# 2024 ASSESSMENT OF THE ISO NEW ENGLAND ELECTRICITY MARKETS

**Prepared By:**

POTOMAC ECONOMICS

**External Market Monitor for ISO-NE**

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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 2024 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 2024.

We wish to express our appreciation to the Internal Market Monitor and other staff of the ISO 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 benefits to the region by coordinating the commitment and dispatch of resources to ensure that the lowest-cost supplies are used to reliably satisfy demand in the short-term. At the same time, the markets 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 and discussion of the market outcomes and trends during the year, which include:[2]

- Real time energy prices increased by 11 percent in 2024, despite natural gas prices remaining relatively flat year-over-year. The increase was primarily driven by higher $CO_2$ emission costs, increased load levels, and a decline in imports from Canada.
    - RGGI prices rose more than 50 percent year-over-year, adding approximately $4 per MWh to electricity prices.
    - Average imports from Quebec fell by more than 500 MW as reduced precipitation led to lower reservoir levels at their hydropower facilities.
- Average load rose 2 percent, while peak load increased 3 percent to 24.9 GW. While these levels increased from the historic lows seen in 2023, load levels have trended downward in recent years because of ongoing growth in energy efficiency improvements and behind-the-meter solar generation.
- The capacity compensation rate was $2.00 per kW-month in the 2023/24 Capacity Commitment Period ("CCP") and $2.61 per kW-month in the 2024/25 CCP.
    - Despite the retirement of the Mystic 8 & 9 units in May 2024, capacity prices will remain at roughly $2.60 per kW-month until the 2027/28 CCP. Then prices will rise to $3.58 per kW-month because of the effects of inflation on FCA demand curve parameters and market participants' offers.

The IMM report provides a detailed discussion of these trends and other market outcomes in 2024, this report complements it by comparing key market outcomes with those in other RTO markets, assessing the competitive performance of the markets, and evaluating specific market design and operational issues. In this year's report, we discuss future issues ISO New England may confront as the penetration of renewable resources increases. As we discuss these issues, we will identify recommendations to address the issues and ensure the markets continue to perform well as the needs of the system evolve.

[2] See ISO New England's Internal Market Monitor 2024 Annual Markets Report, available at https://www.iso-ne.com/markets-operations/market-monitoring-mitigation/internal-monitor.

## Cross-Market Comparison of Key Market Outcomes

ISO-NE faces unique challenges that distinguish it from most other RTOs, which affect the structure and performance of its markets. In particular, ISO-NE is located 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. Additionally, 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 market outcomes in the ISO-NE markets to those in other RTO markets and find that:

| | |
|---|---|
| *Energy Prices* | ISO-NE exhibited the highest average energy prices among ISO markets in the Eastern Interconnect in recent years because of its higher natural gas prices and $CO_2$ emissions allowance costs. |
| *Capacity Prices* | Capacity prices were higher in New England than most other ISOs because of the higher surpluses in some markets (e.g., PJM) and poor market designs that do not set efficient prices (e.g., MISO). However, capacity prices in NYISO were higher over the past two years following retirements of older generation driven by air permit limitations. |
| *Congestion* | ISO-NE experiences significantly less congestion than other ISOs, with an average congestion cost of roughly \$0.33 per MWh of load over the past three years. This was just 8 to 17 percent of the average congestion levels in other RTO markets. This is a result of the large transmission investments made primarily to address relatively conservative local reliability planning criteria. This has resulted in transmission rates of nearly \$24 per MWh in 2024 – more than double the average rates in other RTO markets. However, transmission investment has begun accelerating in the other markets, primarily to increase the deliverability of renewable generation to consumers. |
| *Uplift Costs* | ISO-NE generally incurs higher market-wide uplift costs, adjusting for size, than MISO and NYISO because: (a) ISO-NE's fuel costs are typically higher due to regional supply constraints, (b) it has lacked day-ahead ancillary services markets to coordinate and price reserves, (c) ISO-NE provides real-time NCPC payments in a wider range of circumstances than MISO and NYISO, and (d) its real-time unit commitment model has performed relatively poorly in scheduling fast-start resources. The launch of day-ahead operating reserve markets in March 2025 is a significant step toward addressing the first two issues and we evaluate the fourth issue in detail in this report. |
| *Virtual Trading* | Virtual trading levels in ISO-NE have been only 30 to 50 percent of the levels seen in NYISO and MISO, adjusting for size, primarily because ISO-NE over-allocates real-time NCPC charges to virtual transactions and other real-time |

deviations. Addressing this issue is important crucial because virtual trading can play an important role in aligning the day-ahead and real-time market outcomes, especially as the generation mix. (See Recommendation #2010-4)

*External Transactions* The CTS process between ISO-NE and NYISO has performed significantly better than the CTS processes between PJM and NYISO and between PJM and MISO. This superior performance is largely attributed to the decision not to impose charges on CTS transactions and better price forecasting. Despite this relative success, there remains substantial potential to further enhance the efficiency and effectiveness of the CTS process.

*Shortage Pricing* Aside from ERCOT, ISO-NE has employed the most aggressive shortage pricing among U.S. RTOs, primarily settled through the Pay-for-Performance (PFP) framework rather than the energy market. In June 2025, ISO-NE's shortage PFP rate increased above $9,300 per MWh, which together with its operating reserve demand curves will produce the highest shortage pricing of any centrally-dispatched wholesale market. The PFP framework generates outsized risks associated with modest shortages that generally do not raise substantial reliability concerns. To address this, we recommend ISO-NE vary the penalty rate with the size of the shortage and cap the penalty rate based on a reasonable Value of Lost Load (VOLL). (See Recommendation #2018-7)

Section I also describes how the risk of capacity price fluctuations in prompt capacity markets is managed with bilateral contracting, using the example of the NYISO capacity market. NYISO's prompt auction design has long served as the basis for bilateral contracting and other hedging arrangements between generators and load serving entities (including regulated utilities and competitive retail suppliers). Bilateral contracts shields consumers from near and mid-term price volatility. We also observe that the capacity costs are likely to be less volatile in a prompt market than in a forward capacity market. This is because many of the factors that drive volatility in the forward capacity auction (e.g., load forecasts) are determined four years ahead of the capacity commitment period, which is significantly earlier than most parties are seeking to contract. Hence, it is likely that New England will see reduced volatility of capacity costs to consumers under a prompt capacity market framework.

## Navigating the Clean Energy Transition

As New England moves towards a high intermittent renewable generation mix, we examine the experience of other RTOs that have already integrated high levels of intermittent renewable resources and energy storage in Section II. In 2024, intermittent renewables satisfied 11 percent of system demand in New England, while much higher levels were observed in MISO (17 percent) and ERCOT (35 percent) where high intermittency resulted in:

- High levels of uncertainty regarding energy output and transmission flows;

- Output fluctuations from these resources lead to periods of much greater demands for dispatchable resources to ramp their output up and down;
- Challenges in maintaining voltage levels and system security with increasing reliance on inverter-based resources; and
- Transmission security issues when large intermittent generators either do not follow curtailment instructions or when they respond more quickly than other resource classes.

We discuss the strategies that MISO and ERCOT have developed to help address these issues. Importantly, we find that negative pricing caused by intermittent resources is not a substantial concern because conventional resources will be needed and set prices in most hours, even under very high renewable penetration. Additionally, the increase in reserve shortages and shortage revenues should more than offset any reduction in revenues during non-shortage hours.

As New England states have adopted policies to limit new fossil fuel generation and infrastructure, we observe virtually no active projects in the interconnection queue that are dispatchable resources, excluding energy storage. Given that energy storage does not provide comparable reliability to conventional dispatchable resources, we identify the following priorities for ISO New England and the states:

- It will be critical to retain a large share of the existing dispatchable generation and avoid mandating retirements of fossil fuel resources.
- ISO-NE will need to establish marginal capacity accreditation that accurately signals the reliability value of different types of resources.
- The states should consider permitting the addition of back-up on-site fuel storage at gas-fired resources. This is likely the lowest-cost strategy for addressing winter reliability concerns in the near-term in light of the issues with offshore wind development.
- From an operational perspective, it will be important to focus on the improvements needed to optimize the battery storage resources and other new technologies.

ISO-NE's fundamental market design is robust and well-structured to handle these challenges. The most important market objective is that it efficiently incents flexible resources needed to complement the intermittent resources. The most important markets design elements are:

- *Efficient shortage pricing*. This rewards flexible resources when intermittent forecast errors or output fluctuations cause transitory supply shortages. We believe ISO-NE's shortage pricing and PFP rules adequately address this element.

- *Marginal capacity accreditation*. This is necessary to align the capacity payments with the reliability value flexible resources provide by being able to generate when intermittent output is low.

In addition to these elements, increasing reliance on intermittent resources and battery storage will create dispatch challenges that a 5-minute dispatch model cannot always solve efficiently.

We believe that it will be essential for ISO-NE to develop a look-ahead dispatch model that can optimize the dispatch of the following classes of resources and set prices with this optimization:

- Conventional resources that may need to begin ramping several dispatch intervals in advance of a sharp increase in net load or at times of increased uncertainty; and
- Energy-limited pumped storage, battery storage, and DERs that can only be optimized over a longer time horizon.

A look-ahead dispatch will reduce the costs of managing the expected increases in net load fluctuations and provide efficient incentives for developers of battery storage and other flexible resources. Therefore, we recommend (#2023-1) that ISO-NE evaluate the potential benefits and costs of a look-ahead dispatch model that would optimize for multiple hours into the future. This will require substantial research and development but will likely need to be a key component of ISO-NE's strategy to economically and reliably manage the transition of its generating portfolio.

### Competitive Assessment

Based on our evaluation of ISO-NE's wholesale electricity markets in Section III of this report, we find little evidence of structural market power in New England, either at the system level or in individual sub-regions. The pivotal supplier frequency (a key indicator of potential market power) was comparable in all New England between 2023 and 2024, reflecting combined effects from higher load levels, a continued decline in imports from Quebec driven by reduced rainfall and runoff, and higher nuclear generation because of fewer maintenance and forced outages.

Overall, our evaluation of participant conduct finds no evidence of market power abuses or manipulation, suggesting that the markets performed competitively in 2024. Additionally, we find that the market power mitigation has generally been effective in preventing the exercise of market power in the New England markets and was implemented consistent with Appendix A of Market Rule 1. However, we identified three issues with the current mitigation rules:

- Suppliers with resources needed for local reliability have an incentive to operate in a higher-cost mode and receive higher NCPC payments as a result. In 2024, 41 percent of resources committed for local reliability were committed in a multi-turbine combined cycle configuration when a single-turbine configuration would likely have been adequate to satisfy the reliability need. This inflates NCPC costs, depresses prices in key load pockets, and undermines incentives for flexible resources to be available. We recommend the ISO make tariff changes to expand its authority to address this concern. (Recommendation #2014-5)

- Second, we continue to recommend revisions to the current energy mitigation process to address an inefficiency identified in our 2022 annual report (Recommendation #2022-2a), including implementing hourly conduct and impact tests to ensure mitigation terminated when it is no longer warranted by the supplier's conduct or competitive conditions.

- In addition, we find that, in the initial months of DASI implementation in 2025, market power mitigation was applied frequently and almost exclusively to small suppliers that likely had no incentive to exercise market power. This raises concerns that the current mitigation thresholds may be too tight to accommodate suppliers' risk preferences associated with offering the option-based reserve products. Therefore, we recommend that ISO-NE evaluate the appropriateness of its current conduct and impact threshold levels and revise them, if necessary, to ensure they limit the exercise of market power and avoid interfering with competitive behavior (Recommendation #2024-2).

### Out-of-Market Commitments and Operating Reserve Pricing

Efficient real-time commitments and the pricing of fast-starting resources are important from both cost and reliability perspective. Hence, we evaluate: (a) day-ahead commitments for local second contingency protection requirements; (b) the accuracy and efficiency of the RTC model; and (b) pricing of operating reserves in the real-time fast-start pricing logic in this year's report.

*Day-Ahead Commitments for Local Requirements*. In Section IV.A, we find that day-ahead commitments to satisfy local second contingency requirements occurred in 300 hours and, because these commitments were not reflected in the day-ahead prices, energy prices in affected areas were understated. This lowers net revenues for generators and necessitates NCPC payments. Such commitments are likely to increase over time as older generators retire and new resources enter the market, leading to changes in congestion patterns.

In addition, we continue to observe that out-of-market commitment and NCPC costs are sometimes inflated because: (a) the ISO is often compelled to start combined-cycle resources in a multi-turbine configuration when its reliability needs could be met with a single-turbine configuration; and (b) the ISO does not allow firm energy imports to satisfy forecasted local second contingency requirements in the reserve adequacy assessment, which would reduce the associated need to commit local generation.

To address these concerns, we have made several recommendations to improve the scheduling and pricing of energy and operating reserves. We recommend that the ISO:

- Incorporate reserve market requirements to satisfy local second contingency needs in the day-ahead and real-time markets and consider approaches that would allow it to dynamically define new reserve zones as second contingency protection requirements arise in different areas. (See Recommendation #2019-3)
- Expand its authority to commit combined-cycle units in a single-turbine configuration when that will satisfy its reliability needs. (See Recommendation #2014-5)
- Allow firm energy imports from neighboring areas to contribute towards satisfying local second contingency requirements evaluated in the reserve adequacy assessment. (See Recommendation #2020-1)

*Resource Unit Commitment (RTUC) Model*. The RTUC model is a key operational tool used by ISO-NE to schedule resources while maintaining system security and reliability in the operating day. The primary outputs of RTUC include startup and shutdown recommendations for fast-start resources and DARD pumps (i.e., pumped storage resources), which are passed forward to the Unit Dispatch System (UDS) for execution.

Section IV.B shows indicates that RTUC frequently over-forecasts the need to commit fast-start resources. While we identify several contributors, the primary cause of over-forecasting by RTUC was manual load adjustments by the operator, which frequently led RTUC to "recommend" committing uneconomic fast-start generation. This led to real-time NCPC uplift exceeding $11 million in 2024 and accounting for nearly 70 percent of all real-time economic NCPC paid to internal resources, which is an indicator of inefficient scheduling by the real-time market models. To improve the efficiency of fast-start commitments, we recommend ISO-NE evaluate its procedures related to the load forecast bias used in the RTUC model (Recommendation #2024-1).

*Fast Start Pricing*. Section IV.C identifies an inefficiency in the fast-start pricing logic, which tends to overstate reserves values under certain system conditions. Specifically, the pricing model fails to count unscheduled capacity below generators economic minimum toward meeting the ISO's reserve requirements. We recommend the ISO modify the fast-start pricing logic to utilize the full capability of online resources for energy or reserves, ensuring that reserve prices more accurately reflect the cost of maintaining operating reserves (Recommendation #2022-1).

### Pay-for-Performance Incentives during Capacity Shortage Conditions

Since the inception of the Pay-for-Performance (PFP) rules in 2018, Capacity Shortage Conditions have been infrequent, averaging about one hour per year. In 2024, events occurred on June 18 and August 1. The reserve shortages lasted 30 minutes on June 18 and 90 minutes on August 1, averaging less than 250 MW. We evaluate the PFP rules and outcomes in Sectin V.B.

Although neither event was a significant reliability event that exhibited a meaningful probability of losing load in New England, the settlements from the events were substantial:

- Suppliers incurred performance charges during the events of more than $64 million, most of which were incurred by available combined cycle or steam units that were simply offline because they were not committed in the day-ahead market;
- The total price paid to imports or resources exceeding their CSOs was as high as $8200 per MWh, which includes the $5455 per MWh penalty rate, which is slated to increase to $9337 per MWh in June 2025.

These prices and associated settlements vastly exceed the value of energy during these events and create sizable inefficient incentives to ISO New England's participants. One of these incentives relates to the settlements with imports and exports. Applying the PFP rate to settlements with importers but not exporters is a significant flaw that creates gaming opportunities by simultaneously encouraging scheduling of imports and exports. During these two events, ISO-NE curtailed minimal amounts of and allowed 700 to 900 MW of scheduled exports to flow, providing large opportunities to exploit this gaming opportunity.

To address these issues, we recommend that the ISO:

- Revise its PFP rules to charge exporters at the PFP rate during Capacity Scarcity Conditions. (Recommendation #2022-3)
- Modify its PFP rate structure to align with a reasonable Value of Lost Load ("VOLL") and scale with the severity of reserve shortages. This would ensure that when adjacent regions experience reserve shortages, market participants are appropriately incentivized to schedule power toward the region with a more severe shortage. (Recommendation #2018-7)

### Unavailable Qualified Capacity under Peak Summer Conditions

In Section V.A, we found that summer Qualified Capacity values for generators do not adequately reflect load conditions during periods with the most significant reliability risks because these values generally assume milder humidity and barometric pressure conditions than are likely to prevail during the peak summer load hour. In addition, we observe other factors, such as unreported forced derates, that contribute to the gap between Qualified Capacity and available capacity during peak conditions. Together, these factors caused the available capacity to be 700 MW less than the Qualified Capacity during summer peak conditions during 2024.

Additionally, the severe weather conditions driving planning reliability needs are likely to be hotter, more humid, and lower in barometric pressure than typical summer peak conditions, although we did not quantify the impact of these factors. Hence, we recommend the ISO review compliance with forced derating reporting rules by generators and reassess how ambient conditions are considered in the calculation of Qualified Capacity after the CAR project is completed (#2024-3).

### Addressing Winter Reliability in the Capacity Market

The capacity market was originally designed to satisfy summer peak demand, since this would also make sufficient resources available in winter. Winter reliability needs are growing faster than summer needs and will likely be the primary driver of system needs over the coming decade.[3] ISO-NE is undertaking various measures to address growing winter risk, including: capacity accreditation improvements, transition to a seasonal capacity auction, and development of the PEAT/REST framework to quantify seasonal risk.

3 Key drivers of growing winter risk include: gas pipeline constraints that severely limit fuel available to the region's 9 GW of gas-only generators in cold weather, retirements of fuel-secure resources, growing winter load due to electrification of heat and transportation, and growing winter risk in neighboring systems.

Modeling performed by the EMM and ISO-NE has found that winter resource adequacy risk is driven by the system's ability to serve load over extended cold periods (days or weeks), rather than a small number of peak hours as in the summer.[4] This has profound implications for the reliability value of various resource types in winter:

- Gas-only generators without contracted fuel supplies provide little or no marginal reliability benefit in winter;
- Intermittent renewables provide more reliability benefit than their peak output suggests because they allow dispatchable resources to defer consumption of scarce fuel;
- Battery storage resources provide much less reliability benefit than their peak output suggests, because recharging them during cold periods when the system marginally relies on scarce fuel supplies does not improve reliability.

It is vitally important that the ISO-NE markets accurately signal which resources effectively support reliability and how much capacity is needed. This is necessary to avoid premature retirement of fuel-secure resources, incentivize generators to acquire inventory or firm fuel arrangements, and avoid overpaying for capacity that does not support reliability. Hence, ISO-NE's winter modeling and accreditation enhancements should include the following:

- Accredit all resource types based on their marginal contribution to reliability;
- Explicitly represent fuel inventories in models used for accreditation and ICRs; and
- Use conservative assumptions for the amount of LNG that will be available to gas generators that do not contract for it in extreme winter conditions.

Providing efficient incentives to address winter reliability risk is one of the most critical issues for the ISO-NE capacity market. In addition, we continue to recommend the following key changes to the capacity market from previous reports:

*Recommendation #2020-2:* We recommend that ISO-NE improve its capacity rules to accredit resources based their marginal reliability value and modify the resource adequacy model to enable accurate estimation of the marginal reliability value of different types of resources. Improving accreditation in this manner will:

- Provide efficient incentives to investors by aligning capacity payments with the impacts of resources on system reliability.
- Account for the diminishing value of resources whose availability is correlated and discourage over-dependence on a single resource type.
- Facilitate a diverse resource mix by rewarding resources that provide output that is uncorrelated with other resources or that complement other resources in the system.

4 See Section V of our 2023 Assessment of the ISO-NE Markets (available here) and ISO-NE's December 2023 Final Report on the PEAT Framework and 2027/2032 Study Results (available here).

*Recommendation #2021-1:* We recommend replacing the mandatory forward capacity auction with a mandatory prompt seasonal capacity auction. The auction would retain much of its structure and mechanics, but it would take place closer in time to the corresponding capability period. To fully address this recommendation, ISO New England should:

- Conduct the mandatory capacity auction months prior to the capability period;[5]
- Conduct at least two prompt auctions annually (for the summer and winter seasons) using capacity market demand curves that reflect the marginal value of capacity in each season;
- Simplify the capacity qualification process to account for a shorter lag between qualification and the CCP.

The ISO's Capacity Auction Reform ("CAR") projects address these two recommendations.

*Recommendation #2020-3:* Lastly, we recommend treating Energy Efficiency as a load reduction in the capacity market rather than a supply resource. This would address gaming opportunities that we have identified both in ISO-NE and other RTO markets that allow EE to participate in the capacity market as supply. It would also be substantially less administratively burdensome and would produce more efficient incentives to invest in EE technologies.[6]

## Table of Recommendations

Although we find that the ISO-NE markets have generally performed competitively and efficiently, we identify a number of opportunities for improvement. Therefore, we make the following recommendations based on our evaluation of the ISO-NE markets, indicating those we believe will deliver the highest benefits.

This table includes references to the location of our analyses and discussions supporting each recommendation. A number of the recommendations were first made in prior annual reports. Rather than repeating all past analyses and discussions, the reference is often to 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** | | | | |
| 2020-1 | Consider allowing firm energy imports to satisfy forecasted local second contingency requirements. | | | IIV.A |
| 2014-5 | Utilize the lowest-cost configuration for multi-unit generators when committed for local reliability. | | | III.D, IV.A |

5 This would not preclude running a non-mandatory forward market to facilitate voluntary hedging.

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

7 Recommendation will likely produce considerable efficiency benefits.

| | | | | |
|---|---|---|---|---|
| 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.B |
| 2022-1 | Allow fast-start pricing model to utilize the full capability of online units for energy or reserves. | | | IIV.C |
| 2019-3 | Dynamically 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 forced derate reporting and reassess the use of ambient conditions to determine Qualified Capacity. | | | V.A |
| 2022-3 | Charge exporters the PFP rate during reserve shortages. | | | V.B |
| 2021-1 | Replace the forward capacity market with a prompt seasonal capacity market. | ✓ | CAR-PD Filing Plan 2025-Q4, 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. | ✓ | | V.B |
| 2015-7 | Replace the descending clock auction with a sealed-bid auction to improve competition in the FCA. | | CAR-PD Filing Plan 2025-Q4 | IV of 2017 Report |

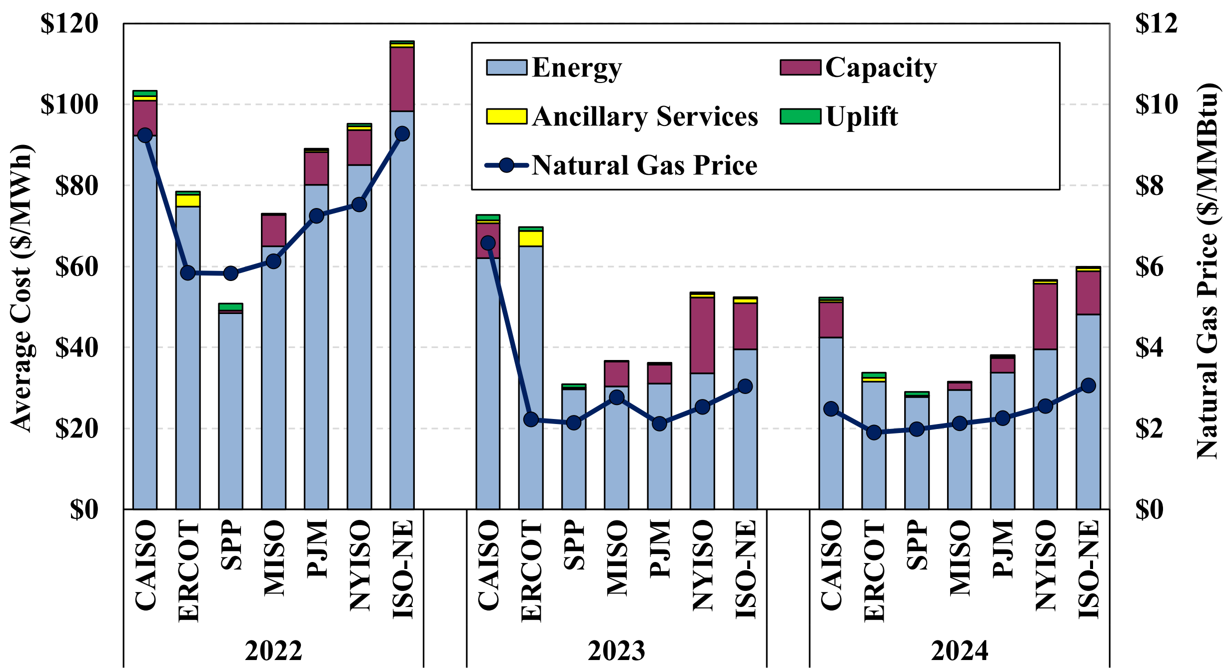
# I. Comparing Key ISO-NE Market Metrics to Other RTOs

The 2024 Annual Markets Report by the Internal Market Monitor (IMM) provides a wide array of descriptive statistics and useful summaries of the market outcomes in the ISO-NE markets. The IMM report provides a good discussion of these market outcomes and the factors that led to changes in the outcomes in 2024. We complement this discussion in this section by comparing New England market outcomes and investment incentives with those in other RTO markets.

## A. Market Prices and Costs

While the RTOs in the US have converged to similar energy and ancillary service market designs, including Locational Marginal Pricing (LMP), some aspects of the market rules vary substantially. In addition, the existence and design of capacity markets are far less consistent. Finally, the market prices and costs across RTOs are affected by many factors, such as the types and vintages of generation assets, state policies supporting specific technologies, fuel market dynamics, and differences in the transmission network's capability. To compare overall prices and costs across RTOs, we show the "all-in price" of electricity in Figure 1.

**Figure 1: All-In Prices in RTO Markets[8]**
2022 – 2024




The all-in price metric provides a comprehensive measure of the wholesale market cost of serving load. It is equal to the load-weighted average real-time energy price plus capacity,

8 These include only wholesale market costs and not, for example, transmission or distribution service charges.

ancillary services, and bid production cost guarantees (referred to as “uplift costs” industry wide) 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 sustained differences in prices and costs among these markets. ISO-NE has exhibited the highest energy prices in the Eastern Interconnect, primarily due to higher natural gas prices at pipeline delivery locations in New England. In contrast, ERCOT often experienced high energy prices during the summer when natural gas prices were low, due to two main factors: (a) high operating reserve demand curves that result in high shortage pricing; and (b) poor implementation of a new reserve product in June 2023 that resulted in frequent artificial shortage pricing. Prices in ERCOT fell in 2024 as large-scale entry of new solar and storage significantly reduced the frequency of shortage pricing.

In the SPP and CAISO markets, the correlation between energy prices and natural gas prices is weaker. Both markets have significantly higher penetration levels of wind and solar resources, which more frequently set the market prices compared to other regions. Natural gas-fired generation sets the clearing price across broad areas of ISO-NE, NYISO, and MISO in at least 75 percent of pricing intervals, while CAISO and SPP experience more frequent conditions when intermittent or hydroelectric generation set the clearing price. In addition, CAISO is the only market that has not implemented fast-start pricing, leading energy prices to be set below efficient levels when fast-start resources are deployed to balance supply and demand.

Other key factors that affect 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 2024, compliance added an average of $11 to $14 per MWh to the costs of gas-fired combined-cycle generators in Massachusetts and $9 to $12 per MWh in the other five New England states in the Regional Greenhouse Gas Initiative (RGGI).
  - Generators in NYISO and a small number PJM states are also subject to RGGI compliance costs. There are no such programs in ERCOT, MISO, or SPP. CAISO is subject to a greenhouse gas (GHG) allowance cap-and-trade system, which raised the costs of combined cycle generators 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 exhibit energy prices substantially higher than prices in New England and contribute to higher system-wide average prices in those markets. Conversely, the unusually low levels of transmission congestion in New England tends to reduce system-wide average energy prices. We discuss congestion levels in more detail in the next subsection.

**Capacity Costs:** The figure also shows that the capacity costs in New England were generally higher than in other RTOs, except for NYISO since 2023. New England has experienced substantial capacity surpluses and relatively low prices below $3.0 per kW-month since 2023, despite having reliability issues in winter that led to OOM retention. The sustained low prices led to 760 MW of retirement bids from units with on-site fuel supplies clearing in FCA18. ISO-NE is going through a major redesign of its capacity market, moving to a prompt, seasonal market with marginal capacity accreditation. This will substantially improve incentives and pricing in New England, which will facilitate better investment, retirement, and fuel supply decisions by market participants.

*New York*. Capacity costs in NYISO rose dramatically following the retirement in 2023 of 800 MW of peaking generation due to air permit limitations and lower capacity imports from neighboring control areas. NYISO has recently implemented marginal capacity accreditation, first taking effect in the 2024/25 capability year. This did not have a major immediate impact on prices because many of the factors driving accreditation values were already included in NYISO's resource adequacy model. NYISO is currently 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 from 2022 to 2024 (usually less than $2.0 per kW-month). These prices reflected large capacity surpluses and were likely below the going-forward costs of many existing units, leading to capacity retirements. Surpluses in PJM were driven by low development costs leading to entry of new capacity in the past decade. However, PJM's capacity auction for the 2025-26 period cleared at prices ranging from $8.2 to $14.2 per kW-month due to a combination of rapid datacenter-driven load growth, recent retirements, and the implementation of a new marginal capacity accreditation approach that significantly discounted the capacity contributions of many resource classes compared to prior auctions.

*MISO*. MISO experienced volatile capacity prices from 2022 to 2024, with most zones clearing at the Net CONE value of $7.2 per kW-year in the 2022-23 auction and below $1 per kW-year in 2023-24 and 2024-25. This volatility has been driven by MISO's use of vertical demand curves, which have led to extremely low prices when there was minimal surplus capacity (resulting in retirements of existing generators) and periodic major price spikes. MISO has undertaken major capacity market enhancements in recent years including the implementation of a seasonal capacity market and capacity accreditation enhancements (in 2023) and a sloped demand curve (in 2025). MISO prices jumped to approximately $6.5 per kW-month (on an annualized basis) in the 2025-26 auction, as the region continues to be affected by recent retirements.

*CAISO*. The California CPUC also implements a resource adequacy program to ensure sufficient capacity to operate the grid reliably, with an effective planning reserve margin requirement between 20 and 22.5 percent. Capacity contracts are negotiated bilaterally between suppliers and LSEs and there is not a uniform clearing price. The capacity cost component in Figure 1 represents the soft offer cap of capacity procurement mechanism in CAISO for procuring backstop capacity. Lagged data (as of 2023) from the CPUC suggests that RA contract prices have risen dramatically in recent years, which is likely due to retirements and shrinking capacity margins. The weighted average prices were $7.7, $10.1 and $9.04 per kW-month for the 2022, 2023 and 2024 delivery periods, respectively.

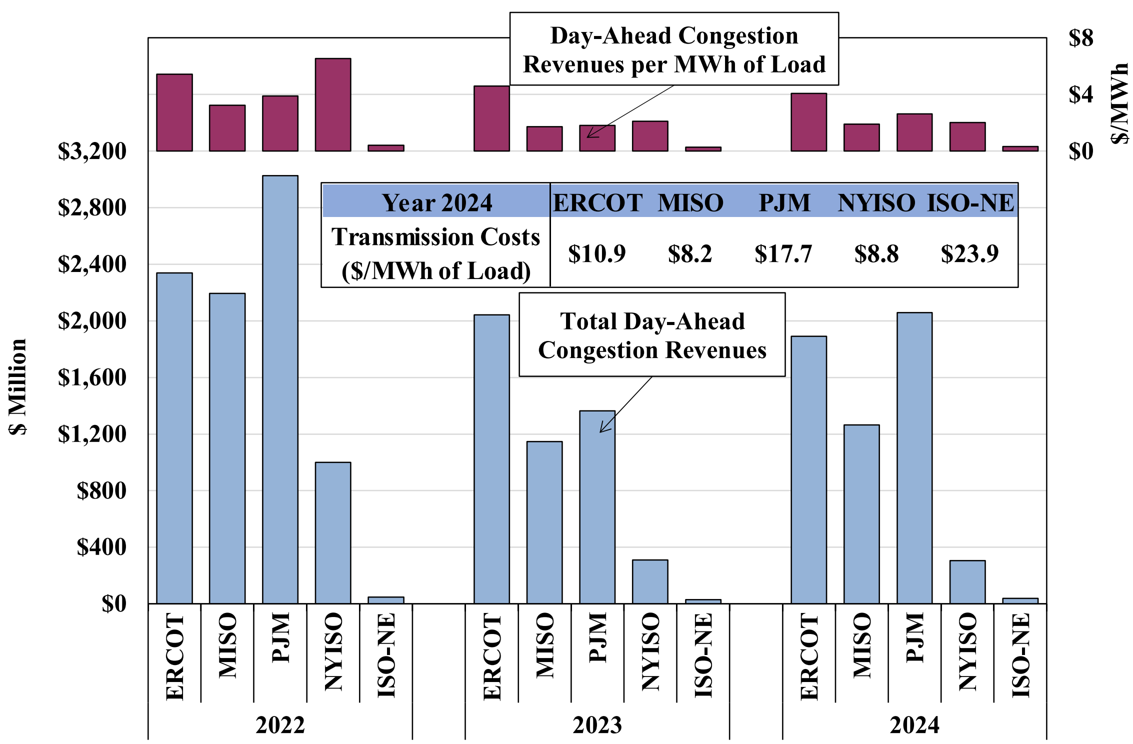
*ERCOT and SPP*. These markets operate "energy-only" markets (i.e., no capacity market), although SPP enforces a 12 percent planning reserve requirement.

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

## B. Transmission Congestion

One of the principal objectives of the day-ahead and real-time markets is to commit and dispatch resources to control flows on the transmission system and efficiently manage transmission congestion. Figure 2 shows the congestion revenues collected through the day-ahead markets across several RTO markets in the U.S. To account for the different sizes of the RTOs, we show the total day-ahead congestion revenues divided by the actual load in the top panel of the figure.

**Figure 2: Day-Ahead Congestion Revenues**
2022-2024




| Year 2024 | ERCOT | MISO | PJM | NYISO | ISO-NE |
|---|---|---|---|---|---|
| Transmission Costs ($/MWh of Load) | $10.9 | $8.2 | $17.7 | $8.8 | $23.9 |

Figure 2 shows that ISO-NE experienced far less congestion than other RTOs, averaging $0.33 per MWh over the past three years. In contrast, congestion levels per MWh of load in the other RTOs were six to thirteen times higher. The low level of congestion in New England can be attributed to substantial investments in transmission infrastructure made over the past 20 years to address reliability needs and support local transmission security. These investments have produced transmission rates of almost $24 per MWh in 2024, which are more than double the average rates observed in the other RTO areas shown in the figure.

The transmission rates in other RTO areas are much lower than in New England, even given the billions in incremental transmission costs that have been incurred in other markets to support the integration of renewable resources:

- ERCOT has incurred more than $5 billion in transmission expansion costs to mitigate the transmission congestion between the wind resources in western Texas and the load centers in eastern Texas.
- MISO has invested in transmission exceeding $15 billion to integrate renewable resources throughout MISO has already approved plans to build more than $35 billion more through its Long Range Transmission Planning process.
- Likewise, the NYISO has approved over $16 billion in transmission projects since 2019 to deliver of renewable energy to downstate load centers and facilitate the delivery of future offshore wind energy. These public policy-driven investments are not included in Figure 2. They have grown at a rate of approximately $0.50 per MWh annually in recent years to $2.50 per MWh in 2025 and are expected to rise more quickly in the future.

As described above, the primary driver of transmission expansion in other markets have revolved around increasing the deliverability of renewable resources. In contrast, ISO-NE's transmission expansion has been driven by local transmission security reliability planning criteria over the past two decades. ISO New England's reliability planning process identifies a local need for transmission when the loss of load would occur under the simultaneous failures of the two largest contingencies during a 90th-percentile peak load scenario. This planning criterion is more stringent than those employed by the other three RTOs. From 2002 through March 2025, investments in New England to maintain reliability totaled approximately $13 billion, with an additional $0.3 billion planned through 2029.[9]

In general, transmission investment is economic when the marginal benefit of congestion reduction exceeds the marginal cost of the investment. Given that average congestion costs in New England have been low, approximately $0.33 per MWh of load over the past three years, additional investment would not likely be economic in the near term. Nonetheless, past transmission investment has eliminated substantial local reliability NCPC costs and better prepared the system to integrate renewable resources in the future.

9 See *RSP Project List and Asset Condition List – March 2025 Update*, Planning Advisory Committee Meeting, March 19, 2025.

## C. Uplift Charges and Cost Allocation

Net Commitment Period Compensation (NCPC) costs, often referred to as "uplift costs" across the industry, typically account for a small share of wholesale market costs. However, they are important because they usually occur when the market requirements fail to fully align with actual system reliability needs or when prices are otherwise not fully efficient. Ultimately, this undermines the economic signals that govern behavior in both day-ahead and real-time markets in the short-term, as well as investment and retirement decisions in the long-term. Hence, we monitor the market for potential inefficiencies by scrutinizing the causes of NCPC payments. Table 1 summarizes the total day-ahead and real-time NCPC charges in ISO-NE over the past three years, along with the comparable 2024 uplift charges for both NYISO and MISO.

**Table 1: Summary of Uplift by RTO**

| | | ISO-NE | | | NYISO | MISO |
|---|---|---|---|---|---|---|
| | | 2022 | 2023 | 2024 | 2024 | 2024 |
| **Real-Time Uplift** | | | | | | |
| **Total** | **Local Reliability ($M)** | $1 | $1 | $1 | $7 | $2 |
| | **Market-Wide ($M)** | $37 | $25 | $27 | $18 | $17 |
| **Per MWh of Load** | **Local Reliability ($/MWh)** | $0.01 | $0.01 | $0.01 | $0.05 | $0.00 |
| | **Market-Wide ($/MWh)** | $0.32 | $0.22 | $0.23 | $0.12 | $0.03 |
| **Day-Ahead Uplift** | | | | | | |
| **Total** | **Local Reliability ($M)** | $1 | $1 | $1 | $9 | $14 |
| | **Market-Wide ($M)** | $13 | $4 | $6 | $6 | $17 |
| **Per MWh of Load** | **Local Reliability ($/MWh)** | $0.01 | $0.01 | $0.01 | $0.06 | $0.02 |
| | **Market-Wide ($/MWh)** | $0.11 | $0.03 | $0.05 | $0.04 | $0.03 |
| **Total Uplift** | | | | | | |
| **Total** | **Local Reliability ($M)** | $2 | $2 | $2 | $16 | $16 |
| | **Market-Wide ($M)** | $50 | $29 | $33 | $24 | $35 |
| **Per MWh of Load** | **Local Reliability ($/MWh)** | **$0.02** | **$0.01** | **$0.02** | **$0.11** | **$0.02** |
| | **Market-Wide ($/MWh)** | **$0.43** | **$0.26** | **$0.28** | **$0.16** | **$0.05** |
| | **All Uplift ($/MWh)** | **$0.45** | **$0.27** | **$0.30** | **$0.27** | **$0.08** |

To allow for meaningful comparison despite the varying size of the ISOs, the table also shows these costs per MWh of load. Additionally, recognizing that different RTOs may differ in their extent of making reliability commitments in the day-ahead horizon versus real-time, the table includes a sum of all day-ahead and real-time uplift at the bottom.

**Market-Wide Uplift:** Table 1 shows that ISO-NE incurred more market-wide uplift costs than the other two markets, adjusted for its size. Like prior years, ISO-NE's market-wide NCPC costs in 2024 more than doubled the average cost per MWh of load incurred by NYISO and MISO.

The higher uplift costs in New England are attributable to several factors:

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 broader of circumstances than those in MISO and NYISO. It would be beneficial to examine these differences to identify best practices across markets.

2) Second, ISO-NE experienced higher levels of real-time economic NCPC payments to fast-start units committed in economic merit order (~$11 million in 2024) than NYISO and MISO. In Section IV.B, we analyze some of the causes these uplift payments.
3) Third, NYISO and MISO typically incur lower market-wide uplift costs partly because of their day-ahead ancillary services markets, which allow a larger share of the costs associated with committing resources for operating reserves to be reflected directly in market prices.

Despite these structural differences, ISO-NE's market-wide cost per MWh of load have fallen significantly over the past two years. This decline was primarily driven by a significant reduction in day-ahead commitments for systemwide operating reserves. Starting in March 2025, the ISO began to procure operating reserves in the day-ahead market, which should significantly reduce the levels of uplift in the day-ahead market going forward.

**Local Reliability Uplift:** Table 1 also indicates a notable reduction in local reliability NCPC uplift over the past three years. This decline reflects minimal supplemental commitments in constrained load pockets because of new resource additions and ongoing transmission upgrades in key areas. As a result, uplift for local reliability in ISO-NE has remained considerably lower than in other RTOs, particularly NYISO. In contrast, NYISO continues to incur substantial local uplift due to the need to commit a large amount of generation for local second contingency protection in New York City and several other load pockets. In addition, oil-fired peaking resources on Long Island are often dispatched out-of-merit in real-time to manage local voltage needs. These local reliability requirements are inadequately reflected in NYISO's energy and reserve markets, leading to inefficient prices, higher uplift costs, and poor investment incentives for resources that could better support local reliability.

**Uplift Allocation:** Beyond differences in the magnitude of uplift costs, the allocation of these costs also varies significantly across RTOs. ISO-NE allocates real-time "Economic" NCPC charges to real-time deviations, including virtual transactions, although most of these NCPC charges are not directly caused by such deviations. In fact, over the past three years, fast-start resources have accounted for more than 60 percent of real-time Economic NCPC payments. These payments are often the result of uneconomic commitments in real-time in response to forecast errors. Real-time deviations such as virtual transactions typically have little or no role in causing this uplift. On the contrary, 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 their gross profitability, representing the difference between the day-ahead and real-time energy prices used to settle the energy bought or sold by the virtual trader. Notably, these profitability numbers do not account for uplift costs allocated to virtual transactions, which are shown separately in an additional column of the table.

**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 | 2021 | 2.8% | -$1.29 | 4.5% | $2.07 | $0.53 |
| | 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 |
| NYISO | 2024 | 6.3% | -$0.64 | 7.4% | $0.82 | < $0.1 |
| MISO | 2024 | 15.8% | $0.39 | 14.5% | $0.51 | $0.11 |

Table 2 shows that virtual trading is generally profitable, suggesting it contributes to improving price convergence between the day-ahead and real-time markets. However, virtual trading activities in ISO-NE remain significantly lower than in the other RTOs, averaging only 9 percent of load compared to 14 to 30 percent in the other two RTOs. This disparity was due in part to the over-allocation of NCPC charges to real-time deviations in New England. Such allocations discourage virtual participation, reduce the day-ahead market liquidity, and ultimately impair market performance. Hence, we continue to recommend the ISO modify the allocation of Economic NCPC charges to align with "cost causation" principles. Specifically, this would involve ceasing the allocation of NCPC costs to virtual load and other real-time deviations that do not cause real-time economic NCPC (See Recommendation #2010-4).

## D. Coordinated Transaction Scheduling

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

The lower panel in Figure 3 shows the annual average quantities of price-sensitive CTS bids and schedules from 2018 to 2024.[10] Positive numbers indicate transactions from neighboring markets to the NYISO or MISO markets, while negative numbers represent transactions from neighboring markets to the PJM or New England markets. The upper panel shows the market efficiency gains from CTS measured by production cost savings, excluding estimates for the PJM-MISO process because of very limited participation.

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

**Figure 3: CTS Scheduling and Efficiency**
2018 – 2024

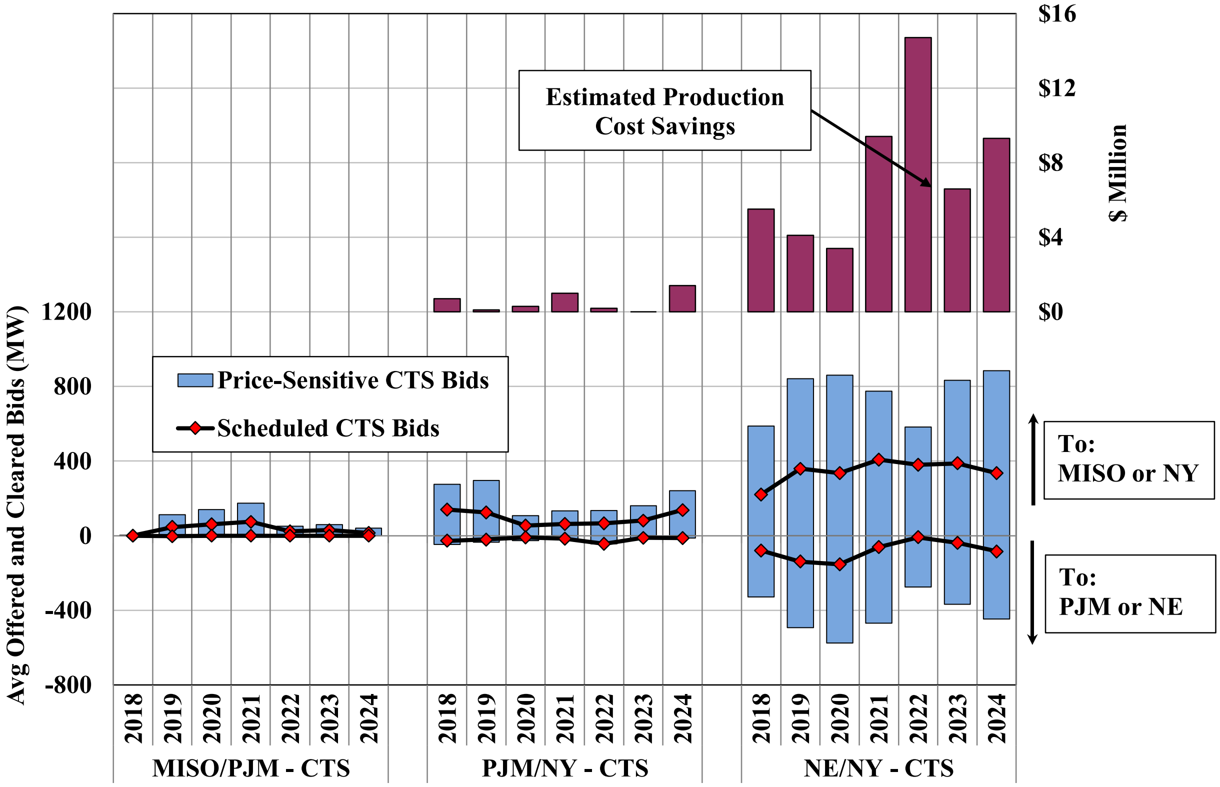



Figure 3 indicates a much higher level of CTS participation at the NE/NY interface compared to the PJM/NY and PJM/MISO interface. This disparity is largely attributable to the substantial transaction fees imposed at both the PJM/NY and PJM/MISO interfaces. In contrast, the NE/NY interface benefits from the absence of significant transmission or uplift charges. These findings underscore that such charges act as economic barriers to achieving the full potential benefits of CTS by discouraging participants from submitting efficient CTS offers.

The estimated production cost savings from the NE/NY CTS process totaled $53 million over the past seven years, while the estimated savings were just $4 million at the PJM/NY interface.[11] In addition to higher liquidity, better price forecasting has also contributed to higher savings at the NE/NY interface. ISO-NE's forecasting is much more accurate than PJM's, partly because ISO-NE forecasts a supply curve with seven interchange levels, while PJM only forecasts a single price point at one assumed interchange level. Enhancing the accuracy of these price forecasts could further increase the cost savings achieved through the CTS processes.

However, forecasting improvements may be limited by the fact that they are produced roughly 40 minutes in advance. An alternative process we have evaluated for MISO and PJM is to make

[11] 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.

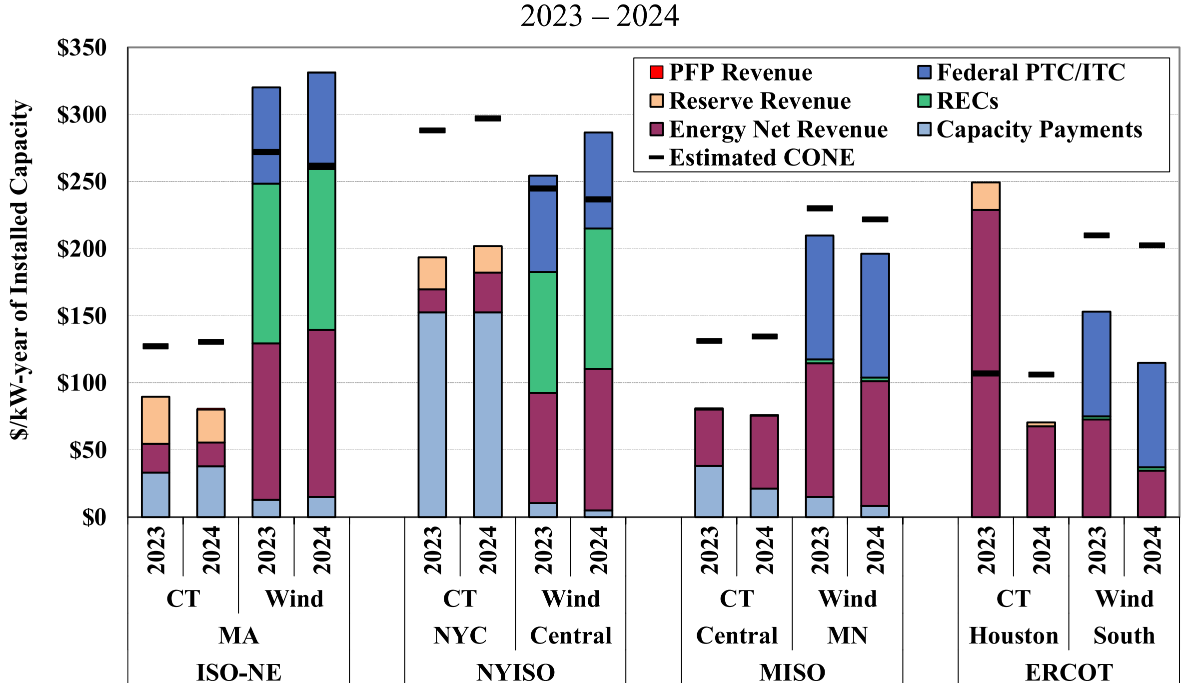
interchange adjustments every five minutes based on the most recent real-time prices. The estimated savings of such a process for MISO and PJM were much larger than those achieved by any of the current CTS processes, warranting consideration for New England and New York.

## E. Net Revenues for New Entrants

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

This section compares the investment incentives in ISO-NE to other markets by estimating the net revenue new resources would have earned from the wholesale markets and applicable state and federal incentives. Figure 4 shows the estimated net revenues for a new combustion turbine and a land-based wind unit from market products and state and federal incentives.[12] The figure also shows the estimated annual net revenue that would be needed for these new investments to be profitable (i.e., the "Cost of New Entry" or CONE) in 2023 and 2024.

**Figure 4: Net Revenues Produced in ISO-NE and Other RTO Markets**
2023 – 2024




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

***Incentives for New Combustion Turbines (CT)***

Net revenues for a CT from the energy and reserve markets were below CONE values in all regions in 2024, generally reflecting surplus conditions in capacity markets. New investment in combustion turbines in most markets is heavily reliant on capacity revenues, which have remained low in ISO-NE. Figure 4 provides the following insights regarding incentives to invest in CTs in each market:

- *New England*. The capacity and energy prices over the last two years in ISO-NE would generally not support investment in new CTs. This is efficient for a market with surplus capacity, where new entry is likely to occur only if a resource has specific advantages (e.g., cost savings due to repowering, access to cheaper gas, etc.). The capacity surplus and associated low capacity prices will continue through at least 2027/28 CCP.
- *New York City*. Net revenues in New York City were below the estimated CONE of a new CT despite relatively tight capacity margins there (which resulted from the retirement of peaking units affected by state environmental regulations in 2023). This is because the CONE of a new CT (based on estimates from the 2024 Demand Curve Reset study) is significantly higher than the CONE values underlying the capacity demand curves in 2023 and 2024, which were determined in 2020 and did not account for cost inflation of CT components being higher than broader indicators of inflation over the the last four years. Beginning in May 2025, the demand curve Net CONE value for NYC is based on a two-hour battery, resulting in a 40 percent increase to the Net CONE from 2024.
- *ERCOT*. The net revenues of a CT in ERCOT were much higher than in other markets in 2023 and lower in 2024. ERCOT does not have a capacity market, so net revenues of peaking units when the market is tight are derived from higher frequency of scarcity pricing hours. ERCOT experienced frequent price spikes in 2023 associated with the poor implementation of a new reserve requirement that overstated the system's level of scarcity, roughly doubling average energy prices from June through December of 2023. Large-scale new entry of solar and storage resources in 2024 significantly reduced the frequency of price spikes, resulting in lower net revenues.
- *MISO*. Capacity prices in MISO were inefficiently low in 2023 and 2024 due to the use of a vertical demand curve, which tends to produce very low price if there is any surplus above the minimum planning reserve margin. MISO held its first auction with a sloped demand curve (among other changes to its capacity market structure and parameters) in 2025, resulting in significantly higher clearing prices sufficient to justify investment in a new CT.

Although shortage pricing is a very important component of the expected revenues in both ISO-NE and ERCOT, a large share of ISO-NE's shortage pricing is settled through its PFP framework. This PFP 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.[13]

ii. ISO-NE has stop-loss provisions that limit, on a monthly and annual basis, the losses that a capacity resource could incur due to poor performance in PFP events.[14] These provisions limit the financial risk to generators while generally maintaining significant supplier 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 is designed to produce a higher reserve margin than in an energy-only market like ERCOT.

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

Hence, the profile of the risks faced by suppliers and consumers, as well as the likelihood of shortage events, is considerably different in ISO-NE than a typical energy-only market.

***Incentives for New Land-Based Wind Projects***

Net revenues for land-based wind units in New England exceeded its CONE in 2023 and 2024. This was largely due to state and federal incentives, which accounted for nearly 60 percent of revenues in both years. Market revenues are also important because they provide price signals that differentiate the value of resources based on the needs of the power system. Hence, the markets complement state policies by guiding investment towards more efficient technologies and locations, enabling the more economic resources to win policy-driven solicitations.

Figure 4 shows that the incentive to invest in wind resources varies widely in other markets. Resources in New York receive significant REC revenues from long-term contracts for 20 years with NYSERDA, which contributes to them being economic in New York.[15] Renewable resources in most of MISO and ERCOT had lower total revenues because they receive much smaller state incentives in those markets and because higher saturation of wind results in lower market prices in hours when wind output is high, especially in ERCOT. Land-based wind investment has historically been stronger in MISO and ERCOT where resource potential is better

13 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.

14 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.

15 The figure reflects NYSERDA Tier 1 REC prices in NY and MA Class I REC prices in New England.

than in New England and New York and there are fewer siting challenges. Indeed, the small amount (~180 MW) of land-based wind generation that has been installed in New England since the beginning of 2023 has been in Maine where there are fewer challenges to siting new wind generation.

Federal tax incentives may be eliminated for land-based wind projects if portions of the Inflation Reduction Act are repealed. While this would tend to reduce investment in wind generation, lower renewable generation investment will lead to higher net revenues for energy and capacity, and some state programs may provide increased incentives to make up for some of the loss in federal incentives.

We evaluate the trends in the development of renewable energy resources in more detail, including a discussion of the alternative contracting approaches employed by different states and other entities in Section II of this report.

## F. Managing Price Volatility in a Prompt Capacity Market

In 2024, ISO-NE launched the Capacity Auction Reforms (CAR) project to explore replacing the current Forward Capacity Market with a prompt auction occurring much closer to the capability period. Some stakeholders have raised concerns that moving to a prompt auction structure will lead to excessive or unmanageable risk for consumers and suppliers due to capacity price fluctuations that are not known in advance. In this subsection we discuss how market participants in neighboring NYISO, which has a prompt capacity market, manage price risk over the short and medium term to mitigate spot market volatility.

### *Overview of NYISO's Prompt Capacity Market*

NYISO's primary capacity auction is its spot auction, which occurs every month a few days prior to the month covered by the auction. NYISO also runs voluntary forward auctions including its Capability Period Auction (a six-month strip traded in the month prior to the summer and winter capability periods) and Monthly Auctions in which capacity can be transacted for each remaining month in the capability period. The spot auction uses an administratively determined demand curve, while the strip and monthly auctions are cleared based on supply and demand offers.

Capacity prices in NYISO over a year in advance are relatively uncertain. Generators' short-term fixed costs for the next month are largely sunk at the time a given spot auction occurs, so suppliers generally offer as price takers in the spot market. As a result, prices are determined by the total amount of supply relative to the demand curve. Preliminary information about the demand curves for the next May-to-April capability year (including the systemwide Installed Reserve Margin, Locational Capacity Requirements, and demand curve price levels) becomes available in fall of the previous year (i.e., six or seven months ahead of the capability year) but is not finalized until March (which is less than 60 days ahead of the capability year). Hence, there is limited information about spot prices more than eight months in advance of the capability year. Unexpected price volatility can also occur within a capability year due to variations in supply such as capacity imports, exports, demand response participation or major unplanned generator outages.

***Hedging Practices in NYISO's Prompt Capacity Market***

NYISO's capacity market has long served as the basis for contracting and other hedging practices. In recent years, over half of systemwide capacity requirements have been satisfied through physical bilateral transactions (~35 percent), which are bilateral transactions or self-supply arrangements that identify a specific resource through the NYISO scheduling system (as opposed to financial hedges that do not identify a specific resource), and purchases in the voluntary "strip" and "monthly" auctions (approximately 20 percent), which occur several months in advance. There is evidence that a large amount of capacity is hedged on a multi-year basis through physical and financial contracts as discussed below.

The landscape for contracting is shaped by New York's industry structure, which includes a dynamic retail choice market for loads and relatively little ownership of generation by the state's regulated utilities. About 42 percent of peak load in New York is 'bundled' load served by the utilities, while approximately 30 percent is served by competitive 'retail choice' load-serving entities (LSEs) and the remainder is served by public power authorities (including NYPA and LIPA) and municipalities. Retail choice LSEs serve most of the state's commercial and industrial load, while the vast majority of residential load are bundled utility customers. Each of the different types of LSEs engage in practices that hedge spot market volatility:

- New York's utilities are required by the Public Service Commission to maintain supply portfolios that are partially, but not fully, hedged for retail and small commercial customers.[16] This guidance is intended to balance shielding unsophisticated customers from price volatility, flexibility in utilities' supply management, efficient incentives for larger loads, and promotion of a competitive retail choice market.
- Retail choice LSEs engage in a variety of hedging practices including bilateral contracting and direct ownership of generation. Major diversified companies such as Constellation and NRG (Direct Energy) have both retail load portfolios and generation portfolios in New York. While the extent of bilateral contracting between LSEs and generators is not publicly available, LSEs routinely offer multiple year fixed price supply contracts to loads. This suggests that LSEs in New York are often able to hedge their capacity price risk through physical or financial contracts or that they are sufficiently diversified to accept spot market volatility.
- The state's Public Power authorities (NYPA and LIPA) either directly own or enter into long term contracts with large amounts of generation capacity, significantly lowering their exposure to spot market volatility.

[16] See April 19, 2007 Order by NYPSC in Case 06-M-1017.

Figure 5 and Figure 6 demonstrate some details on capacity supply management in New York City, the region with the highest and most volatile spot prices in the NYISO market. Figure 5 shows approximately how much of the Locational Capacity Requirement (LCR) is covered by known utility/NYPA supply management arrangements and competitive retail supply. The total size of the pie chart is the LCR of 9.0 GW (UCAP) in 2023. Of this, only 2.4 GW (27 percent) was not covered by Con Edison and NYPA contracts and ownership, competitive retail arrangements, or participation in NYISO's Special Case Resource demand response program (which conveys an innate hedge against capacity prices to participating loads).

Figure 6 compares historic NYC spot capacity prices with the costs of capacity from firm contracts reported by Con Edison rate filings. Con Edison routinely issues competitive RFPs for one-year capacity contracts one, two, and three years in advance, resulting in laddered capacity hedges that mitigate short to mid-term price volatility for its residential and small commercial customers. Over the past decade, the costs of contracted capacity were higher on average but significantly more stable than the spot capacity price.

**Figure 5: Breakdown of New York City Capacity Requirement (GW)**

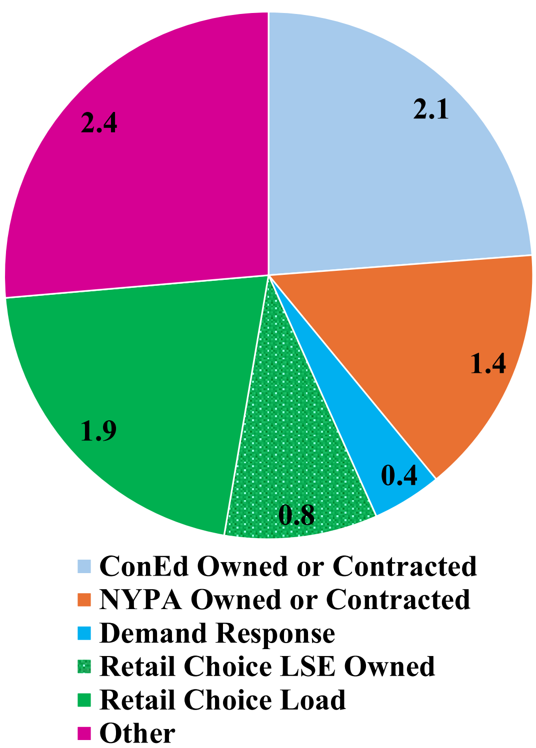
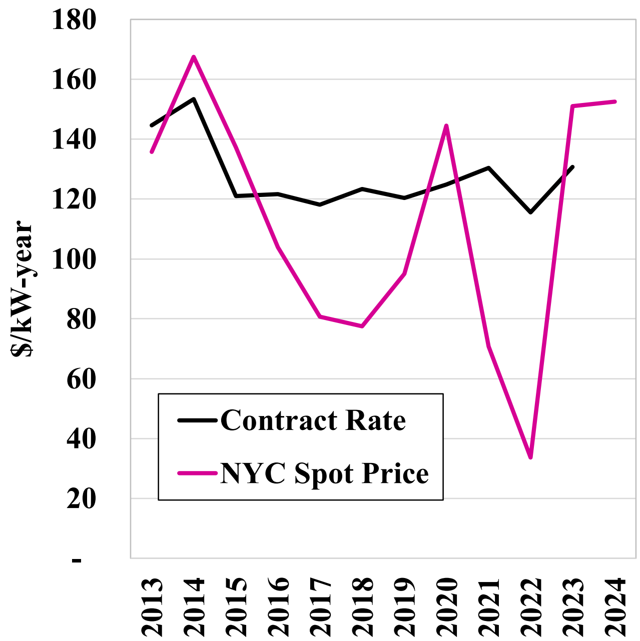



**Figure 6: Con Edison Capacity Contracts vs New York City Price**



### *Conclusions on Risk Management in Prompt Capacity Markets*

While future spot prices in New York's capacity market are relatively uncertain, end users' exposure to price volatility is mitigated by PSC-directed hedging practices of utilities and access to competitive retail suppliers offering contracted rates. The spot market has served as a basis for capacity hedges through bilateral contracts and portfolio strategies of LSEs. Hence, the volatility of overall consumer costs is significantly less than the volatility of spot capacity prices.

ISO-NE' Forward Capacity Auction prices have also fluctuated considerably because of year-to-year changes in load forecasts, locational capacity requirements, and the systemwide capacity requirement as well as unforeseen entry and exit of supply. However, while the New York capacity market facilitates bilateral contracting and other risk management practices, bilateral hedging is much more difficult ahead of New England's FCAs because it requires significantly more lead time in advance of the capability period. Thus, prompt capacity markets like the one in New York are generally expected to produce overall consumer costs that are less volatile than consumer costs in areas with forward capacity markets.

New England shares many characteristics of New York that may facilitate the emergence of bilateral markets and strategic portfolios alongside a prompt capacity auction. Most New England states have introduced retail choice in their electric sectors and many of the same entities that are active as both LSEs and merchant generation owners in New York operate in New England as well. Development of a transparent prompt market design will create incentives for supply management by competitive LSEs, while guidance from state public utility commissions may be required to align the incentives of regulated utilities with stable and lower prices for their captive customers.

# II. Navigating the Clean Energy Transition

All of the RTO markets have been navigating the transition to a much heavier reliance on intermittent renewable resources and energy storage, and some are well ahead of New England in this process. To summarize the penetration of renewable resources in different markets, Figure 7 shows the average portion of the load in each market that is served by renewables.

**Figure 7: Renewable Output as a Share of Load**
2020 – 2024

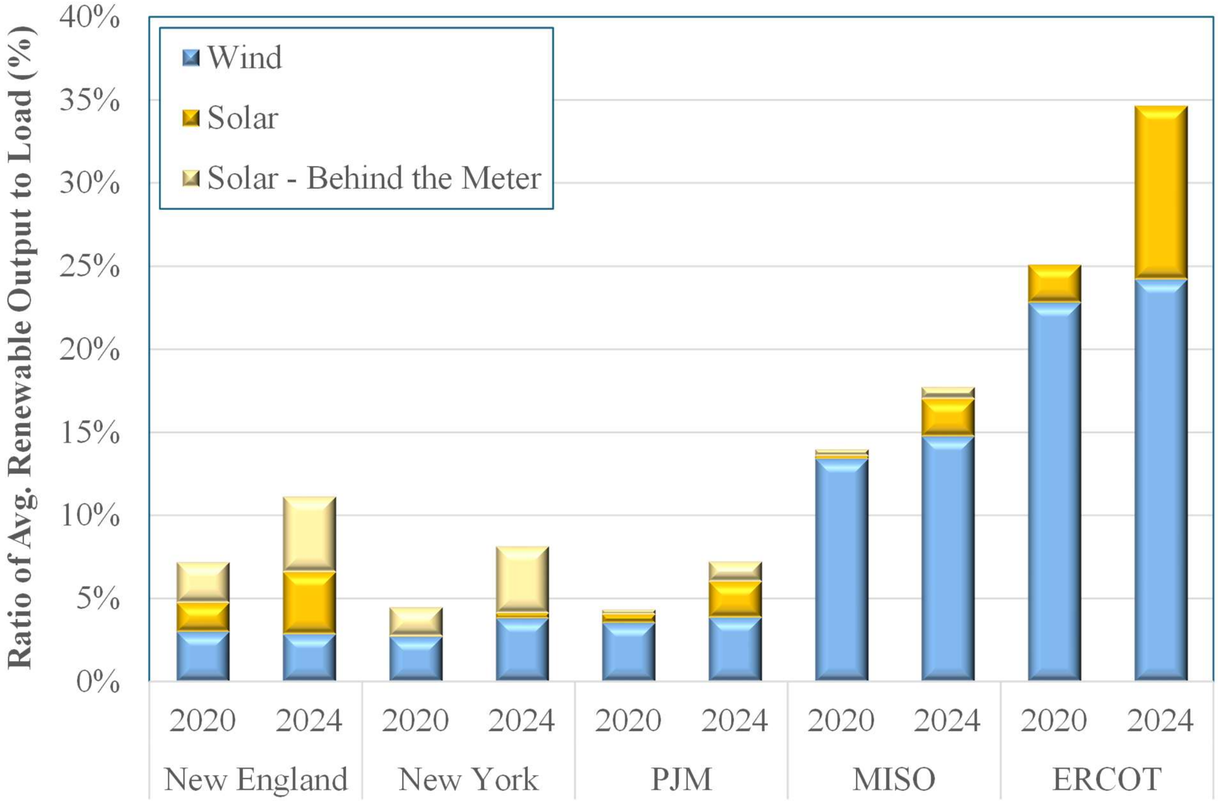



Figure 7 shows that despite the public policy priority placed on the development of renewable resources in both New York and New England, the development of these resources has been slower in the Northeast than in other regions. This figure shows that a much higher share of the renewable output in New England is solar, both in front of and behind the meter, than in any other market. This has important implications for the challenges New England may face that are discussed later in this subsection.

## A. Renewable Resource Development in New England

Although renewable energy development in New England has progressed significantly over the past decade, the pace of development has been slower than necessary to meet the ambitious mandates and targets of most New England states. In the past decade, 3.2 GW of new solar, 0.9

GW of wind, and 0.6 GW of battery storage have entered the ISO-NE market, in addition to approximately 4 GW of new behind-the-meter solar.

Limitations on sites and resource potential for land-based renewables have led several New England states to prioritize offshore wind procurements, with contracts for 4.8 GW of offshore capacity signed by Massachusetts, Rhode Island and Connecticut between 2018 and 2022. Rising costs led to most of these contracts becoming financially non-viable for developers, resulting in cancellation of 3.2 GW. Of the remaining contracts, approximately 800 MW are expected to begin participating in the ISO-NE market in 2025 and 700 MW in 2026.[17] Massachusetts and Rhode Island announced selection of an additional 2.9 GW of offshore projects through a coordinated multi-state procurement in September 2024, with Connecticut declining to select any projects. The timing of these projects is uncertain, as contracts have yet to be finalized and at least one project developer has reportedly withdrawn from negotiations.[18]

New England states have also made major policy commitments to energy storage, with combined mandates of 7 GW of storage by the 2030 to 2033 timeframe. Roughly 40 percent of the projects in the interconnection queue are energy storage projects, which total more than 18 GW. Storage projects in ISO-NE to date have consisted of short duration batteries, which are less expensive and have benefited from ISO-NE capacity market rules that grant full capacity credit to two-hour systems, which overvalues their reliability benefits. Massachusetts' recently enacted mandate of 5 GW of battery storage by 2030 explicitly targets longer duration-systems, while ISO-NE's proposal to implement marginal capacity accreditation will also reward longer duration storage. Hence, ISO-NE is likely to see an influx of new storage resources with longer durations in the next five years.

### *Current Status of the Interconnection Queue*

In evaluating the evolution of the generation portfolio in New England, it is instructive to review the new generation interconnection queue although many of the projects in the queue may not ultimately be constructed. As of the end of May 2025, the queue included more than 400 projects totaling more than 50 GW of installed capacity.

Table 3 summarizes the active projects in the queue by technology type and the share of the total installed capacity that each represents. It is important to recognize that the installed capacity from different types of resources provide very different reliability to the system. ISO New England will be implementing a marginal accreditation framework that translates these installed

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17 The 800 MW Vineyard Wind project began to deliver power from initial turbines in late 2023 but encountered setbacks due to a major turbine failure in 2024 requiring replacement of defective blades on the installed turbine towers. The project is expected to commence full operations in 2025. The 700 MW Revolution Wind project is currently under construction.

18 See January 20, 2025 article "Massachusetts Offshore Wind Contract Signing Pushed Back Again" at offshorewind.biz (link).

capacity levels into fungible capacity quantities. For example, the marginal value of wind and solar resources are substantially less than the value of dispatchable resources. Wind resources in most markets are trending toward accreditation in the 5 to 10 percent range and solar resources will trend to zero as more enters.

**Table 3: Active Projects in the Interconnection Queue**

| Technology | # Projects | GW | % of GWs |
|---|---|---|---|
| Solar* | 228 | 4.9 | 12% |
| Battery Storage | 122 | 18.4 | 45% |
| Land Based Wind | 15 | 2.7 | 7% |
| Offshore Wind (Active Contract) | 2 | 1.5 | 4% |
| Offshore Wind (No Contract) | 19 | 11.9 | 29% |
| HVDC | 1 | 1.2 | 3% |
| Fossil | 6 | 0.1 | 0% |

* Includes 94 hybrid solar projects (incl. storage) totaling 1.4 GW

Table 3 shows that virtually none of the generation projects in the interconnection queue are dispatchable conventional resources. Although roughly 45 percent of the resources are battery storage that are technically dispatchable, they are limited in their ability to satisfy certain key reliability needs. For example, limited duration batteries provide much less reliability support to the system during extended cold spells during the winter.

The table shows that apart from the battery storage resources, the largest quantity of new resources is offshore wind at roughly one third of all installed capacity. Almost 90 percent of these offshore wind resources currently have no contracts and are at substantial risk of not proceeding because of federal policy actions, supply chain issues, and economic pressures that have caused a large number of developers to withdraw or postpone their projects. Offshore wind operates at a higher and more consistent capacity factor than land-based wind. Hence, these resources would provide far more support for winter reliability than other intermittent renewable resources. If these resources do not proceed to completion, ISO New England will need new dispatchable resources to meet its reliability requirements.

Unfortunately, no dispatchable resources are in the interconnection queue, other than battery storage resources. This establishes some clear priorities for ISO New England and the states:

- It will be critical to retain a large share of the existing dispatchable generation and avoid mandating retirements of fossil fuel resources;
- ISO-NE will need to establish marginal capacity accreditation that accurately signals the reliability value of different types of resources;
- The states should consider permitting the addition of back-up on-site fuel storage at gas-fired resources. This is likely the lowest-cost strategy for addressing winter reliability concerns in the near-term in light of the issues with offshore wind development.

- From an operational perspective, it will be important to focus on the improvements needed to optimize the battery storage resources and other new technologies.

### *Alternative Contracting Structures for New Renewable Resources*

As described above, a number of the New England states are seeking to promote the development of renewable resources to support carbon reduction goals. This includes state-sponsored procurement processes and contracting. Hence, the investment incentives in renewable resources depend not only on wholesale prices and federal tax incentives, but also on the offtake contract structures employed in different regions:

- Investment in ERCOT is supported by private financial hedges and contracts.
- Long-term PPAs are the dominant mechanism for stabilizing revenues for renewable resources in ISO-NE and NYISO.

*Incentive Effects of Bundled REC PPAs*. These PPAs (typically with utilities) generally pay a fixed-price for every MWh of energy produced by the project and tend to be 20-years long. The buyers in such contracts (ultimately consumers) generally assume three key risks:

- *Basis risk* – risk of congestion between the wind node and the hub;
- *Volumetric risk* – risk of underperformance that would require buyers to purchase any shortfall at spot prices; and
- *Cannibalization risk* – risk that if new projects offer at more negative prices to reflect rising state and federal incentives, it may cause older renewable resources offering at higher prices to be curtailed.

It is not ideal for these risks to be assumed by consumers because they have little control over the location of the project, the project's technology, or the operation and maintenance of the project. Project owners are in a better position to manage these risks when compared to off takers.

*Incentive Effects of Index REC PPAs*. These PPAs have become common in New York, which has sought to combine certain financial risk-reducing characteristics of bundled REC PPAs with provisions that still encourage firms to invest and operate efficiently. Index REC PPAs pay for a price per MWh of energy equal to the contract strike price minus a published monthly index price for energy. The generator also collects revenue for energy production at the spot energy price.[19] This partially insulates the developer from wholesale energy price volatility driven by key factors such as natural gas prices. However, the developer retains the three key risks that arise from high intermittent renewable penetration listed above.

*Incentive Effects of Financial Hedges.* Hedges between private entities have allowed for significant development of clean energy resources in other markets (e.g., ERCOT). This

19 For example, if the strike price is $70/MWh and the monthly index energy price is $28/MWh and the LMP is $15/MWh, the generator receives a REC payment of $42/MWh (= $70/MWh - $28/MWh) plus $15/MWh.

demonstrates that renewable resources can be developed on a merchant basis, even if there are no available PPAs with state agencies or regulated utilities. A typical hedge is a “contract for differences” where the supply pays or receives the difference between the prevailing price and a contract strike price and a specified location, typically for less than the full output of the unit.

Overall, owners of projects financed using hedges are exposed to the basis risk and volumetric risk that those with traditional PPAs do not face. This is good because the wind supplier is in the best position to manage these risks. If units under PPAs underperform, it is the ratepayers that would generally bear the costs of the poor performance rather than the wind unit owner. Even though relying on financial hedges is preferred, the availability of attractive PPAs offered by state agencies or regulated utilities will inhibit hedging with private counterparties.

## B. Future Potential Challenges and Issues to Address

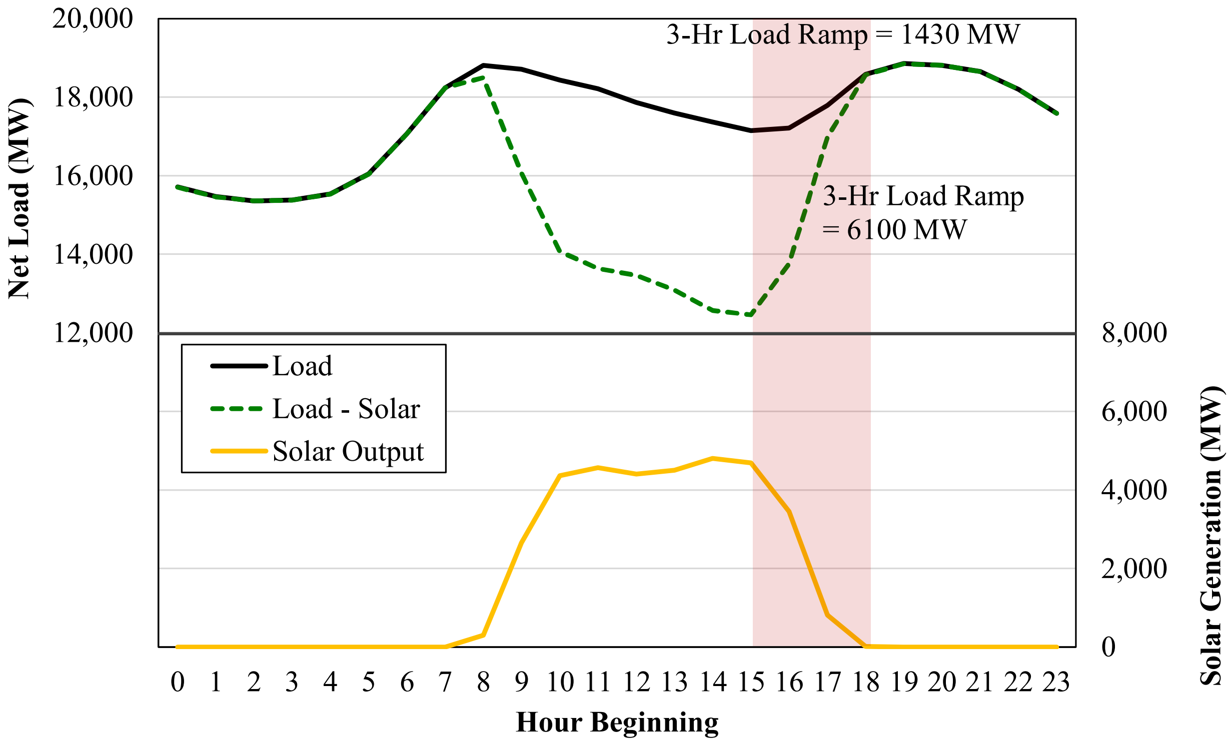
Other markets with higher penetration have experienced substantial operating challenges that intermittent renewable resources raise. Concerns have been raised regarding renewable resources setting negative prices that could adversely affect conventional resources. Since most resources receive production tax, they offer at negative prices because they only have an incentive to stop producing energy when the LMP is more negative than the production tax credit. However, this has not been a substantial concern in any of the RTO markets. Renewables rarely set system-wide prices in any market because conventional resources are always needed to meet the total system demands and they tend to set prices. For example, system-wide prices were negative in New England in only 0.35 percent of intervals. In ERCOT, the market shown above with the highest penetration of renewables, system-wide prices were negative in only 2.4 percent of intervals.

However, renewable energy resources and energy storage resources do raise unique and substantial operating concerns that each of the markets are working hard to address. These challenges are described below.

### *Increased Output Uncertainty and Ramping Demands*

Given the operating profile of solar resources, these resources will lead to significant changes in the system’s ramping needs that must be satisfied by conventional resources. For example, as solar output falls in the evening in the winter months, the load is typically increasing to the second peak load of the day. This can place great stress on the conventional generating fleet to satisfy this ramp demand. One metric for measuring the demand on conventional generation is “net load”, which is load minus renewable energy output. Figure 8 shows a representative load on a high-load winter day, representative solar output in three to four years as solar capacity continues to grow, and the load net of solar output. This net load curve has been referred to as the “duck curve” because of its shape.

**Figure 8: Solar Output and Net Load Ramp**
High-Load Winter Day




This figure shows that because the solar output rises and peaks between the two daily winter peaks, it increases the need for the conventional generation fleet to ramp. As shown, the net load ramp from 3 to 6 p.m. can be relatively sharp. The figure shows that while the load ramp is just over 1400 MW, the net load ramp is more than 4 times larger. This ramp can be even larger if wind output happens to be falling in these hours. This underscores the importance of having dispatchable generation available to satisfy the system's needs.

### *Voltage and System Support*

Traditional synchronous generators inherently produce and absorb reactive power, which is critical for voltage regulation across the system. As these generators are displaced by renewables, the system loses a key source of dynamic and steady-state voltage support. While renewable resources and energy storage, inverter-based resources (IBRs), can provide reactive power through their inverters, this capability is often underutilized or unavailable. If renewable resources enter at network locations characterized by high impedance and low short-circuit strength, it can reduce the voltage regulation and stability in these areas.

Additionally, while synchronous generators contribute system inertia that helps stabilize voltage and frequency in the immediate aftermath of disturbances, IBRs lack this inertia unless synthetic inertia or fast frequency response features are implemented. Moreover, some IBRs may trip offline during transient voltage dips, exacerbating the voltage recovery problem.

MISO and ERCOT, the two markets shown above with the highest penetration of renewable resources, are addressing these issues with the following initiatives:

- MISO has strengthened its generator interconnection procedures to require new renewable resources to provide reactive power capability and voltage regulation. In addition, MISO has imposed automatic voltage control obligations, ensuring IBRs actively participate in voltage regulation.
- Likewise, ERCOT has implemented new protocols that require inverter-based resources to contribute to system reliability through the Fast Frequency Response (FFR) service and mandatory reactive power and voltage control requirements for new generators.
- MISO and ERCOT have supported the deployment of synchronous condensers to provide both dynamic reactive support and short-circuit current, mitigating voltage instability and supporting system strength.
- MISO incorporates voltage support needs into its regional planning framework.
- ERCOT employs a "Short Circuit Ratio" (SCR) screening methodology to identify areas with weak grid conditions and it may require mitigation measures such as additional reactive support devices, re-dispatch, or project downsizing.
- ERCOT monitors voltage stability and inverter behavior during disturbances. Lessons learned from events—such as widespread IBR tripping during voltage sags—inform ongoing updates to performance requirements.

As the penetration of renewable resources and storage resources increases, ISO-New England may need to consider some of these strategies to address these voltage and system support issues.

### *Dispatch Performance and Control*

One issue that has arisen in markets where renewable energy resources contribute to transmission congestion is that some units do not adhere to dispatch instructions. This has likely not been a problem yet in ISO-NE because of the very low levels of congestion and limited renewable penetration.

This issue arises when renewable resources are on the margin for providing relief on the constraint and setting the price at its location. If a renewable resource is offering at -$30 per MWh and receiving a curtailment dispatch instruction from the ISO because it is overloading a transmission constraint, the price at its location will be -$30 per MWh. A supplier then has two choices:

- Respond to the curtailment and lose $30 because it will lose its production tax credit; or
- Ignore the curtailment and pay ISO-NE $30 because its LMP is -$30 per MWh.

Hence, the supplier is economically indifferent in this example between following the curtailment instruction and not following. This raises significant operational risks because the ISO will not be indifferent. The value of congestion reflected in the LMPs is calculated assuming resources follow dispatch instructions. In cases where renewable resources have not followed curtailment instructions in other markets, the systems often experience severe constraint violations that raise substantial reliability risks. If one were to calculate the LMP at the resource's location in this example based on the actual constraint violation when it does not follow dispatch instructions, the price could be an order of magnitude more negative or greater.

Because of these pervasive concerns in other markets, we have recommended dispatch deviation penalties based on the congestion component at resources' locations to ensure that suppliers are never indifferent to following the ISO's dispatch instructions to curtail when needed to manage congestion.

An additional dispatch issue pertains to the length of the dispatch intervals. Generators are expected to achieve the instructed output by the end of the upcoming interval. In ISO New England, this is 10 to 15 minutes in the future as opposed to the five-minute interval used in MISO, ERCOT and some of the other RTOs. This is important because renewable resources can ramp extraordinarily quickly. Because renewable resources may achieve the instructed dispatch levels in less than one minute, rather than at the end of the dispatch interval, system operators have experienced generation imbalances and transmission flow deviations that must be managed.

#### *Renewable Resource Forecasting*

As renewable resource penetration increases, uncertainty related to output forecasting tends to increase. Forecasting occurs in multiple timeframes:

- Real-time dispatch timeframes – the upcoming 15 minutes – which is based heavily on the current observed output of the intermittent
- Forward timeframes ranging from 1 or more hours ahead of real time to one or more days ahead of real time.

The real-time forecast is critical because it determines the dispatch instructions sent to all resources in the market to satisfy demand and manage transmission flows. Real-time forecasts that lag the renewable output changes as wind speed or cloud cover changes can reduce the ISO's control of the system.

The forward forecasts are also important because they allow the ISO to plan for the changes in the output of dispatchable resources needed to accommodate the changes in output of the intermittent renewable resources. This often requires the commitment or decommitment of such resources. It is equally important to accurately forecast both the magnitude and timing of the renewable output changes.

The markets with higher penetrations of renewable resources have faced substantial forecasting challenges, both in the real-time and forward timeframes. MISO, for example, has made a number of changes to its real-time forecasting processes to reduce the renewable dispatch deviations that have caused challenges in managing congestion of constraints affected by these resources. Likewise, the magnitude of the forward forecast errors has increased as MISO's renewable resource base has expanded. To address these errors, MISO has made a number of changes to its processes over time:

- MISO had relied heavily on forecasts produced by the wind resource operators, but these forecasts often exhibited high and biased errors;
- MISO utilized a vendor to produce forecasts for its resources and implemented settlement rules that provide a strong incentive for its wind suppliers to allow MISO to use MISO's own forecast rather than submitting their own forecasts.
- Although the forward forecasts are no longer biased, MISO continued to periodically struggle with large forecast errors. It has worked with its vendor to improve the forecasts and secured a second vendor.

Developing and improving the real-time and forward forecasting processes is a continuing priority for all RTOs and ISOs engaged in the rapid transition of their generating fleet.

#### *Utilizing the Markets to Facilitate the Transition*

Given these operational challenges faced in other RTO markets, it is advisable to consider the lessons learned to prepare to reliably manage the fleet transition over the upcoming decade. Fortunately, ISO-NE's fundamental market design is robust and well-structured to handle these challenges. From a market design standpoint, it is critical for the markets to efficiently incent investment in and retention of the flexible resources needed to complement the intermittent resources. This requires two essential market design elements:

- *Efficient shortage pricing* mechanism that will reward flexible resources when intermittent forecast errors or output fluctuations cause transitory supply shortages. We believe ISO-NE's shortage pricing and PFP rules adequately address this element.
- *Marginal capacity accreditation* that will compensate resources in the capacity market consistent with their marginal contribution to maintaining reliability. ISO-NE is actively pursuing changes that should address this element.

Some have been concerned that intermittent resources will set negative energy prices in many hours and substantially reduce the market incentives for conventional resources. This is not a substantial concern because conventional resources will continue to be needed in most hours, even under high renewable penetration. Additionally, the increase in reserve shortages and shortage revenues should more than offset the reduction in revenues during non-shortage hours.

In addition to these elements, increasing reliance on intermittent resources and battery storage will create dispatch challenges that a 5-minute dispatch model cannot always solve efficiently. We believe that it will be essential for ISO-NE to develop a look-ahead dispatch model that can optimize the dispatch of the following classes of resources and set prices with this optimization:

- Conventional resources that may need to begin ramping several dispatch intervals in advance of a sharp increase in net load or at times of increased uncertainty; and

- Energy-limited pumped storage, battery storage, and DERs that can only be optimized over a longer time horizon.

A look-ahead dispatch will reduce the costs of managing the expected increases in net load fluctuations and provide efficient incentives for developers of battery storage and other flexible resources. Therefore, we recommend (#2023-1) that ISO-NE evaluate the potential benefits and costs of a look-ahead dispatch model that would optimize for multiple hours into the future and set prices that provide individual resources with incentives to offer efficiently and follow dispatch instructions. This will require substantial research and development but will likely need to be a key component of ISO-NE's strategy to economically and reliably manage the transition of its generating portfolio.

# III. Competitive Assessment of the Energy & Reserve Markets

This section evaluates the competitive performance of the ISO-NE energy market in 2024. Although Locational Marginal Pricing (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, existing only in certain areas and 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 important to evaluate the competitive structure and conduct in the ISO-NE markets because participants may still have incentives to exercise market power at levels below mitigation thresholds.

Based on the analysis in this section, we identify the geographic areas and market conditions that present the greatest potential for market power abuse. We use a methodology for identifying competitive concerns developed in prior assessments of ISO-NE's competitive performance.[20] We address five main areas in this section:

- Mechanisms by which sellers exercise market power in LMP markets;
- Structural market power indicators to assess competitive market conditions;
- Potential economic and physical withholding;
- Market power mitigation in 2024; and
- Market power mitigation during the initial implementation of DASI.

These evaluations allow us to fully 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 economic or physical withholding of generating capacity. Economic withholding occurs when a resource is offered at prices above competitive levels, reducing its output or otherwise raising the market clearing price. Physical withholding occurs when all or part of the output range of a resource is not offered into the market when it is available and economic to operate. Physical withholding can be accomplished by "derating" a generating unit (i.e., reducing the unit's high operating limit).

While many suppliers can increase prices by withholding, not every supplier can profit from doing so. For withholding to be profitable, the benefit of selling the remaining supply at prices above the competitive level must exceed the lost profits from the withheld output. In other words, withholding is only profitable when the price impact exceeds the opportunity cost of lost

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

sales for the supplier. The larger a supplier is relative to the market, the more likely it will have the ability and incentive to withhold resources to raise prices.

Several factors (other than supplier size) affect the potential for exercising market power:

- **Price sensitivity to withholding**: Prices can be highly sensitive to withholding during high-load conditions or in congested local areas;
- **Forward contracts:** These can reduce a supplier's incentive to raise market prices;[21] and
- **Information availability**: Access to information that helps predict market vulnerability can enable suppliers to time their 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 of greatest concern in areas where capacity margins are small, particularly in import-constrained areas. Hence, this subsection analyzes the three main import-constrained regions and all 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 square 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.

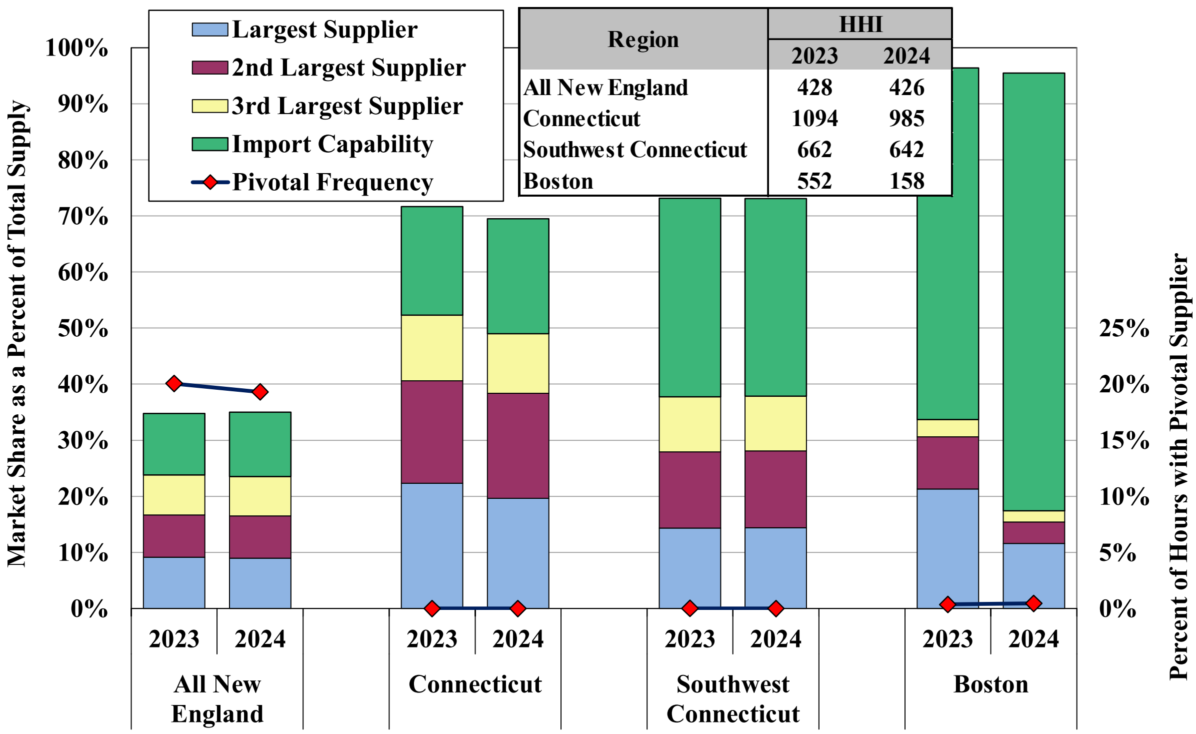
The first two structural indicators focus exclusively on the supply side. Although widely used in other industries, their usefulness is limited in electricity markets because they ignore that the inelastic demand for electricity substantially affects the competitiveness of the market.

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

21 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 still exists because spot prices will eventually affect prices in the forward market.

Figure 9 shows three structural market power indicators for four regions in the past two years. It shows the market shares of the largest three suppliers and the import capability in each region using stacked bars. The remainder of the supply in each region is held by smaller suppliers.

**Figure 9: Structural Market Power Indicators**
2023 – 2024




The import capability and market shares are based on public ISO-NE data, and the inset table shows the HHI for each region.[22,23] We assume imports are highly competitive, treating the market share of imports as zero in our 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 typically cannot ramp down substantially and would be costly to withhold due to their low marginal costs.

Figure 9 indicates that the market concentration of internal generation remained relatively stable from 2023 to 2024 across most regions, with the exception of Boston. Although there were some changes in asset ownership during this period, these shifts did not significantly affect the market shares of the top suppliers in most areas. In Boston, however, the retirement of two combined-

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22 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.

23 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.

cycle units, Mystic 8 and 9, at the end of May in 2024 resulted in significant changes. The second largest supplier in the region became the largest, and the share of supply from competitive imports rose significantly from 63 percent to 78 percent.

Market concentration varied significantly across the four regions. In Boston, import capability accounted for the vast majority (78 percent) of total supply, which includes both internal generation and imports. In contrast, in all New England, the three largest suppliers held comparable market shares, each below 10 percent, with import capability contributing a more modest 11 percent of total supply.

The market concentration, as measured by the HHI, remained low in 2024, under 1,000 in all regions. HHI values above 1800 are typically considered highly concentrated by the U.S. Antitrust Agencies and FERC when evaluating the competitive effects of mergers. However, it is important to note that the absence of high HHI values does not necessarily eliminate market power concerns. These concerns are most accurately assessed in our pivotal supplier analysis for 2024, which indicates that:

- There were almost no hours with a pivotal supplier in Southwest Connecticut and Connecticut.
- In Boston, the pivotal supplier frequency remained low, occurring in less than 0.5 percent of hours even following the retirement of two large combined-cycle units. In addition, these infrequent instances were generally associated with minimal congestion into the Boston area; and
- In all New England, at least one supplier was pivotal in 19 percent of hours.[24]

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

In all New England, the pivotal supplier frequency fell slightly from 2023 to 2024. In 2023, the pivotal supplier frequency was higher than usual in the months from September through December, coinciding with planned outages of several pumped storage units that reduced available reserves at the system level. Excluding these months, pivotal supplier frequency rose modestly in 2024. The increase reflected higher load levels and a continued decline in net imports from Quebec, partly due to reduced rainfall and runoff.[25] This was partially offset by

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24 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.

25 In practice, some of the unused import capability is offered into ISO-NE's real-time market, although it is have, if scheduled, passed through the check-out procedure with the neighboring control area. Thus, basing

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higher nuclear generation resulting from fewer maintenance and forced outages. Given these findings, we review supplier conduct in all of New England in the next subsection.

## C. Economic and Physical Withholding

Suppliers with market power can exercise it by either economically or physically withholding resources. We measure potential economic and physical withholding using the following metrics:

- **Economic withholding:** we estimate an "output gap" for units that produce less output because they have raised their economic offer parameters (start-up, no-load, and incremental energy) significantly above competitive levels. The output gap is defined as the difference between a unit's capacity that would be economic at the prevailing clearing price and the unit's actual output.[26]
- **Physical withholding:** we focus on short-term deratings and outages, as they are most likely to represent strategic physical withholding behavior. Short-term withholding is generally less costly than long-term outages, which typically result in 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 participant size because market power is most likely when load is high (and excess supply held by competitors is low) and the participants' size is large. Evaluating the correlation of conduct with these factors helps test whether the output gap and short-term physical deratings are consistent with attempts to exercise market power, thereby indicating potential market abuse.

Because the pivotal supplier analysis raises potential competitive concerns in all New England, Figure 10 shows the output gap and short-term physical deratings by load level in this region. The output gap is calculated separately for:

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

Our short-term physical withholding analyses examine:

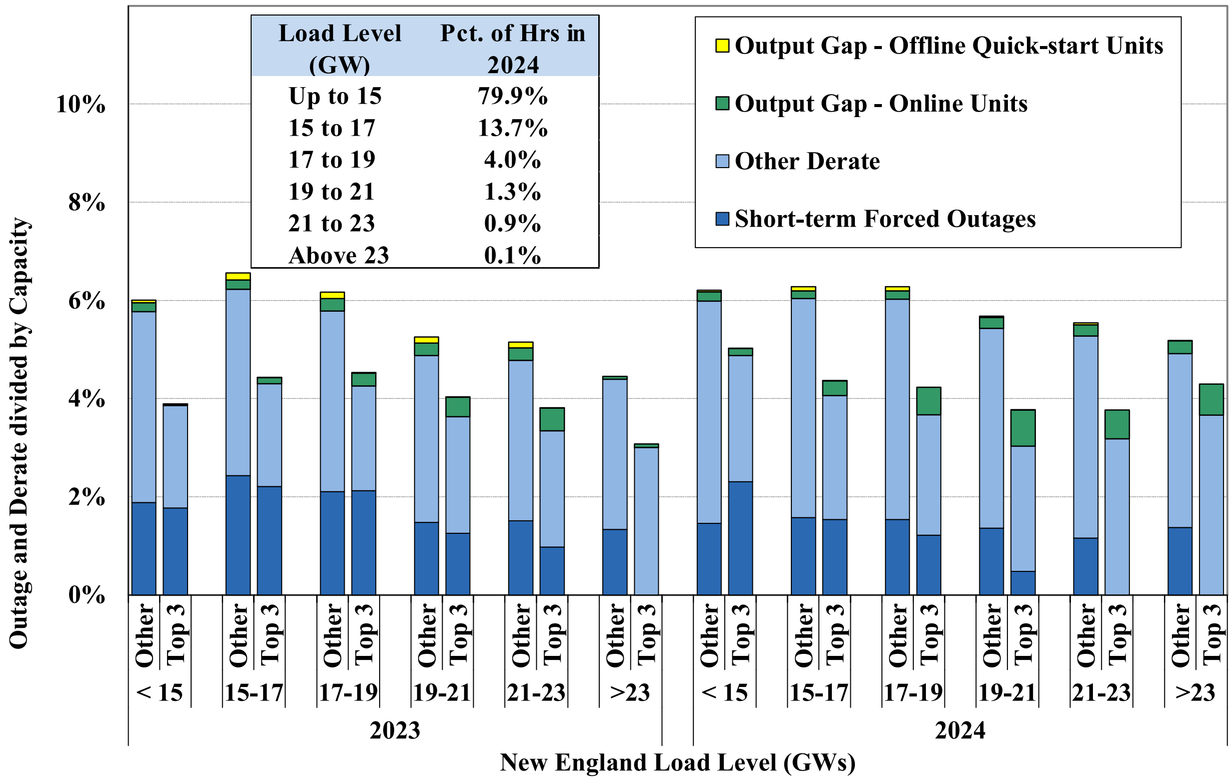
- **Short-term forced outages** that typically last less than one week; and
- **Other derates** that include reductions in the hourly capability of a unit not logged as a forced or planned outage. This can result from ambient temperature changes or other legitimate factors.

our pivotal supplier analysis on actual import schedules is conservative because it may underestimate the amount of competitive supply that is available in a given hour.

26 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 10 shows these metrics as a percentage of suppliers' portfolio size, distinguishing between the largest suppliers and the other suppliers in the past two years. The analysis compares the three largest suppliers, who collectively owned 27 percent of internal generating capacity in both years, to all other suppliers.

**Figure 10: Average Output Gap and Deratings by Load Level and Type of Supplier**
All New England, 2023 – 2024




The figure indicates that the "Other Derate" category was usually higher than the other categories. This category includes instances when some combined-cycle capacity was offered and operated in configurations with reduced capability during off-peak hours, which is an operationally efficient practice that generally does not raise significant competitive concerns. In addition, high ambient temperatures during summer peak load hours often reduce the capacity ratings of thermal resources. Excluding the contributions of the "Other Derate", the overall output gap and deratings in 2024 were modest relative to total system capacity, consistent with observations from 2023.

The levels of overall output gap and short-term deratings generally decreased as load levels increased. The output gap and short-term forced outages (excluding 'Other Derate') were very low during the highest load hours (above 23 GW) when prices are most sensitive to withholding. Additionally, compared to small suppliers, the largest suppliers generally exhibited lower levels of overall output gap and short-term deratings, particularly at higher load levels. These are both indications that the conduct of large suppliers was generally competitive, especially when it mattered most.

Overall, these results indicate that the energy market performed competitively in 2024, with no significant evidence of withholding aimed at raising market clearing prices.

## D. Market Power Mitigation in 2024

Mitigation measures are intended to mitigate abuses of market power while minimizing interference with the market when it is workably competitive. The 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). Mitigation is only imposed when suppliers' conduct exceeds well-defined conduct thresholds above a unit's reference levels and the impact on market outcomes exceeds specified market impact thresholds. This framework ensures mitigation is used only when necessary to address market power, while allowing high prices during legitimate periods of shortage.

In import-constrained areas, the market can be substantially more concentrated, necessitating more restrictive conduct and impact thresholds than those employed market-wide. The ISO has two structural tests (i.e., Pivotal Supplier and Constrained Area Tests) to determine which of the following mitigation rules are applied: [27]

- **Market-Wide Energy Mitigation (ME):** ME mitigation evaluates the incremental energy offers of online resources. This 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). This 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 that is committed to manage congestion into a constrained area.
- **Local Reliability Commitment Mitigation (RC)**: RC mitigation is applied to a resource that is committed or kept online for local reliability.
- **Start-up and No-load Mitigation (SUNL):** SUNL mitigation is applied to any resource that is committed in the market.
- **Manual Dispatch Mitigation (MDE):** MDE mitigation is applied to resources that are dispatched out of merit above their Economic Minimum Limit levels.

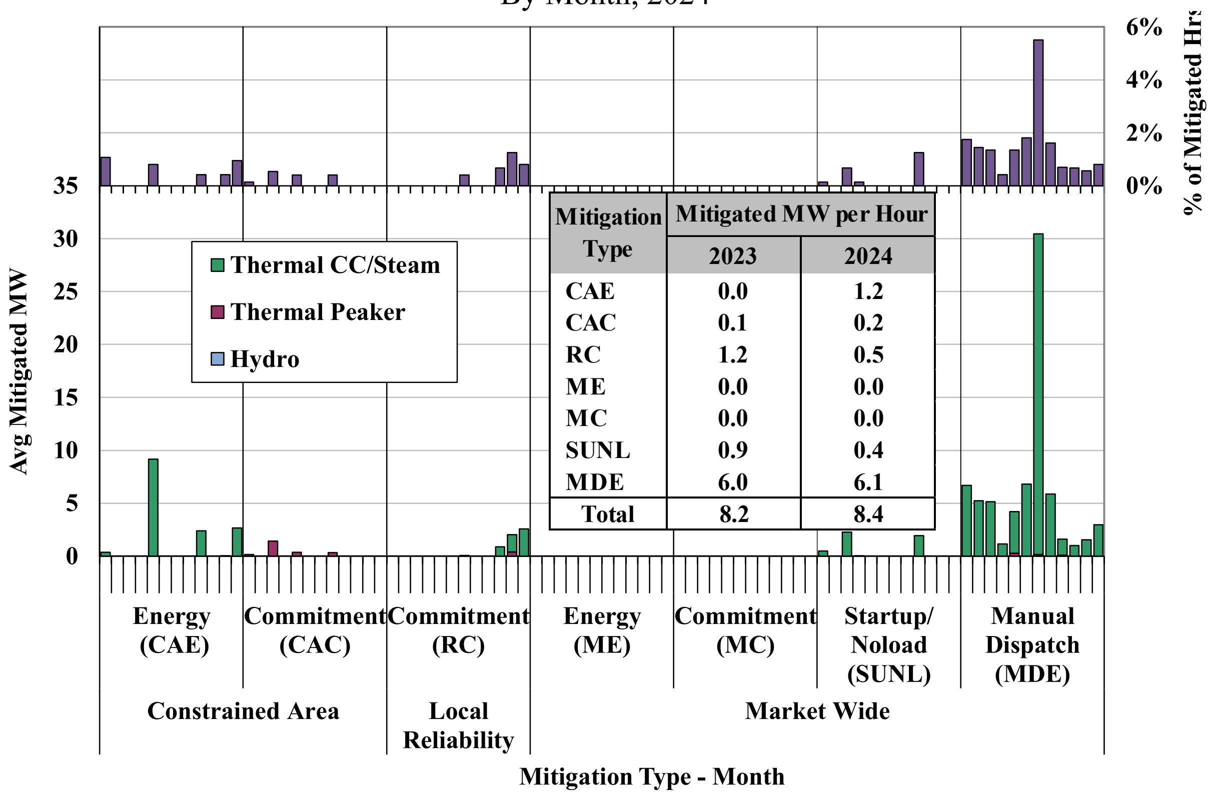
There are no separate impact tests for the SUNL mitigation, the MDE mitigation, and the three types of commitment mitigation (i.e., MC, CAC, and RC). Consequently, suppliers are mitigated

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

if they fail the conduct test in these five categories. This approach is reasonable because this type of mitigation normally only affects uplift payments, which increase as offer prices rise, making it unnecessary to determine whether the conduct test-failing offer had an impact on 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 11 examines the frequency and quantity of mitigation in the real-time market during each month of 2024. This analysis does not include any mitigation changes made after the automated mitigation process, since they constitute a very small share of the overall mitigation.

**Figure 11: Frequency of Real-Time Mitigation by Mitigation Type and Unit Type**
By Month, 2024




| Mitigation Type | Mitigated MW per Hour | |
|---|---|---|
| | 2023 | 2024 |
| CAE | 0.0 | 1.2 |
| CAC | 0.1 | 0.2 |
| RC | 1.2 | 0.5 |
| ME | 0.0 | 0.0 |
| MC | 0.0 | 0.0 |
| SUNL | 0.9 | 0.4 |
| MDE | 6.0 | 6.1 |
| Total | 8.2 | 8.4 |

The upper portion of the figure shows the portion of hours affected by each type of mitigation. If multiple resources were mitigated during the same hour, only one hour was counted. The lower portion of the figure 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 three categories of resources: hydroelectric units, thermal peaking units, and thermal combined cycle and steam units. The inset table compares the annual average amount of mitigation for each type over the past two years.

Mitigation has been infrequent in recent years, occurring in slightly more than 2 percent of all hours in 2024, down modestly from 2023. In 2024, nearly 80 percent of mitigation in the real-time market was for manual dispatch energy and local reliability commitment. This high proportion is expected because local reliability areas raise the most significant potential 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 their offers are not necessarily disciplined by competition. These two mitigation categories typically only affect NCPC payments and have little impact on energy or ancillary service prices. Most of MDE mitigation was on combined-cycle units that were typically instructed to provide regulation service or dispatched manually to address transient network issues.

Although local reliability mitigation has the tightest threshold (10 percent) among all types of mitigation, it is not fully effective because suppliers sometimes have the incentive to operate in a more costly mode and receive larger NCPC payments as a result. For example, combined-cycle units capable of operating in both multi-turbine configuration and single-turbine configuration often do not offer the single-turbine configuration when they are likely to be needed for local reliability. By offering a multi-turbine configuration, these units receive higher NCPC payments. We discuss this issue in more detail in Section I and continue to recommend that the ISO consider tariff changes that would expand its authority to address it.

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, while low reference levels may lead to mitigation below cost, suppressing prices inefficiently. Accurate cost estimation is challenging for certain generators, including:

- **Energy-limited hydroelectric and battery storage resources:** Their costs are almost entirely opportunity costs (the trade-off of producing more now versus producing or not charging later), which are difficult to accurately reflect.
- **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 natural gas prices in the winter create fuel cost uncertainties, which can be difficult to reflect accurately in offers and reference levels. This uncertainty is exacerbated by the requirement to determine offers and reference levels for the day-ahead market by 10 am the prior day.

Appropriately recognizing opportunity costs in resources' reference levels reduces inappropriate mitigation of competitive offers, helps conserve 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 to include in their reference prices. The model estimates opportunity costs by forecasting the profit-maximizing generation schedule for each unit with limited fuel supply over a rolling seven-day period and the opportunity cost adder ("Energy Market Opportunity Cost" or "EMOC") that would be required to limit its generation accordingly.

Market wide energy mitigation has been rare in recent years. The only occurrence was on December 24, 2022, when nine resources in one Lead Market Participant's portfolio were mitigated over multiple hours. Our 2022 report identified several aspects of the mitigation measures that resulted in inefficient market outcomes.[28] To address these inefficiencies, we recommended the ISO implement the following revisions to the current energy mitigation process (Recommendation #2022-2):

a) **Implement hourly conduct and impact tests**: Resources should only be mitigated in hours when they violate both conduct and impact tests, ensuring that mitigation is applied only when warranted.
b) **Allow multiple FPAs for calculating reference levels**: Enabling the use of multiple Fuel Price Adjustments (FPAs) to calculate reference levels for different output ranges will provide a more accurate representation of the variation in resources' costs over their output range. This flexibility would improve the accuracy of the reference levels and prevent inappropriate mitigation.
c) **Mitigate only offer segments that fail the conduct test**: Only the offer segments that exceed the conduct threshold should be mitigated rather than all segments. However, the offer prices of other segments might still be adjusted to ensure that the overall offer is monotonic. This would ensure that no resource is mitigated to a *higher* offer price.

In December 2023, ISO-NE partially addressed part "c" of the recommendation by using the lower of the offer and the reference level when imposing mitigation, thereby preventing offers from being mitigated upward.[29] This change will prevent the software from imposing mitigation on an offer component that does not fail the conduct test when the corresponding reference level is higher than the original offer, but it will continue to mitigate offer components that do not fail the conduct test if the reference level is lower than the offer. While this change does not fully address the concern, it is sufficient to adequately address Recommendation #2022-2c.

In November 2024, ISO-NE partially addressed part "b" of Recommendation #2022-2 by enabling generators to use FPAs to adjust reference levels for up to two different output ranges.[30] This will enable generators to represent their fuel costs more accurately and enable the IMM to monitor the use of FPAs more effectively, since it will reduce the uncertainties that lead to differences between reference levels and actual costs for generators.

We continue to recommend #2022-2a in this report since the current mitigation rules may continue to impose mitigation on resources for hours after their conduct does not fail the conduct test and/or the price impact does not exceed the impact threshold. The ISO has not yet determined whether and how to address this recommendation.

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

29 See *Revisions to ISO New England Transmission, Markets and Services Tariff to Eliminate Energy Supply Offer Upward Mitigation*, Docket No. ER24-324-000 (November 2, 2023).

30 See *Revisions to Expand Fuel Price Adjustment Functionality*, Docket No. ER24-2584-000 (July 24, 2024).

## E. Market Power Mitigation Measures under DASI

The Day-Ahead Ancillary Services Initiative (DASI) marks a major advancement in ISO-NE's day-ahead market, which had historically cleared only a single product, day-ahead energy. Launched on March 1, 2025, DASI enhances the market's ability to meet next-day system reliability needs by procuring ancillary services in the day-ahead market.

DASI introduced four new ancillary service products into the day-ahead market. Three of these, Ten-Minute Spinning Reserves (TMSR), Ten-Minute Non-Spinning Reserves (TMNSR), and Thirty-Minute Operating Reserves (TMOR), are classified as 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 a sufficient amount of energy and EIR to satisfy the forecasted load in the day-ahead market. All four products are co-optimized with energy in the day-ahead market and cleared using marginal-cost pricing. Their settlements are based on a call-option structure, linking day-ahead commitments with real-time performance obligations, and creating a more efficient and transparent framework for ensuring operational reliability.

Offers for DASI are structured differently from traditional energy offers. For each hour of the day-ahead market, participants submit a single quantity, representing the maximum amount of ancillary services they are willing to provide across all four eligible products. Alongside this quantity, participants may submit up to four separate prices, one for each reserve product.

Similar to energy offers, DASI offers are subject to mitigation measures that prevent the exercise of market power. The mitigation framework includes the following key 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, then an impact test is performed to evaluate whether the conduct-failing offers materially affected day-ahead market prices. If the impact test identifies a sufficiently large effect on one or more prices in the day-ahead market, all conduct-failing offers are mitigated to their calculated Benchmark Levels.[31]
- **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 with the Internal Market Monitor (IMM) and submit analytically supported override requests to ensure their specific cost expectations are considered.

31 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.

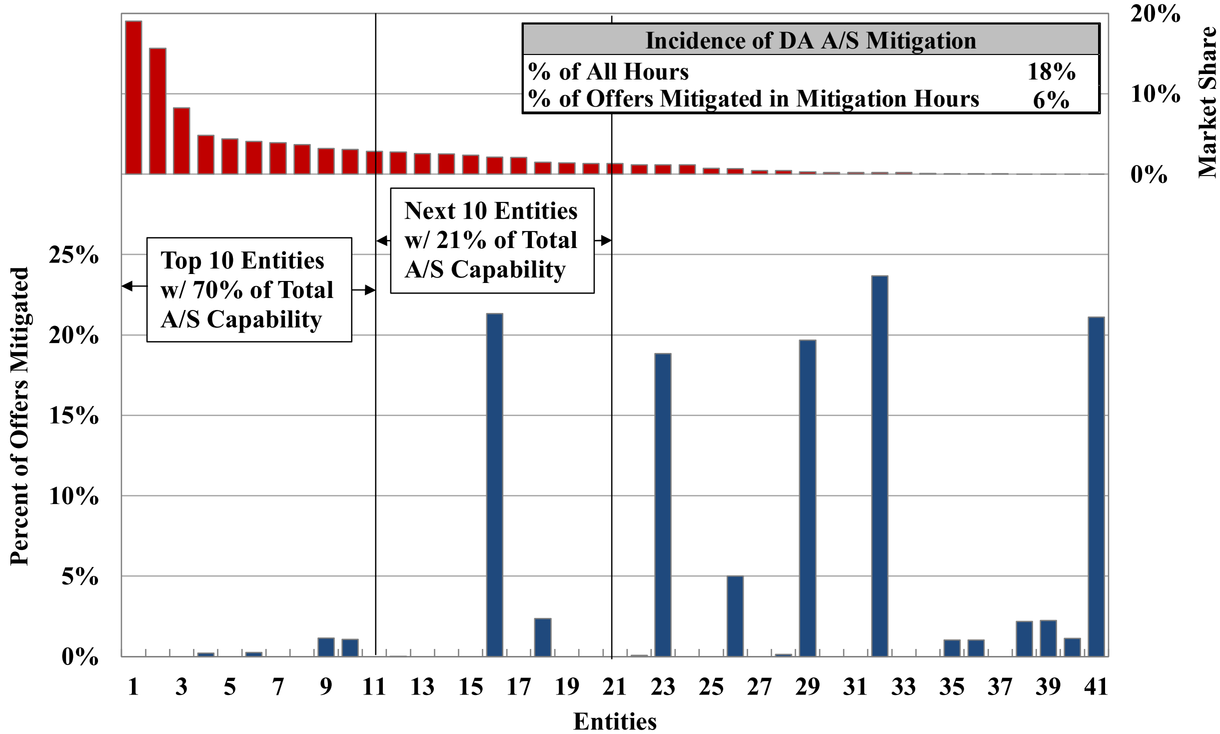
This mitigation structure is designed to deter exercises of market power and support efficient pricing, while allowing offer flexibility for legitimate cost deviations and reasonable variations in risk tolerances associated selling these option-based ancillary services. Mitigating offers that reflect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

Figure 12 presents an analysis of mitigation instances observed during the initial phase of DASI implementation. The analysis excludes the first 15 days of implementation (from March 1 to 15) when suppliers were adjusting to the new market design and evaluates the subsequent two-month period. The top panel of the figure illustrates the amount of reserve capability offered by each market participant as a percentage of the overall market, arranged in descending order from left to right. The bottom panel shows the share of each participant's reserve offers that were mitigated during the two-month period.

The figure shows that mitigation of day-ahead reserve offers occurred in 18 percent of all hours during the two-month study period of DASI implementation, far exceeding the frequency of energy market mitigation. Each instance of mitigation typically involved a substantial volume of reserve offers and many suppliers. On average, mitigated megawatt-hours (MWh) represented about 6 percent of all ancillary service offers in hours when mitigation occurred.

**Figure 12: Day-Ahead Ancillary Services Mitigation**

March 16 – May 15, 2025



The figure reveals that the vast majority of mitigation was imposed on relatively small suppliers that are unlikely to have market power. The top 10 suppliers together accounted for roughly 70 percent of total offered reserve capability, but only 9 percent of all mitigated offers. In contrast, small suppliers with approximately 6 percent of reserve offers were responsible for 35 percent of all mitigation. Notably, four of these smaller suppliers experienced mitigation rates of 20 to 25 percent on their offers during the first two months.

Additionally, the general pattern of mitigation has been different from expectations when the mitigation rules were designed. The ISO's Market Power Assessment found that (if not properly mitigated) the exercise of market power was most likely to be profitable on "tight" (i.e., very high demand) days. The Market Power Assessment did not identify market power concerns in the sort of low to moderate demand conditions that prevailed during the two-month period evaluated in Figure 12.[32]

We find that one of the primary reasons for the relatively frequent market power mitigation is the size of the conduct and impact thresholds. The formulas for the thresholds are described above and are based in part on the expected close-out costs for the option-based reserve products. Because the expected closeout costs are frequently near or less than $1 per MWh and the avoided input costs are generally low or zero, participants can begin to violate the conduct threshold by offering higher than $2 per MWh. However, the actual closeout costs have been volatile and frequently above $20 per MWh. Hence, this conduct threshold is likely to interfere with competitive participant reflecting legitimate risk preferences. Similarly, the impact threshold in this case can be as low as $1.50 per MWh, which we would consider too low to warrant market power mitigation.

These mitigation results, together with the relatively small size of the mitigation thresholds, raise concerns that current thresholds are excessively tight and resulting in mitigation of conduct that is unlikely to constitute and exercise of market power. Hence, we recommend that ISO-NE evaluate the appropriateness of its current conduct and impact threshold levels and revise them, if necessary, to avoid overly aggressive mitigation that may unduly burden smaller suppliers without addressing actual market power concerns (Recommendation #2024-2).

## F. Competitive Performance Conclusions

Overall, we find little evidence of structural market power in New England, either at the system level or in sub-regions. Our evaluation of participant conduct also suggests that the markets performed competitively with no evidence of market power abuse or manipulation in 2024. The pivotal supplier analysis suggests that structural market power concerns have diminished noticeably in Boston in recent years because of transmission upgrades. In 2024, one supplier

[32] See discussion before the NEPOOL Markets Committee in early 2023 here.

was pivotal in less than 0.5 percent of hours even after the retirement of two large combined-cycle units. In all of New England, the pivotal supplier frequency was comparable between 2023 and 2024, reflecting offsetting effects from higher load levels, declining in imports from Quebec driven by reduced rainfall, and higher nuclear output because of fewer maintenance and forced outages.

Although the market power mitigation rules have generally been effective in preventing the exercise of market power in the New England markets, we find one area where the mitigation measures have not been fully effective. This relates to resources that are frequently committed for local reliability. Despite the tight mitigation thresholds for these resources, suppliers have the incentive to operate in a higher-cost mode and receive higher NCPC payments as a result. This is discussed in more detail in Section IV.A. Hence, we recommend the ISO require resources to operate in the lowest-cost configuration when they are committed for local reliability or transmission security (Recommendation #2014-5).

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

In addition, we find that in the initial months of DASI implementation, market power mitigation was applied frequently and almost exclusively to small suppliers that are unlikely to have market power. Given these results and relatively tight mitigation thresholds, we find that the current mitigation measures warrant reassessment. Therefore, we 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 while avoiding interfering with competitive behavior (Recommendation #2024-2).

# IV. Assessment of Resource Commitment and Pricing Issues

To maintain system reliability, sufficient resources must be available to satisfy load and operating reserve requirements in the operating day, both at the system level and in local areas. The day-ahead market is designed to incentivize market participants to make these resources available at the lowest cost. Satisfying reliability requirements in the day-ahead market is more efficient than waiting until after the day-ahead market clears because reliability commitments are not coordinated economically as is the case in the day-ahead market.

However, the day-ahead market has not economically committed and scheduled all resources needed to satisfy the system's requirements historically, partly because it lacked day-ahead operating reserve products required in real time. Instead, the day-ahead market process included commitment constraints that:

- Ensured the ISO would be able to maintain reliability in key local areas in response to both the first *and* second largest contingencies; and
- Satisfied system-level operating reserve requirements.

In March 2025, the ISO improved the ability of the day-ahead market to satisfy New England's needs by introducing system-level operating reserves requirements in the day-ahead market. However, local reliability needs are still satisfied by the commitment constraint, resulting in commitments whose costs are not reflected in ISO-NE's market pricing. Hence, ISO-NE has to provide 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 the market requirements are not aligned with the system's reliability needs, or when prices are otherwise not fully efficient. This alignment is key for providing efficient short-term performance incentives and long-term investment incentives. Efficient incentives for flexible low-cost providers of operating reserves will become increasingly important with the rising penetration of intermittent renewable generation.

After the day-ahead market, ISO New England runs the Real-Time Commitment model to determine the resources that may need to be committed to satisfy the system's needs. It is important for this model to accurately determine the potential need for real-time commitments to avoid inefficient commitments that will tend to increase NCPC costs.

This section includes subsections that evaluate: (a) day-ahead commitments for local second contingency protection requirements; (b) the accuracy and efficiency of the RTC model; and (b) 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. While these commitments may be justified from a reliability perspective, the underlying local requirements are not currently enforced in the day-ahead market pricing software, even with the implementation of the newly launched day-ahead reserve markets. As a result, they can lead to inefficient prices and concomitant NCPC uplift. Most NCPC charges for local reliability commitments are incurred in the day-ahead market rather than the real-time market, as is the case for most other RTOs.

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

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

The table below shows these values for each import-constrained area for which LSCP commitments were made in the day-ahead market. The implied marginal reserve values are additive for areas that are nested within a broader import-constrained area.[33]

**Table 4: Day-Ahead Commitment for Local Second Contingency and NCPC Charges**
2022 – 2024

| 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) |
|---|---|---|---|---|---|---|---|
| **2022** | **NH-to-Maine** | 11 | 121 | 244 | $0.2 | $7.31 | $1.32 |
| | **NEMA/Boston** | 2 | 27 | 397 | $0.2 | $23.01 | $0.65 |
| | **Lw. SEMA & East RI** | 1 | 8 | 167 | $0.02 | $15.80 | $0.13 |
| | **NE West-to-East** | 17 | 207 | 357 | $0.4 | $5.66 | $1.70 |
| **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 |

33 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).

There has been a decline in day-ahead commitments for local second contingency protection in recent years, driven primarily by reliability transmission upgrades in areas with such needs. The table shows that these commitments were most frequent in the broader region east of the New England West-to-East interface, occurring on 17 to 26 days per year and averaging just over 200 hours annually. Most of these commitments occurred in periods when planned transmission outages reduced the transfer capability across the West-to-East interface, highlighting the continued sensitivity of local reliability commitments to transmission system conditions.

Despite the decrease in total uplift costs, the uplift cost per MWh of committed capacity remained significant in 2024, ranging from $4.6 per MWh in the broader region east of the New England West-to-East interface to $32.8 per MWh in in Rhode Island. This raises two significant efficiency concerns:

- First, units receiving NCPC payments are typically higher-cost and inflexible and systematically receive more revenue than flexible, low-cost resources that generally do not require NCPC payments.
- Second, the costs of resources receiving NCPC payments are not reflected in operating reserve prices paid to other resources that help satisfy the same reliability requirement.

These inefficiencies distort incentives in favor of higher-cost, less flexible units and reduce prices for all other units. The final column in the table shows that if all reserves providers in the area received the implied marginal value of local reserves, it would increase the estimated annual net revenue received by a fast start unit over the three-year period by roughly $1.6 per kW-year in eastern New England (east of the West-to-East interface).

Despite their small size, the reliance on out-of-market NCPC payments highlights the need for market reforms to improve the efficiency of prices for energy and operating reserves in local areas. Satisfying local requirements through a day-ahead operating reserve market would substantially reduce the need for out-of-market commitments. These concerns are exacerbated by two other issues that lead to excessive commitment of capacity for local second contingency protection when additional reserves are needed:

- **Multi-Turbine Configuration**. Some generators committed for local second contingency protection are offered as multi-turbine groups, necessitating the commitment of multiple turbines even when one single turbine would suffice. This unnecessary commitment of the full multi-turbine configuration can displace other more efficient generation and depress prices below efficient levels. In 2024, multi-turbine combined-cycle commitments accounted for 41 percent of capacity committed for local reliability in the day-ahead market and 39 percent of associated NCPC payments. ISO-NE could reduce excess commitment by modifying its tariff to require capacity suppliers to offer multiple unit configurations, giving the ISO with the flexibility to commit only the necessary portion of a multi-turbine group. This would improve market incentives for flexibility and availability.

- **Treatment of Imports**. Day-ahead scheduled energy imports, even when associated with a Capacity Supply Obligation (CSO), are not counted towards satisfying local second contingency needs in the same manner as energy scheduled on internal resources. In 2024, an average of roughly 110 MW of net imports from New Brunswick were scheduled in the day-ahead market on the days when LSCP commitments occurred either for the Northeast New England interface or the New England West-to-East interface. If these imports were allowed to satisfy local second contingency requirements, it could have reduced the need for LSCP commitments by 57 percent. However, due to the absence of a day-ahead reserve market with a comprehensive set of local requirements, firm imports that satisfy local requirements are not compensated efficiently.

## B. Resource Scheduling Efficiency by RTUC

Real-Time Unit Commitment (RTUC) is a key operational tool used by ISO-NE to schedule resources while maintaining system security and reliability in the operating day. RTUC is executed every 15 minutes (at minutes :05, :20, :35, :50 of each hour) for a look-ahead period typically of 85 minutes.[34] It evaluates near-term forecast conditions and commits fast-start resources to ensure reliability and reserve adequacy. The primary outputs of RTUC include startup and shutdown recommendations for fast-start resources and DARD pumps (i.e., pumped storage resources), which are passed forward to the Unit Dispatch System (UDS) for execution.[35]

While the vast majority of unit commitment decisions are made in the day-ahead market or earlier, RTUC allows the ISO additional flexibility to commit non-dispatchable resources in the operating day. As New England attracts more investment in intermittent renewable generation, it will become more challenging to match supply and demand over the operating day without the additional flexibility provided by RTUC. Efficient commitment of peaking resources in the operating day will reduce the ramp demands on dispatchable resources.

Given that RTUC commits fast-start resources in anticipation of supply shortfalls or system stress, it is important to evaluate the efficiency of these commitment decisions. This subsection evaluates conditions when poor forecasting leads to uneconomic commitment of fast-start resources, as well as the key drivers of inaccurate forecasting by RTUC.

### *Uneconomic Commitment of Fast-Start Resources by RTUC*

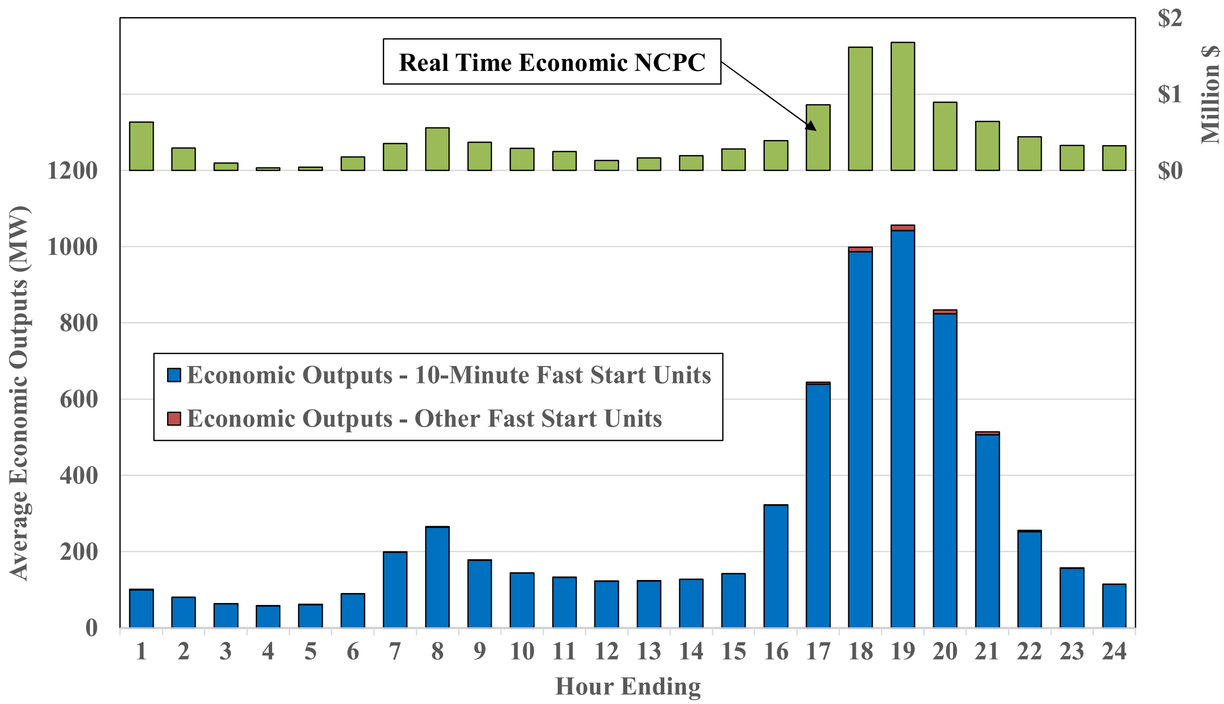
Figure 13 shows the average amount of economically scheduled output from fast-start generators by hour in 2024. These values exclude output from self-scheduling, out-of-merit dispatch, and

34 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.

35 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.

out-of-market commitments. Fast-start generators capable of starting and synchronizing within 10 minutes are grouped separately from other fast-start resources. The upper portion of the figure shows the corresponding real-time economic NCPC uplift payments made to these resources, highlighting periods when RTUC has the greatest impact on real-time market outcomes. While the magnitude of these uplift payments is small relative to the overall magnitude of the wholesale market, uplift payments are a useful indicator of when fast-start units are committed inefficiently by RTUC.

**Figure 13: Economic Outputs from Fast-Start Generators and Associated RT NCPC Uplift**
By hour, 2024




The figure provides several key insights:

- In 2024, fast-start generators incurred over $11 million in real-time economic NCPC uplift, accounting for nearly 70 percent of all such uplift payments to internal resources. This share is significantly higher than typically observed in other RTOs. 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 able to start and synchronize within 10 minutes, highlighting the predominance of 10-minute fast-start units, which make up 90 percent of all fast start units.
- Approximately 60 percent of the economic starts occurred during the evening peak period from hours ending 17 to 21, which also accounted for over half of the associated real-time NCPC uplift payments. Thus, the ISO routinely relies on fast-start units to satisfy daily peak demand.

High make-whole payments to economically committed fast-start units tend to result from over-forecasting of needs in the operating day. The next analysis examines RTUC forecasts of real-time systemwide LMPs compared with actual LMPs to identify potential drivers of over-forecasting, which is shown in Figure 13. The figure is divided into four panels, each representing a different RTUC forecast time horizon. Look-Ahead (LA) one through four corresponds to forecast windows from less than 15 minutes (LA1) to up 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 with positive values corresponding to hours when RTUC prices exceeded UDS prices. The black line in each panel indicates the average hourly difference between RTUC and UDS prices.

**Figure 14: Price Forecasting by RTUC vs. UDS LMPs**
By hour, 2024

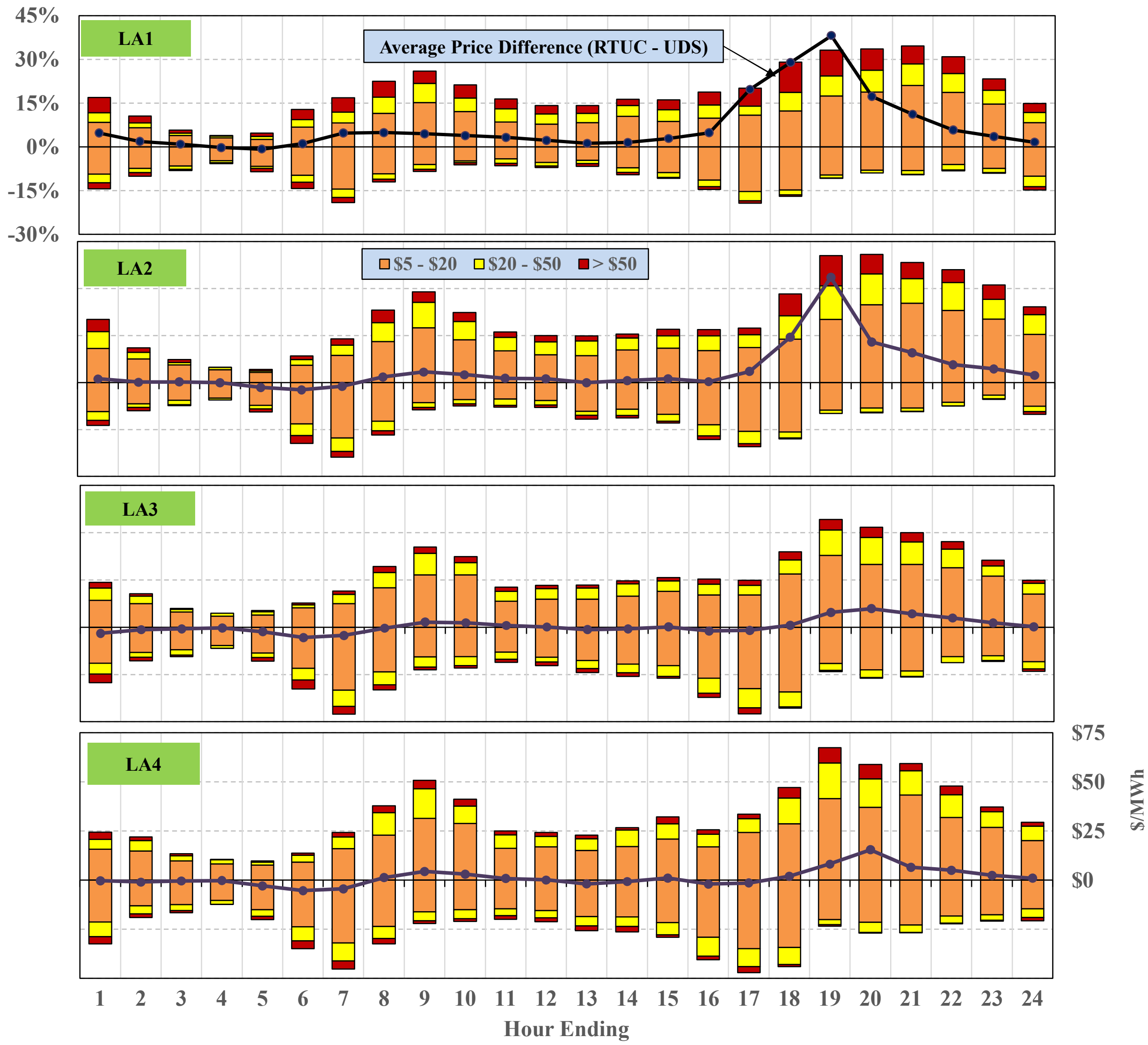


Figure 14 indicates that the average hourly differences between RTUC and UDS prices were generally close to zero in most hours across all four forecast horizons. However, during evening peak hours, RTUC prices were systematically higher than UDS prices across all four forecast windows. This was especially pronounced in Look-Ahead periods One and Two, when average RTUC prices exceeded average UDS prices by as much as $64 per MWh in hour ending 19. This figure highlights several issues with the performance of RTUC:

- RTUC frequently committed fast-start resources inefficiently during the evening peak hours, and when actual real-time prices materialized lower than forecasted prices, these units frequently ran at a loss, requiring substantial real-time economic NCPC payments to cover their operating costs. This is consistent with the patterns observed in Figure 13.
- If market participants perceive a bias in these commitment models, it may undermine 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 have incentives to offer above marginal cost.
- There is a smaller but still discernible bias in LA3 and LA4, which generally use the same inputs as the CTSPE model forecast used for transactions scheduling with NYISO.

***Drivers of Price Over-Forecasting in RTUC***

This subsection provides our evaluation of factors contributing to inconsistencies between RTUC and UDS prices discussed above. This evaluation quantifies the magnitude of each factor's contribution using a metric described below, distinguishing between factors that tend to reduce inconsistencies and those that exacerbate inconsistencies between RTUC and UDS prices.

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

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

Using the example above, the metric is calculated as follows by 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, increasing 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 the generator's contribution was "beneficial", as it helped meet the unexpected load and mitigated the price gap.

- Foregone Fast-Start Unit:

$$Metric_{Fast-Star\ \ Unit} = 0\ MW \times (\$50 - \$70) = \$0$$

The zero value reflects that the fast-start unit itself did not cause the divergence; rather, its absence from the RTUC commitment was a consequence of the load under forecast.

An important feature of this metric is that it differentiates between "detrimental" that increase the price divergences between RTUC and UDS and "beneficial" factors that reduce the divergence. Flexible resources such as a fast-ramping units tend to be "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 15 evaluates the inconsistency metric values for four key factors that contributed to differences between RTUC and UDS prices in 2024: (i) Net demand (demand minus behind-the-meter solar) forecast; (ii) Operator load adjustments; (iii) Scheduled net imports; and (iv) Grid-scale wind & solar forecast.

The figure presents the cumulative "detrimental" and "beneficial" metric values for each factor over the entire year. To highlight the impact during peak periods, the analysis compares evening ramp hours (HE 17 to 21) with all other hours, grouping them separately. Additionally, the results are disaggregated by the four RTUC forecast horizons to show how contributions vary across different look-ahead intervals. For comparability, the figure displays hourly average metric values with each group, rather than absolute totals. The actual metric values are shown, as the focus of this analysis is on the relative significance of each factor in driving price inconsistencies, rather than their exact magnitudes.

**Figure 15: Factors Contributing to RTUC Price Forecast Errors**

2024

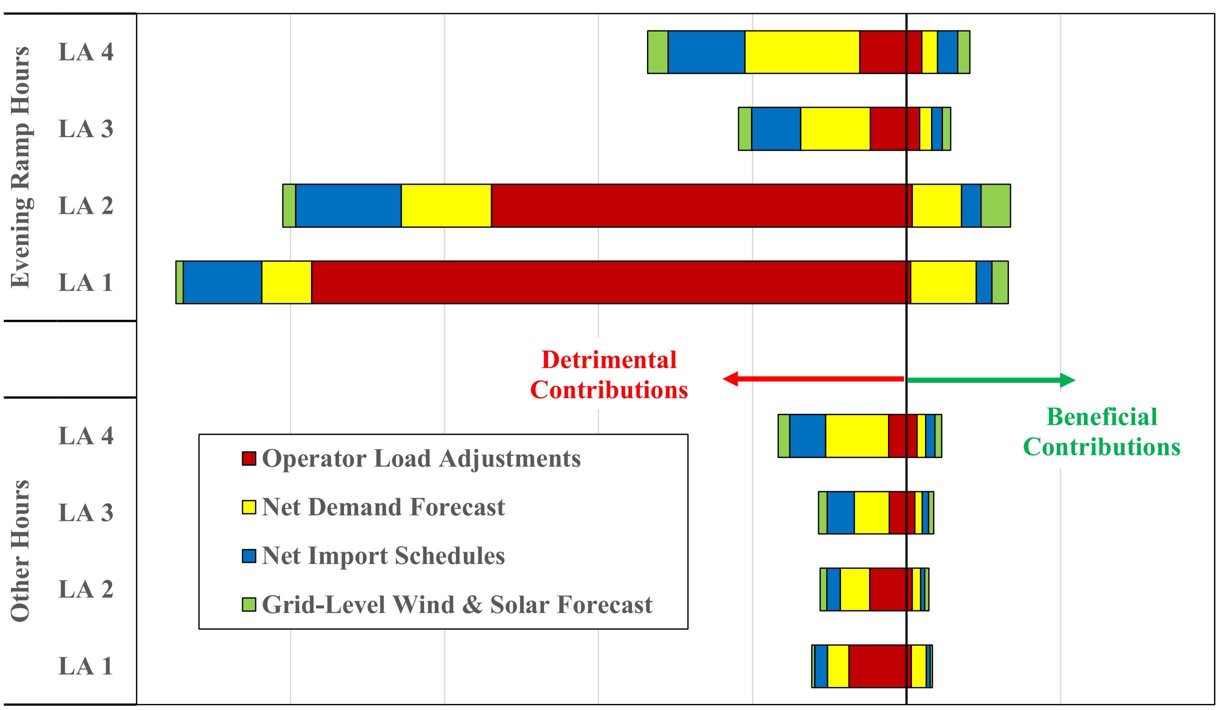


Figure 15 reveals important insights into the drivers of price these divergences in 2024:

- *Impact Primarily Detrimental* – While all four factors had some beneficial effects at times, their overall impact was primarily detrimental.
- *Minor Impacts for Grid-Level Wind and Solar* – Forecast errors in grid-scale wind and solar had relatively minor effects, both beneficial and detrimental, compared to the other three factors. This is expected given that ISO-NE currently has a modest amount of grid-level renewable generation capacity. Retail-level solar is embedded in the load forecast.
- *Modest Impact for Net Import Schedule Changes* – Net import variation had a modest impact on price inconsistencies overall, but its contribution to price divergence increased as the forecast window extended to longer horizons (i.e., LA3 and LA4).
- *Primary Driver of Divergence was Operator Load Adjustments* – These emerged as the main detrimental factor contributing to price inconsistencies during Look-Ahead periods One and Two, particularly during the evening peak hours (HE 17 to 21).

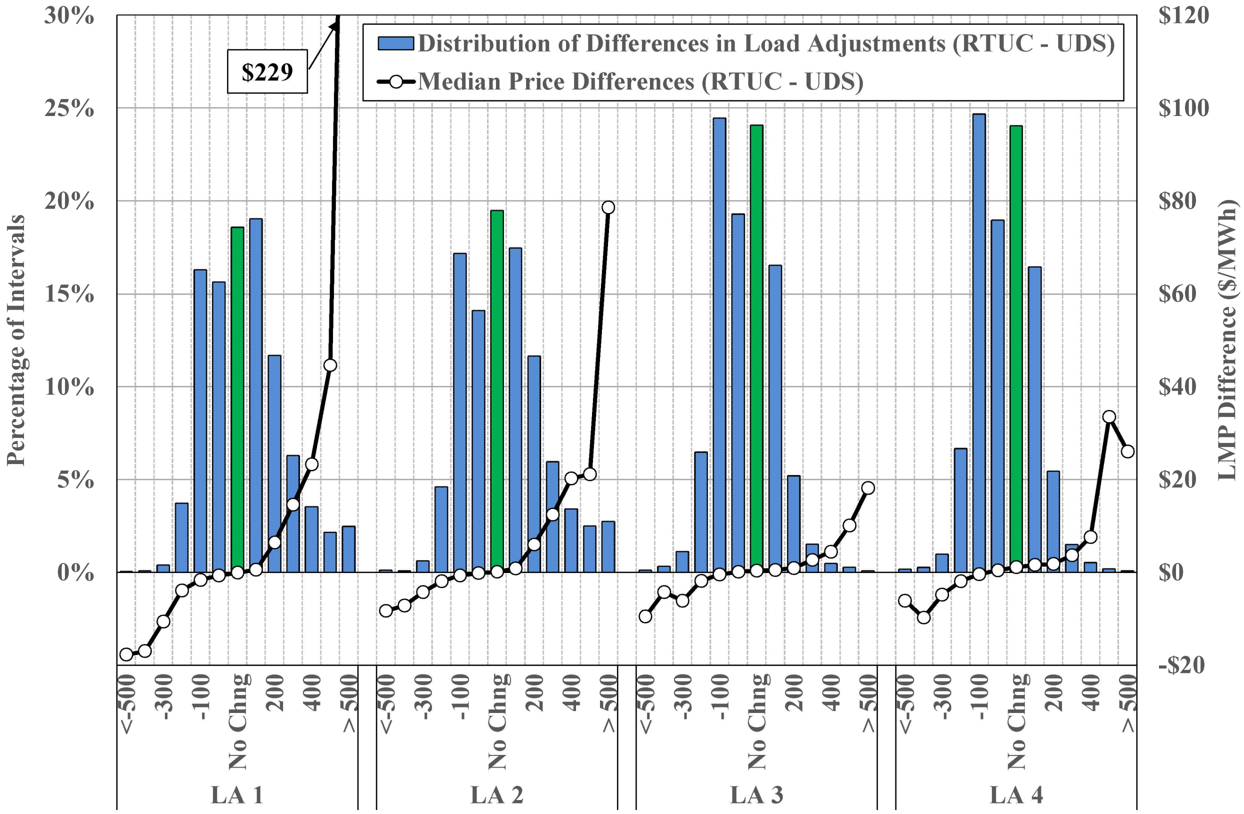
As the forecast horizon extended into LA3 and LA4, the influence of operator load adjustments diminished. Instead, net demand forecast errors became the most significant detrimental factor in LA3 and LA4, reflecting the increasing uncertainty associated with longer-term demand forecasting and infrequent load adjustments by operators for these periods.

Figure 16 provides a closer examination of the evening ramp hours, evaluating the relationship between load adjustment differences and price differences between RTUC and UDS, across the four look-ahead horizons. The bars represent the distribution of load adjustment differences, grouped in 100 MW increments, with differences exceeding ±500 MW consolidated into the outermost categories.[36] The green bars indicate the percentage of intervals where no load adjustment was made, or the same adjustment was applied to both RTUC and UDS. The black lines mark the median price differences between RTUC and UDS, offering insight into how variation in load adjustments correlates with price inconsistencies.

Operators can make load adjustments in RTUC in two ways: either by applying the same adjustment across all look-ahead intervals or by targeting specific intervals individually. Figure 16 illustrates that Look-Ahead periods One and Two (LA1 and LA2) exhibited similar distribution of load adjustment differences, which were distinctly different from the patterns observed in LA3 and LA4, which also share comparable distributions. In particular, the distributions of load adjustments were skewed in the positive direction in near-term forecasts (LA1 and LA2) and in the negative direction in longer-term forecasts (LA3 and LA4). In addition, load adjustment differences exceeding 300 MW occurred in nearly 10 percent of intervals in LA1 and LA2, but in only 1 percent of intervals in LA3 and LA4. These patterns suggest that operators are more likely to apply higher or targeted load increases in the shorter-term horizons, while making fewer specific adjustments in the longer-term forecast windows.

36 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.

**Figure 16: Differences in Load Adjustments and LMPs Between RTUC and UDS**
Evening Peak Hours, 2024




Only 20 to 25 percent of intervals had no difference in load adjustments between RTUC and UDS in the four forecast windows, represented by the green bars in Figure 16. These intervals were also associated with near-zero median price differences, suggesting that greater consistency in load adjustments between RTUC and UDS contributes to more accurate price forecasting. In contrast, the largest load adjustments generally led to the largest RTUC/UDS price inconsistencies. Across all four look-ahead horizons, load adjustment differences exceeding ±300 MW were associated with substantially higher median price differences.

Given that most fast-start resources in ISO-NE can be started and synchronized within 10 minutes, RTUC has the operational flexibility to commit these units beginning in its first or second look-ahead interval. However, the frequent and 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 and consistent approach to applying load adjustments in RTUC could help reduce inefficient commitments and improve alignment with real-time system needs.

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

In conclusion, we are recommending that ISO New England address the causes of the price divergence between RTUC and UDS evaluated in this subsection. A comprehensive evaluation of these divergences and other root causes of fast-start commitment inefficiencies will facilitate more economically efficient and reliable real-time market operations.

## C. Pricing of Operating Reserves in the Fast-Start Pricing Logic

Fast-start units create challenges for setting LMPs due to their inability to continuously operate from zero to maximum output. Instead, they typically incur a fixed cost to operate at a minimum level, making it difficult for them to set price as the marginal unit. In March 2017, the ISO implemented a 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.

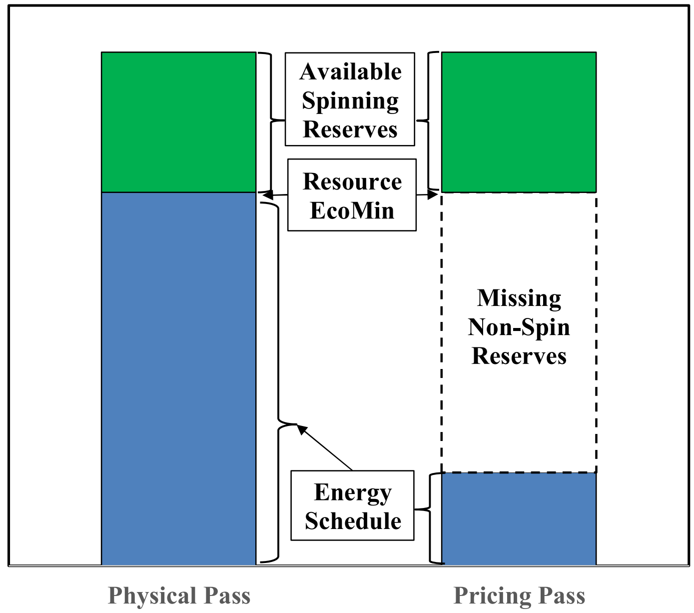
The real-time market is cleared using an optimization model to determine the dispatch quantity from each resource, minimizing as-offered production costs while enforcing transmission and operational constraints. Following this physical dispatch, known as the "physical pass", the fast-start pricing logic is implemented in the "pricing pass". The pricing pass re-runs the dispatch model with the EcoMin constraints of fast-start units relaxed to zero, allowing them to "set the price" for energy. In addition, the energy offer of fast-start resources is adjusted to reflect their full cost by adding the 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 utilizing fast-start resources to meet demand and reserve needs in the real-time market.

However, a flaw in the fast-start pricing logic has been identified, which results in inefficient reserve pricing under some conditions.

- The pricing pass does not allow fast-start units to hold reserves below their EcoMin level;
- When the EcoMin is relaxed to zero and the fast-starting resources are ramped down, other units that would hold reserves are ramped up for energy – this exchange lowers the available operating reserves in the pricing pass.
- This reduction in available reserves often raises reserve and energy prices inefficiently.

The loss in available reserves is illustrated in Figure 17 which assumes that in the physical pass, a fast-start unit is dispatched at its physical EcoMin level, with the head room above its EcoMin allocated for spinning reserves. However, in the pricing pass, the fast-start unit is dispatched below its physical EcoMin level as the EcoMin is relaxed to zero and the unit becomes marginal for setting prices. While the pricing pass still accounts for the head room above the unit's physical EcoMin for spinning reserves, it excludes the undispatched portion below its physical EcoMin for providing reserves, depicted by the white dashed box labeled as "missing non-spin reserves."

**Figure 17: Illustration of Available Reserves in Physical Pass and Pricing Pass**




As a result, a portion of capacity from online fast-start resources becomes unavailable in the pricing pass. However, this same capacity is typically scheduled for energy in the physical pass, thereby freeing up other online capacity for additional operating reserves. Although this inconsistency does not cause inefficient prices in the vast majority of intervals due to surplus reserves within the system, under certain system conditions when the margin on operating reserves is small, this issue will cause reserve prices to be overstated.

To highlight instances where this issue affected prices, Figure 18 and Figure 19 below compare 10-minute and 30-minute reserve availability and associated shadow prices between the physical pass and pricing pass in the real-time market during the UDS intervals where the reserve constraints were binding in the pricing pass. The upper portion of each figure presents a side-by-side comparison of shadow prices of reserve requirement constraints between the two passes. The shadow price indicates the marginal cost of satisfying the reserve requirement and contributes to the pricing of reserve products and energy. The lower portion shows modeled reserve availability in each pass as dashed lines, compared to the requirements represented by a solid black line. When the dashed line is above the requirement line, it indicates surplus reserves in the system, whereas when it falls below, it signifies a shortage.

**Figure 18: Available 10-Minute Reserves in UDS**
Physical Pass vs. Pricing Pass, 2024

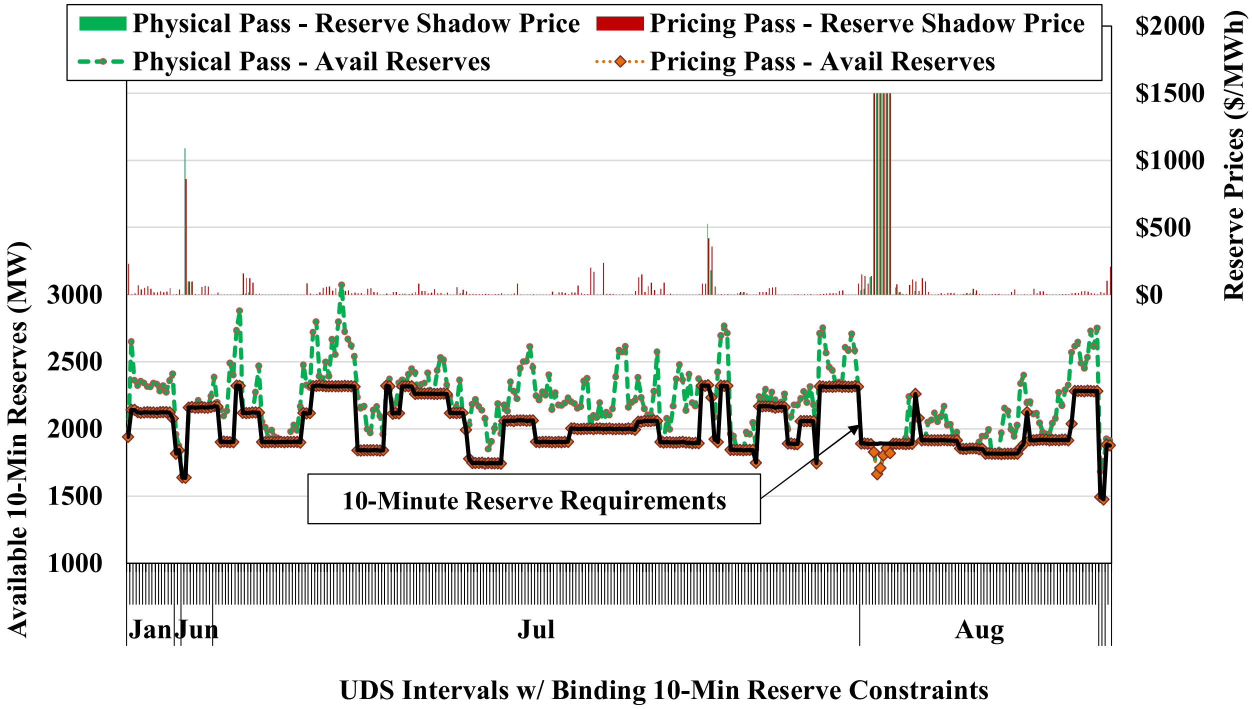
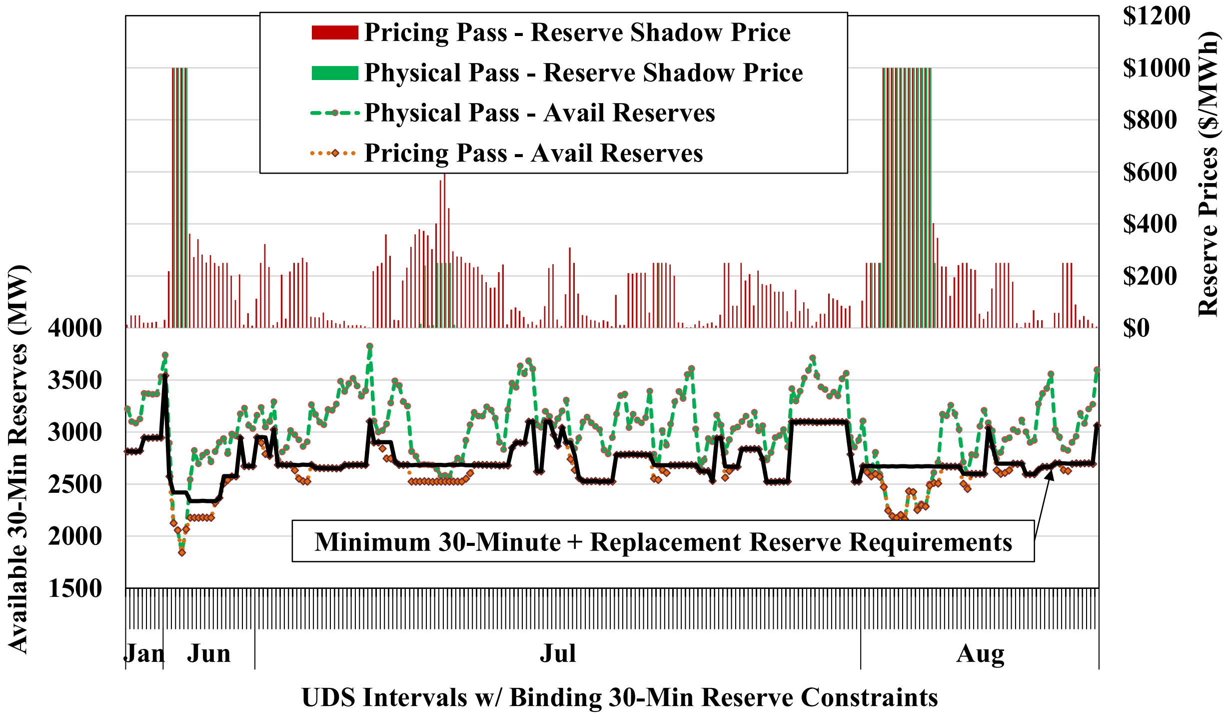



**Figure 19: Available 30-Minute Reserves in UDS**
Physical Pass vs. Pricing Pass, 2024



In 2024, there were 416 intervals where at least one of the 10-minute and 30-minute reserve constraints were binding in the pricing pass. During these intervals:

- The physical pass consistently exhibited an equal or greater amount of available reserves. On average, the physical pass had approximately 215 MW and 360 MW more available 10-minute and 30-minute reserves, respectively.
- Shadow prices of the reserves were often significantly higher in the pricing pass compared to the physical pass. The clearing reserve prices averaged $113 per MWh and $155 per MWh for 30-minute and 10-minute reserves, respectively, whereas in the physical pass, they were only $44 per MWh and $71 per MWh.

The reduction in available reserves in the pricing pass highlights a flaw in the fast-start pricing algorithm, which sometimes produces overstated clearing prices for both 10-minute and 30-minute reserves. This issue commonly arises in two scenarios:

- First, when the look-ahead model commits an excessive number of fast-start resources due to over-forecasted demand or other key inputs, some or all of these resources may become uneconomic relative to the marginal resource(s) in the real-time market. Consequently, the pricing pass dispatches them to zero for energy, leading to a significant amount of capacity below EcoMin being excluded from providing operating reserves.
- Second, when 30-minute quick-start resources are started to address a deficiency of 10-minute reserves, their undispatched capacity below EcoMin is not counted towards meeting the 30-minute reserve requirements in the pricing pass. This can lead to artificially inflated 30-minute reserves prices, even when sufficient capacity is technically available.

To address this pricing inefficiency, we recommend the ISO refine the fast-start pricing logic to utilize the full capability of online resources for reserves. Specifically, the undispatched capacity below EcoMin from fast-start resources should be treated as available 10-minute non-spinning reserves (from 10-minute fast-start resources only) or 30-minute non-spinning reserves and utilized to meet the applicable 10-minute and 30-minute reserve requirements in the pricing pass of the real-time market. This adjustment will ensure that reserve prices more accurately reflect the cost of maintaining operating reserves.

## D. Conclusions and Recommendations

This section presents findings in three areas that affect the operation of the ISO New England system and its real-time pricing and costs:

- Day-ahead commitments are frequently made to satisfy local second contingency requirements that are not priced, resulting in understated locational pricing, reduced generators' net revenues in these areas and higher NCPC payments. These commitments are likely to become more frequent over time as existing generators retire and new resources enter the market, leading to changes in congestion patterns.

- RTUC frequently over-forecasts the need to commit fast-start resources primarily because of operators' manual load adjustments and less assumed ramp capability in RTUC. This has led to over $11 million of NCPC costs in 2024, accounting for nearly 70 percent of all real-time economic NCPC paid to internal resources.
- Real-time reserve prices were set at excessively high levels in some intervals because of an issue with the fast start pricing logic.

These findings support our recommendations that ISO-New England:

- Modify its local reserve market requirements to satisfy all local second contingency needs (Recommendation #2019-3). The ISO should consider approaches that would allow it to dynamically define new reserve zones as second contingency protection requirements arise in different areas.
- Expand its authority to commit combined-cycle units in a single-turbine configuration when that will satisfy its reliability needs (Recommendation #2014-5). The ISO is often compelled to start combined-cycle resources in a more costly multi-turbine configuration.
- Consider allowing firm energy imports from neighboring areas to contribute towards satisfying local second contingency requirements (Recommendation #2020-1). This would reduce the local reserve requirements and associated costs.
- Improve the efficiency of fast-start commitments by addressing the causes of the price divergence produced by the RTUC model (Recommendation #2024-1).
- Address inefficient reserve prices in the fast-start pricing logic by modifying the fast-start pricing logic to utilize the full capability of online resources in the pricing pass of the real-time market (Recommendation #2022-1). This will ensure that reserve prices more accurately reflect the true cost of maintaining operating reserves.

# V. Capacity Availability and Performance Incentives

Capacity markets provide incentives to ensure adequate resources will be available to satisfy the planning reliability needs of the system. For capacity markets to be effective and provide efficient incentives governing resource investment and retirement decisions, it is important to quantify the available capacity accurately and provide efficient performance incentives.

ISO New England is in the midst of fundamental changes in its capacity market to move to a prompt seasonal capacity market with resources accredited to sell capacity based on their marginal reliability value. We have recommended these changes and consider them amongst the highest priority design changes for addressing the region's future reliability needs. In this section, we evaluate two more specific issues that impact the performance of the capacity market: (i) the availability of capacity during the tightest summer conditions when reliability risks are the highest, and (ii) the incentives provided by the Pay-for-Performance (PFP) rules.

## A. Summer Qualified Capacity and Actual Availability

Capacity markets provide incentives to ensure adequate resources will be available to satisfy the planning reliability needs of the system. Resource adequacy and transmission security criteria generally require sufficient resources to avoid load shedding under conditions much more severe than the average annual peak demand level (e.g., a 90$^{th}$ or 95$^{th}$ percentile annual peak load forecast). Therefore, load forecasts quantify the additional demand expected under these relatively severe conditions when setting capacity requirements. Ideally, the capability sold by each generator 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 qualification rules do not take these factors into account, it will lead to an overestimate of the available capability under severe weather conditions.

Each resource that participates in the capacity market is qualified to sell an amount up to its summer or winter Qualified Capacity (QC). For thermal generators, the QC is generally based the Seasonal Claimed Capability (SCC) Audits. Since audits are generally not conducted under peak conditions, the ISO partially accounts for the difference between Audit conditions and severe conditions by adjusting test results to a standard peak temperature condition of 90°F.[37]

The ISO uses capability curves that are submitted by owners of gas turbine and combined cycle facilities showing capability as a function of dry bulb temperature in one-degree increments.[38] 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-

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

38 See Section 4 of https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op14/op14a_rto_final.pdf.

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. 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.[39]

While SCC Audit results can be adjusted based on barometric pressure and relative humidity, those adjustments are optional, and no generators have opted to do so historically.[40] Instead, the vast majority of tests are conducted under relatively favorable humidity and pressure conditions, which tends to inflate QC values. This section investigates these and other factors that lead to inflated summer QC values for the thermal generation fleet. This section is divided into the following subsections:

A. *Ambient Humidity* – Analyzes the effects of humidity on the capabilities of combustion turbines with certain types of inlet cooling systems;
B. *Barometric Pressure* – Evaluates the effects of barometric pressure on the performance of combustion turbines;
C. *Shift in peak load from afternoon to evening* – The peak load hour has been shifting later in the afternoon as retail-level solar penetration has risen, altering the typical ambient conditions at the peak towards cooler, more humid, lower-pressure hours; and
D. *Actual performance in summer 2024* – We identify a gap between summer QC values and actual generator availability which is partially explained by the lack of adjustment for humidity and pressure to peak load conditions.

***Ambient Humidity***

Humid air significantly reduces the capability of combustion turbines with certain inlet cooling systems, which add moisture to the inlet air to cool it down, thereby increasing the output of the turbine.[41] As the humidity of the ambient air increases, the effectiveness of inlet cooling falls. In New England, the most common inlet cooling systems are evaporative coolers and inlet fogging systems, which are among the most affected high ambient humidity conditions.

We have identified that at least 10.2 GW of combined cycle and combustion turbine generators in New England that utilize inlet cooling systems that are affected by humidity.[42] Each generator submits a curve to the ISO in its NX-12 data submission showing plant capability as a function

39 Market Rule 1 III.13.1.2.2.

40 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.

41 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

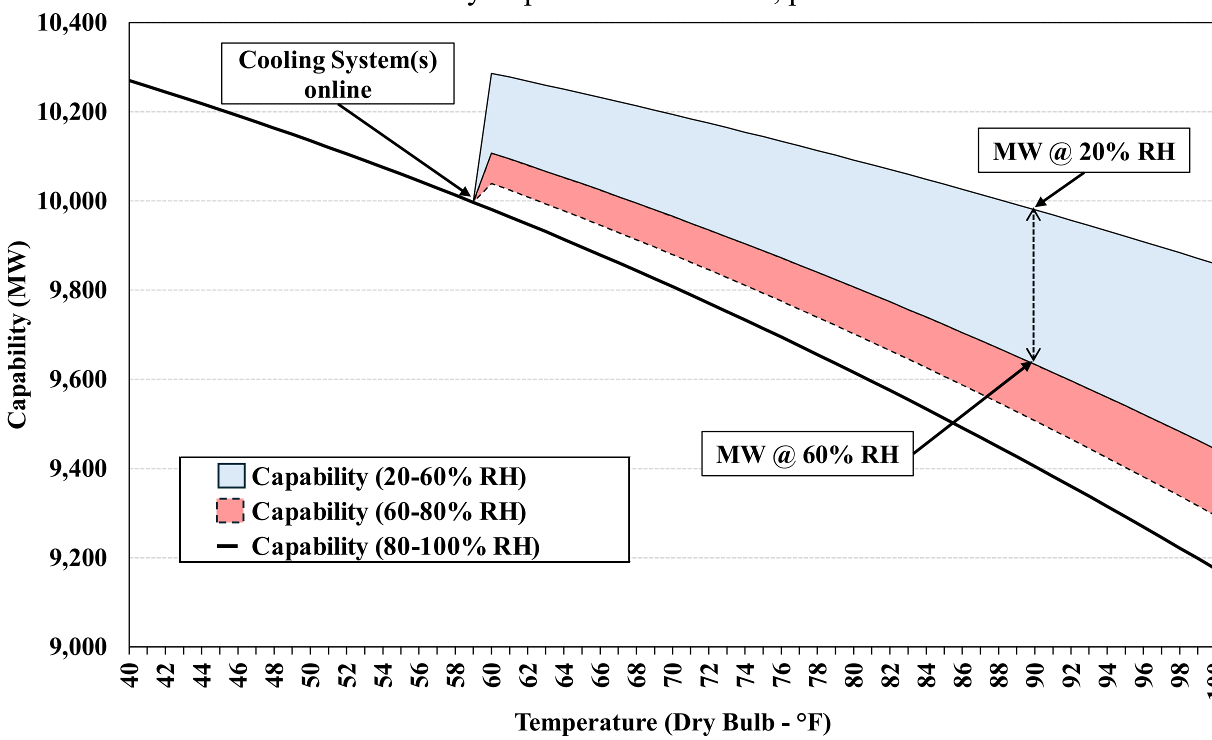
42 It is likely that additional generators have evaporative coolers or inlet fogging systems. However, we only include generators with a system documented in the facility's air permit, siting applications, generation company websites and/or NX-12 data. The 10.2 GW value is based on plant ratings at 40°F ambient dry bulb temperatures.

of air temperature. Capability curves for units with inlet cooling systems were extrapolated from the NX-12 data assuming 90 percent cooling efficiency.

Figure 20 shows aggregate capability curves combining all generators identified as humidity dependent. The curves show estimated capability by temperature at various humidity levels. Cooling systems are generally not used below 60°F due to freezing risks, so humidity is only relevant when ambient temperature is above this level. The blue-colored range shows the impact on capability if relative humidity rises from 20 to 60 percent for a given ambient temperature. The red-colored range shows the impact if the inlet cooling system is used while the relative humidity rises from 60 to 80 percent. However, these systems begin to undermine plant reliability in this range, so individual units typically shut off the system at a relative humidity level threshold between 60 and 80 percent. Thus, when relative humidity reaches 80 percent, capability falls to the level excluding any effect of inlet cooling (see black line).

**Figure 20: Seasonal Claimed Capability by Relative Humidity**

Humidity-dependent Generators, per °F



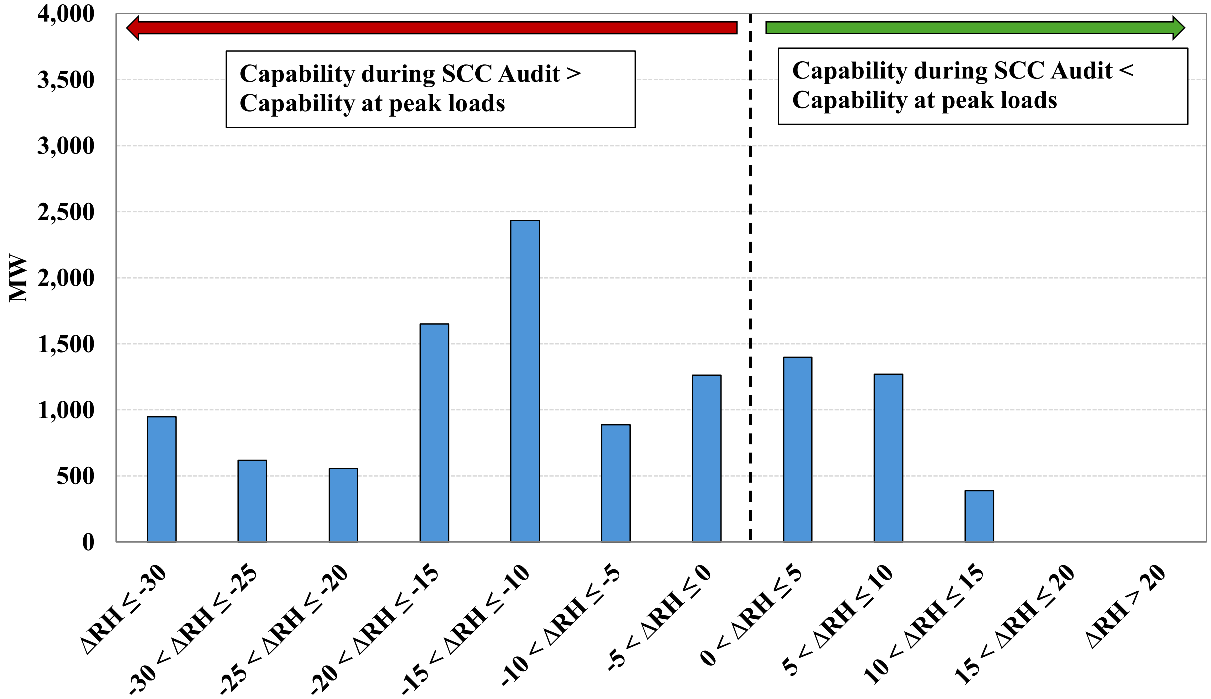

This chart illustrates several facts related to the use of inlet foggers and evaporative coolers:

- Plant capability is highest when relative humidity is lowest. The difference between 20 percent RH and 60 percent RH across the fleet is estimated to be 260 MW at 90°F.
- The impact of inlet cooling is higher at warmer temperatures (for a given RH level).
- Inlet cooling systems must usually be shut off under high humidity conditions, typically between 60 and 80 percent RH, thereby increasing the impact of humidity above 60 percent RH on the capability of the generation fleet.

We estimated the difference in capability for humidity-dependent generators between ambient conditions during SCC Audits and actual peak load hours from 2022 to 2024. Peak load hours are taken from the five highest peak load days of each summer. Figure 21 summarizes the differences between audit conditions and peak conditions for these generators. For example, nearly 1.7 GW of capacity was tested at average relative humidity conditions that were 15-to-20 percent lower than actual conditions during peak hours in these three years.

**Figure 21: Humidity Conditions in Summer SCC Audits vs Peak Load Hours**

Average of Audits, 2022 – 2024




This analysis reveals that 73 percent of humidity-dependent generators conducted SCC Audits under favorable conditions, which increased summer qualified capacity values by an estimated 105 MW relative to annual peak load conditions.[43] While this impact is relatively modest, we explain later in this subsection why summer peak conditions are becoming more humid, which is likely to exacerbate this issue.

***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, the mass of air flowing through the CT is lower, which reduces its output.[44] Therefore, barometric pressure and the capability of CTs are positively correlated.

43 See Appendix for methodology.

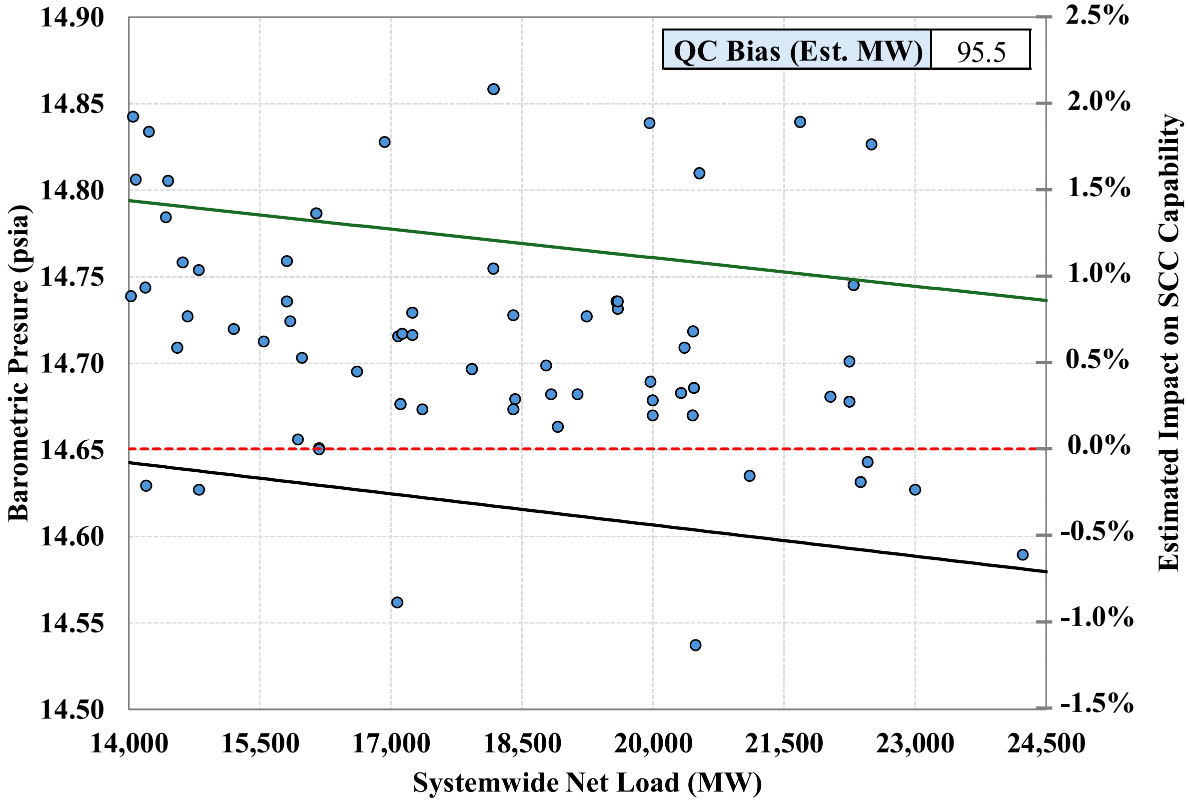
44 See: https://www.gevernova.com/content/dam/gepower-new/global/en_US/downloads/gas-new-site/resources/reference/ger-3567h-ge-gas-turbine-performance-characteristics.pdf

Temperature and humidity also impact barometric pressure. Warm air is naturally less dense than cool air, and humid air is less dense than dry air because water vapor is less dense than nitrogen and oxygen gas. Since summer reliability risks are highest during hot and humid conditions, barometric pressure is lowest under high summer load conditions.

Since summer SCC audits are usually conducted outside of peak load conditions, they generally occur under higher barometric pressures than expected under peak load condition. Figure 22 shows the pressure conditions and system load during summer SCC audits for all ambient condition dependent units from 2022 to 2024.[45] Two sloped lines show the linear trend in the 10th and 90th percentiles of barometric pressure values by load level, while the red line shows the predicted value of the linear trend line for all points at the load level corresponding to the 2025 summer forecasted peak load.

**Figure 22: Barometric Pressure in Summer SCC Audits vs Peak Load Hours**

Summer 2022 – 2024



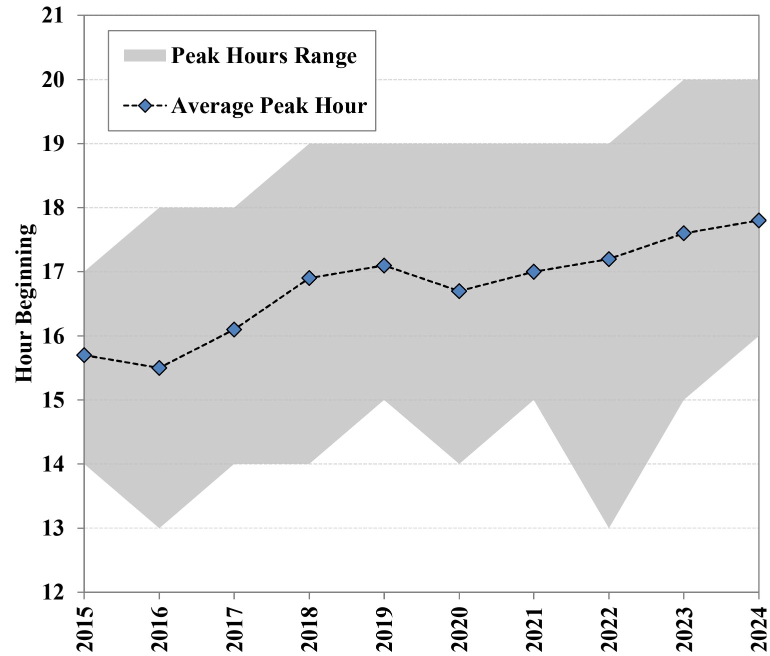

Between 2022 and 2024, 88 percent of all Summer SCC Audits occurred at barometric pressures greater than the red line, resulting in higher performance in audits than expected at summer peak conditions. Around half of all audits fell in the 0.3-to-1.0 percent impact for pressure-related capacity rating bias, but some generators benefited by more than 2 percent. Favorable pressure conditions during SCC Audits inflated Qualified Capacity by an estimated 95.5 MW.

45 For analysis methodology, see Appendix.

### *Ambient Conditions during Peak Load Hours*

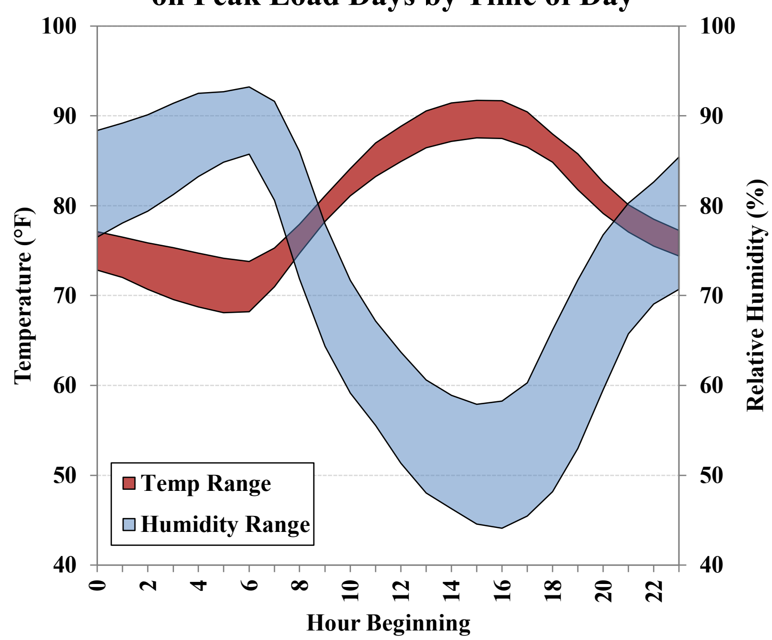
The time of day of the summer peak load hour has shifted over time largely because of the increased penetration of behind-the-meter solar generation in the region. Figure 23 shows the distribution of the top ten summer load hours in each year from 2015 to 2024, including the average time of the ten hours and the range between the earliest and latest of the ten hours in each year.

**Figure 23: Peak Load Hour from Ten Highest Load Hours by Year, 2015-2024**




Ambient conditions exhibit a typical pattern by time of day in peak summer months. Temperatures usually peak between 2 and 5 PM (i.e., HB 14-16), while relative humidity is usually lowest at this time. As time moves from afternoon to evening, the temperature falls and relative humidity tends to increase.

**Figure 24: Temperature and Humidity Range on Peak Load Days by Time of Day**




This relationship is shown in Figure 24 below, which shows the range of temperatures and humidities across each hour of the day based on the five days with the highest peak loads from each year between 2015-2024.[46] The ranges in the chart show the spread between the minimum and maximum average (across generator locations for the five days) values over the ten-year period. From HB 15 to HB 19, the average drop in

46 Ambient conditions data was taken from each ZIP Code where a generator with a temperature dependency was located.

temperature is 5°F to 7°F, while the average increase in relative humidity is approximately 9 to 15 percentage points.

While the shift in the peak load hour from afternoon to early evening generally reduces temperature (normally raising capability), the capability reductions due to humidity are likely to outweigh the temperature effect. For example, the upper bound of the temperature and humidity range in the afternoon is 92 degrees and 58 percent, while the upper bounds in HB 19 are 85 degrees and 73 percent.

Based on Figure 20 earlier in this subsection, this shift would be expected to reduce the net capability of humidity-dependent units by 90 MW.

***Qualified Capacity Unavailable under Peak Conditions – Summer 2024***

This subsection provides our estimates of how much Qualified Capacity on generators affected by ambient conditions was unavailable during actual peak conditions in July and August 2024 and not reported as a forced derating. While much of the capacity was likely unavailable because of ambient conditions, we find a substantial quantity that is not explained by ambient conditions and that was not reported as derated.

**Figure 25: Unavailable Capacity under Peak Conditions in Summer 2024**

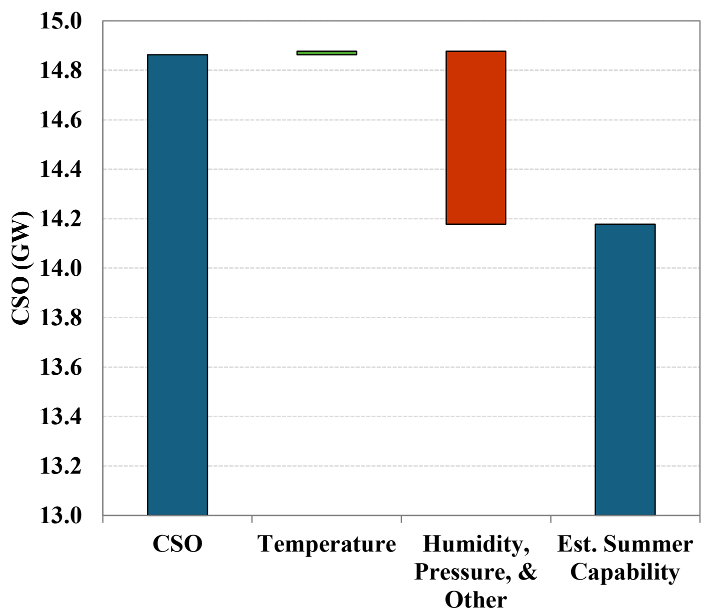



Figure 25 shows the combined CSOs of all combustion turbines and combined cycles compared to the actual capability available under peak conditions. Since each generator submits a curve relating maximum capability to ambient temperature, we quantify separately the impact of ambient temperature, which was slightly positive. We used a two-pronged approach to identifying potential ambient-related capacity shortfalls. First, we analyzed the difference between each generator's actual performance when dispatched to economic maximum at peak load conditions in recent years to identify what each resource's capability truly was. Where a resource had not been dispatched to its economic maximum on peak summer days, we compared the difference between the economic maximum offered and the resource's CSO to identify unavailable capacity.

We identified a remaining difference of approximately 700 MW of QC that was unavailable under peak conditions. Based on the analysis in Subsections A and C, we estimate that 195 MW was likely attributable to ambient relative humidity, while approximately 95 MW was likely due to low barometric pressure conditions. This leaves more than 400 MW that was likely due to other factors such as unreported forced derates.

## B. Assessment of Capacity Shortage Events

ISO-NE implemented the Pay-for-Performance ("PFP") rule in June 2018 to strengthen incentives for generators to contribute to grid reliability and stability during Capacity Scarcity Conditions ("CSCs"). Under the PFP framework, generators are compensated or penalized based on their performance relative to their Capacity Supply Obligations ("CSOs") during CSC events.[47] Since its inception, PFP events have been infrequent, occurring for an average of about one hour per year.

In 2024, two PFP events occurred on June 18 and August 1, respectively.

- On June 18, load peaked at just over 22 GW. Several generator outages and deratings resulted in a total supply loss of approximately 1,600 MW, leading to a 30-minute reserve deficiency for six intervals between 5 and 7 p.m.
- On August 1, load exceeded the forecast by 350 MW and peaked at more than 23 GW. Together with outages and deratings totaling roughly 750 MW, this led to shortages in 22 intervals, including 10-minute reserve shortages in 13 intervals and 30-minute reserve shortages in 20 intervals in the late afternoon.

Although neither event created a significant probability of losing load in New England, the total price paid for imports or resources exceeding their CSOs was as high as $8200 per MWh, which includes the $5455 per MWh penalty rate, which is slated to increase to $9337 per MWh in June 2025. These prices resulted in performance charges to suppliers of more than $64 million, most of which were incurred by available steam units or combined cycle units that were simply offline because they were not committed in the day-ahead market. These prices and settlements vastly exceed the reliability value of energy during these events, which creates inefficient incentives for the market participants. This section discusses the incentives created by the PFP mechanism and shortage pricing after an examination of external transaction scheduling during the two capacity shortage events.

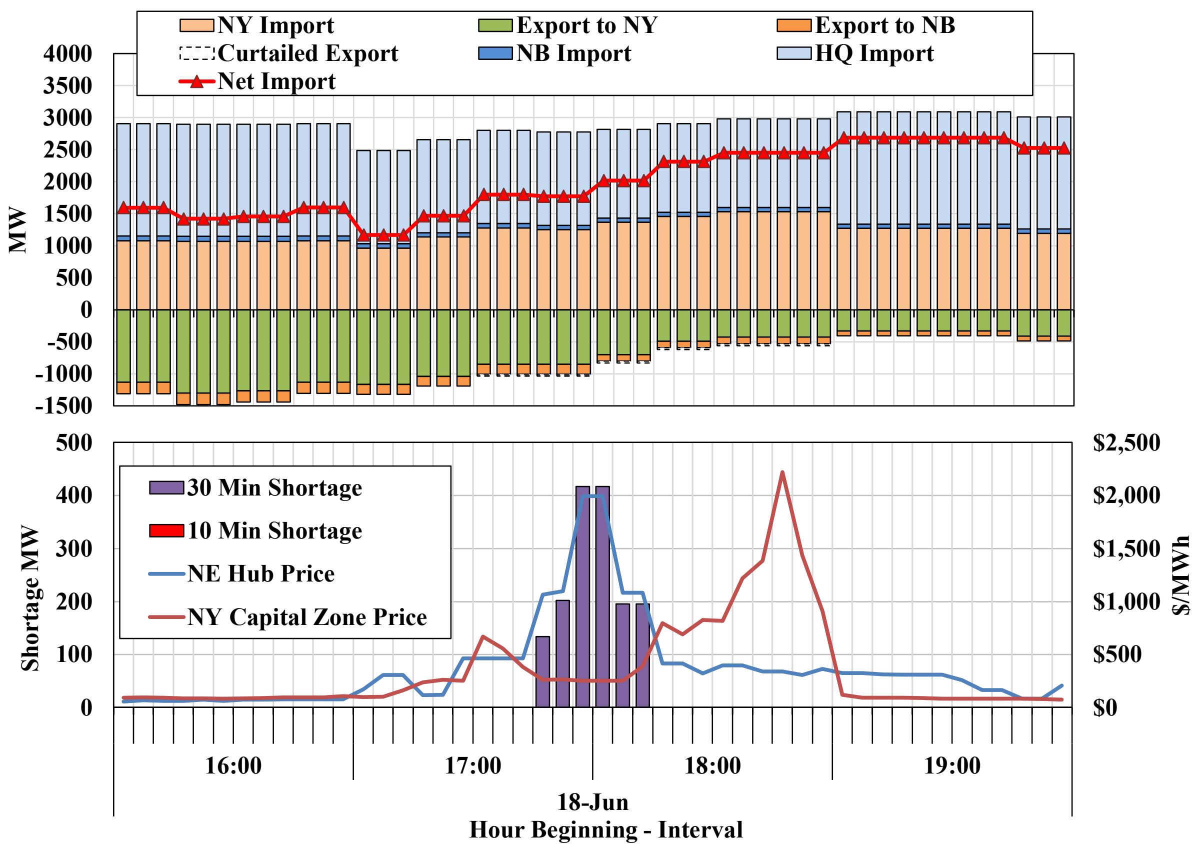
47 A CSC occurs when the ISO is short of one or more of the three reserve requirements and the Reserve Constraint Penalty Factor ("RCPF") is setting the real-time reserve prices: (a) systemwide 10-minute reserve requirement; (b) systemwide 30-minute reserve requirement; and (c) local 30-minute reserve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

### *Imports and Exports Scheduled During Shortage Events*

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

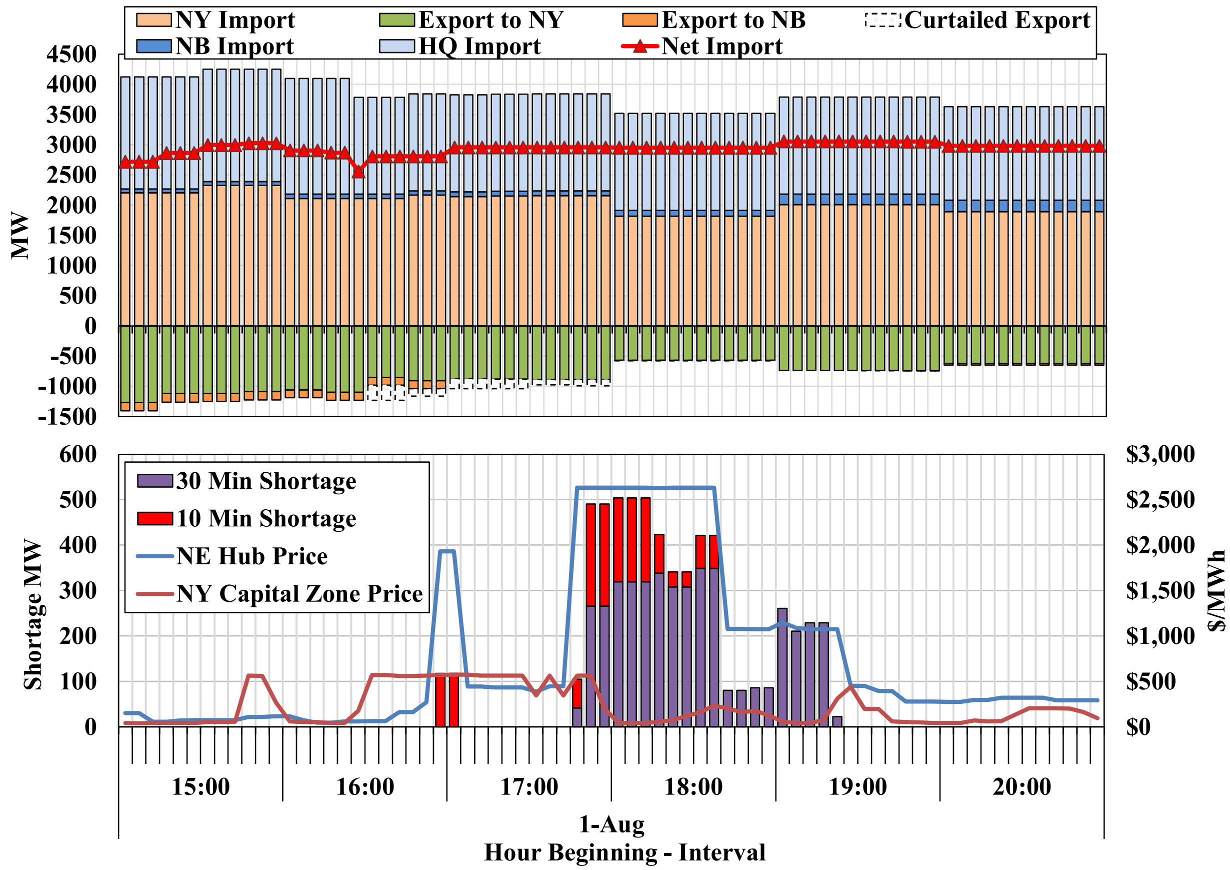
Figure 26 and Figure 27 examine the scheduling of external transactions with neighboring areas during the capacity scarcity conditions on June 18 and August 1, respectively. The upper panel of each figure shows the scheduled imports and exports at each interface. Transactions across the Highgate and the Phase I/II interfaces from Quebec are aggregated. Similarly, transactions across the interfaces with New York, including the primary interface with upstate New York and the 1385 interface and the Cross Sound Cable interface with Long Island, are grouped together. Scheduled transactions that were subsequently curtailed are depicted as hollow bars. The red line represents the total net imports across all interfaces during the shortage periods.

**Figure 26: Scheduling of External Transactions During Reserve Shortages**
June 18, 2024




The lower panel of each figure displays the types and magnitudes of reserve shortages observed in the ISO-NE market. The magnitude of 30-minute reserve shortages is measured relative to the minimum 30-minute reserve requirement, which is defined as the capacity needed to cover the largest contingency plus half of the second-largest contingency. This reserve product is associated with a Reserve Constraint Penalty Factor (RCPF) of $1000.[48] The panel also shows energy prices at the New England Hub compared to those in the NYISO Capital Zone.

**Figure 27: Scheduling of External Transactions During Reserve Shortages**
August 1, 2024




On June 18, ISO-NE experienced systemwide 30-minute reserve shortages across six 5-minute intervals from 17:50 to 18:15, with magnitudes ranging from roughly 135 to 420 MW and averaging 260 MW. NYISO also encountered systemwide 30-minute reserve shortages, ranging from 210 to 375 MW and averaging 300 MW, along with small local 30-minute reserve shortages in Southeast New York, and generally aligning with intervals when the NY Capital Zone energy price exceeded $700 per MWh.[49] However, NYISO's shortages occurred approximately 20 minutes later than ISO-NE's, meaning the events did not overlap.

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48 This excludes the 160 MW of replacement reserve requirement, which has a much lower RCPF of $250.

49 In the NYISO market, the magnitude of 30-minute reserve shortages is measured against the minimum requirement of 1965 MW, which has a demand curve value of $750. NYISO procures 2620 MW of 30-minute reserves equivalent to the size of two largest contingencies. For shortages less than 655 MW, the demand curve value ranges between $40 and $625 depending on the magnitude of the shortage.

On August 1, energy prices exceeded $2,600 per MWh during the shortages. In contrast, NYISO did not experience any 10-minute or 30-minute reserve shortages, although energy prices exceeded $500 per MWh in several intervals, indicating tight reserve margins.

On both days, ISO-NE curtailed only minimal amounts of scheduled exports so about 900 MW of scheduled exports to New York and New Brunswick remained un-curtailed on June 18, and about 700 MW of scheduled exports to New York remained un-curtailed on August 1. ISO-NE may have chosen not to fully curtail exports to avoid creating or exacerbating shortage conditions in neighboring areas.

Although the shortage conditions were brief, the events triggered the application of the $5,455 PFP rate. Because the current framework credits imports at the PFP rate while excluding exports from charges, it incents participants to engage in transactions in both directions because they can be simultaneously profitable. This is inefficient is a gaming opportunity.[50] These incentives and others created by the PFP framework are discussed in more detail in the next subsection.

#### *Pay-for-Performance Incentives During Reserve Shortages*

Overall, the PFP rules contribute to ensuring grid reliability in key ways. First, they help reduce the likelihood, duration, and severity of system-wide emergencies by incentivizing resources to be more reliable and available. Second, they provide financial incentives to invest in new resources and maintaining existing ones to enhance reliability.

Under the PFP rules, resources that fail to deliver energy or operating reserves during shortage events, regardless of the reason, face financial penalties, known as PFP charges. Conversely, resources that perform well and contribute to system reliability are rewarded with PFP credits. Figure 28 and Figure 29 summarize the PFP credits and charges during the shortage events on June 18 and August 1, respectively. Resources are categorized by whether they held Capacity Supply Obligations (CSOs) and by resource type. PFP credits and charges were calculated using a penalty rate of $5,455 per MWh.

Each figure also shows: (a) the amount *not* charged to exports; (b) the "*Additional Credits*" that resources in other categories would have received and the *"Reduced Charges"* for resources in other categories if the PFP event Balancing Ratio had been calculated by treating exports as under-performers.[51]

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50 NYISO's RTC model over-forecasted prices on the NYISO side, while ISO-NE's CTSPE model significantly under-forecasted prices on the New England side. These discrepancies led to exports being scheduled to New York even though the actual price differentials were in the opposite direction.

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

**Figure 28: PFP Settlements and Impact of Export Treatment**
June 18, 2024

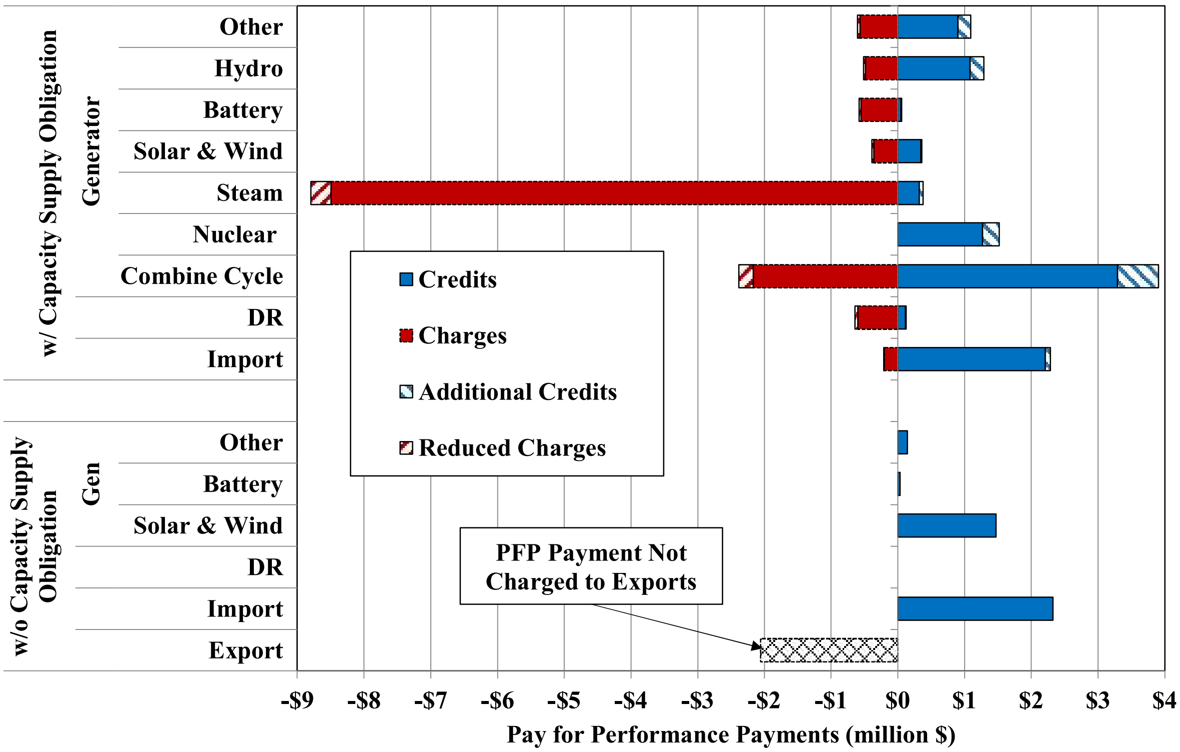



**Figure 29: PFP Settlements and Impact of Export Treatment**
August 1, 2024

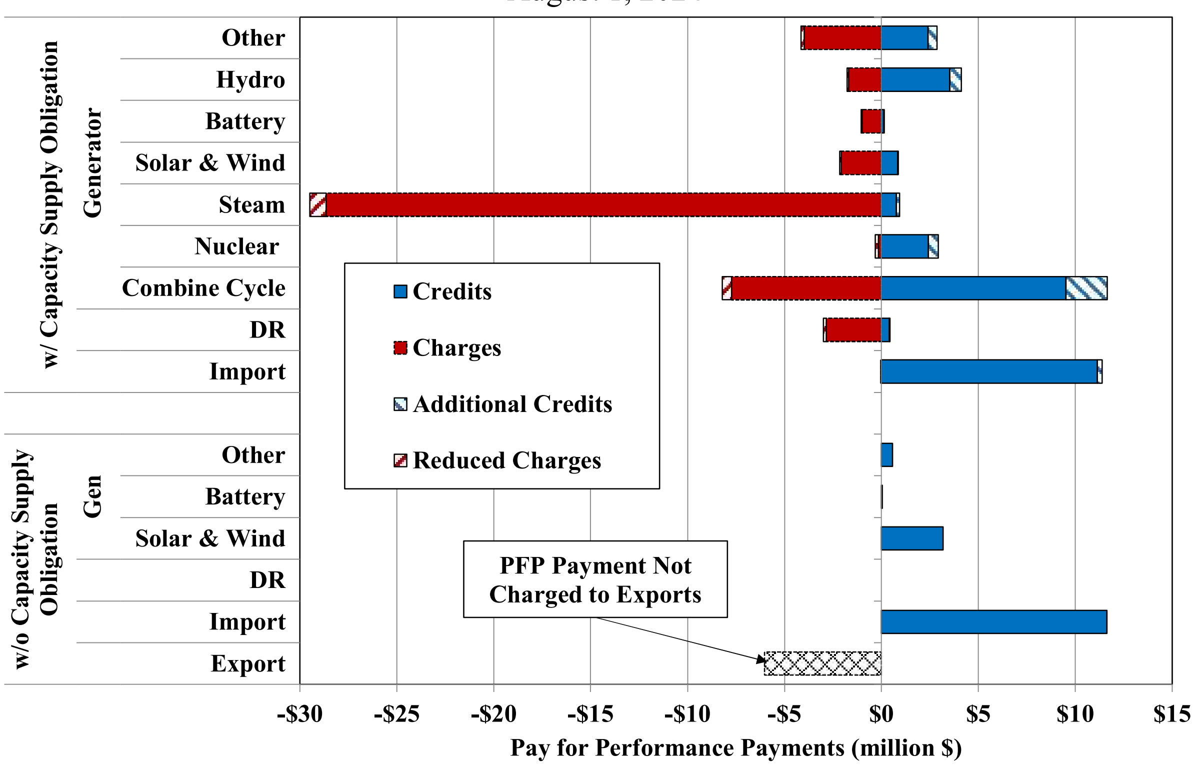


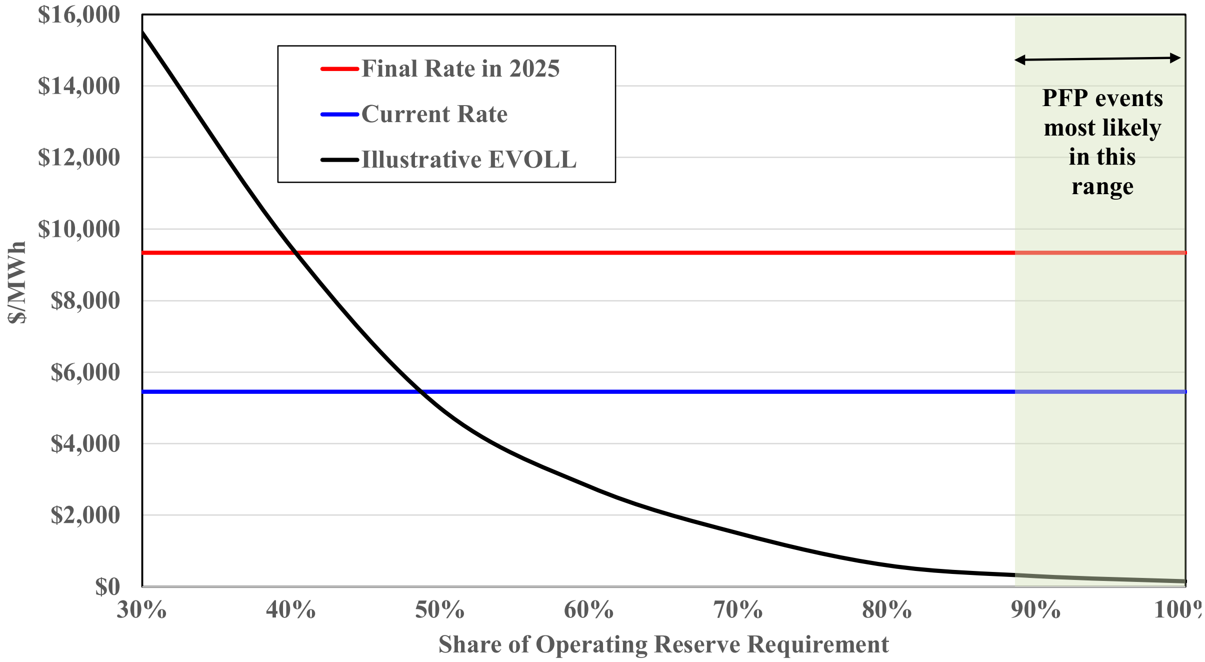
Figure 28 and Figure 29 indicate that resources with CSOs that under-performed during the two shortage events incurred more than $64 million in PFP charges. A substantial portion, approximately 84 percent, of these charges were borne by conventional slow-start generators, such as steam turbines and combined-cycle units. While some of these units experienced forced outages or deratings, most were simply not committed in the day-ahead market. This highlights the significant PFP risk faced by units with longer lead times during unforeseen real-time shortage events. While it is appropriate for such units to bear some level of risk, it should be aligned with the value of the reliability risk to the system, which were relatively modest during these events.

*Incentives for Imports and Exports*. Importers without CSOs received $14 million in performance payments during the two shortage events because they received the PFP incentive of $5,455 per MWh. In contrast, exporters did not incur any PFP charges, which provides poor incentives for efficient external transaction scheduling. It also encourages gaming by enabling a participant, through different bidding entities, to simultaneously schedule equal quanties of imports and exports. This would result in no power flowing, but allowing the participant to extract PFP rate of $5455 for each MW scheduled. The figures indicate that if exports were charged at the PFP rate, they would have been charged $8.1 million during the two events. Other categories of resources would have received an additional $5.6 million in credits and a reduction of $2.7 million in charges.

Apart from this gaming opportunity, the PFP rules create a sizable disparity in scheduling incentives for imports and exports that is inefficient. The total incentive for scheduling imports and exports during shortages includes the ORDC shortage values that 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 is only applied to imports, the total incentive can reach $8,200 per MWh for importers versus a maximum of $2,750 per MWh for exporters. This disparity will not support efficient import and export scheduling during shortage conditions. Hence, we recommend the ISO revise the PFP settlement rules to charge exporters the PFP rate during Capacity Scarcity Conditions. (Recommendation #2022-3)

*Misalignment with the Value of Lost Load*. This is perhaps the most significant concern with the current PFP design. During the 2024 events, importers and other suppliers were paid as much as $8,100 per MWh, combining reserve shortage pricing and PFP settlements. This compensation level substantially exceeds the true value of energy in New England, as represented by the Expected Value of Lost Load (EVOLL). EVOLL is equal to the value of lost load (i.e., the value of keeping the lights on) times the probability of losing load, which increases as the shortage deepens. Unlike EVOLL, the current PFP rules employ a constant rate regardless of the severity of the reserve shortage. Figure 30 illustrates how EVOLL increases as reserve margins decline and compares this with both the PFP Rate used during the summer of 2024 and the higher PFP rate set to take effect in June 2025.

**Figure 30: PFP Rates and the Value of Lost Load**




As shown in Figure 30, 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. The figure does not fully capture the potential problem with overstated prices because it does not include the shortage pricing in the energy market, which can add up to an additional $2,750 per MWh.

Our concerns about the risks and incentives associated with overstated prices are expected to grow in the future for two reasons:

- The PFP rate is slated to increase to $9,337 per MWh in June 2025; and
- Growing uncertainties associated with fuel supply and increasing reliance on intermittent resources will likely result in more frequent and unpredictable shortages.

While strong performance incentives are important, excessively high incentives can create inefficient risk for less flexible resources and may lead to inefficient retirement decisions. Hence, we recommend that the ISO modify its PFP rate to align with a reasonable estimate of VOLL and the likelihood of load shedding at various operating reserve shortage levels. This recommendation (#2018-7) includes the adoption of a graduated, stepwise PFP structure, where market compensation incentives rise efficiently with the severity of the shortage. Such a design would ensure that:

- Resources are appropriately incentivized to respond during deep reserve shortages, where the risk of load loss is high; and
- Unnecessary costs are avoided during shallow shortages when reliability risk is minimal.

Furthermore, when two neighboring systems are both short of reserves, having PFP rates that rise with the magnitude of the shortage based on reliability risk would contribute towards a more efficient allocation of reserves between regions.

## C. Conclusions and Recommendations

In this Section, we evaluated two issues that affect the performance of ISO New England's capacity market.

***Availability of Qualified Capacity***

We found that qualified capacity values for generators do not adequately reflect load conditions during periods with the most significant reliability risks because these values generally assume milder humidity and barometric pressure conditions than are likely to prevail during the peak summer load hour and they do not account for unreported forced derates. Together, these factors caused the available capacity to be 700 MW less than the qualified capacity during summer peak conditions during 2024.

Additionally, the severe weather conditions driving planning reliability needs are likely to be hotter, more humid, and lower in barometric pressure than typical summer peak conditions, although we did not quantify the impact of these factors. Hence, we recommend the ISO review compliance with forced derating reporting rules by generators and reassess how ambient conditions are considered in the calculation of Qualified Capacity soon after the CAR project is completed (#2024-3).

***Pay for Performance Events***

Two capacity shortage events occurred in 2024 that ranged from roughly 30 to 90 minutes and averaging almost 250 MW. Although neither event was a significant reliability event that exhibited a meaningful probability of losing load in New England, the settlements from the events were substantial:

- Suppliers incurred performance charges during the events of more than $64 million, most of which were incurred by available combined cycle or steam units that were simply offline because they were not committed in the day-ahead market;
- The total price paid to imports or resources exceeding their CSOs was as high as $8200 per MWh, which includes the $5455 per MWh penalty rate, which is slated to increase to $9337 per MWh in June 2025.

These prices and associated settlements vastly exceed the value of energy during these events and create sizable inefficient incentives to ISO New England's participants. One of these incentives relates to the settlements with imports and exports. Applying the PFP rate to settlements with importers but not exporters is a significant flaw that creates gaming opportunities by simultaneously encouraging scheduling of imports and exports. During these two events, ISO-NE curtailed minimal amounts of and allowed 700 to 900 MW of scheduled exports to flow, providing large opportunities to exploit this gaming opportunity.

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

- Revise its PFP rules to charge exporters at the PFP rate during Capacity Scarcity Conditions. (Recommendation #2022-3)
- Modify the PFP rates to levels that are in line with a reasonable estimate of VOLL and that escalate as reserve shortages grow deeper. (Recommendation #2018-7)

# 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.

### *Net Revenues of Combustion Units*

Our net revenue estimates of combustion 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, CTs 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, CTs are committed in real-time based on hourly real-time prices and settle with the ISO on the deviation from their day-ahead schedule.
- CTs are assumed to sell forward reserves in a capability period when it will be more profitable than selling real-time reserves.[52]
- Fuel costs assume transportation and other charges of $0.27 per MMBtu for gas 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. Regional Greenhouse Gas Initiative (RGGI) compliance costs are included, if applicable.
- The assumed operating parameters for combustion units are shown in Table 5:

**Table 5: Unit Parameters for Net Revenue Estimates of CTs**

| Characteristics | CT - 7HA |
|---|---|
| Summer Capacity (MW) | 364 |
| Winter Capacity (MW) | 394 |
| Heat Rate (Btu/kWh) | 8,054 |
| Min Run Time (hrs) | 1 |
| Variable O&M ($/MWh) | $1.8 |
| Startup Cost ($) | $11,000 |
| Startup Cost (MMBTU) | 508.5 |

- 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.

52 We assume that CTs are capable of providing 70 percent of the UOL as the 30-minute reserve product and the remaining 30 percent as the 10-minute reserves.

### *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 16 percent for land-based wind in ISO-NE.
- We estimated the REC revenues for land-based wind using a 4-year average of the MA Class I REC Index for 2023 and 2024 vintages 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.[53]
- Capital and operating costs are based on NREL's 2024 Annual Technology Baseline (ATB) with adjustments applied for regional cost differences.

### *Net Revenues of Land-Based Wind 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.[54] 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 South zone in ERCOT and in Minnesota 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 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.

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53 See Norton Rose Fulbright Cost of Capital: 2025 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 most recent ISO-NE and NYISO demand curve update processes. For 2024, we calculate an ATWACC of 8.6 percent for wind.

54 See Section III and Appendix VII of our 2024 report on the New York ISO markets, available here.

- Consistent with the assumption for other markets, we assumed full PTC revenues for the land-based wind plants in ERCOT and MISO regions.
- We used capital and fixed O&M costs for ERCOT and MISO based on the 2023 NREL Annual Technology baseline (ATB). We assumed a 35 percent annual average capacity factor for wind in ERCOT south and a 46 percent annual capacity factor for wind in MISO.

## 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 20 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.[55] To calculate the wet bulb temperature at each relative humidity level, we used the following equation:[56]

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

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.[57] 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.[58]

55 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.

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

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

58 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)