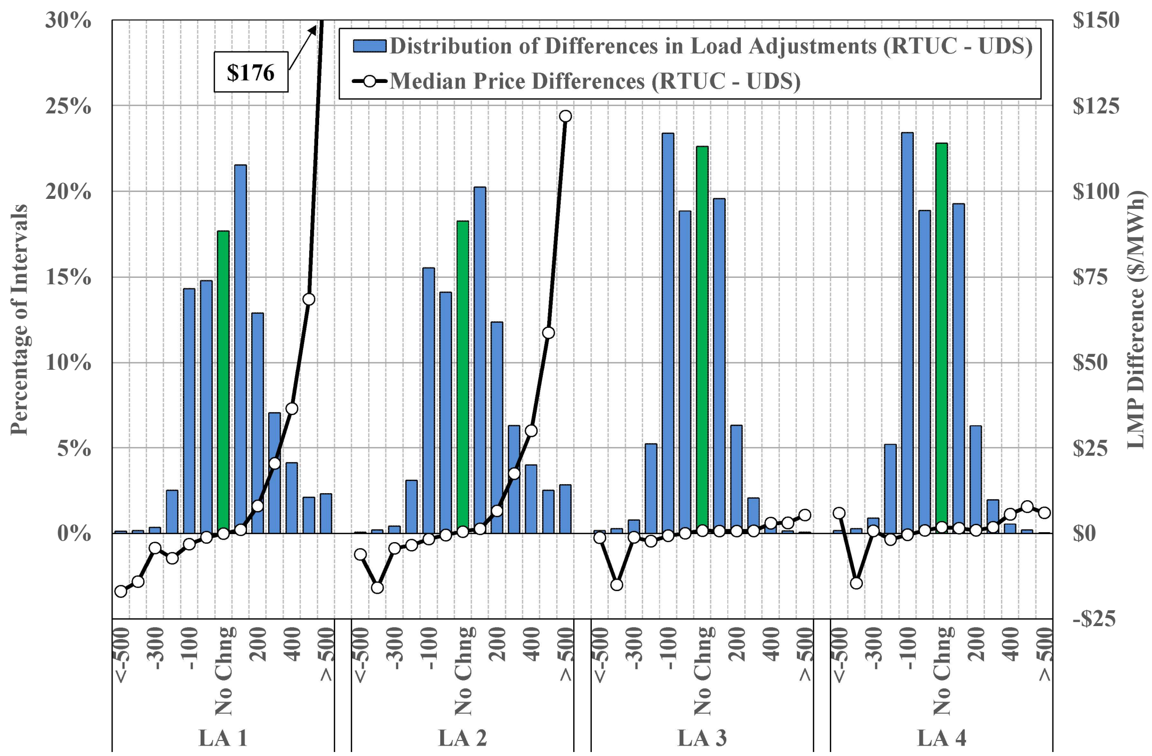
because ISO-NE currently has a modest amount of grid-level renewable generation capacity. By contrast, retail-level solar generation is embedded in the load forecast.

- **Modest Impact for Net Import Schedule Changes** – Net import variation had a modest overall effect on price inconsistencies. However, it contributed more to price divergence at the longer forecast horizons in LA3 and LA4.
- **Primary Driver of Divergence was Operator Load Adjustments** – Operator load adjustments were the largest detrimental factor in price inconsistencies during LA1 and LA2, particularly during evening peak hours (HE 17 to 21).

As the forecast horizon extended to LA3 and LA4, operator load adjustments had less influence. Instead, net demand forecast errors became the largest detrimental factor, reflecting greater uncertainty in longer-term demand forecasting and less frequent operator load adjustments.

Figure 17 examines the evening peak hours and the relationship between load adjustment differences and price differences between RTUC and UDS across the four look-ahead horizons. The bars show the distribution of load adjustment differences in 100 MW increments.[46] The green bars indicate the percentage of intervals where operators applied the same adjustment to both RTUC and UDS. The black lines mark the median price differences between RTUC and UDS, showing how variation in load adjustments correlates with price inconsistencies.

Figure 17: Differences in Load Adjustments and LMPs Between RTUC and UDS
Evening Peak Hours, 2025



46 The MW values on the x-axis represent the upper bound of each tranche. For example, the 200 MW tranche includes the load adjustment differences between 100 and 200 MW.

Operators can make load adjustments in RTUC by applying the same adjustment across all look-ahead intervals, or by targeting specific intervals. Figure 17 shows that LA1 and LA2 had similar distributions of load adjustment differences that differed from those in LA3 and LA4, which also had similar distributions. In particular, the load-adjustment distributions in the near-term forecasts (LA1 and LA2) were skewed toward positive values, while those in the longer-term forecasts (LA3 and LA4) were skewed toward negative values. In addition, load adjustment differences exceeding 300 MW occurred in nearly 10 percent of intervals in LA1 and LA2, but in only 2 percent of intervals in LA3 and LA4. These patterns suggest that operators are more likely to apply larger or targeted upward load adjustments in the shorter-term horizons, while making fewer specific adjustments in the longer-term forecast windows.

Only 18 to 23 percent of intervals had no difference in load adjustments between RTUC and UDS across the four forecast windows, as the green bars in Figure 17 show. These intervals had near-zero median price differences, suggesting that more consistent load adjustments between RTUC and UDS improve price forecasting accuracy. In contrast, the largest load adjustments generally corresponded to the largest RTUC/UDS price inconsistencies. Across all four look-ahead horizons, load adjustment differences exceeding ±300 MW corresponded to substantially higher median price differences.

Because most fast-start resources in ISO-NE can start and synchronize within 10 minutes, RTUC can commit these units beginning in its first or second look-ahead interval. However, the frequent, large load adjustments observed in LA1 and LA2 inflated expected demand levels, leading to higher projected LMPs and premature or excessive commitment of fast-start resources. A more measured, consistent approach to load adjustments in RTUC could reduce inefficient commitments and improve alignment with actual real-time system conditions.

Inconsistent Ramp Assumptions. We found that inconsistent ramp assumptions contributed to the large price differences between RTUC and UDS in the LA1 evaluation. UDS assumes a 15-minute ramp window regardless of the actual time available until the evaluation's "target time" (i.e., the forecasted point in time for which generation is scheduled). By contrast, RTUC always executes LA1 ten minutes ahead of the relevant target time and assumes a 10-minute ramp window. This inconsistency generally makes more supply available in UDS than in RTUC, contributing to lower prices in UDS. The inconsistent ramp assumptions in RTUC LA1 and UDS contributed to the observed price differences, particularly during periods of high system stress, when ramping flexibility is critical. UDS's inflated ramp assumption allows more aggressive dispatch solutions and leads to lower realized prices.

We recommend (see #2024-1) that ISO New England address the underlying causes of the price divergence between RTUC and UDS identified in this subsection. A comprehensive evaluation of these divergences and other drivers of fast-start commitment inefficiencies would improve the economic efficiency and reliability of real-time market operations.

D. Pricing of Operating Reserves in the Fast-Start Pricing Logic

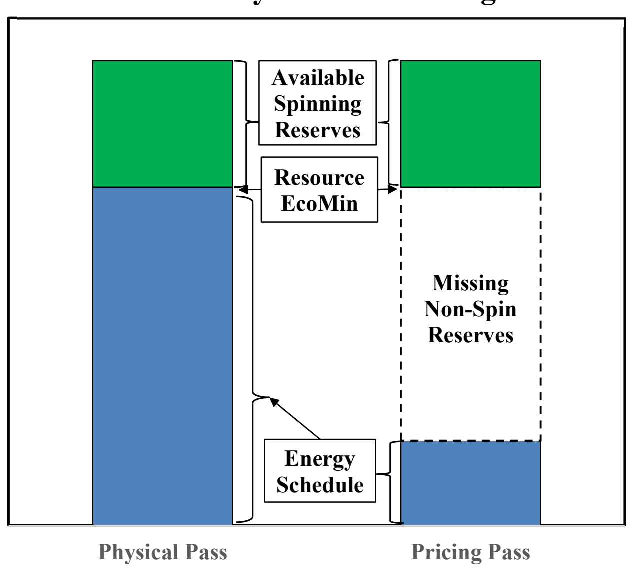
Fast-start units create challenges for price formation because they often have limited dispatch ranges and relatively high costs, causing them to frequently run at their minimum output level where they cannot set the price as the marginal unit. In March 2017, the ISO implemented fast-start pricing logic in the real-time energy market, allowing fast-start resources to set prices when their output displaces output from more expensive resources.

An optimal real-time dispatch model determines each resource's dispatch quantity to minimize as-offered production costs while enforcing transmission and operational constraints. After this physical dispatch (i.e., the "physical pass"), the fast-start pricing model produces the "pricing pass", re-running the dispatch model re-runs with the EcoMin constraints of fast-start units relaxed to zero and allowing them to "set the price" for energy. In addition, the pricing pass adjusts the energy offers of fast-start resources to reflect their full costs by adding fixed start-up and no-load costs amortized over EcoMax for the minimum run-time duration. As a result, energy prices more accurately reflect the full costs of using fast-start resources to the real-time system needs. However, the fast-start pricing logic contains a flaw that can produce inefficient reserve pricing under certain conditions:

- In the pricing pass, fast-start units cannot provide reserves below their EcoMin level;
- When the pricing pass relaxes the EcoMin to zero and economically ramps down fast-starting resources, other units that would otherwise provide reserves ramp up to supply additional energy.
- This substitution reduces the available operating reserves in the pricing pass, which can inefficiently raise both reserve and energy prices.

Figure 18 illustrates the loss of available reserves. In the physical pass, a fast-start unit is dispatched at its EcoMin level and the headroom above EcoMin provides spinning reserves. In the pricing pass, the unit's EcoMin is relaxed to zero, allowing the unit to be dispatched down so it can be marginal and set prices. While the pricing pass continues to recognize the headroom above the unit's EcoMin as available spinning reserves, it does not account for the un-dispatched portion below the physical EcoMin level as available reserves. This omitted capability is depicted by the white dashed box labeled "missing non-spin reserves."

Figure 18: Illustration of Available Reserves in Physical and Pricing Passes



As a result, less capacity from online fast-start resources is available in the pricing pass than in the physical pass. This inconsistency primarily affects prices materially under tight conditions, causing reserve prices to be overstated. To highlight these price effects, Figure 19 and Figure 20 compare 10 and 30-minute reserve availability and shadow prices in the physical and pricing passes during UDS intervals when reserve constraints were binding in the pricing pass.

Figure 19: Available 10-Minute Reserves in UDS
Physical Pass vs. Pricing Pass, 2025

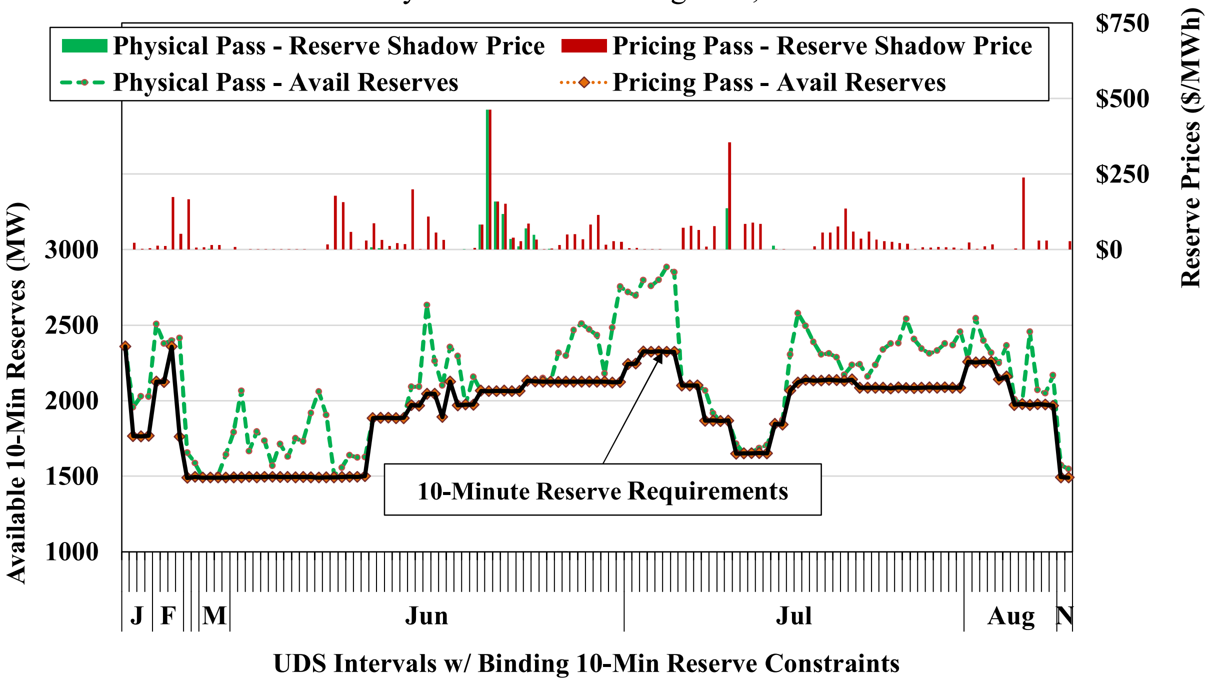
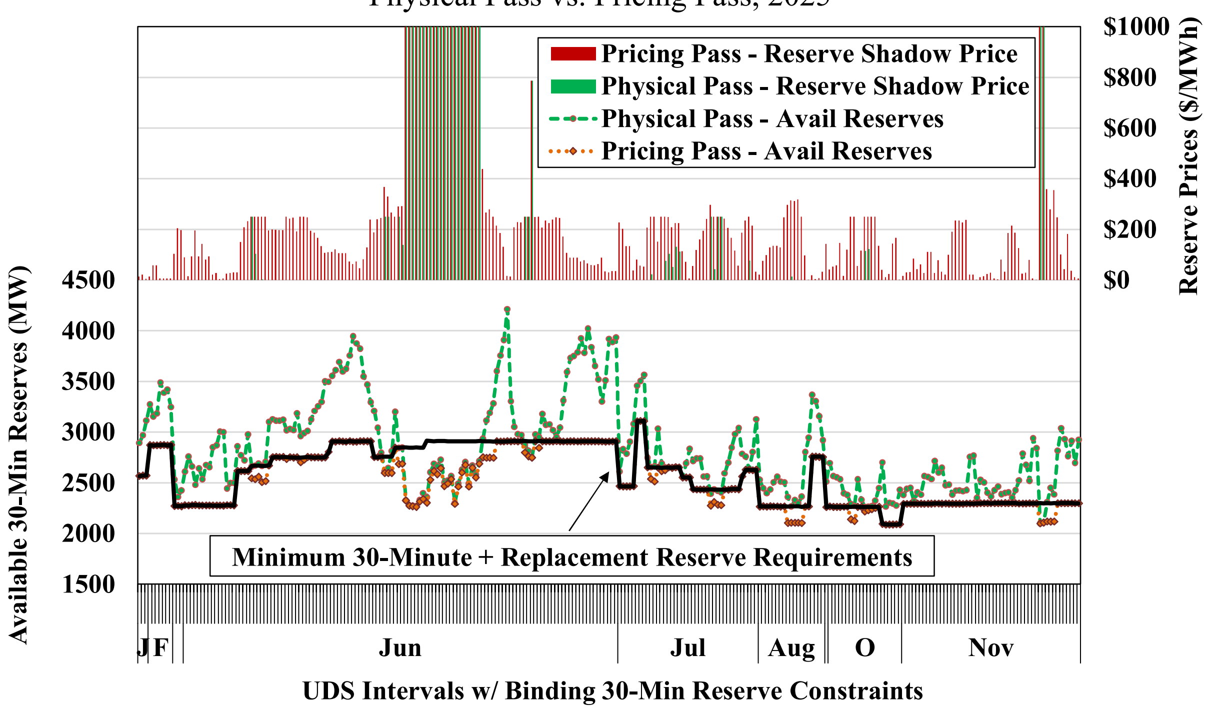


Figure 20: Available 30-Minute Reserves in UDS
Physical Pass vs. Pricing Pass, 2025



The upper portion of each figure compares the shadow prices of reserve constraints in the two passes. The shadow price indicates the marginal cost of satisfying the reserve requirement and contributes to the reserves and energy pricing. The lower portion shows modeled reserve availability in each pass as dashed lines and the requirements as a solid black line. A surplus is evident when the dashed line is above the solid line and a shortage when the dashed line is lower.

In 2025, 354 UDS intervals had at least one binding 10-minute or 30-minute reserve constraint in the pricing pass. During these intervals:

- The physical pass consistently showed greater reserve availability than the pricing pass – averaging 205 MW more 10-minute reserves and 320 MW more 30-minute reserves.
- Reserve prices were often much higher in the pricing pass, averaging $165-$179 per MWh for 30 and 10-minute reserves versus to $80-$83 per MWh in the physical pass.

These results highlight the flaw described above, which arises when any of the 10 or 30-minute fast-start resources are dispatched below their EcoMin in the pricing pass. To address this pricing inefficiency, we recommend that the ISO refine the fast-start pricing logic to treat un-dispatched capacity below EcoMin from 10 and 30-minute fast-start resources as available operating reserves for those respective products.

E. Conclusions and Recommendations

Day-ahead commitments for local reserve needs – These commitments satisfy unpriced local second-contingency requirements. Relying on out-of-market NCPC payments to satisfy these requirements does not compensate other resources efficiently for contributing to them.

- Recommendation #2019-3: Define local operating reserve requirements in the day-ahead and real-time markets to satisfy these reliability needs through the competitive market.

Eligibility to Receive FER Payments – Day-ahead imports receive FER payments even when they are not available in real time. Such transactions are not obligated to be available in real time so they do not provide comparable value to resources that receive FER payments. This could reduce the reliability benefits of the DA A/S market so it should be evaluated by the ISO.

Real Time Unit Commitment model performance – This Section shows that RTUC frequently over-forecasts the need to commit fast-start resources, which caused over $10 million of NCPC costs in 2025 – 65 percent of all real-time economic NCPC paid to internal resources.

- Recommendation #2024-1: Address the causes price divergences between the RTUC and real-time models to make its fast-start commitments more efficient.

Excessive real-time reserve prices – An issue with the fast-start pricing logic caused inefficiently high real-time reserve prices in some intervals.

- Recommendation #2022-1: Address inefficient reserve prices in the fast-start pricing logic by modifying it to use the full capability of online resources in the pricing pass.

V. Capacity Availability and Performance Incentives

Capacity markets provide incentives to ensure adequate resources will be available to satisfy the system's planning reliability needs. To provide efficient incentives for resource investment and retirement decisions, capacity markets should quantify available capacity accurately and provide efficient performance incentives.

ISO New England is replacing its forward capacity market with a prompt seasonal capacity market that bases resource accreditation on the marginal reliability value of capacity. We strongly support these design changes to address the region's future reliability needs. In this section, we evaluate two aspects of capacity market performance: (i) the consistency between the amount of qualified capacity and the amount actually available during the tightest summer conditions and (ii) the incentives the Pay-for-Performance rules provide.

A. Qualified Capacity and Actual Availability during Peak Summer Conditions

Resource adequacy and transmission security criteria generally require enough resources to avoid load shedding under conditions more severe than the average annual peak demand level (e.g., a 90th percentile annual peak load forecast). Therefore, when setting capacity requirements, load forecasts quantify the additional demand expected under these relatively severe conditions. Ideally, the accreditation of each generator sells reflects its expected capability under the same severe conditions. For most thermal generators, maximum capability falls as summer weather conditions become more extreme. If the accreditation rules do not consider these factors, the total Qualified Capacity ("QC") will exceed the amount available under the tightest conditions.

This section examines the factors that inflate summer QC values for the thermal generation fleet. It is divided into the following parts:

- *Ambient Conditions Background* – Overviews the ambient conditions that most affect conventional generator performance: air temperature, humidity, barometric pressure, and water temperature;
- *Quantification of Ambient Impacts in Summer 2025* – Analyzes how the ambient assumptions used to determine Summer 2025 QC values differ from actual peak-hour ambient conditions and the overestimate of QC values for certain capacity types; and
- *Actual Performance in Summer 2025* – Analyzes the gap between summer QC values and actual generator availability to quantify the underlying drivers in summer 2025.

Ambient Conditions and Generator Output – Background

Each resource that participates in the capacity market is qualified to sell up to its summer or winter QC. For thermal generators, QC is generally based on the Seasonal Claimed Capability (SCC) Audits, which are usually conducted under conditions more favorable than expected peak conditions. For some thermal generators, the ISO partially addresses the difference between

Audit conditions and peak conditions by adjusting test results to a uniform systemwide peak temperature of 90°F.[47] The ISO uses capability curves submitted by owners of gas turbine and combined cycle facilities that show capability as a function of dry bulb temperature in one-degree increments.[48,49]

The gas turbine capability of combined cycle and simple cycle generators is also affected by humidity and barometric pressure. Higher relative humidity reduces the effectiveness of inlet cooling equipment that adds moisture to cool compressor inlet air to offset the effects of higher air temperatures on gas turbine output.[50,51] Barometric pressure directly affects gas turbine capability because gas turbines can produce more output when air is denser. Generators can choose to adjust SCC Audit results based on barometric pressure and relative humidity, but doing so would generally not benefit the generator so none have opted to do so.[52] In practice, audits are usually conducted under relatively favorable humidity and pressure conditions, which tends to inflate QC values. In this subsection, we estimate the effects of these ambient conditions on gas turbine capability.

The steam turbine capability of combined cycle units, older fossil-fueled steam turbines, and nuclear power plants with a steam cycle may decline at higher ambient air or water temperatures. The steam cycle of combined cycle generators with air-cooled condensers may be limited at higher air temperatures.[53] Older steam turbines with once-through cooling systems may be

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47 The normalization procedure is outlined in Market Rule 1 III.1.5.

48 For example, if a combined cycle conducts an SCC Audit operating to 300 MW at an average temperature of 80°F and the relationship between capability (MW) and temperature between 80-and-90°F is -1 MW/°F, the weather-normalized Summer SCC of this resource would be 290 MW at the 90°F seasonal adjustment value. See Section 4 of https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op14/op14a_rto_final.pdf.

49 The Qualified Capacity of an existing resource is equal to the median SCC from the resource's seasonal SCC Audits over the past five years. See Market Rule 1 III.13.1.2.2.

50 Inlet cooling systems work to collapse the ambient dry bulb air temperatures towards the corresponding wet bulb temperature at the given ambient conditions. As relative humidity levels rise, the gap between dry bulb and wet bulb temperatures diminish which restricts the ability of the inlet cooling systems to decrease inlet air temperatures. In New England, the most common inlet cooling systems are evaporative coolers and inlet fogging systems, which are also the most prone to efficiency degradation with higher relative humidity conditions.

51 There is a smaller impact on CTs without these systems, amounting to roughly 0.4 percent between 0-and-100 percent humidity. See: https://www.gevernova.com/content/dam/gepower-new/global/en_US/downloads/gas-new-site/resources/reference/ger-3567h-ge-gas-turbine-performance-characteristics.pdf

52 See Market Rule 1 III.1.5.1.4 (c). The relative humidity normalization value is 64 percent, while the barometric pressure is normalized to the value of the previous Establish Claimed Capability Audit.

53 If a combined cycle power plant is equipped with duct burners and an air-cooled condenser (ACC) that is designed to handle 90°F conditions, the ACC equipment will be inadequate at higher temperatures, limiting output further because duct firing must be backed off to reduce steam flow to the condenser.

limited by the temperature of their cooling-water source during the summer. In this report, we do not estimate the effects of air and water temperatures on steam turbine capability. However, our review of generator performance during summer peak conditions identifies some deratings that were likely attributable to these factors.

Impact of Ambient Conditions on SCC Ratings – Air Temperature & Humidity

Current market rules acknowledge the importance of air temperature by requiring generators to adjust SCC Audit results from test conditions to a planning temperature of 90°F. However, the uniform 90°F temperature adjustment is inadequate for two reasons:

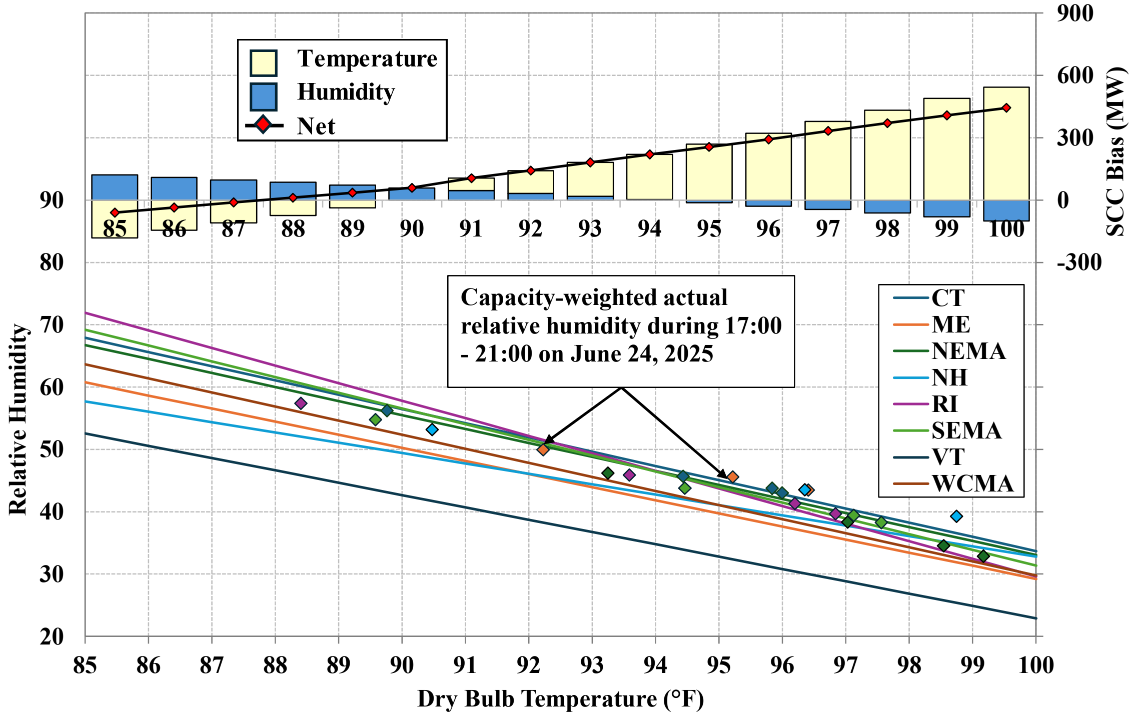
- Temperatures are not uniform across the system. Generators in certain load zones predictably experience warmer or cooler temperatures than those in other zones.[54]
- Planning reliability requirements are driven by peak summer conditions when temperatures across New England exceed 90°F.

Hence, the uniform adjustment to 90°F is insufficient and favors generators in warmer areas. In many cases, the marginal effects of air temperature increase more rapidly above 90°F, especially for combined cycle generators. Under peak summer conditions that drive New England's planning reliability requirements, air temperature and humidity are inversely related. From late afternoon to early evening, air temperatures fall while relative humidity rises. To estimate the overall effects of ambient conditions on generator capability, we examined the 25 highest-load hours from the last seven years and calculated the capacity-weighted average temperature and relative humidity for each load zone. We then derived a linear trendline relating humidity to temperature. This is shown in Figure 21 for temperatures between 85 and 100 degrees Fahrenheit.

We estimate the relationship between humidity and capability for humidity-dependent generators based on SCC Audit results applicable to Summer 2025, observed generator performance at various temperature levels, and each generator's submitted capability curve relating capability to air temperature. Figure 21 summarizes how temperature and humidity combinations under peak summer conditions affect SCC and drive New England's installed capacity requirements. For example, if the temperature were 92°F throughout New England, relative humidity would range from 39 percent in Vermont to 52 percent in Rhode Island. Applying these temperature and locational humidity thresholds would *lower SCC by 142 MW overall*: 111 MW because of higher temperature and 31 MW because of lower humidity during SCC Audits. In reality, temperature is not uniform throughout New England, because southern regions are generally warmer than northern regions. However, the figure illustrates the correlation between temperature and humidity at a given location and the effects on generator capability.

54 For example, generators in the NH and NEMA load zones often experience temperatures that are several degrees warmer than those resources in other zones while Maine generators often experience the coolest temperatures (excluding the small amount of capacity in Vermont).

Figure 21: Temperature & Humidity Impact on SCC Ratings
Summer 2025



Because of the increased penetration of distributed solar generation in recent years, summer peak load hours have shifted later in the day. For example, on June 24, 2025, the four peak load hours were hours-ending 18 to 21. At that time of day, temperature starts to fall while relative humidity increases. The figure shows that air temperature and humidity are both significant factors and that air temperatures were generally well above 90 degrees across much of New England during peak conditions. QC values should be adjusted to account for the combination of temperature and humidity conditions likely to prevail under the peak summer weather conditions the system is planned for (i.e., peak conditions more severe than expected in an average year).

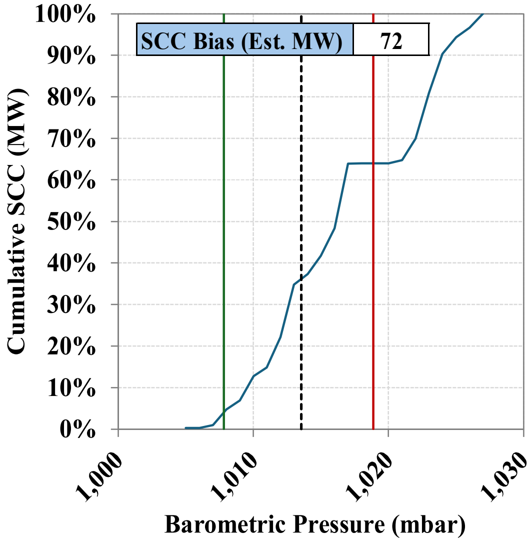
Impact of Ambient Conditions on SCC Ratings – Barometric Pressure

Barometric pressure affects the power output and efficiency of certain generation technologies, particularly CTs in simple-cycle and combined-cycle configurations. When the air is less dense, less air mass flows through the CT, reducing its output.[55] Therefore, barometric pressure and CT capability are positively correlated.

Barometric pressure tends to fall as air temperature and humidity rise. Warm air is less dense than cool air, and humid air is less dense than dry air because water vapor is less dense than nitrogen and oxygen. Since summer reliability risks are highest in hot, humid conditions, barometric pressure is lowest under high summer load conditions.

55 See: https://www.gevernova.com/content/dam/gepower-new/global/en_US/downloads/gas-new-site/resources/reference/ger-3567h-ge-gas-turbine-performance-characteristics.pdf

Figure 22: Barometric Pressure during SCC Tests, Summer 2025



Since summer SCC audits are usually conducted outside peak load conditions, they generally occur at higher barometric pressures than expected during peak load conditions. Figure 22 shows the percentage of cumulative capacity from power plants with one or more CT that conducted an SCC Audit applicable to Summer 2025 at or below a given barometric pressure level, in mbar. Three additional lines provide context on typical barometric pressure conditions during peak load hours. The green line shows the 10th percentile of barometric pressure conditions across load zones during peak load days, whereas the red line shows the 90th percentile. The black dashed line shows the mean barometric pressure on peak load days.[56]

For Summer 2025, 62 percent of all applicable Summer SCC Audits occurred at barometric pressures above the average barometric pressure (roughly 1013.6 mbar), which increased audit performance relative to expected summer peak conditions. In addition, 36 percent of SCC Audits occurred at barometric pressures above the 90th percentile band. We estimate that the difference between pressure conditions during SCC Audits and the mean pressure condition during historic peak load hours inflated Qualified Capacity *by 72 MW*.

Qualified Capacity Unavailable under Peak Conditions – Summer 2025

This subsection estimates how much Qualified Capacity was unavailable because of ambient conditions and unreported deratings during the June 2025 heat wave. While we estimated that ambient condition effects on gas turbine output likely accounted for much of the unavailable capacity, we did not estimate the effects of ambient conditions on steam turbine production, so to the extent these occurred, it would show up as an "unreported derate".

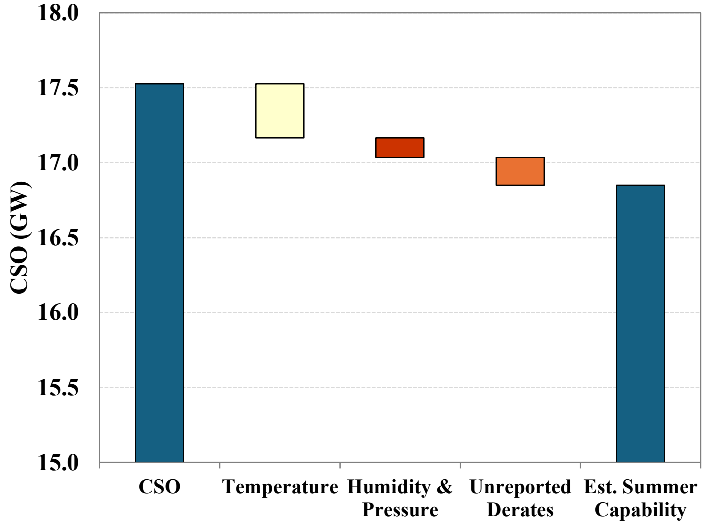
Figure 23 shows the combined CSOs of all steam turbines, gas turbines, and combined cycles compared to the actual capability available under peak conditions. Ambient air temperature effects on gas turbine output (including the gas turbine component of combined cycles) are shown separately from humidity and pressure effects. On the peak load day (i.e., June 24, 2025), temperatures exceeded 90°F by a wide margin in all load zones except Vermont, significantly reducing generating capacity (~360 MW).

For steam turbines (including the steam cycle of combined cycles), ambient conditions likely explained a large quantity of the unreported deratings. Since ISO New England will begin using

56 See Appendix for methodology.

NERC Generating and Availability Data System (GADS) data as an input to its capacity market in 2027, monitoring generator compliance with reporting requirements during deratings will be important.

Figure 23: Unavailable Capacity under Peak Conditions in Summer 2025



Besides the estimated air temperature effect, ~320 MW of QC was unavailable under peak conditions. We estimate that relative humidity accounted for 60 MW and low barometric pressure accounted for 70 MW. We estimate that the remaining 190 MW resulted from unreported forced derates, much of which was credited as good performance during the PFP events.[57] Hence, we continue to recommend robust enforcement of GADS reporting obligations and reassessment of the ambient condition adjustments to Qualified Capacity (2024-3).

B. Assessment of Capacity Shortage Events

ISO-NE implemented the PFP rules in June 2018 to strengthen incentives for generators to support grid reliability and stability during Capacity Scarcity Conditions ("CSCs"). Under the PFP framework, generators receive payments or penalties based on their performance relative to their CSOs during CSC events.[58] Since implementation, PFP events have been infrequent, occurring only seven times in eight years, including five events over the past three years that lasted between 30 minutes and three hours.

Although none of these events posed a significant risk of firm load shedding in New England, they produced extremely strong financial incentives. During the November 23, 2025 event, total payments to imports and resources performing above their CSOs exceeded $12,000 per MWh, including the applicable PFP rate of $9,337 per MWh. Over the past three years, shortage events resulted in more than $230 million in performance charges to suppliers. Available steam and combined-cycle resources that were offline because they had not been committed in the day-ahead market incurred most of these charges.

57 See subsequent subsection of this report for further analysis on this.

58 A CSC occurs when the ISO is short of one or more of the three reserve requirements and the Reserve Constraint Penalty Factor ("RCPF") is setting the real-time reserve prices: (a) systemwide 10-minute reserve requirement; (b) systemwide 30-minute reserve requirement; and (c) local 30-minute reserve requirements that exist to meet the second-contingency requirement in import-constrained areas.

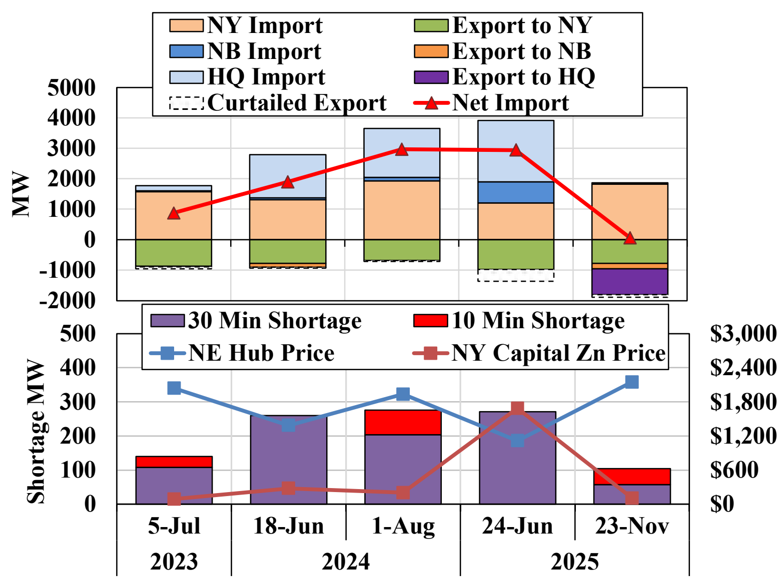
These settlements vastly exceed the underlying reliability value associated with the relatively small reserve shortages observed during these events and create inefficient incentives for market participants. This subsection examines several aspects of the PFP rules that fail to provide efficient incentives, including those related to the scheduling of export transactions, the reporting of generator deratings in real-time operations, and the shortage pricing levels used during 2025 PFP events.

Imports and Exports Scheduled During Shortage Events

Wholesale markets facilitate efficient use of transmission interfaces between control areas, allowing low-cost resources in one area to serve consumers in another and improving reliability in both. ISO-NE imports and exports substantial amounts of power from New York, Quebec, and New Brunswick, so it is critical to schedule the interfaces efficiently. During reserve shortages, efficient scheduling enables ISOs to optimize resource utilization across neighboring regions and minimize the overall cost of maintaining grid reliability.

Figure 24 summarizes external transaction scheduling with neighboring areas during capacity scarcity conditions over the past three years. The upper panel shows the average quantity of scheduled imports and exports at each interface during each PFP event. It aggregates transactions across the Highgate and Phase I/II interfaces with Quebec and groups together transactions across the three interfaces with New York. Hollow bars depict scheduled transactions that were subsequently cut or curtailed. The red line shows total net imports across all interfaces during these shortage periods.

Figure 24: Scheduling of External Transactions during Reserve Shortages from 2023 to 2025



The lower panel of the figure shows the average 10-minute and 30-minute reserve shortages during these events. It measures 30-minute reserve shortages relative to the minimum 30-minute reserve requirement, defined as the capacity needed to cover the largest contingency plus half of the second-largest contingency. This reserve product has a Reserve Constraint Penalty Factor (RCPF) of $1000.[59] The panel also compares average energy prices at the New England Hub and the NYISO Capital Zone during

59 This excludes the additional replacement reserve requirement of 160 MW during the summer events and 180 MW during the winter events, which is associated with a substantially lower RCPF of $250.

the shortage periods, providing additional context for evaluating external transaction scheduling and regional market conditions.

During the five PFP events over the past three years, ISO-NE had systemwide 10-minute reserve shortages in only three events, which averaged approximately 50 MW. 30-minute reserve shortages occurred in all five events and averaged roughly 180 MW. Although these shortages were relatively small, they resulted in very high average energy prices at the New England hub, ranging from approximately $1,100 per MWh to over $2,100 per MWh.

Conditions in neighboring areas were generally much less severe during these events. In four of the five events, NYISO did not experience significant 10-minute or 30-minute reserve shortages, and average energy prices in Capital Zone remained below $170 per MWh. The only exception was June 24, 2025. On that day, NYISO also experienced multiple reserve shortages, and average energy prices approached $1,700 per MWh, exceeding Hub LMPs in New England. These pricing outcomes suggest that NYISO generally had substantially more favorable supply conditions than ISO-NE during four of the five shortage events.

Despite these conditions, ISO-NE curtailed only small quantities of scheduled exports during the five events, leaving approximately 700 MW to 1800 MW of scheduled exports to neighboring areas uncurtailed in each event. During the June 24, 2025 event, additional export curtailments would have worsened shortage conditions in the neighboring area because it was experiencing a more significant reserve shortage. However, during the other four events, additional export curtailments would have reduced or potentially eliminated reserve shortages in ISO-NE without causing reserve shortages in the neighboring area.

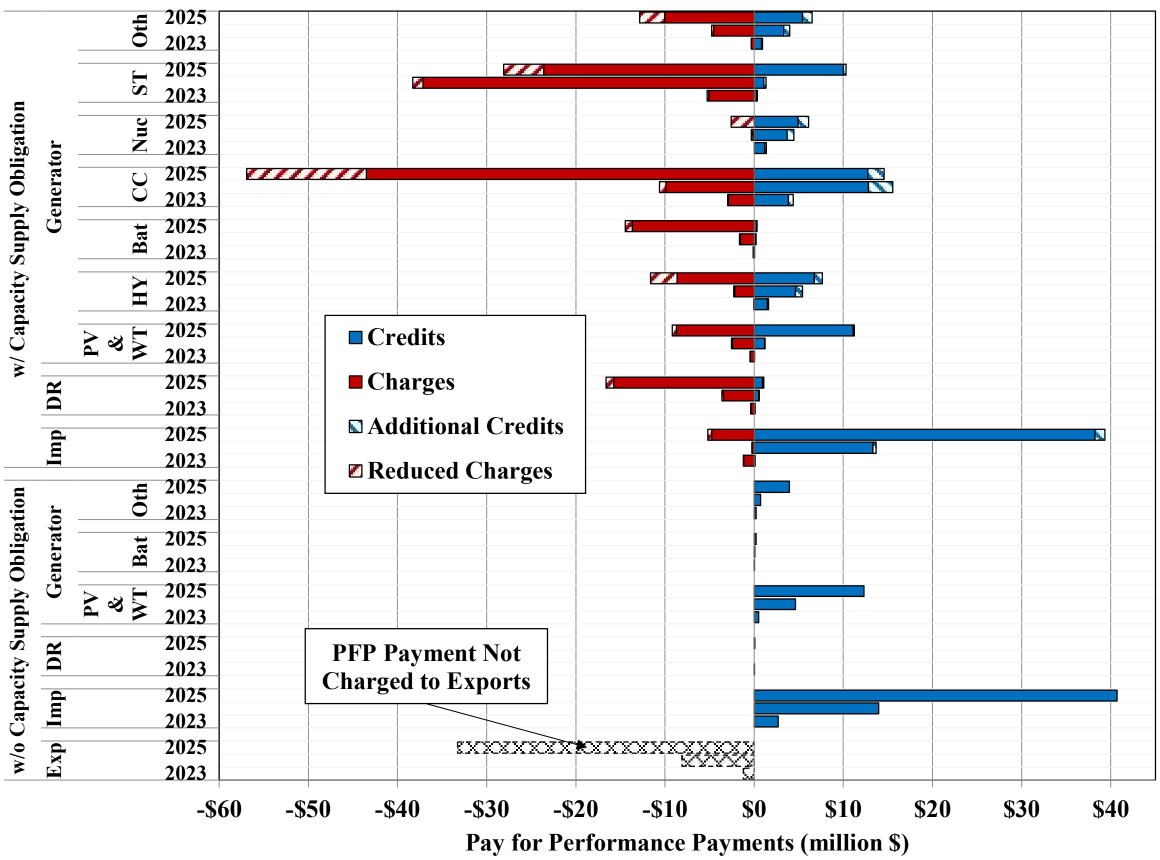
Although shortage conditions were generally brief during each of the five events, they triggered PFP rates of $3,500 per MWh in 2023, $5,455 per MWh in 2024, and $9,337 per MWh in 2025. Under the current rules, imports receive credits at the PFP rate, while exports are exempt from corresponding charges. As a result, some market participants schedule imports while others schedule exports simultaneously because both transactions are profitable during shortage conditions. This outcome is inefficient because the market should reward participants for scheduling power from the area with more surplus supply to the area with less surplus supply.

Pay-for-Performance Settlements During Reserve Shortages

Overall, the PFP rules contribute to grid reliability in several ways. First, they help reduce the likelihood, duration, and severity of system-wide emergencies by incentivizing resources to improve their availability and operational performance during shortage conditions. Second, they strengthen financial incentives to invest in new resources with high availability. However, if PFP rules provide excessive incentives for flexibility, they may inefficiently discourage the retention of existing generation with less flexible characteristics.

Under the PFP rules, resources that fail to deliver energy or operating reserves during shortage events incur financial penalties, referred to as PFP charges, regardless of the reason. Conversely, resources that perform well and help maintain system reliability receive PFP credits. Figure 25 summarizes the distribution of PFP credits and charges during shortage events over the past three years. It categorizes resources by type and by whether they held CSOs. It shows units with longer lead times, including fossil fuel-fired steam turbines, combined cycle units, and nuclear units, separately from intermittent resources (solar and wind), battery storage resources, and hydro resources. It groups peaking units and all remaining resources in the "Other" category. It also shows imports, exports, and demand response resources separately from generation resources.

Figure 25: PFP Settlements and Impact of Export Treatment
2023-2025



The figure also shows: (a) the amount *not* charged to exports; and (b) the "*Additional Credits*" that performing resources would have received, along with the *"Reduced Charges"* that under-performing resources would have incurred, if exports had been treated as under-performers in the calculation of the PFP event Balancing Ratio.[60] We calculated these values using applicable PFP penalty rates of $3,500 per MWh in 2023, $5,455 in 2024, and $9,337 in 2025. Approximately

60 In the figure, the sum of the "Charges" category and the "Reduced Charges" category equals the total charges under the current PFP rules.

$26 million in stop-loss adjustments were associated with the June 24, 2025 event. Any performance charges not covered by resources that reached their stop-loss limits were allocated to all other CSO holders. These stop-loss adjustments are not reflected in the figure.

Figure 25 indicates that resources with CSOs that underperformed during the five shortage events over the past three years incurred more than $230 million in PFP charges. Approximately 63 percent of these charges fell on conventional slow-start generators, such as steam turbines and combined-cycle units. While some of these units experienced forced outages or deratings, many were simply offline because they were not committed in the day-ahead market. These outcomes highlight the significant PFP risk that resources with long lead times face during unforeseen real-time shortage events. While it is appropriate for such resources to bear some reliability risk, the resulting penalties should remain aligned with the system's underlying reliability value, which was relatively modest during these events.

Inefficient Incentives for External Transactions

Import transactions without CSOs received more than $57 million in PFP credits during the five shortage events because imports were eligible for the full PFP incentives, which rose from $3,500 per MWh in 2023 to $9,337 per MWh in 2025. In contrast, exports did not incur any PFP charges, creating inefficient incentives for external transaction scheduling during shortage conditions. These rules may also create a gaming opportunity if a participant uses separate bidding entities to schedule equal quantities of imports and exports simultaneously. No net power would flow across the interface, yet the participant could still receive PFP credits for imports while avoiding corresponding charges on exports, up to $9,337 for each MW scheduled. The figure indicates that, had exports incurred PFP charges, exporters would have incurred approximately $43 million during the five events. In addition, other resource categories would have received $13 million in additional credits and $32 million less in charges.

Apart from the gaming opportunity described above, the treatment of exports also creates scheduling incentives that can lead to inefficiently high exports. The total incentive for scheduling imports and exports during shortages already includes ORDC shortage values, which start at $1,000 per MWh for 30-minute reserve shortages and can rise to $2,750 per MWh during simultaneous shortages of 10- and 30-minute reserves. However, because the PFP rate applies only to imports, import incentives can exceed $12,000 per MWh when combined with the 2025 PFP rate of $9,337 per MWh, while export incentives are capped at $2,750 per MWh. This large disparity does not support efficient import and export scheduling during shortage conditions and may distort transaction behavior in ways inconsistent with reliability needs. Accordingly, we recommend that the ISO revise the PFP settlement rules to charge exporters the PFP rate during Capacity Scarcity Conditions. (Recommendation #2022-3)

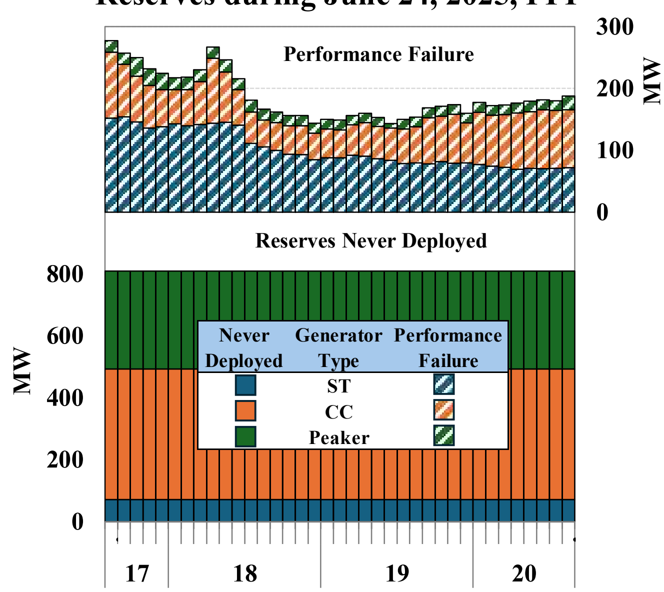
ISO-NE has proposed revisions to the PFP treatment of external transactions that would create a new PFP charge quantity called System-Backed Exports (SBE). SBE represents excess energy exported from ISO-NE when a generator-backed export exceeds the energy and reserves provided by its backing generator or when a market participant schedules exports in excess of imports. These quantities would be charged the applicable PFP rate and excluded from the Capacity Balancing Ratio calculation.[61] The proposed revisions are consistent with our recommendation, and we fully support this rule change.

Impact of Unreported Derates on PFP Settlements

The PFP mechanism compensates resources based on their actual performance during reserve shortages. It is straightforward to assess the performance of capacity that is generating energy. However, for capacity providing operating reserves during a PFP event, it can be difficult to determine whether the capacity is actually available for the full amount of its reserve schedule. Output ranges offered at high price levels are generally scheduled for reserves rather than energy. If a resource is partially or fully unavailable, the owner has a strong financial incentive to offer the resource so it will be scheduled for reserves. This allows the owner to avoid demonstrating that the resource is unavailable while being compensated for reserves. To provide efficient incentives for capacity performance, the market must accurately determine whether resources were truly available during each event. The following analysis evaluates resources that were credited with providing reserves during the June 24, 2025 PFP event to determine whether those reserves were actually available to provide energy.

Figure 26 summarizes our analysis of units scheduled for operating reserves during the June 24, 2025 PFP event. The top portion of the chart shows the amount of capacity credited as reserves in the PFP settlements that either: (a) was scheduled for reserves because it could not ramp up in a previous interval, or (b) was subsequently dispatched up but failed to follow the instruction. In both cases, the capacity was credited with providing reserves but may not have been able to produce energy during the PFP event. The amount of capacity shown in the top portion fell during the event because the operator entered derates for some units after they demonstrated an inability to follow dispatch instructions. After the operator entered the derate, the resource was no longer credited with providing reserves. The figure breaks down this capacity into three generator types: conventional steam turbines, combined cycle generators, and peaking facilities.

Figure 26: Evaluation of Operating Reserves during June 24, 2025, PFP



61 See *Pay-for-Performance Revisions: Treatment of External Transactions*. NEPOOL Market Committee, April 14-16, 2026.

The bottom portion of the figure shows the quantity of reserves held on resources that were never dispatched for energy in those ranges during the event. There is no indication that most of this capacity is unavailable. However, for a relatively small portion, the generators were scheduled at quantities substantially higher than their Summer SCC value. Further investigation is needed to determine whether this capacity was available.

Misalignment with the Value of Lost Load

This may be the most significant concern with the current PFP design. During the 2025 shortage events, importers and other suppliers received average compensation exceeding $11,000 per MWh from reserve shortage pricing and PFP settlements combined. This compensation substantially exceeds the true marginal reliability value of energy in New England during small reserve shortages, as measured by the Expected Value of Lost Load ("EVOLL").

EVOLL equals the value of lost load (i.e., the value of keeping the lights on) times the probability of losing load, which increases as the reserve shortage deepens. Accordingly, EVOLL should rise as system conditions deteriorate. By contrast, the PFP rules use a constant rate regardless of the severity of the reserve shortage. Figure 27 shows how EVOLL increases as reserve margins decline and compares it with the fixed PFP rate used since June 2025.

Figure 27: PFP Rates and the Value of Lost Load

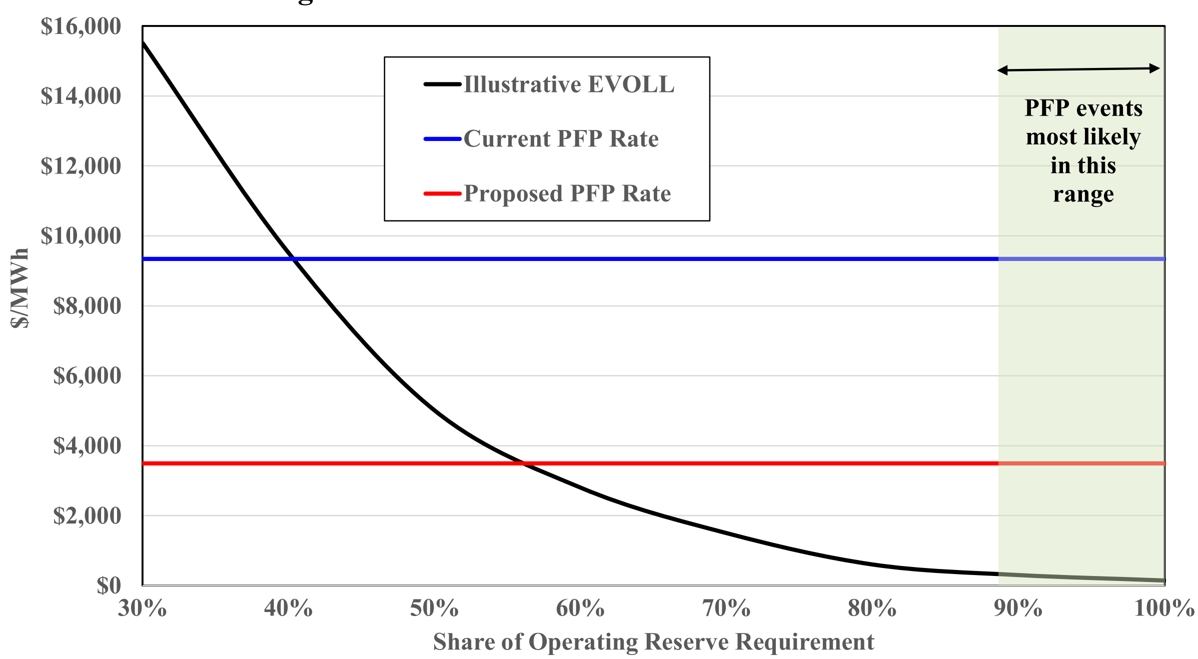


Figure 27 shows that applying a constant PFP rate across all levels of reserve shortages tends to overvalue energy and reserves during shallow shortages, when the probability of losing load is very low, and may undervalue them during deeper shortages. Moreover, the figure understates the potential overvaluation because it does not include shortage pricing in the energy market, which can contribute up to an additional $2,750 per MWh.

While strong performance incentives are important, excessively high incentives can create inefficient risk for less flexible resources and may lead to inefficient retirement decisions. Therefore, we recommend that the ISO modify its PFP rate to align with a reasonable estimate of Value of Lost Load ("VOLL") and the probability of load shedding based on the severity of the operating reserve shortage (see #2018-7). This approach would ensure that:

- Deep reserve shortages, when the risk of load loss is high, appropriately incentivize resources to respond; and
- Shallow shortages do not result in unnecessary costs when reliability risk is minimal.

Furthermore, when two neighboring systems simultaneously experience reserve shortages, a PFP structure that rises with shortage severity and underlying reliability risk would contribute to a more efficient allocation of reserves between regions by providing incentives for firms to schedule transactions from the area with a shallower shortage to the area with a deeper shortage.

ISO-NE recently proposed reducing the PFP rate from the current formula-based value of $9,337 per MWh to a fixed rate of $3,500 per MWh.[62] In support of this proposal, the ISO recognized that the current PFP rate may unnecessarily increase supplier risk, raise capacity costs for consumers, and encourage the retirement of resources that still provide reliability value. We support this revision because the lower proposed rate better balances strong incentives for reliability and performance against excessive market risk, inefficient costs, and unnecessary resource retirements during most reserve shortages. In addition, the proposed $3,500 per MWh rate is more consistent with EVOLL during significant reserve shortages as shown in Figure 27.

The proposal partially addresses Recommendation #2018-7, but we continue to recommend that the ISO consider implementing a graduated stepwise PFP structure that better aligns incentives with the severity of reserve shortages and the associated reliability risk. In the longer term, the ISO should consider means to shift more of the performance incentives into the energy market.

C. Conclusions and Recommendations

This section evaluates two issues that affect the performance of the capacity market.

Comparison of Qualified Capacity to Actual Availability under Peak Summer Conditions

We found that qualified capacity values for generators with combustion turbines do not adequately reflect ambient conditions during periods with the greatest reliability risks because these values generally assume milder temperature, humidity, and barometric pressure conditions than the conditions that drive planning reliability needs. We also observed additional derates under peak summer conditions related to the effect of ambient conditions on cooling equipment. Together, these factors caused available capacity to be 680 MW less than qualified capacity

62 See *Pay-for-Performance Revisions: Proposed Change to the Performance Payment Rate (PPR)*. NEPOOL Market Committee, April 14-16, 2026.

during the summer peak conditions of 2025. Hence, we recommend that the ISO monitor compliance with forced derating reporting rules by generators and reassess how it considers ambient conditions in the calculation of Qualified Capacity after the CAR-SA project (#2024-3) is implemented.

Pay for Performance Events

Pay-for-performance events have occurred only five times over the past three years, generally lasting between 30 minutes and three hours and exhibiting average 10-minute and 30-minute reserve shortages of less than 250 MW. Although none of these events posed a significant probability of firm load shedding, settlement amounts were substantial in these events:

- Suppliers incurred more than $230 million in performance charges, most for available combined cycle or steam units that were not committed in the day-ahead market.
- The total price paid to imports or resources performing above their CSOs was as high as $12,000 per MWh, including the $9,337 per MWh penalty rate in 2025.

These prices and associated settlements vastly exceed the reliability value of energy during these events and create substantial inefficient incentives for ISO New England participants.

One key inefficiency is the inconsistent settlement of imports and exports. Applying the PFP rate to importers but not exporters is a significant flaw that distorts scheduling incentives. During these five events, ISO-NE curtailed minimal amounts of scheduled exports, allowing 700 to 1800 MW of scheduled exports to flow, which led to additional PFP charges for other suppliers.

We also identified generators that experienced partial derates during the June 2025 PFP event and did not promptly report them to the ISO. Consequently, the PFP settlement treated much of this capacity as operating reserves, resulting in a net benefit of $6 million to these generators. Monitoring compliance with generators' obligations to report the status of their units is particularly important when operating reserves are compensated at a marginal rate of more than $10,000 per MWh (as we recommend in #2024-3).

To address these inefficient incentives, we recommend that the ISO:

- Revise the PFP rules to charge exporters at the PFP rate during Capacity Scarcity Conditions (Recommendation #2022-3). The ISO has recently proposed a revision that would charge System-Backed Exports under the PFP framework, which addresses our recommendation, and we fully support this rule change.
- Modify the PFP rates to levels in line with a reasonable estimate of VOLL and that escalate as reserve shortages deepen (Recommendation #2018-7). The ISO has recently proposed reducing the PFP rate from the current formula-based value of $9,337 per MWh to a fixed rate of $3,500 per MWh, which partially addresses our recommendation. However, we continue to recommend that the ISO consider implementing a graduated stepwise PFP structure that aligns incentives more closely with the severity of reserve shortages and the associated reliability risk.

I. Appendix

A. Assumptions Used in Net Revenue Analysis

In this section, we list various assumptions underlying the net revenue estimates for various technologies discussed in Section I.E and II.C.

Net Revenues of Fossil Units

Our net revenue estimates of CC, CT and ST units are based on the following assumptions:

- Natural gas costs are based on the Algonquin City Gates gas price index.
- In the day-ahead market, generators are scheduled based on day-ahead prices, considering commitment costs, minimum run times, minimum generation levels, and other physical limitations.
- In the real-time market, units are committed in real-time based on hourly real-time prices and settle with the ISO on the deviation from their day-ahead schedule.
- Prior to March 2025, CTs are assumed to sell forward reserves in a capability period when it will be more profitable than selling real-time reserves. Following the introduction of DA A/S markets, CTs sell reserves up to their UOL when doing so would be more profitable than generating, and CC and ST units may sell available headroom as reserves subject to ramp limitations when scheduled for energy.
- Fuel costs assume transportation and other charges of $0.50 per MMBtu in winter and $0.10 in other months and $2 per MMBtu for oil on top of the day-ahead index price. Intraday gas purchases are assumed to be at a 20% premium due to gas market illiquidity and balancing charges, while intraday gas sales are assumed to be at a 20% discount for these reasons. RGGI compliance costs are included, if applicable.
- The assumed operating parameters are shown in Table **5**:

Table 5: Unit Parameters for Net Revenue Estimates

Characteristic	CT-7HA	CC (Newer)	CC (Older)	CC (Small)	CT (Newer)	CT (Older)	ST
Average Heat Rate (MMBTU/MWh)	9.2	6.6	7.5	8.5	10	12	9.7
Min Run Time (Hours)	1	4	6	6	1	1	16
Variable O&M ($/MWh)	1.75	3	3.5	3.5	7	7	6
Startup Cost ($/MW)	30.6	0	30	30	30	30	22
Startup Cost (MMBTU/MW)	10	10	10	10	1.25	1.25	10

- The heat rate and capacity for a unit on a given day are assumed to vary linearly between the summer values on August 1 and the winter values on February 1.

Net Revenues of Renewable Resources in New England

We estimated the net revenues of renewable units in ISO-NE using the following assumptions:

- Net E&AS revenues are calculated using real time energy prices.
- For cross-market comparison of land-based wind revenues, we utilized a generation profile that is based on inputs to NREL's ReEDS model.
- The capacity revenues in each year are estimated using clearing prices from the corresponding FCAs. For our cross-market comparison of revenues, we assumed a capacity value of 18.9 percent for solar and 39.3 percent wind in ISO-NE based on FCA18 ORTP assumptions.
- We estimated the REC revenues for land-based wind using MA Class I REC prices obtained from S&P Global Market Intelligence.
- The net revenues of all renewable projects included Investment Tax Credit (ITC) or Production Tax Credit (PTC). The ITC reduces the federal income tax of the investors in the first year of the project's commercial operation. The PTC is a per-kWh tax credit for the electricity produced by a wind facility over a period of 10 years.
- The CONE for renewable units was calculated using the financing parameters and tax rates specified in the ISO-NE Net CONE study and publicly available market data.[63]
- We estimate capital and operating costs using publicly available sources including NREL's Annual Technology baseline (ATB) and Lazard's Levelized Cost of Energy.

Net Revenues of Wind and Solar Resources in Other Markets

In this subsection we discuss assumptions underlying our net revenue estimates for land-based wind resources in three other markets. Net revenues and CONE estimates for the wind plant in NYISO are based on the information presented in the NYISO State of the Market report.[64] Net revenues of wind units in MISO and ERCOT are based on the following assumptions:

- Net E&AS revenues are calculated using real time energy prices in the West zone in ERCOT and in Minnesota / North for MISO.
- The energy produced by these units is calculated using location-specific hourly capacity factors. We considered capacity factor for recent wind installations in MISO and ERCOT, and the capacity factor information presented in 2024 NREL ATB for our assumption regarding the capacity factor for land-based wind in these regions. We assumed a 40 percent annual average capacity factor for wind in ERCOT west and a 45

63 See Norton Rose Fulbright Cost of Capital: 2026 Outlook, available here. We estimated cost of capital in each year assuming a pre-tax cost of debt equal to the Secured Overnight Financing Rate (SOFR) plus indicated lender spreads, a debt to equity ratio targeting a debt service coverage ratio (DSCR) that reflects a combination of merchant and contractual revenues, and a cost of equity based on the NYISO and ISO-NE Net CONE studies. For 2025, we calculate an ATWACC of 8.0 percent for wind and 7.8 percent for solar.

64 See Section IV and Appendix VII of our 2025 report on the New York ISO markets, available here.

percent annual capacity factor for wind in MISO. We assumed a 30 percent capacity factor for solar in ERCOT.

- We estimated the value of RECs produced by the wind unit in ERCOT the Texas REC Index reported by S&P Global Market Intelligence. For MISO, we utilized publicly available information on the REC prices in Minnesota.
- Consistent with the assumption for other markets, we assumed full PTC revenues for the land-based wind plants in ERCOT and MISO regions.

B. Assumptions Used in Evaluation of Ambient Conditions Effects on SCC

Common Types of Ancillary Cooling Systems on Combustion Turbines

Combustion turbines are frequently equipped with one or more of the following inlet cooling systems:

- Evaporative Coolers
    - Uses a water-saturated media to cool CT inlet air.
- Inlet Fogging
    - Sprays a mist of water into the inlet air flow which then evaporates and cools the inlet air comparably to evap coolers.
- Chillers
    - Relies on a refrigeration cycle to absorb heat.
- Wet Compression
    - Sprays atomized water directly into the compressor inlet to cool inlet air via evaporation.

Of the systems listed above, the cooling efficiencies of evap coolers and inlet fogging systems are dependent on relative humidity conditions at the site since. Both systems work to add moisture to the ambient air entering the CT inlet. Therefore, the more humid the ambient air is, the less cooling capacity these systems can provide. Consequently, it is only those ambient conditions dependent generators that have either or both of evaporative cooling or inlet fogging systems installed that ought to be normalized to peak humidity conditions.

Figure 21 Methodology

When the system is off, the GT inlet air temperature will be consistent with the ambient air temperature. However, with the evaporative coolers or inlet foggers in use, the GT inlet air temperature converges on the corresponding wet bulb temperature, itself dependent on the dry bulb temperature and the relative humidity of the ambient air. The ability of the ancillary system to reduce the GT inlet air temperature from dry bulb to wet bulb is called the system efficiency.

For this analysis, we used an efficiency assumption of 90 percent.[65] To calculate the wet bulb temperature at each relative humidity level, we used the following equation:[66]

$$Tw = T * arctan\left(0.151977 * \sqrt{RH + 8.31659}\right) + 0.00391838 * \sqrt{RH^3} * \arctan(0.023101 * RH) - \arctan(RH - 1.676331) + \arctan(T + RH) - 4.686035$$

The equation to estimate GT inlet air temperature with ancillary system in service based on the efficiency metric "e" was:

$$T_{inlet} = T - [e * (T - Tw)]$$

We assumed that the ancillary cooling systems would only be used at ambient temperatures of 60°F or greater.

Figure 22 Methodology

We matched hourly barometric pressure values to each ZIP code where a generator with a combustion turbine in New England is located when systemwide load was above 14 GW. All barometric pressure measurements were grouped into categories of 200 MWs from 14 GW to 24.2 GW (i.e., 14 GW, 14.2 GW, 14.4 GW, etc.). We calculated the 90th and 10th percentile values from each group and created linear regressions between the percentile values against load. The solid green line shows the results of the regression for the 90th percentile barometric pressure value while the solid black line denotes the 10th percentile per bucket as a function of systemwide load. Together, these lines give a sense of the likely range of barometric pressures at a given load level.

Next, we ran a similar regression based on the mean barometric pressure for each load bucket. This curve gave the expected value barometric pressure at the peak load condition observed in the weather data. From that curve, we estimated the mean barometric pressure at the forecasted 2025 peak load level and plotted as the dashed red line.[67] The blue markers denote the actual barometric pressures for each Summer SCC Audit of relevant generators from 2022-2024. Finally, the secondary y-axis shows the estimated impact on SCC Audit results based on the delta between audit pressure conditions and expected peak pressure conditions for 2025.[68]

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65 The actual efficiency of the cooling systems of each resource are unknown, but 90 percent is a commonly assumed average efficiency number. For example, see https://www.iso-ne.com/static-assets/documents/2017/01/npc_20170106_composite4.pdf.

66 See https://www.omnicalculator.com/physics/wet-bulb.

67 Forecasted peak (net) load for 2025, per the ISONE CELT Report, is 24,579 MW (net).

68 Impact of barometric pressure on generator output was assumed to be +1% per +0.1 psia which was derived from Figure 10 of GE Gas Turbine Performance Characteristics, Frank J. Brooks.

Adjustments for Barometric Pressure and Relative Humidity

Temperature normalization relies on capability curves in the current ISO processes. These are curves given by market participants to the ISO that depict generator capability as a function of air temperature in one-degree Fahrenheit increments. Temperature dependencies are given based on the slopes between points on the curve. Adjustments for barometric pressure and relative humidity could be incorporated using the following approach.

Ambient Adjusted SCC = T * P * H * Audit MW

Where T = Temperature Normalization factor
    P = Pressure normalization factor
    H = Humidity Normalization Factor (which equals 1 for non-humidity dependent units)