2023 Assessment of the ISO New England Electricity Markets

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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 2023 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 2023.

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 fell 58 percent in 2023, driven primarily by a 67 percent decrease in natural gas prices. This correlation is consistent with our finding that the market performed competitively because energy offers should track input costs in a competitive market. Average imports from Canada also fell significantly (355 MW) as reduced precipitation led to lower reservoir levels at their hydropower facilities.
- Average load declined 4 percent from 2022, while peak load fell 3 percent to just above 24 GW. Both average and peak load were at their lowest levels of the last decade. Load levels have trended downward in recent years because of continued installation of energy efficiency and behind-the-meter solar generation.
- The capacity compensation rate was $3.80 per kW-month in the 2022/23 Capacity Commitment Period ("CCP") and $2.00 per kW-month in the 2023/24 CCP.
  - The decline in capacity prices was driven by falling load forecasts and the retention of the Mystic 8 & 9 units until May 2024.
  - Capacity prices will rise slightly and remain at roughly $2.60 to $2.70 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 results in 2023. This report complements the IMM report by comparing key market outcomes with those in other RTO markets, assessing the competitive performance of the markets, and evaluating market design issues. Specifically, this report evaluates the competitive performance of the ISO-NE markets along with key operational and economic issues that will affect its performance in the future. In each area, we 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 2023 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 and 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. ERCOT, which operates an "energy-only" market, exhibited higher energy prices because high operating reserve demand curves that result in high shortage pricing; and poor implementation of a new reserve product in 2023 that resulted in frequent artificial shortage pricing.
Capacity Prices	Current capacity prices in New England were higher than other RTOs because of the higher surpluses in other markets and MISO's poor market design. Additionally, ISO-NE's forward capacity market has a slower process (spanning three years) for addressing over-forecasted peak loads that drive requirements. However, capacity prices in NYISO increased in 2023 following retirements of older generation driven by air permit limitations.
Congestion	ISO-NE experiences significantly less congestion than other RTOs, with an average congestion cost of roughly \$0.37 per MWh of load. This is just 10 to 20 percent of the average congestion levels in other RTO markets. This is a result of the large transmission investments made over the past decade, resulting in transmission rates of around \$22 per MWh in 2023 – more than double the average rates in other RTO markets. Transmission investments in ISO-NE have been primarily driven by relatively conservative local reliability planning criteria. Recently, transmission investment has increased in ERCOT, MISO, and NYISO, primarily to increase the deliverability of renewable generation to consumers.
Uplift Costs	ISO-NE generally incurs more market-wide uplift costs, adjusted for its size, compared to MISO and NYISO. The higher costs arise because: (a) ISO-NE's fuel costs tend to be higher, (b) it lacks day-ahead ancillary services markets to coordinate and price its operating reserve requirements, and (c) ISO-NE makes real-time NCPC payments to resources under a wider range of circumstances than MISO and NYISO. Introducing day-ahead operating reserve markets will help reduce these costs.

Virtual Trading	Virtual trading levels in ISO-NE have been only 30 to 40 percent of the levels seen in NYISO and MISO primarily because ISO-NE over-allocates real-time NCPC charges to virtual transactions and other real-time deviations. Addressing this issue is crucial because virtual trading can play an important role in aligning the day-ahead and real-time market outcomes, especially as the generation mix transitions to a much heavier reliance on intermittent renewable resources. (See Recommendation #2010-4)
External Transactions	The CTS process between New England and New York has performed far better than the CTS processes between PJM and NYISO and between PJM and MISO. ISO-NE's process with NYISO exhibits much higher bid liquidity, largely because of the decision not to impose charges on CTS transactions and better price forecasting. However, there is still substantial room for improvement in the performance of CTS.
Shortage Pricing	Aside from ERCOT, ISO-NE has the most aggressive shortage pricing in the country, primarily settled through the Pay-for-Performance (PFP) framework rather than the energy market. In June 2025, ISO-NE's shortage pricing rate will increase above even ERCOT's. 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)

Competitive Assessment

Based on our evaluation of ISO-NE's wholesale electricity markets in Section II of this report, we find little evidence of structural market power in New England, either at the system level or in individual sub-regions. However, the pivotal supplier frequency (a key indicator of potential market power) increased at the system level from 2022 to 2023. This was largely due to: (a) reduced import levels from Quebec since May, and (b) reduced available operating reserves in the last four months of the year because of planned outages of pumped-storage facilities. Despite this increase, our evaluation of participant conduct finds no evidence of market power abuses or manipulation, suggesting that the markets performed competitively in 2023. 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 two 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 2023, 35 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. (See 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 terminates when it is no longer warranted by the supplier's conduct or competitive conditions.

Navigating the Clean Energy Transition

The experience of other RTOs in managing the rapid influx of intermittent renewable resources and energy storage has highlighted the substantial operating challenges that intermittent renewable resource raise, including:

- Much higher levels of uncertainty regarding energy output and transmission flows; and
- Output fluctuations from these resources lead to periods of much greater demands for dispatchable resources to ramp their output up and down.

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, which 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 energy prices at or below zero in many hours and substantially reduce the market incentives for conventional resources. This is not a substantial concern because dispatchable resources will be needed and set price in many hours, even under high renewable penetration. Additionally, the increase in reserve shortages and shortage revenues should more than offset any 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 single-period 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 efficient 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.

Out-of-Market Commitments and Operating Reserve Pricing

The ISO includes two commitment constraints in the day-ahead market scheduling process to:

- Ensure the ISO is able to maintain reliability in key local areas in response to both the first *and* second largest contingencies; and
- Satisfy system-level operating reserve requirements.

Although these commitments are primarily made through the day-ahead market, the clearing prices of energy (and reserves) are understated because they do not reflect the costs of satisfying these requirements. Pricing these requirements in the day-ahead market would result in additional net revenues, especially for flexible resources such as fast-start peaking units and battery storage units, which are valuable for integrating intermittent renewable generation.

In Section III of this report, we evaluate supplemental commitment by the ISO to maintain reliability, the resulting NCPC charges, and impacts on market incentives. We find that such day-ahead reliability commitments have decreased over the past two years, due largely to changes in operational requirements and transmission upgrades. However, these reliability commitments still occurred in approximately 2,500 hours in 2023, accounting for 77 percent of the total day-ahead NCPC uplift. Because these reliability commitments are not reflected in the pricing software, day-ahead energy prices are generally understated, reducing generators' net revenues and necessitating NCPC payments to cover these commitment costs. We estimate that pricing these requirements in the day-ahead market would result in additional revenue of:

- Up to $3 to $7 per kW-year for units in the areas with local second contingency protection requirements; and
- Up to $12 per kW-year for units providing energy and/or system-level 10-minute spinning reserves.

Given that the annualized net cost of entry of a new peaking resource is typically estimated to be roughly $110 per kW-year, pricing these requirements would help incent investment in new and existing resources with flexible characteristics in key locations.

In addition, we continue to find 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.

Given these findings, 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)

We note two major improvements that we have recommended and which the ISO plans to implement in March 2025 under its *Day-Ahead Ancillary Services Initiative (DASI)* project:

- Introduce co-optimized operating reserves in the day-ahead market that reflect the ISO's operational needs. (See Recommendation #2012-8 in previous reports)
- Eliminate the Forward Reserve Market, which has resulted in inefficient economic signals and market costs. (See Recommendation #2014-7 in previous reports)

Lastly, we identify an inefficiency in the fast-start pricing logic, which tends to overstate the value of reserves under certain system conditions. Specifically, it fails to count unscheduled capacity below generators economic minimum toward meeting the ISO's reserve requirements. To address this inefficiency, we recommend the ISO modify the fast-start pricing logic to utilize the full capability of online resources for energy or reserves (Recommendation #2022-1). This will ensure that prices more accurately reflect the cost of maintaining operating reserves.

Assessment of Market Incentives during Capacity Shortage Conditions

In 2023, capacity shortage conditions occurred on July 5 for just 30-minutes shortly after 6 pm. The shortage was triggered by a forced outage of the Phase II interface between New England and Quebec, combined with higher-than-expected load levels. ISO-NE curtailed roughly 10 percent of scheduled exports to neighboring areas in an effort to minimize the magnitude and duration of the shortages. These shortages could have been avoided by curtailing larger quantities, as NYISO did not experience any reserve shortages during the same intervals.

Our evaluation of the PFP framework identified that it produces inefficient market incentives, simultaneously encouraging the scheduling of imports and exports. Specifically, under the PFP rules during this event, importers had a large incentive ($3,500/MWh in addition to the real-time energy price) to move power into New England during reserve shortages, while exporters do not face reciprocal charges when moving power out of New England. This disparity not only creates opportunity for potential gaming, but also raises costs for New England capacity suppliers.

Although the direct cost of not charging exports at the PFP rate may be small relative to the overall ISO-NE market, this flaw undermines the efficiency of scheduling incentives during reserve shortages. This inefficiency may compromise reliability or increase the frequency of reserve shortages. In addition, the costs and adverse incentives from this flaw will increase if Capacity Scarcity Conditions become more frequent, particularly when the PFP rate increases to more than $9300/MWh in June 2025.

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 to reasonable levels that are generally in line with the Value of Lost Load ("VOLL") and the likelihood that various operating reserve shortage levels could result in load shedding. This includes establishing multiple steps of the PFP rate so that market incentives rise efficiently with the severity of the shortage. 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)

Addressing Winter Reliability in the Forward 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 several projects to improve its ability to model winter risk and to update capacity market rules to reflect winter needs. These include:

- The *Resource Capacity Accreditation (RCA)* project will represent winter fuel limitations in the resource adequacy models used in the capacity market and consider generators' fuel arrangements when establishing their marginal capacity credit values;
- Developing proposed rules for a *prompt seasonal capacity market* as opposed to the current three-year forward annual market; and

[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 from electrification of heat and transportation, and growing winter risk in neighboring systems.

- Developing the *Probabilistic Energy Adequacy Tool (PEAT)* and *Winter Energy Risk Threshold (REST)* framework, which are intended to anticipate and address winter reliability needs driven by fuel security at the planning level.

Section V demonstrates how decisions by market participants can mitigate winter reliability risk to acceptable levels in the coming decade and discusses how the capacity market can facilitate these decisions. We discuss areas for improvement in the processes under development by ISO-NE that could have major impacts on resources' incentives that support winter reliability.

Assessment of Winter Reliability by 2031/32

We simulated reliability risk in the ISO-NE system using Potomac Economics' Resource Adequacy Model (PE-RAM), which is an hourly resource adequacy simulation that considers load, generator forced outages, and intermittent generator profiles. It is capable of modeling dispatch and replenishment of resources with limited fuel inventories (such as oil, stored LNG, and battery storage). We used inputs derived from the PEAT study, the 2024 CELT forecast, and the results of FCA18. We draw the following key conclusions:

- *Winter reliability risks are driven by limited fuel inventories* – The ISO-NE system faces elevated reliability risk in winter in the coming decade. Reliability risk is driven by low-probability, high severity events where stored fuel inventories were insufficient to preserve reliability through cold waves lasting approximately 12 days or longer.
- *Participant actions and market conditions can substantially affect winter reliability* – These include: LNG quantities available to gas generators, fuel inventory levels of oil and dual fuel units, entry of wind generation, and retirements of fuel-secure units (including coal and oil units with large tanks). We found that the entry of battery storage did not substantially mitigate winter reliability risks.
- *Everett Marine Terminal is beneficial but not essential for winter reliability* – Scenarios that modeled the Everett LNG terminal as retired generally resulted in higher winter reliability risk, but this was manageable in all cases by holding larger oil inventories and/or more LNG from the Saint John terminal.
- *Well-designed risk models and capacity market rules are essential.* They will: accurately signaling the value of procuring firm fuel, avoid premature retirements of fuel-secure units, and attract entry of resources that contribute to winter fuel security. Reliability models used for setting requirements and accreditation will need to accurately represent the key drivers of winter reliability risk. We identified the following areas where improvements to planning models and processes are needed:
  - *Secondary Available LNG*: The amount of uncontracted LNG available to gas-only generators is a critical assumption in the reliability models. Optimistic assumptions of LNG availability will understate winter risk, negate incentives for generators to procure fuel and incentivize premature retirements. ISO-NE has used assumptions in recent studies that may not account for annual variability in LNG imports and in-season inflexibility.

- *Including Opportunity Costs in the Dispatch Logic*: Reliability models should account for economic incentives for holders of stored fuels (including oil and LNG) to avoid premature depletion of inventories during long cold events. Failure to do so may result in unrealistically high estimated reliability risks and distort the estimated value of potential solutions.
- *Inventory Representation in Accreditation Models*: Models used to determine capacity credit should explicitly represent depletion of LNG and oil inventories. This will allow marginal accreditation values to accurately reflect each resource's contribution to winter reliability risk that is driven by energy adequacy.

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.

ISO-NE is currently pursuing major changes to its resource adequacy modeling and accreditation methods in order to accredit resources based on the marginal reliability benefit they provide. We generally support these changes and also highlight the need for further improvements in the modeling of factors affecting winter reliability and resulting accreditation.

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;[4]
- 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.

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

If the ISO transitions to a prompt market framework, we recognize that it will require significant conforming changes to the interconnection and reliability planning processes. However, it would generate the following substantial benefits:

- Reduce development risk associated with FCA participation by awarding a CSO only when a resource is in service or nearly complete;
- Facilitate more efficient investment in resources with fast development timelines by allowing them to receive capacity payments more quickly after entry;
- Align assumptions underlying GE-MARS with the actual resource mix so that the ICR and capacity credit ratings are determined accurately;
- Efficiently compensate resources that provide different summer and winter capacity;
- Facilitate efficient retirement decisions by old existing generating resources by eliminating the risk of accepting CSOs three to four years in advance.
- Permit a greater range of capacity cost hedging options by load-serving entities instead of requiring all obligations to be satisfied three years in advance; and
- Simplify administration of the capacity market by eliminating the need to rely on multi-year forecasts of auction parameters and closely monitor the progress of new projects.

Recommendation #2020-3: 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 a supply resource. It would also be substantially less administratively burdensome and would produce more efficient incentives to invest in EE technologies.[5]

Recommendation #2015-7: We recommend replacing the descending clock auction with a sealed-bid auction. We have detailed in previous reports that ISO-NE's DCA process inadvertently provides information that may help suppliers with market power influence auction prices.[6] A sealed bid auction would eliminate such information and improve the incentives for suppliers to submit competitive offers. In addition, the DCA format adds unnecessary complications that may interfere with other enhancements recommended in this section.

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.

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

6 See our 2014, 2015 and 2017 Assessment of the ISO New England Electricity Markets.

The table below includes references to the location of our analyses and discussions supporting each recommendation. A number of the recommendations were first made in a prior annual report. 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 from neighboring areas to satisfy forecasted local second contingency requirements.			III.B
2010-4	Modify allocation of "Economic" NCPC charges to make it consistent with a "cost causation" principle.			III of 2018 Report
2014-5	Utilize the lowest-cost configuration for multi-unit generators when committed for local reliability.			III.B
Energy and Operating Reserve Markets				
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.	✓		Exec Summary
2022-1	Allow fast-start pricing model to utilize the full capability of online units for energy or reserves.			III.C
2019-3	Dynamically define a full set of local operating reserve requirements in the day-ahead and real-time markets.			III.B
Energy Market Mitigation				
2022-2a	Implement hourly conduct and impact tests in the automated energy mitigation procedure.			II.D
Capacity Market				
2022-3	Charge exporters the PFP rate during reserve shortages.			IV.B
2021-1	Replace the forward capacity market with a prompt seasonal capacity market.	✓	FCA19 Delay / Assessment of Prompt Seasonal	V.H
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.	✓	Resource Capacity Accreditation	V.G
2020-3	Account for energy efficiency as a reduction in load instead of as a supply resource in the FCM.			V of 2020 Report

7 Recommendation will likely produce considerable efficiency benefits.

Recommendation Number and Description		High Benefit[7]	Current/ Planned Efforts	Report Reference
2018-7	Modify the PPR to rise with the reserve shortage level, and do not implement the planned increase in the PPR.	✓		IV.B
2015-7	Replace the descending clock auction with a sealed-bid auction to improve competition in the FCA.			IV of 2017 Report

Substantial Progress or Resolution of Prior Recommendations

Recommendation Number and Description		High Benefit	Status
Energy and Operating Reserve Markets			
2014-7	Eliminate the forward reserve market.		Expected Mar. 1,2025
2012-8	Introduce co-optimized operating reserves in the day-ahead market reflecting forecasted system needs.	✓	Expected Mar. 1,2025
Energy Market Mitigation			
2022-2bc	Implement energy mitigation reforms including: (b) mitigation of only conduct-failing offer ranges, and (c) fuel-price adjustments that vary by output level.		Elimination of Upward Mitigation Dec. 2023 / MW-Dependent Fuel Price Adjustment proposed for Nov. 2026
Capacity Market			
2022-4	Postpone to forward capacity auction to support the transition to a prompt capacity market.	✓	FCA Further Delay Approved
2021-2	Include the effects of MOPR elimination on investment risk when establishing the net CONE for the demand curve.		Net CONE study considered this qualitatively

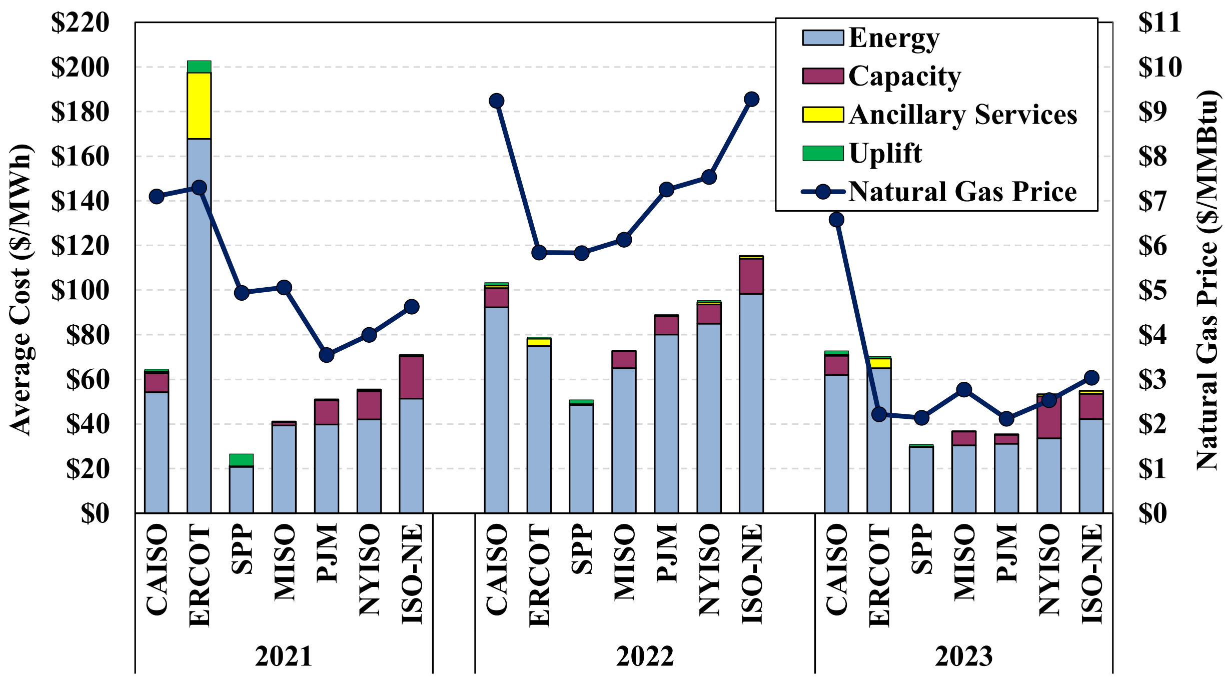
I. Comparing Key ISO-NE Market Metrics to Other RTOs

The 2023 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 very good discussion of these market outcomes and the factors that led to changes in the outcomes in 2023. We complement this discussion by placing the key market outcomes into perspective in this section by comparing them to outcomes in other RTO markets. We also discuss the clean energy transition in New England and other 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]
2021 – 2023



[8] These include only wholesale market costs and not, for example, costs recovered through regulated retail rates. Such costs may be large in vertically-integrated areas such as MISO.

The all-in price metric provides a comprehensive measure of the total cost of serving load. It is equal to the load-weighted average real-time energy price plus capacity, 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: This figure shows sustained differences in prices and costs among these markets. ISO-NE has exhibited the highest energy prices in the Eastern Interconnect, primarily because of 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, because of 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. However, during the winter months, ERCOT has experienced high energy prices accompanied by high natural gas prices when the shortages of operating reserves and energy were driven by natural gas scarcity. This was particularly evident in 2021 when extraordinary shortages occurred during Winter Storm Uri in February.

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:

- *Carbon Emission Costs.* ISO-NE energy prices are affected more than most other regions by the state greenhouse gas compliance costs. In 2023, compliance added an average of \$8 to \$11 per MWh to the costs of gas-fired combined-cycle generators in Massachusetts and \$6 to \$8 per MWh in the other five New England states that are in the Regional Greenhouse Gas Initiative (RGGI) region. NYISO generators are also subject to RGGI compliance costs. There are no such programs for generators in ERCOT, MISO, or SPP. RGGI compliance costs are included in a small number of PJM states. CAISO is subject to a greenhouse gas (GHG) allowance cap-and-trade system, which added an average of \$15 to \$20 per MWh to the production costs of gas-fired combined-cycle generators.
- *Transmission Congestion Costs*. Although we do not show the most congested locations in neighboring markets (e.g., Long Island), 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 in 2023. Capacity costs in NYISO rose dramatically following the retirement of 800 MW of peaking generation because of air permit limitations, lower capacity imports from neighboring control areas, and higher capacity requirements. Before 2023, NYISO's capacity costs were lower than those of ISO-NE because of its larger capacity surplus, which was partly due to nuclear capacity retained through out-of-market subsidies called Zero Emission Credits. Load forecasts have also played a key role in the outcomes of these two markets, affecting the NYISO spot market more quickly than the three-year forward market in New England:

- Load forecasts have fallen significantly in both markets in recent years because of the growth of energy efficiency programs and behind-the-meter ("BTM") and other distribution-level solar installations. By the end of 2023, BTM and other distribution-level solar installations exceeded 5 GW in New York and 6 GW in New England.
- ISO-NE's 4-year ahead load forecast used to determine the capacity requirement in each FCA fell from 25.2 GW for the summer of 2021 to 24.5 GW for the summer of 2023, resulting in a decline of 3 percent and a 32 percent decrease in capacity prices from the 2022/23 Capability Year to the 2026/27 Capability Year. NYISO's load forecast, set six months ahead, fell by less than 1 percent from the summer of 2021 to 2023.

Lower capacity costs for PJM are attributable to its capacity surpluses resulting from large amounts of capacity imports and low generation development costs. Low capacity costs in MISO are attributable to its poor market design and surpluses generally produced by its regulated utilities. MISO has operated a capacity auction with a vertical demand curve that is prone to volatility and generally not designed to reveal the true value of capacity. As a result, capacity prices have generally been understated and do not provide efficient long-term incentives.

CAISO also implements a resource adequacy program to ensure the system has enough capacity to operate the grid reliably, with an effective planning reserve margin (PRM) requirement between 20 and 22.5 percent. The capacity cost component shown in the figure represents the soft offer cap of capacity procurement mechanism in CAISO for procuring backstop capacity.

ERCOT and SPP operate an "energy-only" market (i.e., no capacity market), although SPP does not operate a capacity market, it enforces a 12 percent planning reserve requirement.

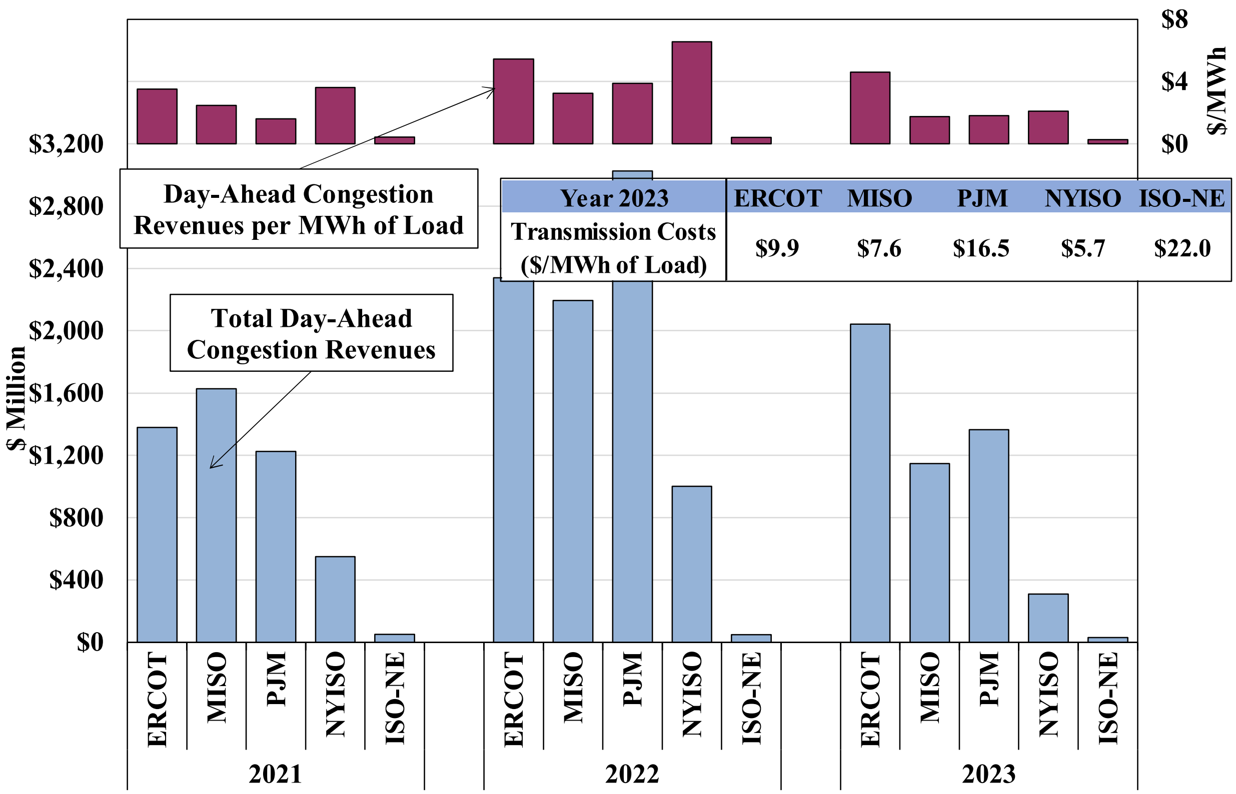
Uplift Costs: The last cost component shown in the figure, although difficult to discern, is the average uplift costs per MWh of load in each region. Although this amount is small, it is important because it is difficult to hedge and tends to occur when the market requirements are not fully aligned with 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 shows that ISO-NE experienced far less congestion than other RTOs – an average of \$0.37 per MWh over the past three years. In contrast, congestion levels per MWh of load in the other RTOs were six to eleven times higher than in New England based. The low level of congestion in New England can be attributed to substantial investments in transmission infrastructure made over the past decade as a part of the reliability planning process to support local transmission security. These investments have resulted in transmission rates of approximately \$22 per MWh each year over the past three years, which are more than double the average rates observed in the other RTO areas shown in the figure.

Figure 2: Day-Ahead Congestion Revenues
2021-2023



Year 2023	ERCOT	MISO	PJM	NYISO	ISO-NE
Transmission Costs ($/MWh of Load)	$9.9	$7.6	$16.5	$5.7	$22.0

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 Texas and MISO to support the integration of wind resources. For example, 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, while MISO has invested in transmission exceeding $15 billion to integrate renewable resources throughout MISO and plans to build far more through its Long Range Transmission Planning process.

Likewise, the NYISO and New York State have approved over $17 billion in transmission projects since 2019, primarily designed to deliver land-based renewable energy from upstate New York to load centers downstate. Additionally, the NYISO concluded a solicitation in 2023 for transmission to move offshore wind output from Long Island to other areas of the state with a proposed cost exceeding $3 billion.

The primary drivers of transmission expansion in ERCOT, MISO, and NYISO have revolved around increasing the deliverability of renewable resources to end consumers. In contrast, although the transmission investments in ISO-NE are evolving to facilitate the clean energy transition, the majority of its investments have been driven by different factors:

- In northern New England, transmission upgrades have been focused on improving the performance of the long 345 kV corridors, particularly through Maine.
- In southern New England, investments have been driven by ISO New England's planning requirements to ensure system reliability amidst generation retirements in this region.

ISO New England's reliability planning process identifies a local need for transmission whenever the largest two contingencies would result in the loss of load under a 90th-percentile peak load scenario. This criterion is more stringent than the reliability planning criteria used in the other three markets. Investments in New England to maintain reliability totaled $12.1 billion from 2002 through March 2024, with $1.3 billion more planned through 2032.[9]

In general, transmission investment is economic when the marginal benefit of reducing congestion is greater than the marginal cost of the transmission investment. Given that the average congestion cost per MWh of load in New England has been roughly $0.37 per MWh over the past three years, it is unlikely that additional investment would 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.

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

9 See *RSP Project List and Asset Condition List – March 2024 Update*, Planning Advisory Committee Meeting, March 20, 2024.

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 2023 uplift charges for both NYISO and MISO. 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.

Table 1: Summary of Uplift by RTO

		ISO-NE			NYISO	MISO
		2021	**2022**	**2023**	**2023**	**2023**
Real-Time Uplift						
Total	**Local Reliability ($M)**	$2	$1	$1	$20	$1
	Market-Wide ($M)	$19	$37	$25	$15	$24
Per MWh of Load	**Local Reliability ($/MWh)**	$0.01	$0.01	$0.01	$0.13	$0.00
	Market-Wide ($/MWh)	$0.16	$0.32	$0.22	$0.10	$0.04
Day-Ahead Uplift						
Total	**Local Reliability ($M)**	$6	$1	$1	$16	$16
	Market-Wide ($M)	$9	$13	$4	$8	$34
Per MWh of Load	**Local Reliability ($/MWh)**	$0.05	$0.01	$0.01	$0.11	$0.02
	Market-Wide ($/MWh)	$0.08	$0.11	$0.03	$0.05	$0.05
Total Uplift						
Total	**Local Reliability ($M)**	$8	$2	$2	$35	$17
	Market-Wide ($M)	$28	$50	$29	$23	$58
Per MWh of Load	**Local Reliability ($/MWh)**	**$0.07**	**$0.02**	**$0.01**	**$0.24**	**$0.03**
	Market-Wide ($/MWh)	**$0.24**	**$0.43**	**$0.26**	**$0.16**	**$0.09**
	All Uplift ($/MWh)	**$0.31**	**$0.45**	**$0.27**	**$0.40**	**$0.11**

Market-Wide Uplift: Table 1 shows that ISO-NE incurred more market-wide uplift costs than the other two markets, adjusted for its size. Despite a decrease in uplift charges across all three regions in 2023 because of lower natural gas prices, ISO-NE's market-wide NCPC uplift 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 at least two factors:

- First, while all three markets have rules for compensating a generator when its scheduled output level differs from its most profitable output level, ISO-NE's rules provide compensation in certain circumstances where MISO and NYISO rules do not. It would be beneficial to examine these differences to identify best practices across markets.
- Second, market-wide costs for NYISO and MISO are typically lower partly because of their day-ahead ancillary services markets, which allow a larger share of the costs of committing resources needed for operating reserves to be reflected in the market.

However, ISO-NE's market-wide cost per MWh of load fell significantly in 2023 compared to prior years because of a significant reduction in the frequency of day-ahead commitments for operating reserves (rather than a change in the way these resources are compensated for reserves). We discuss these in more detail in Section III.

Local Reliability Uplift: Table 1 also indicates a notable trend of decreasing local reliability NCPC uplift over the past three years. This decline reflects minimal supplemental commitments in the load pockets because of new resource additions and ongoing transmission upgrades in key areas. Uplift for local reliability in ISO-NE remained considerably lower than in other RTOs, particularly in NYISO. NYISO, for instance, commits 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 the NYISO energy and reserve markets, leading to inefficient prices, higher uplift costs, and poor incentives for investment in resources that could help maintain local security and reliability.

Uplift Allocation: In addition to the differences in the magnitude of uplift costs, there are substantial variations in how these costs are allocated. 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 real-time deviations. Fast-start resources accounted for 58 to 68 percent of the real-time Economic NCPC payments over the past three years, which often results from resources being committed uneconomically in real time in response to a forecast error. Real-time deviations such as virtual transactions have little or no impact on this uplift. In fact, virtual load tends to reduce NCPC charges because they contribute to committing more resources through the day-ahead market and reduce reliance on fast-start resources.

Table 2 shows the average volume of virtual supply and demand cleared in the three eastern RTOs we monitor as a percent of total load. It also shows their gross profitability, which represents the difference between the day-ahead and real-time energy prices used to settle the energy bought or sold by the virtual trader. The profitability numbers do not account for uplift costs allocated to virtual transactions, which are shown in a separate column in 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	2020	2.8%	$0.36	4.6%	$0.72	$0.46
	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
NYISO	2023	7.2%	-$0.76	8.6%	$0.64	< $0.1
MISO	2023	16.1%	$0.40	15.9%	$1.11	$0.16

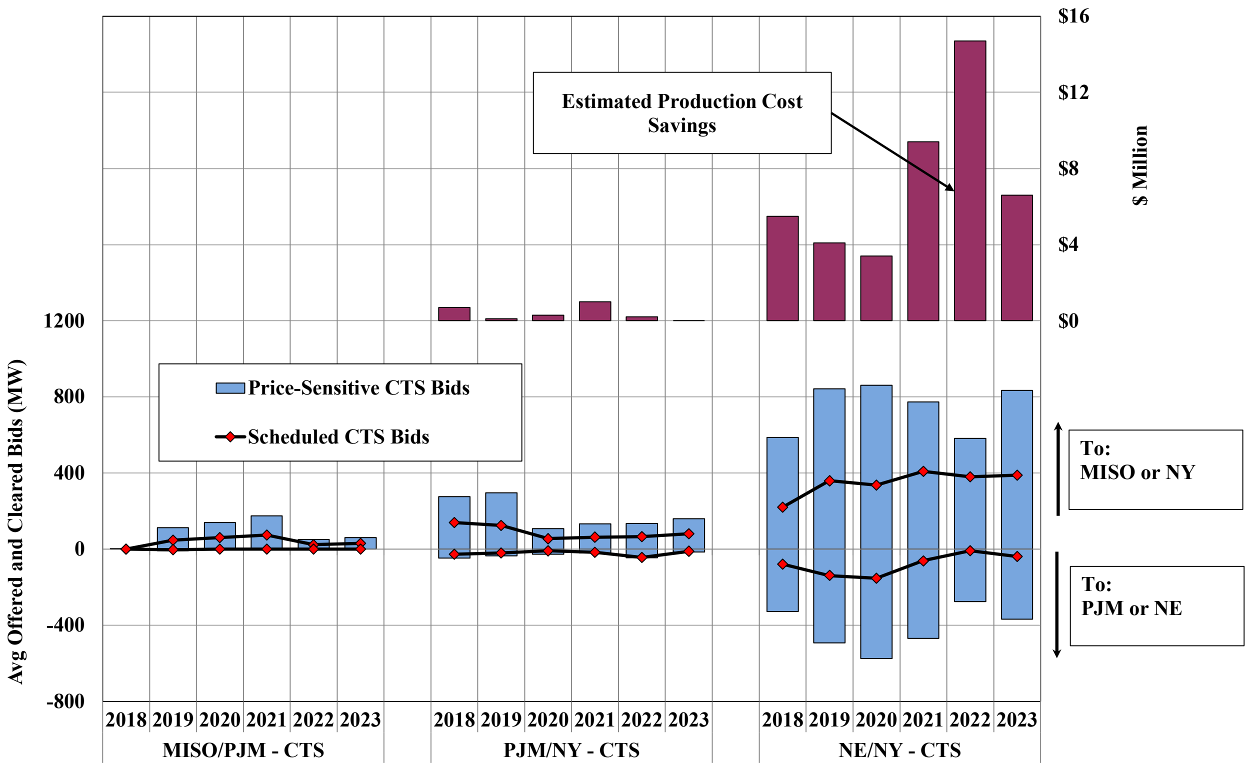
Table 2 shows that virtual trading is generally profitable, suggesting it tends to improve price convergence between the day-ahead and real-time markets, although it was slightly unprofitable overall in 2023 (averaging -$0.07 per MWh across all transactions).

Table 2 also shows that virtual trading levels are much lower than in the other RTOs, averaging only 8 percent of load compared to 16 to 32 percent for the other two RTOs. This was due in part to the over-allocation of NCPC charges to real-time deviations in New England. This reduces the day-ahead market liquidity and ultimately reduces its 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 not allocating 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 intermittent generation grows, CTS will become even more important for RTOs to efficiently balance supply and demand. Figure 3 compares CTS performance between the NE-NY process to the PJM-NY and MISO-PJM processes.

Figure 3: CTS Scheduling and Efficiency
2018 – 2023



The lower panel in Figure 3 shows the annual average quantities of price-sensitive CTS bids and schedules from 2018 to 2023.[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.

Figure 3 indicates a much higher level of CTS participation at the NE/NY interface compared to the PJM/NY and PJM/MISO interfaces, which we attribute to the substantial transaction fees imposed at both the PJM/NY and PJM/MISO interfaces. Fortunately, there are no significant transmission or uplift charges at the NE/NY interface. These findings underscore that these charges act as economic barriers to achieving the benefits of CTS by discouraging participants from submitting efficient CTS offers.

The estimated production cost savings from the NE/NY CTS process totaled nearly $44 million over the past six years, while the estimated savings were just over $2 million at the PJM/NY interface.[11] In addition to higher liquidity, better price forecasting 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. If the ISOs can further improve the price forecasts that underlie the CTS prices, it will allow the process to achieve larger savings.

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

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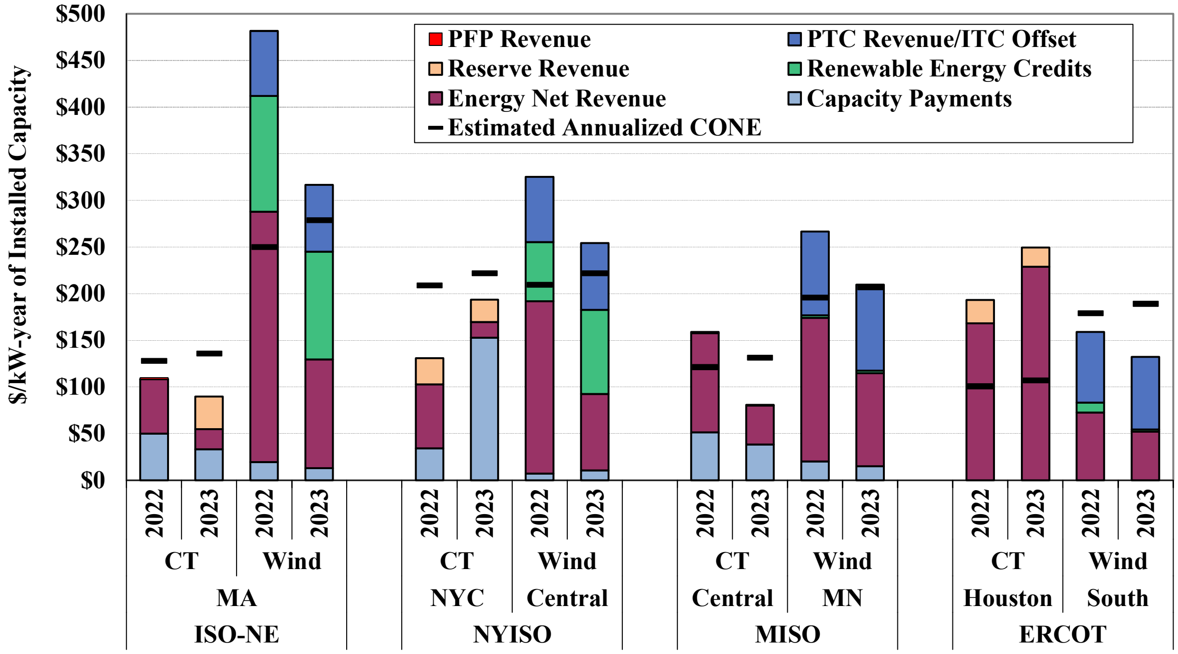
10 CTS bids in the price range of -$10 to $10 per MWh are considered price-sensitive for this evaluation.

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.

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 2022 and 2023.

Figure 4: Net Revenues Produced in ISO-NE and Other RTO Markets
2022 – 2023



Incentives for New Combustion Turbines (CT)

Net revenues for a CT from the energy and reserve markets generally fell in 2023 as falling natural gas prices led to lower energy prices. This was not true in ERCOT, which we discuss below. New investment in combustion turbines in most markets are 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 from repowering, access to cheaper gas, etc.). The capacity surplus and associated decline in capacity prices will continue through at least 2027/28 CCP.

12 See Appendix Section VI for the assumptions used for this analysis. The combustion turbines chosen for each market reflect those that are most economic and likely to be built: a F Class Frame CT (7FA) in MISO and ERCOT and a H Class Frame CT (7HA) in New England and New York because of siting regulations. For the CT in ISO-NE, the reserves revenue is near zero in 2022 because the unit would receive higher net revenue by not selling Forward Reserves, thereby earning more from selling energy and real-time reserves.

- *New York City*. Capacity prices rose significantly in New York City due to retirements of combustion turbine peaking units affected by environmental regulations. For the 2023/24 capability year (May 2023 through April 2024), capacity prices *exceeded* the Net Cost of New Entry in New York City. However, it is unclear if a new gas CT unit can be developed in New York because of the siting and environmental permitting process.
- *ERCOT*. The net revenues of a CT in ERCOT were much higher than in other markets in 2022 and 2023. This is largely due to frequent price spikes associated with the poor implementation of a new reserve product. These price spikes doubled average energy prices from June through December and raised net revenues substantially.
- *MISO*. In 2022, MISO's was short of capacity in the Midwest region, causing the price to clear at the CONE level. Additional supply and changes to capacity market parameters resulted in inefficiently low capacity prices in 2023, the natural result of using vertical demand curves. MISO has since filed to implement sloped reliability-based demand curves, which should generally raise prices to much more efficient levels.

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 because of 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.

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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.

Incentives for New Land-Based Wind Projects

Net revenues for land-based wind units in New England exceeded its CONE in 2022 and 2023 because of higher energy revenues. State and federal incentives were still important, accounting for 59 percent in 2023. 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.

The figure 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. However, land-based wind investment remains strong in MISO and ERCOT where resource potential is better than in New England and New York. High gas prices in the Northeast U.S. in 2022 also contributed to higher revenues for wind projects in New York and New England than in MISO and ERCOT.

The federal government has encouraged the development of wind resources over the past three decades through the Production Tax Credit, where resources receive a credit per MWh generated in the first ten years of commercial operation. The level of the PTC has been variable, and sometimes been retroactively extended or modified. In 2022, the Inflation Reduction Act ("IRA") was enacted, increasing wind investment incentives:

- Increasing the effective PTC from $18.40 per MWh for projects entering service in 2021 to $26 per MWh for projects entering from 2022 through at least 2032.[16]
- Making the tax credit refundable starting in 2022, while the tax credit was previously limited by the taxable income of the investor(s). This change has greatly expanded the set of firms able to benefit from investments in land-based wind; and
- Making land-based wind projects eligible for the Investment Tax Credit ("ITC") of 30 percent of the overnight capital cost of the project as an alternative to the PTC. Many land-based wind generators will continue to prefer the PTC, although some tax investors may prefer the risk exposure of the ITC, which is fully credited when the unit becomes operational. The PTC accrues over the first ten years of commercial operation.

Alternative Contracting Structures for New Renewable Resources

Ultimately, the investment incentives in wind resources depend not only on wholesale prices and federal tax incentives, but also on the offtake contract structures employed in different regions:

- ERCOT has been transitioning from long-term PPAs to private financial hedges.

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

16 The PTC is a credit on after-tax income, making it more valuable than RECs of the same magnitude.

- 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 projects will offer at negative prices to reflect their state and federal incentives, which may cause a resource offering 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.[17] 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 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.

17 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.

F. 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. Their experience has highlighted the substantial operating challenges that intermittent renewable resource raise, including:

- Much higher levels of uncertainty regarding energy output and transmission flows; and
- Output fluctuations from these resources lead to periods of much greater demands for dispatchable resources to ramp their output up and down.

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, which 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 energy prices at or below zero in many hours and substantially reduce the market incentives for conventional resources. This is not a substantial concern because conventional resources will be needed and set 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.

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.

II. Competitive Assessment of the Energy Market

This section evaluates the competitive performance of the ISO-NE energy market in 2023. 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.[18] We address four 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; and
- Market power mitigation.

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

[18] 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;[19] 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.

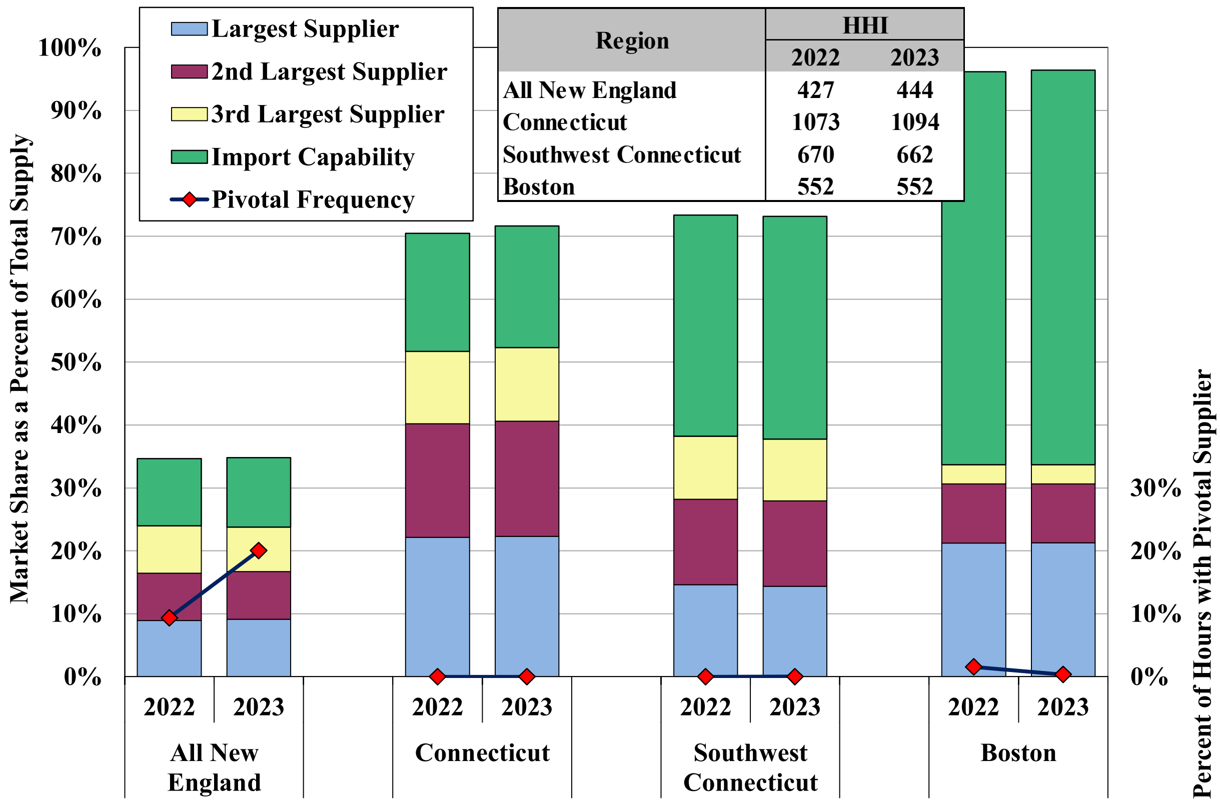
The first two structural indicators focus exclusively on the supply side. Although widely used in other industries, their usefulness is limited in electricity markets because they ignore that the inelastic demand for electricity substantially affects the competitiveness of the market.

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 price. 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).

19 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 5 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 5: Structural Market Power Indicators
2022 – 2023



Region	HHI	
	2022	2023
All New England	427	444
Connecticut	1073	1094
Southwest Connecticut	670	662
Boston	552	552

The import capability and market shares are based on ISO-NE data and the inset table shows the HHI for each region.[20,21] 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 because of their low marginal costs.

Figure 5 indicates that the market concentration of internal generation remained relatively stable from 2022 to 2023 despite some changes in asset ownership. RWE acquired Con Edison Clean

20 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.

21 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.

Energy Businesses in the first half of 2023 and became a top supplier in New England. However, this acquisition did not alter the shares of the largest three suppliers in New England or the largest suppliers in the subareas.

Market concentration varied significantly across the four regions. Boston had a single supplier with a large market share of 21 percent (including import capability as part of the total supply), while all New England had three suppliers with comparable market shares, each below 10 percent. Import capability accounted for a significant share of total supply in each region, ranging from 11 percent in all of New England to 63 percent in Boston.

The market concentration, as measured by the HHI, remained low (under 1,100) 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 2023, which indicates that:

- There were almost no hours with a pivotal supplier in Southwest Connecticut and Connecticut.
- In Boston, although one supplier owned 57 percent of the internal capacity, it was pivotal in less than 0.5 percent of hours. This underscores the importance of import capability into constrained areas in providing competitive discipline; and
- In all New England, at least one supplier was pivotal in 20 percent of hours.[22]

The pivotal supplier frequency continued to decline in Boston because of a 4 percent reduction in average load levels from 2022 and the completion of Boston Area Optimized Solution project in June 2023. However, the pivotal supplier frequency rose in all New England from 2022 to 2023 despite lower load levels. This increase was partly due to significantly reduced net imports from Quebec across the Phase II and Highgate interfaces, which fell by an average of approximately 515 MW from May through December 2023 compared to the same period in 2022.[23] The reduction in imports was driven partly by reduced rainfall and runoff, leading to widespread wildfires starting in May and low reservoir levels.

Additionally, the pivotal supplier frequency rose from September through December because of planned outages of several pumped storage units from mid-September to late December, which

22 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.

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

reduced available reserves at the system level. Given these findings, we review the conduct of suppliers in the Boston and all of New England areas in the next section because these areas have the highest pivotal supplier frequencies.

C. Economic and Physical Withholding

Suppliers with market power can exercise it by 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 the difference between the unit's capacity that is economic at the prevailing clearing price and the amount that is actually produced by the unit.[24]
- **Physical withholding:** We focus on short-term deratings and outages because they are most likely to reflect attempts to physically withhold resources. 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 Boston and all New England, Figure 6 shows the output gap and short-term physical deratings by load level in these two regions. 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:

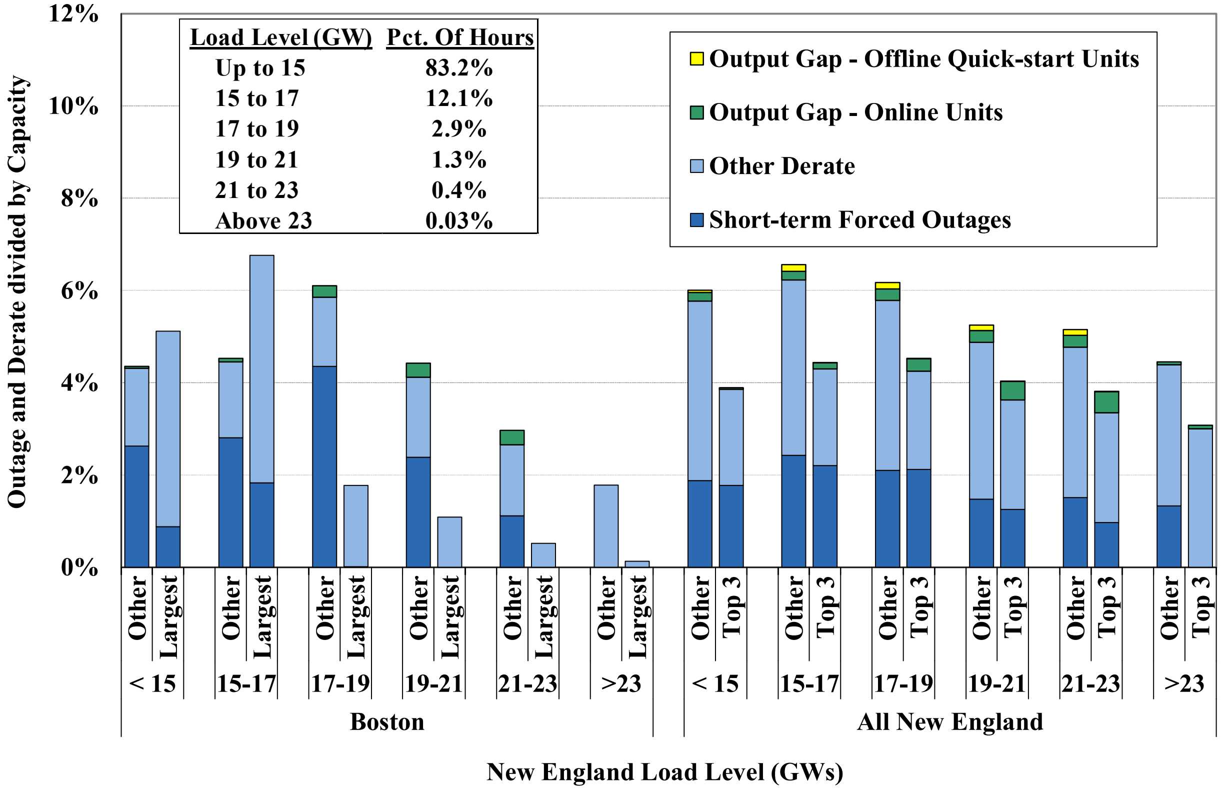
- **Short-term forced outages** that typically last less than one week; and
- **Other derates** that include reductions in the hourly capability of a unit not logged as a forced or planned outage. This can result from ambient temperature changes or other legitimate factors.

Figure 6 shows these metrics as a percentage of suppliers' portfolio size, distinguishing between the largest suppliers and the other suppliers. In Boston, the analysis includes only the largest

24 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.

supplier, which owned 57 percent of internal generation in 2023. In all New England, the analysis compares the three largest suppliers, who collectively owned 27 percent of internal generating capacity in 2023, to all other suppliers.

Figure 6: Average Output Gap and Deratings by Load Level and Type of Supplier
Boston and All New England, 2023



The figure shows that the "Other Derate" category was usually higher than the other categories. The Other Derate category includes instances where some combined-cycle capacity was offered and operated in a configuration with reduced capability during off-peak hours, which is generally efficient and does not raise significant competitive concerns. In addition, high ambient temperatures during high summer peak load hours tend to reduce the ratings of thermal resources. Excluding the contributions of the "Other Derate," the overall output gap and deratings were not significant as a share of the total capacity during 2023.

In both Boston and all New England, 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 during high-load conditions.

Overall, these results indicate that the energy market performed competitively in 2023, with no significant concerns about withholding to raise market clearing prices.

D. Market Power Mitigation

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: [25]

- **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.

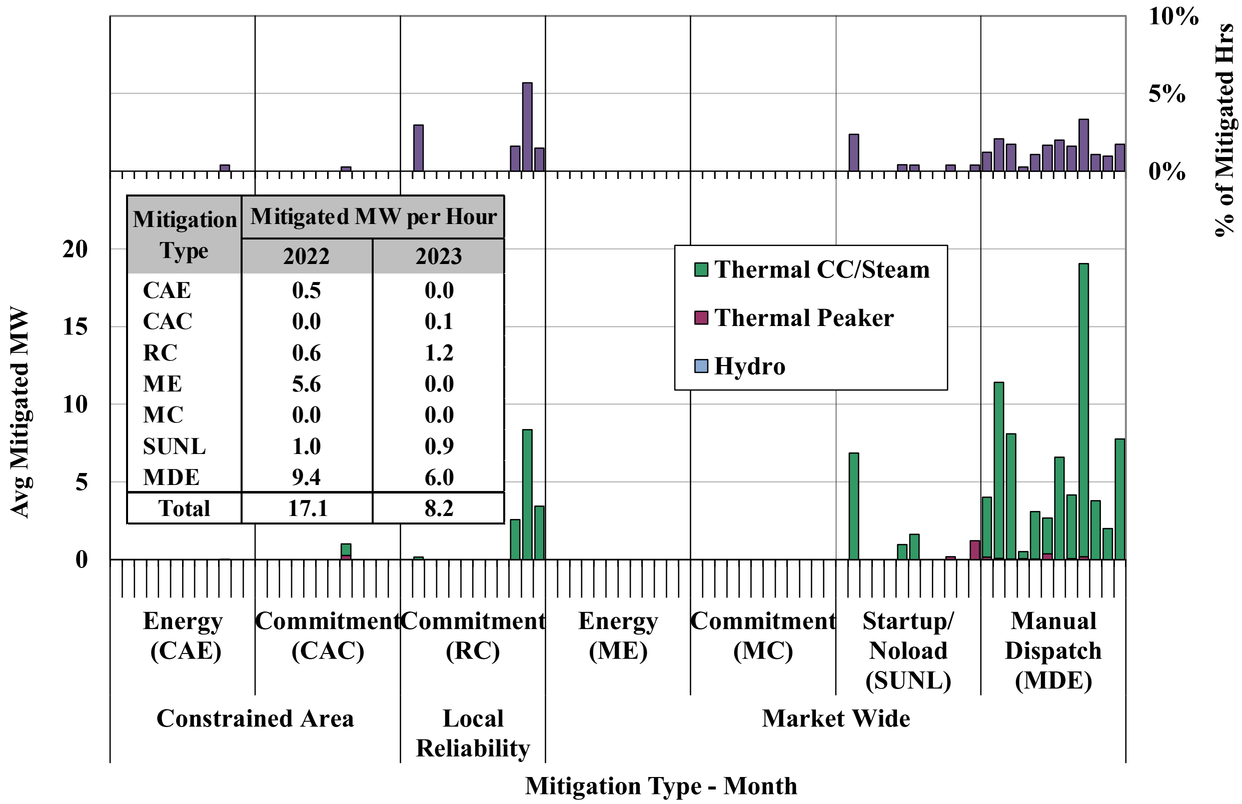
There are no separate impact tests for the SUNL mitigation, the MDE mitigation, and the three types of commitment mitigation (i.e., MC, CAC, and RC). Consequently, suppliers are mitigated if they fail the conduct test in these five categories. This approach is reasonable because this type of mitigation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

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

payment to the generator. When a generator is mitigated, all offer cost parameters are set to their reference levels for the entire hour.

Figure 7 examines the frequency and quantity of mitigation in the real-time market during each month of 2023. 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 7: Frequency of Real-Time Mitigation by Mitigation Type and Unit Type
By Month, 2023



Mitigation Type	Mitigated MW per Hour	
	2022	2023
CAE	0.5	0.0
CAC	0.0	0.1
RC	0.6	1.2
ME	5.6	0.0
MC	0.0	0.0
SUNL	1.0	0.9
MDE	9.4	6.0
Total	17.1	8.2

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 between 2022 and 2023.

Mitigation has been infrequent in recent years, occurring in less than 3 percent of all hours in 2023, down modestly from 2022. In 2023, nearly 90 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 III 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 last annual market report identified several aspects of the mitigation measures that resulted in inefficient market outcomes.[26] 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 (c) of the recommendation by using the lower of the offer and the reference level when imposing mitigation, thereby preventing mitigating offer prices upward.[27] 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 the coming months, ISO-NE expects to file a proposal to address part "b" of Recommendation #2022-2 by enabling generators to use FPAs to adjust reference levels for up to two different output ranges.[28] 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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26 See *2022 Assessment of The ISO New England Electricity Markets*, Potomac Economics, June 2023.

27 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).

28 See *Revise Energy Offer Mitigation to Address FERC Show Cause Order, MW-Dependent Fuel Price Adjustment (FPA) Proposal*, NEPOOL Markets Committee presentation, May 7-8, 2024.

E. Competitive Performance Conclusions

The pivotal supplier analysis suggests that structural market power concerns have diminished noticeably in Boston in recent years because of transmission upgrades and declining load levels. In 2023, one supplier was pivotal in less than 0.5 percent of hours. However, the pivotal supplier frequency increased in all New England from 2022 to 2023 largely because of:

- Greatly reduced import levels from Quebec from May through December, driven by wildfires and lower reservoir levels; and
- Planned outages of multiple pumped-storage facilities from September through December, reducing available operating reserves.

Overall, we find little evidence of structural market power in New England, either at the system level or in individual sub-regions. Our evaluation of participant conduct also suggests that the markets performed competitively with no evidence of market power abuses or manipulation in 2023.

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 III.B. Hence, we recommend the ISO require resources to operate in the lowest-cost configuration when they are committed for local reliability (Recommendation #2014-5).

In addition, 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.

III. Out-of-Market Commitments and Operating Reserve Pricing

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 does not economically commit and schedule all resources needed to satisfy the system's requirements partly because it lacks operating reserve products required in real time. Instead, the day-ahead market process includes two commitment constraints that are designed to:

- Ensure the ISO is able to maintain reliability in key local areas in response to both the first *and* second largest contingencies; and
- Satisfy system-level operating reserve requirements.

Although these commitments are primarily made through the day-ahead market process, the resulting costs are not reflected in ISO-NE's market pricing. This results in understated clearing prices for energy and reserves because they do not reflect the costs of satisfying these requirements. When resources are scheduled at clearing prices insufficient for them to recoup their full as-bid costs, ISO-NE provides an NCPC payment to cover the revenue shortfall.

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.

While the general concern with out-of-market commitments and NCPC uplift is that prices will be understated, prices can be overstated in some cases (i.e., inefficiently high relative to the costs of satisfying short-term system needs). This is because the fast-start pricing model does not count some capacity of online fast-start resources towards satisfying the operating reserve requirements. We discuss this issue in this section and recommend improvements to address it.

This section includes three subsections that evaluate: (a) day-ahead commitments for system-level operating reserve requirements; (b) day-ahead commitments for local second contingency protection requirements; and (c) 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 System-Level Operating Reserves

The day-ahead market software commits sufficient resources to satisfy system-level operating reserve requirements and bid load. However, these reserve requirements are not enforced as market products in the day-ahead market dispatch or pricing software (because ISO-NE does not have day-ahead reserve markets). Consequently, generators are frequently committed in the day-ahead market to satisfy reserve requirements, but they are not scheduled or paid to provide reserves. As a result, the clearing prices of energy (and reserves) are understated because they do not reflect the costs of satisfying the reserve requirements. This discrepancy between commitment and actual scheduling/compensation for reserves leads to inefficient compensation and suboptimal resource utilization.

Table 3 summarizes the additional commitments made to satisfy the system-level 10-minute spinning reserve requirements in the past three years. It includes the following estimates:

- The total number of hours each year with such commitments;
- The average capacity (i.e., the Economic Max of the unit) committed in these hours;
- The total amount of NCPC uplift charges incurred and its share of the total day-ahead NCPC uplift; and
- The annual average marginal value of 10-minute spinning reserves that was not reflected in the day-ahead market clearing prices.

Table 3: Day-Ahead Commitment for System 10-Minute Spinning Reserve Requirement
2021 - 2023

Year	# Hours	Average Capacity Committed per Hour (MW)	DA NCPC		Average Reserve Value ($/MWh)
			Million $	% of Total DA NCPC	
2021	3389	514	$5.4	35%	$1.94
2022	2450	496	$5.8	40%	$1.81
2023	2263	536	$2.9	63%	$0.46

The table shows that additional generating capacity was committed to satisfy the system-level 10-minute spinning reserve requirement in approximately 25 to 40 percent of hours each year over the past three years. This commitment constituted the largest contributor to the NCPC uplift charges in the day-ahead market in 2023.

Implementing co-optimized procurement and pricing mechanisms for this reserve product in the day-ahead market would improve the pricing of 10-minute spinning reserves and energy. By doing so, the opportunity cost of not providing reserves would be factored into energy prices. We estimate that the absence of a day-ahead 10-minute spinning reserve product reduced energy prices across the system by an average of $1.40 per MWh over the past three years.

Furthermore, pricing such a product would likely increase the energy and ancillary services net revenues for a 4-hour battery storage unit by an estimated $12 per kW-year.

Setting more efficient prices for energy and spinning reserves would provide better incentives for reliable performance, flexibility, and availability. Under-compensating generators with flexible characteristics will become increasingly undesirable as the penetration of intermittent renewable generation increases over the coming decade because these resources will be essential to complement intermittent resources and maintain reliability. Therefore, we recommend the ISO procure operating reserves in the day-ahead market, as discussed further below.

B. 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 enforced in the day-ahead market pricing software. 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.[29]

The table indicates a decline in day-ahead commitments for local second contingency protection in recent years, which was primarily due to reliability transmission upgrades in areas with such needs. As a result, associated NCPC uplift costs fell to less than $1 million each year in 2022 and 2023. In 2023, these commitments were most frequent in the broader region east of the New England West-to-East interface, occurring on 25 days for just over 200 hours. Most of these

[29] 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).

commitments occurred in periods when planned transmission outages reduced the transfer capability across the West-to-East interface.

Table 4: Day-Ahead Commitment for Local Second Contingency and NCPC Charges
2021 – 2023

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)
2021	NH-to-Maine	38	510	311	$1.6	$10.22	$8.11
	NEMA/Boston	4	42	651	$0.4	$14.31	$0.55
	Lw. SEMA & East RI	9	61	244	$0.1	$7.01	$1.05
	NE West-to-East	52	683	639	$3.5	$8.07	$6.55
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

Despite the decrease in total uplift costs, the uplift cost per MWh of committed capacity remained significant, ranging from $7.2 per MWh in the broader region east of the New England West-to-East interface to $13.5 per MWh in in the combined area of Lower SEMA and Eastern Rhode Island. This raises two significant efficiency concerns:

- First, units receiving NCPC payments, typically higher-cost and inflexible, systematically receive more revenues than flexible, low-cost resources that generally do not require NCPC payments.
- Second, 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 $3.4 per kW-year in eastern New England (east of the West-to-East interface) and $6.8 per kW-year in Maine.

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 when one would suffice. This unnecessary commitment of the multi-turbine configuration displaces other more efficient generation and depresses prices below efficient levels. In 2023, multi-turbine combined-cycle commitments accounted for ~35 percent of capacity committed for local reliability in the day-ahead market and 25 percent of associated NCPC payments. The ISO could avoid excess commitment by modifying its tariff to require capacity suppliers to offer multiple unit configurations, which would provide the ISO with the option of committing just one turbine from a multi-turbine group. This would improve market incentives for flexibility and availability.

- ***Treatment of Imports***. Day-ahead scheduled energy imports from neighboring areas, even when associated with a Capacity Supply Obligation (CSO), are not counted towards satisfying local second contingency protection needs in the same manner as energy scheduled on internal resources. In 2023, an average of roughly 120 MW of net imports from New Brunswick were scheduled in the day-ahead market on the days when LSCP commitments occurred either for the New Hampshire-to-Maine 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 49 percent. However, because of 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.

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

Fast-start units present significant challenges for setting locational marginal prices because of 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.

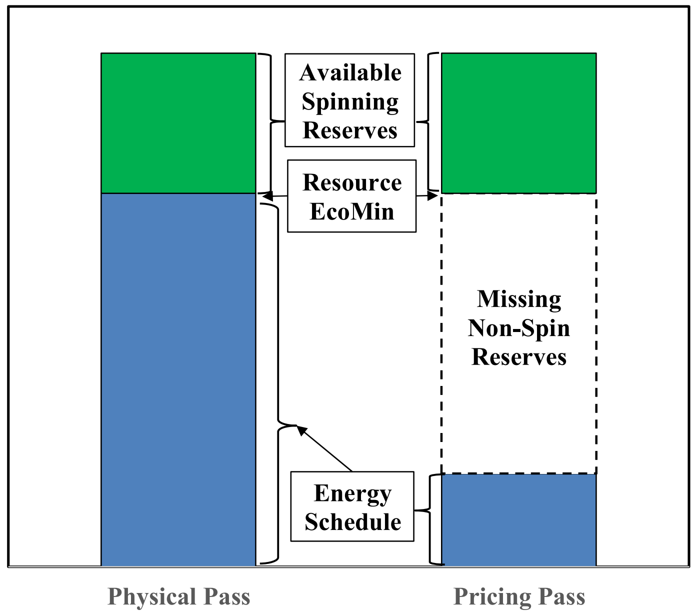
The real-time energy market is cleared using an optimization model to determine the optimal production quantity from each resource, minimizing overall as-offered production costs across the market while considering transmission and operational constraints. Following this physical scheduling step, known as the "physical pass," the fast-start pricing logic is implemented in the "pricing pass." While the physical dispatch accurately reflects the physical characteristics of each unit, the pricing pass re-runs the optimization 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 8, 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 8: 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 because of 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 9 and Figure 10 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 9: Available 10-Minute Reserves in UDS

Physical Pass vs. Pricing Pass, 2023

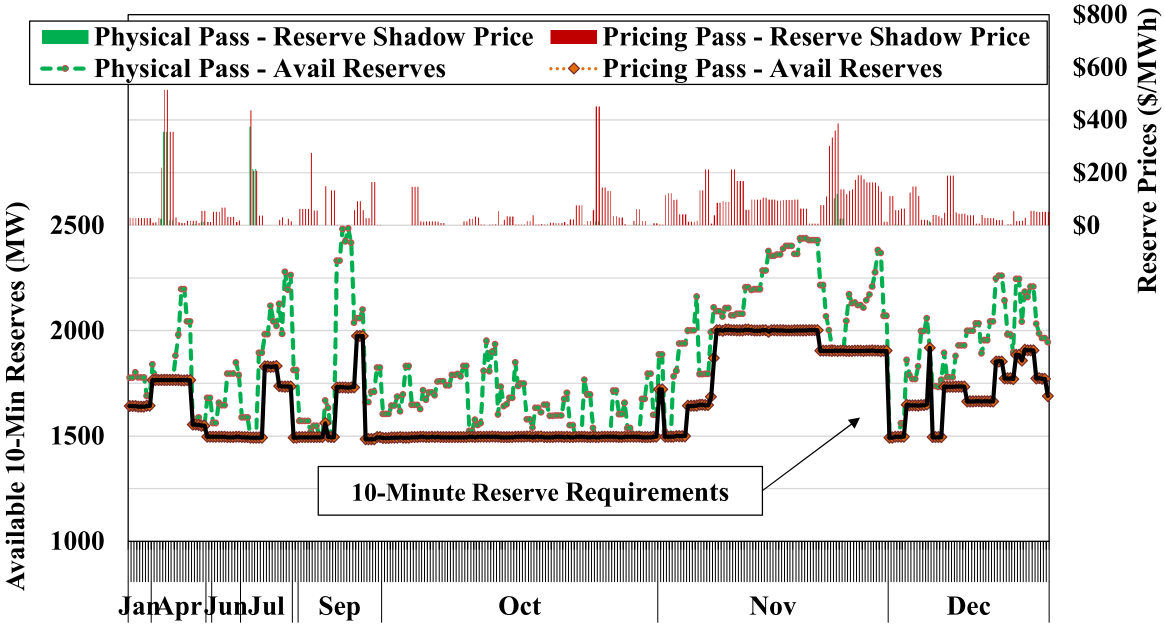
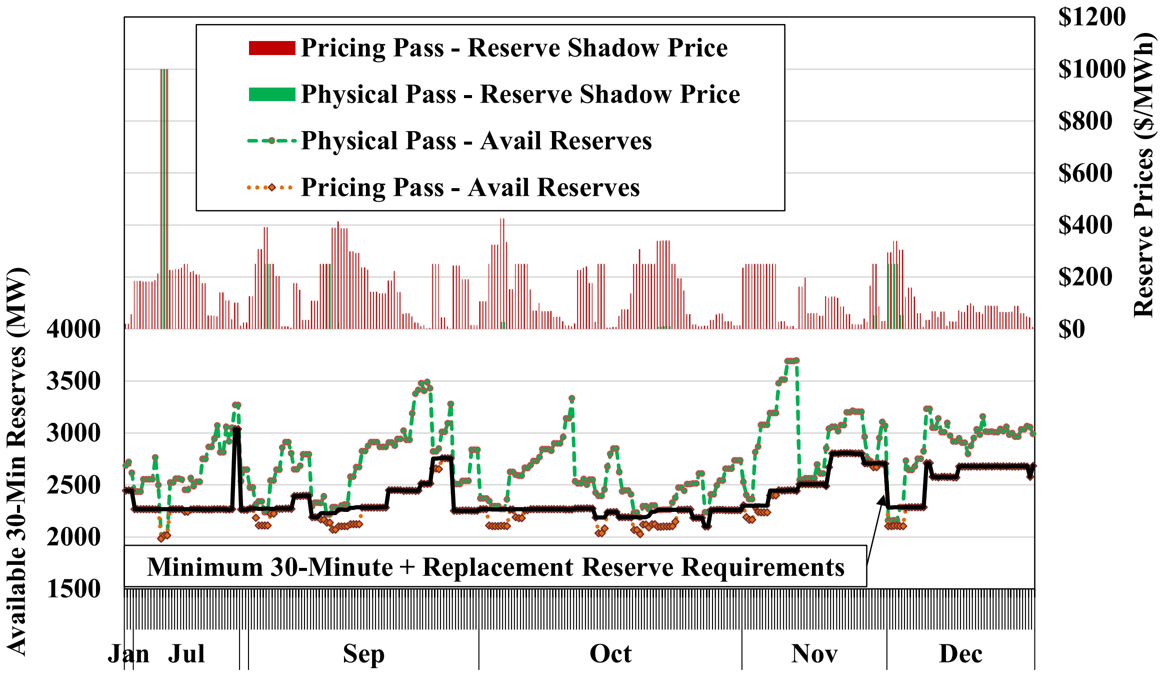


Figure 10: Available 30-Minute Reserves in UDS

Physical Pass vs. Pricing Pass, 2023



In 2023, there were 532 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 240 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 $86 per MWh and $124 per MWh for 30-minute and 10-minute reserves, respectively, whereas in the physical pass, they were only $10 per MWh and $14 per MWh.

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

- When the look-ahead model commits an excessive number of fast-start units because of 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 tends to dispatch them to zero for energy, leading to a significant amount of capacity below EcoMin being excluded from providing operating reserves.
- When 30-minute quick-start resources are started to resolve the deficiency of 10-minute reserves, the undispatched capacity below EcoMin is not counted towards meeting the 30-minute reserve requirements in the pricing pass. This can lead to unnecessarily overstated 30-minute reserves prices.

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

Day-ahead commitments to satisfy the system-level 10-minute spinning reserve requirement and local second contingency requirements occurred in approximately 2500 hours in 2023, resulting in $3.6 million in the NCPC payments – 77 percent of the total day-ahead NCPC uplift. Because these commitments are not reflected in the day-ahead pricing, energy prices are generally understated, reducing generators' net revenues and necessitating NCPC payments to cover these commitment costs. Because the ISO does not procure the reserves it will need in the day-ahead market, resulting in a large share of the operating reserves needed to satisfy NERC and NPCC criteria being supplied by "latent reserves" – resources receiving no day-ahead reserve schedules or related compensation.

This is problematic because:

- The cost of the marginal resource committed in the day-ahead market to provide spinning reserves is not fully reflected in the marginal clearing prices.
- Many resources counted on for reserves have energy limitations that prevent them from converting reserves to energy for extended periods; and
- Others rely on pipeline gas that is not always available on short notice.
- Hence, their availability is less certain than resources that are procured in the day-ahead market. This concern may become more acute as the resource mix shifts toward relying more on short-duration battery storage.

This underscores the importance of the ISO's *Day-Ahead Ancillary Services Initiative (DASI)* project, which will incorporate operating reserve requirements in the day-ahead market co-optimized with energy in March 2025.[30] Procuring and pricing reserve requirements in the day-ahead market will result in substantial additional net revenues, especially for the flexible resources needed to integrate intermittent renewable generation.

This section also supports our recommendations that ISO-New England:

- Modify its local reserve market requirements in the satisfy all local second contingency needs.[31] 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.
- 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.

[30] DASI satisfies the objectives of our Recommendation #2012-8, which was made in previous years.

[31] See Recommendation #2019-3.

IV. Assessment of Capacity Shortage Event on July 5

ISO-NE implemented the Pay-for-Performance ("PFP") rule in June 2018 to provide incentives for generators to contribute to grid reliability and stability during Capacity Scarcity Conditions ("CSCs"). The PFP mechanism compensates or charges generators based on their performance relative to their Capacity Supply Obligations ("CSOs") during CSCs.[32] There have been only a handful of PFP events since implementation. In 2023, a CSC event occurred on July 5 and lasted just 30 minutes shortly after 6 pm. The shortage was triggered by a forced outage of the Phase II interface between New England and Quebec, combined with higher-than-expected load levels.

This section: (a) examines external transaction scheduling during the capacity shortage event on July 5, and (b) discusses the incentives provided by the PFP rules and shortage pricing. The final subsection summarizes the conclusions and recommendations derived from the evaluation.

A. Imports and Exports Scheduled During Shortage Events

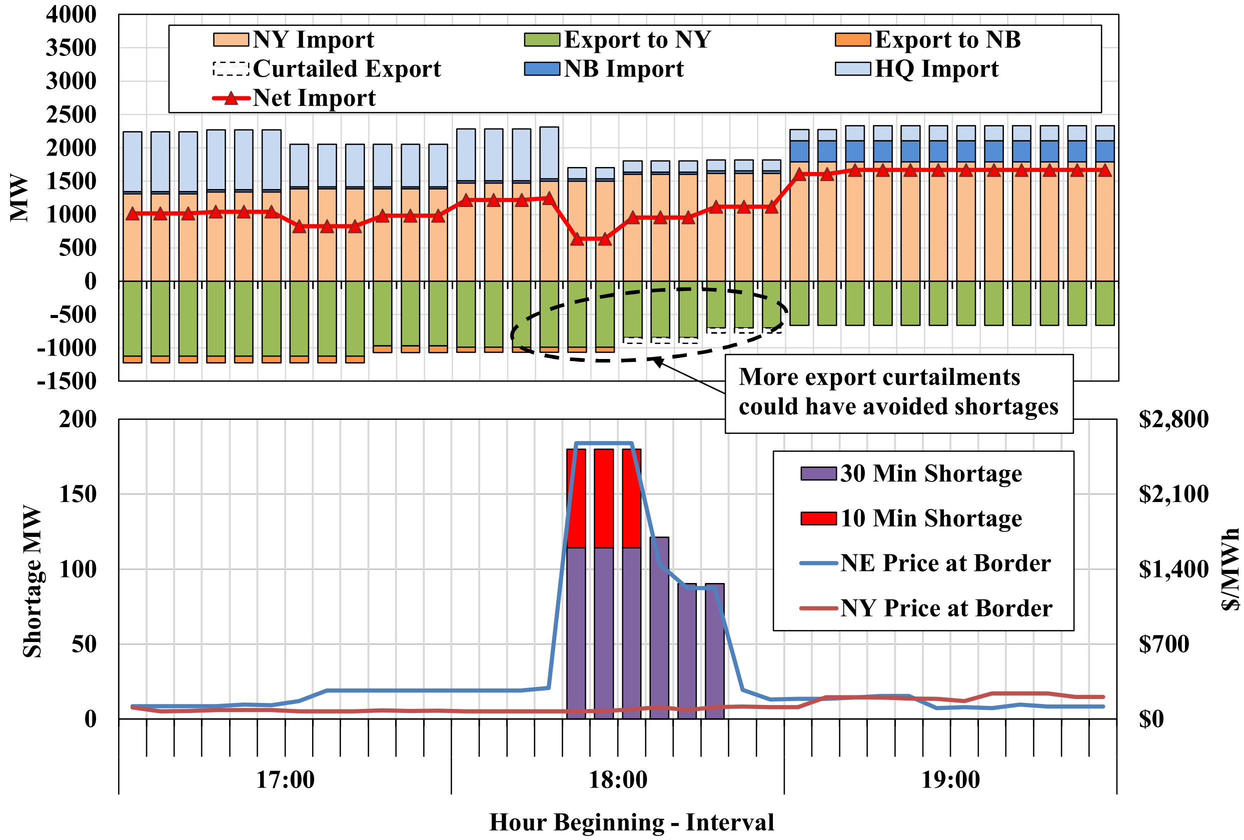
Wholesale markets facilitate the efficient use of transmission interfaces between control areas, allowing low-cost resources in one area to serve consumers in another area and enabling ISOs to access emergency power and reserves from neighboring areas, thereby ensuring reliability standards are met in each control area.

ISO-NE imports and exports substantial amounts of power from New York, Quebec, and New Brunswick. Given the significant import capability relative to New England's load, it is crucial 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 11 examines the scheduling of external transactions with neighboring areas during the capacity scarcity conditions on July 5. In the upper panel of the figure, the stacked bars represent the quantity of scheduled imports and exports at each interface. Transactions scheduled across the two interfaces with Hydro Quebec, the Highgate interface, and the Phase I/II interface, are combined. Similarly, transactions scheduled 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 also grouped. Scheduled transactions that were subsequently curtailed are depicted as empty bars. The red line indicates the overall level of net imports across all interfaces.

32 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.

Figure 11: Scheduling of External Transaction During Reserve Shortages
July 5, 2023



The lower panel of the figure displays the types of reserve shortages and their respective magnitudes in the ISO-NE market. The magnitude of 30-minute reserve shortages is measured against the minimum 30-minute reserve requirement, which covers the largest contingency and half of the second-largest contingency and has a $1000 RCPF.[33] The energy prices at the New England Hub are also shown in the figure, compared to those at the NE/NY border in the NYISO market.

In ISO-NE, systemwide 30-minute reserve shortages occurred in six five-minute intervals between 18:25 and 18:50, with an average magnitude of 110 MW. Systemwide 10-minute reserve shortages occurred in three five-minute intervals between 18:25 and 18:35, with an average magnitude of 65 MW. During these intervals, energy prices exceeded $2700 per MWh, reflecting the effect of shortage pricing with RCPFs. On the other hand, the NYISO did not experience any 10-minute or 30-minute reserve shortages, with energy prices around $100 per MWh during these same intervals.

Despite no reserve shortages in the NYISO market, ISO-NE curtailed only roughly 10 percent of scheduled exports to neighboring areas as it sought to minimize the magnitude and duration of

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

shortages. Consequently, about 700 to 800 MW of scheduled exports to New York remained un-curtailed during the shortage intervals. Given the short duration and small magnitude of shortages, it is likely ISO-NE operators underestimated the amount of curtailments needed to avoid shortages.

This short-lived and shallow capacity shortage condition, which could have been avoided with more aggressive export curtailments, invoked the $3500 PFP rate and resulted in $11 million in PFP credits and charges allocated among resources. This highlights two significant market inefficiencies in the ISO-NE's PFP rules:

- A constant PFP rate for all 30-minute reserve shortages, regardless of the depth, of the shortage provides inefficient market incentives because the reliability risk of a reserve deficiency increases by several orders of magnitude as the size the shortage increases.
- Not charging exports while crediting imports at the PFP rate leads to situations when transactions in both directions are simultaneously profitable.[34] This outcome is clearly inefficient, since efficient markets should reward firms for scheduling power to the area with a greater reliability need and discourage firms from doing the opposite.

These inefficient incentives are discussed in more detail in the next subsection.

B. Pay-for-Performance Incentives During Reserve Shortages

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

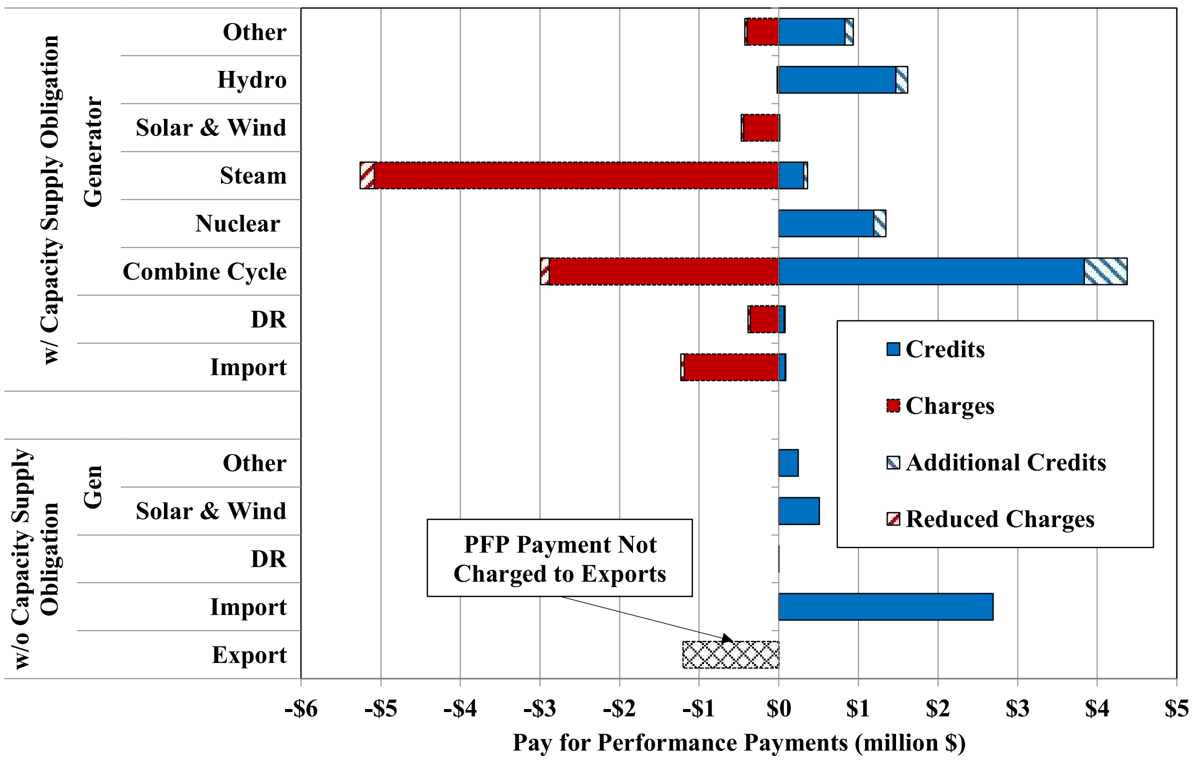
Under the PFP rules, resources that fail to deliver energy or operating reserves during shortage events for whatever reason face financial penalties, known as PFP charges. Conversely, resources that perform well and contribute to system reliability are rewarded with PFP credits. Figure 12 summarizes the PFP credits and charges during the shortage event on July 5. Resources are grouped based on whether they had Capacity Supply Obligations (CSOs) and by resource type. PFP credits and charges were calculated using a penalty rate of $3,500/MWh. The figure also shows: (a) the amount *not* charged to exports; (b) the "*Additional Credits*" that resources in other categories would have received; and (c) the *"Reduced Charges"* for resources in other categories, [35] if the PFP event Balancing Ratio was calculated taking the exports into account as under-performers.

34 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.

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

Figure 12 shows that resources with CSOs that performed poorly during the shortage event incurred nearly $11 million of PFP charges. Conventional slow-start generators, including steam turbines and combined-cycle units, accounted for approximately 77 percent of these charges. Most of these units were not committed in the day-ahead market because they were not anticipated to be needed. Others experienced forced outages or deratings. This underscores the significant PFP risk faced by units with longer lead times from unforeseen real-time shortage events. While these units should face some risk, it should be aligned with the reliability risks faced by the system, which were relatively low during this event.

Figure 12: PFP Settlements and Impact of Export Treatment
July 5, 2023



Importers without CSOs received 25 percent of the performance payments. While importers received the PFP incentive of $3500/MWh to move power into New England, exporters did not incur any PFP charges to move power out of New England. This disparate treatment for imports and exports constitutes a major flaw, creating inefficient incentives and encouraging gaming. The figure shows that if exports were charged at the PFP rate, they would have been charged $1.2 million during the event. Other categories of resources would have received an additional $1.0 million in credits and incurred a reduction of $0.4 million in charges.

One potential gaming strategy involves a participant, through different bidding entities, simultaneously scheduling equal amounts of imports and exports at the NE/NY border. This pair of transactions would result in no actual power transfers between the two markets, but they would be profitable since the imports would receive a PFP credit at a rate of $3500/MWh, while the exports would not be charged. The ISO-NE rules are designed to prevent this by netting imports and exports for a single entity, but these rules do not prevent two entities from coordinating to take advantage of the settlement rules. Although we did not observe such behavior from any individual participants during the shortage event on July 5, it remains a significant gaming concern. Hence, we recommend the ISO revise the PFP settlement rules to charge exporters the PFP rate during Capacity Scarcity Conditions. (Recommendation #2022-3)

Even though no participants appear to have engaged in this specific gaming strategy, imports and exports were simultaneously scheduled by different participants during the shortage event. ISO-NE curtailed only 10 percent of the scheduled exports during the reserve deficiency, leaving 845 MW of exports not curtailed. These exports offset the benefits from the imports. The additional cost from inefficient PFP rules for exporters will become more significant if reserve deficiencies become more frequent and when ISO-NE escalates the PFP rate to $9337/MWh in 2025.

Figure 13: Market Incentive for Imports and Exports During Reserve Shortages

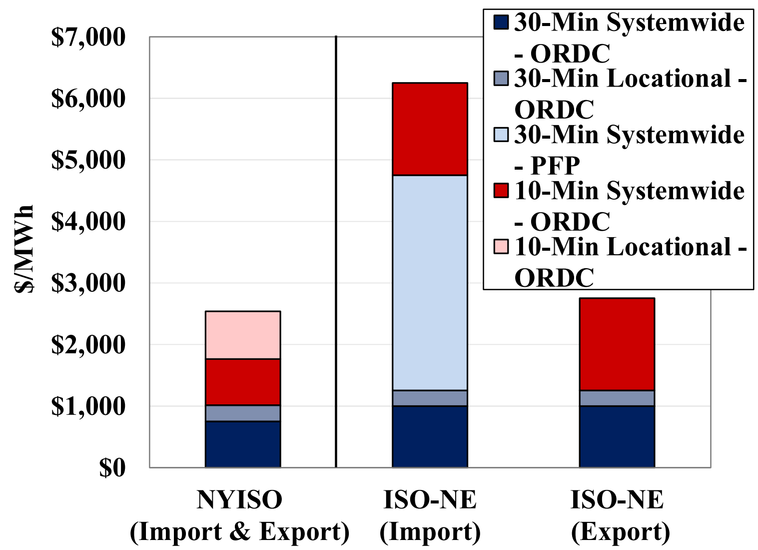


Figure 13 illustrates the current disparity in PFP incentives for imports and exports by comparing the shortage pricing incentives between the NYISO and ISO-NE markets, including applicable 10-minute and 30-minute operating reserve RCPFs (or demand curve values for the NYISO market) and the PFP rate.[36] The total incentive for a resource is based on the sum of these sources when multiple reserve product shortages and/or PFP shortage conditions are in effect simultaneously. The figure highlights the following:

- In ISO-NE, the PFP rate was $3500/MWh during the July 2023 event,[37] but this only applies to imports, creating an imbalance between imports and exports. Both imports and exports face reserve shortage pricing, which starts at $1000/MWh for 30-minute reserve shortages and can rise to $2750/MWh for simultaneous shortages of 10 and 30-minute reserves. This resulted in an overall incentive of up to $6250/MWh for importers and $2750/MWh for exporters.

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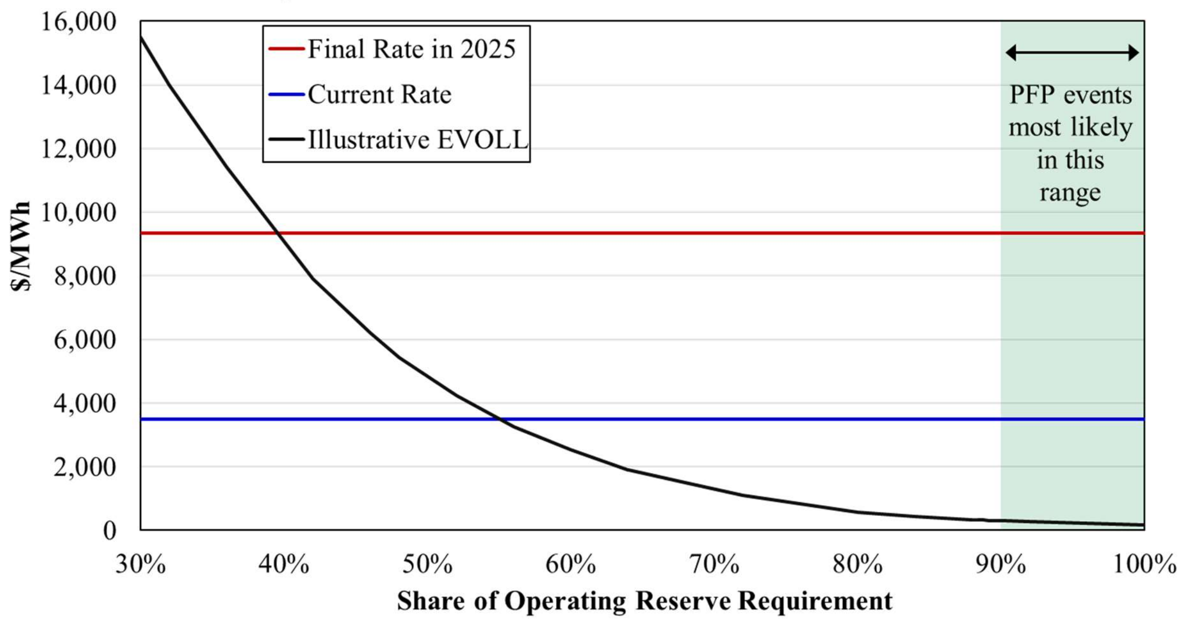
36 Locational prices for ISO-NE refer to Connecticut. Locational prices for NYISO include the full value of East 30-minute and East 10-minute shadow prices and assign 45 percent weight to the SENY 30-minute shadow price.

37 The PFP rate rises to $5455/MWh in June 2024 and $9337/MWh in June 2025.

- In the NYISO, however, the incentives during reserve shortages are the same for imports and exports. In shortages of multiple 10-minute and 30-minute reserve requirements, NYISO invokes shortage pricing of up to $2500/MWh in eastern New York.

Finally, potentially the largest issue with the current PFP design is that it is misaligned with the value of reliability in New England. During this event, importers and other suppliers were paid as much as $5400 per MWh, including shortage pricing and the PFP settlements. This is substantially higher than the true value of energy in New England based on 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. In contrast, the current PFP rules employ a constant rate regardless of the depth of the reserve shortage. Figure 14 illustrates the EVOLL as reserve levels fall and shows the current PFP Rate during the summer of 2023 and the higher PFP rate that will be effective in June 2025.

Figure 14: PFP Rates and the Value of Lost Load



As shown in Figure 14, applying a constant PFP rate for all reserve shortage quantities tends to overvalue energy and reserves during shallow reserve shortages when the probability of losing load is very low and can understate prices during deep reserve 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 be as high as an additional $2750 per MWh.

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

- The PFP rates are slated to increase to over $9300 per MWh next year; and
- Growing uncertainties associated with fuel supply and increasing reliance on intermittent resources will likely result in more frequent and unpredictable shortages.

While very strong performance incentives may be appealing, massively overstating them can create inefficient risk for less flexible resources and lead to poor 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 includes establishing multiple steps for PFP rate so that market compensation incentives rise efficiently with the severity of the shortage. This would ensure that market participants are appropriately incentivized to address deeper reserve shortages, where the risk of load loss is higher, while avoiding unnecessary costs during shallower shortages (Recommendation #2018-7).

Furthermore, when two neighboring systems are both short of reserves (as ISO-NE and NYISO were during the PFP event on December 24, 2022, but not during the event on July 5, 2023), having PFP rates that rise with the magnitude of the shortage based on reliability risk would contribute towards an efficient allocation of reserves between regions.

C. Conclusions and Recommendations

In 2023, capacity shortage conditions occurred on July 5 for a short duration of 30 minutes, driven by a forced outage of the Phase II interface with Quebec and higher-than-expected load levels. The reserve shortages during this event ranged from 65 MW to 110 MW. ISO-NE curtailed roughly 10 percent of scheduled exports as it sought to minimize the magnitude and duration of shortages. The short-lived and shallow shortages could have been avoided with more aggressive curtailments as NYISO was not near shortages conditions during the event.

Our analysis of this event highlights some inefficient incentives created by the PFP rules:

- Applying the PFP rate to settlements with importers but not exporters is a significant flaw that creates gaming opportunities, and simultaneously encourages scheduling of imports and exports. It undermines the efficiency of scheduling incentives during reserve deficiencies and may undermine reliability.
- The constant PFP rate, applied during all reserve shortages and slated to increase substantially in June 2025, will result in excessively large financial risks and inefficient incentives under conditions with small to moderate reserve shortages. The effects of these incentives will grow as shortages become more frequent in the future.

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)

V. Winter Reliability in the Forward Capacity Market

The capacity market is the primary market-based mechanism for satisfying ISO-NE's resource adequacy requirements, which are designed to ensure a minimum reliability standard of no more than 1 day of load shedding every 10 years. ISO-NE operates a centralized auction where suppliers offer to take capacity supply obligations (CSOs) in exchange for payments at the auction clearing price. The capacity market provides incentives that facilitate new investment and retirement decisions.

The capacity market has historically been designed to satisfy summer peak demand, as it was assumed that this would also make sufficient resources available in winter. Reliability risk factors in winter are now growing faster than summer and are likely to drive system needs in the coming decade.[38] ISO-NE is undertaking several projects to improve its ability to model and detect winter risk and to update capacity market rules to reflect winter needs. These include:

- The *Resource Capacity Accreditation (RCA)* project will represent winter fuel limitations in the resource adequacy models used in the capacity market and consider generators' fuel arrangements when establishing their marginal capacity credit values;
- Developing proposed rules for a *prompt seasonal capacity market* as opposed to the current three-year forward annual capacity market; and
- Developing the *Probabilistic Energy Adequacy Tool (PEAT)* and *Winter Energy Risk Threshold (REST)* framework, which are intended to anticipate and address winter reliability needs driven by fuel security at the planning level.

In Section F of this chapter, we demonstrate how the capacity market can facilitate investment decisions by market participants that will reduce winter reliability risks to acceptable levels in the coming decade.

In addition, the models and market rules listed above that ISO-NE is developing to address winter reliability are essential for allowing the capacity market to send efficient economic signals. In Section G of this chapter, we discuss these rules and models, and recommend the following key improvements needed to ensure good market performance in maintaining winter reliability:

- Realistic modeling of LNG imports,
- Accurately modeling utilization of fuel-limited resources in reliability models, considering market incentives from opportunity costs, and
- A marginal capacity accreditation framework that accurately captures resources' reliability value in addressing fuel security issues.

[38] Key drivers of growing winter risk include: (i) gas pipeline constraints that limit fuel available to the region's 9 GW of gas-only generators in cold weather, (ii) retirements of fuel-secure resources, (iii) growing winter load from electrification of heat and transportation, and (iv) growing winter risk in neighboring systems.

F. Impact of Market Participant Actions on Winter Reliability

In this subsection, we evaluate winter reliability risk in New England in the coming decade and demonstrate how actions of market participants can improve or aggravate it. Our key finding is that forecasted electrification may lead to elevated winter risk, but decisions regarding retirements, fuel procurement and new entry can effectively address this. Therefore, it is essential to provide efficient incentives for participants to make these decisions.

We simulated reliability risk in the ISO-NE system using Potomac Economics' Resource Adequacy Model (PE-RAM). The PE-RAM is an hourly resource adequacy simulation that considers load, generator forced outages, and intermittent generator profiles. It is capable of modeling dispatch and replenishment of resource types with limited fuel inventories (such as oil, stored LNG, and battery storage) using a variety of heuristic approaches.

We developed cases for Winter 2031/32 using inputs developed by ISO-NE and EPRI for the recently completed PEAT study.[39] A detailed discussion of the case inputs can be found in the Appendix to this Chapter. In addition to the base case, we assessed three sensitivity cases:

- *Delayed Off-Shore Wind (OSW)*: OSW drops from 4.8 GW in the base case to 3.2 GW.
- *Delayed OSW + Low Retirements*: 800 MW retirement of fuel-secure resources (not including Mystic 8 & 9) rather than 1.7 GW in the base case.
- *Delayed OSW + Energy Storage Resources (ESRs)*: 3.5 GW rather than 1.9 GW of 2-hour ESRs in the base case.

One factor that plays a key role in the results of any winter reliability analysis is how resources with limited fuel inventories are assumed to be dispatched together with resources that do not have limitations, which is presented below before the results of this assessment.

Dispatch Logic in Winter Risk Model

The dispatch logic for units with limited fuel inventories has key implications for modeling winter reliability. We used the following approach to analyze how market incentives from opportunity costs would encourage generators to conserve fuel while recognizing their limited foresight (see additional discussion in Section GG.2):

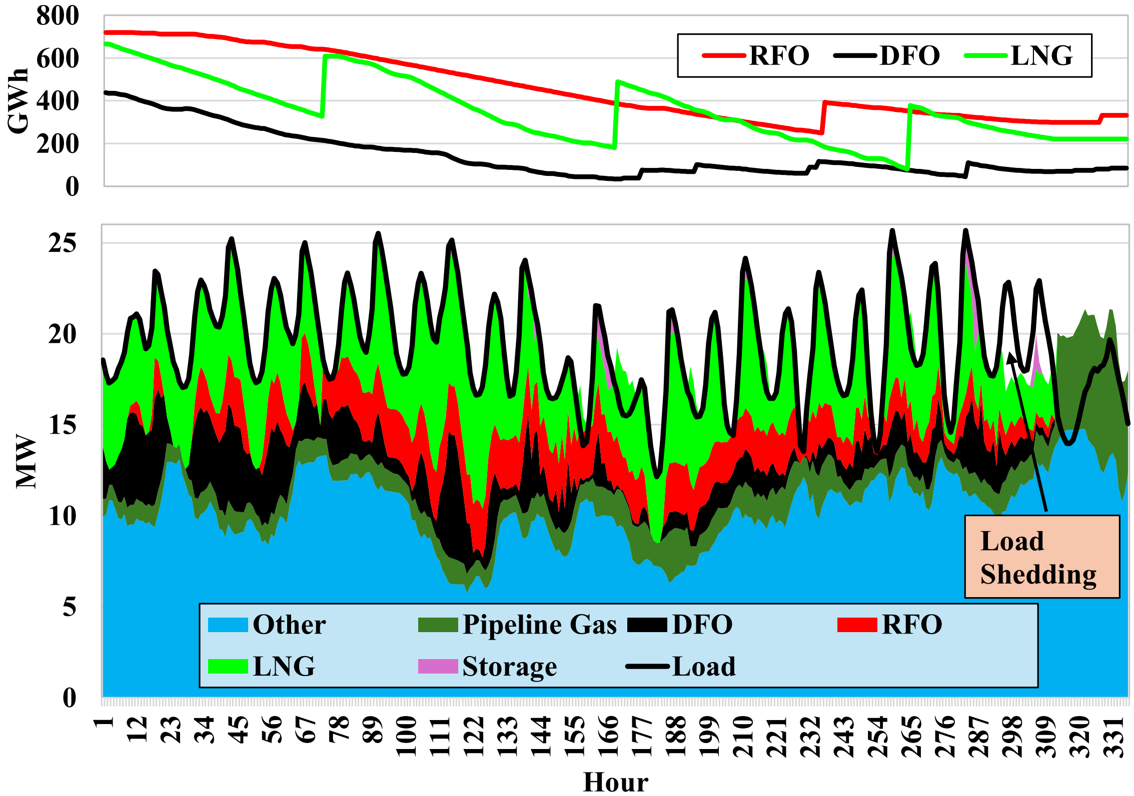
- Units are dispatched in order of production costs until they reach low inventory levels;
- Units with low fuel inventories are not deployed until hours when there are insufficient non-inventory-limited resources to fully satisfy load;
- Oil units are dispatched in ascending order of heat rate unless they have a low inventory (defined as the lower of 24 hours or half of the unit's starting inventory);

[39] See ISO-NE, "Operational Impact of Extreme Weather Events - Final Report on the Probabilistic Energy Adequacy Tool (PEAT) Framework and 2027/2032 Study Results", December 2023, available here.

- Stored LNG from the Saint John terminal is used until there is limited supply remaining (defined as two days of maximum sendout through the M&N pipeline), after which LNG is used alongside oil considering remaining inventory stocks;
- ESRs are modeled with 2-hour duration. Batteries discharge when supply from other resources is insufficient and recharge when surplus is available from other resources.

Figure 15 illustrates the dispatch logic of the PE-RAM over a two-week cold period with load shedding. The bottom panel shows dispatch of various resource types, while the top panel shows remaining inventories of residual fuel oil (RFO) and distillate fuel oil (DFO) and LNG. The lines decrease as the fuel is consumed and increase when deliveries occur that replenish the fuels (e.g., three deliveries of LNG are made in this example). This example shows that load shedding occurs towards the end of the period after oil inventories have been fallen and some resources experience forced outages that have some of the remaining inventory.

Figure 15: Example Winter Risk Model Scenario



Results of Winter Reliability Analysis

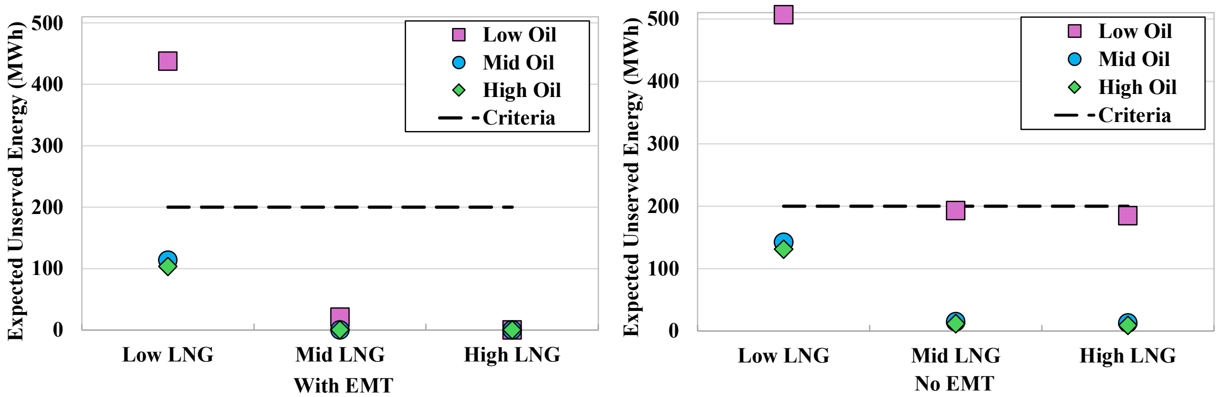
This subsection shows the winter reliability risk in ISO-NE estimated using the PE-RAM model in a variety of cases for Winter 2031/32. In each case, we show results assuming: three levels oil inventories (low, medium, and high), three levels of LNG, and two assumptions (with and without) for the Everett LNG terminal (EMT)[40] – for a total of eighteen estimates for each case.

40 LNG deliveries to EMT are allocated to Saint John instead in the No EMT scenarios.

The measure of winter reliability rise we use is the expected unserved energy (EUE). The EUE results are shown in Figure 16 through Figure 19. Each data point summarizes the probability-weighted results of 80 simulated years (two weather profiles with approximate probability weights[41], two import levels, and 20 forced outage samples). The line labeled "Criteria" is a rough estimate of the EUE level when the system is at its one-in-ten-year LOLE criteria.

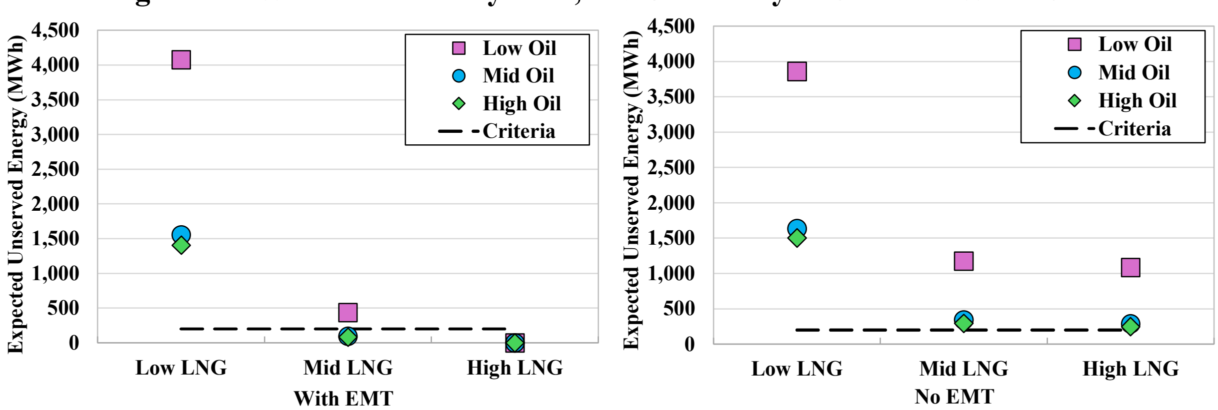
Although the EUE results do not include all potential conditions, they are intended to demonstrate the relative impact of different decisions by market participants. Hence, they provide insight into the importance of developing capacity market rules that reward fuel-secure resources for their marginal impact on reliability.

Figure 16: Winter Reliability Risk, 2031/32 – 2024 CELT FCA18 Case



This initial base case shows that the levels of LNG and oil inventories have a tremendous impact on the winter reliability risk in New England. The reliability criteria is substantially violated in the scenario with Low LNG and Low Oil, but generally satisfied in all other scenarios. The EUE falls to close to zero in cases with higher levels of LNG *and* oil.

Figure 17: Winter Reliability Risk, 2031/2 – Delayed Offshore Wind Case



41 We assigned a 1-in-14 probability to the 1961 weather year and a 1-in-5 probability to the 2015 weather year. These are intended to combine the return periods for winter weather clusters from the PEAT study with the relative severity of the weather events modeled.

Figure 18: Winter Reliability Risk, 2031/2 – Delayed Offshore Wind + Low Retirements

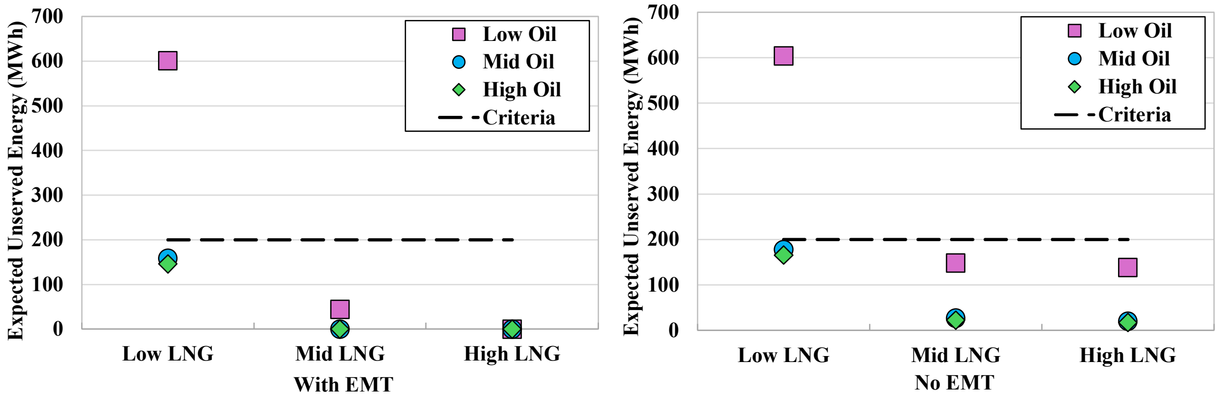
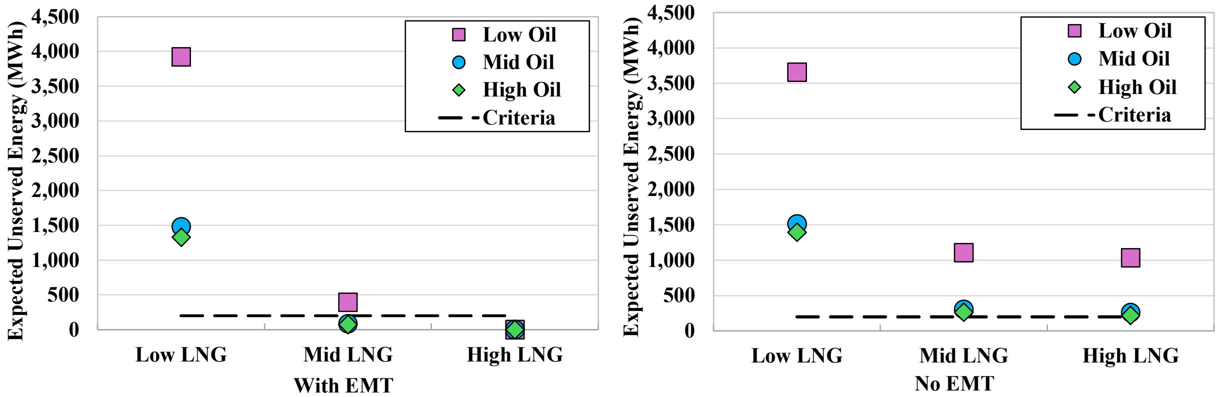


Figure 19: Winter Reliability Risk, 2031/2 – Delayed Offshore Wind + Higher ESR



The results of the sensitivity cases in Figure 16 through Figure 19, support the following conclusions:

- *Delayed Offshore Wind case* – Lower OSW requires at least Mid LNG, Mid Oil, and EMT being in service to satisfy the reliability criteria;
- *Delayed OSW + Low Retirements case* – Modeling the Merrimack and Montville units as available significantly reduces EUE, but reliability risk continues to violate criteria in some Low LNG scenarios;
- *Delayed OSW + Higher ESR case* – The addition of 1,600 MW of two-hour batteries does very little to improve reliability. This is because most of the modeled load shedding events are of much longer duration than two hours and are driven by shortages of fuel across the two-week period, which additional storage capacity does little to address;
- Winter risk is generally slightly higher in the No EMT scenarios, particularly in low oil cases. This is because EMT allows more gas-fired capacity to operate simultaneously during periods of high forced outages and/or low oil inventories;
- The reported EUE values are driven by severe and prolonged load shedding events that occur with low probability. In the 2024 CELT FCA18 case with EMT in service, the maximum load shedding in a single simulated winter was about 260 GWh. In the Delayed Offshore Wind case with EMT in service, it was almost 500 GWh.

Winter Reliability Conclusions

Based on our analyses in this subsection, we draw conclusions in several areas:

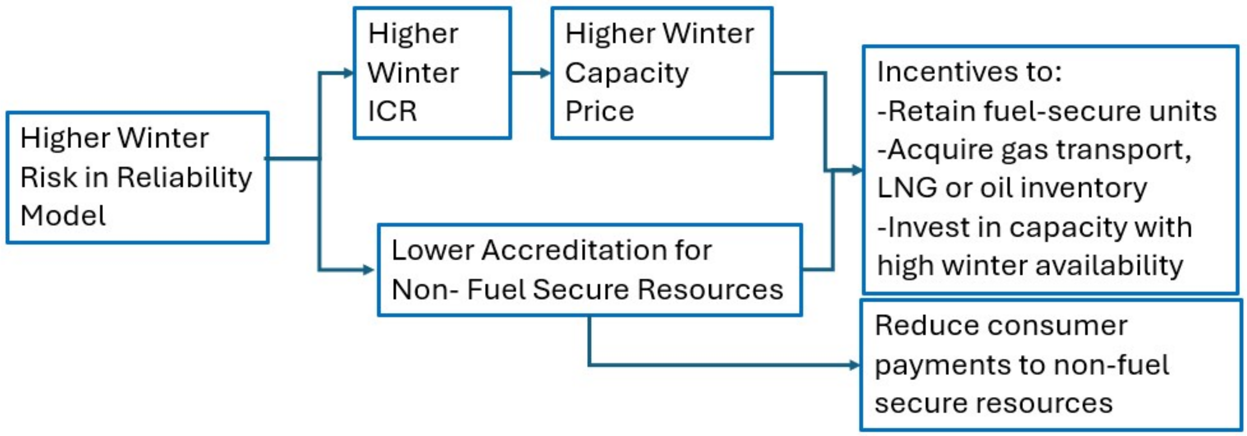
- ***LNG volumes***: The total amount of LNG available to generators has a major impact on reliability and is a primary determinant of whether the system would satisfy reliability criteria in most cases. Historically, most LNG used by generators has been "non-firm" in the sense that those generators did not contract for the LNG shipments. It is critical to ensure that generators have adequate incentives to contract for firm LNG shipments (or contract for firm transport to an extent that induces LDCs to contract for firm LNG shipments) in the future when winter reliability risk is high. In the next subsection, we discuss the effect of assumptions related to LNG deliveries on the incentives of generators to contract for firm fuel;
- ***Oil inventories***: Scenarios with higher oil inventories had lower EUE, indicating that market incentives for existing units to acquire and maintain larger volumes of oil can play a key role in managing winter reliability risks;
- ***Retirements***: Higher levels of retirements of fuel-secure units led to much higher EUE. As winter risk grows because of electrification or delays in renewable development, it is important to ensure that a sufficient quantity of existing units remain in service and do not retire prematurely. This indicates that the Inventoried Energy Program (IEP) on its own is not sufficient to address fuel security concerns. While it is designed to cover the costs of maintaining fuel within a given winter, it does not provide adequate incentives for generators with high fixed costs to remain in service.
- ***New Entry*:** The amount of offshore wind entry had a major impact on winter EUE, while the amount of battery storage did not. Capacity market signals should accurately reward each resource type for the reliability benefits it provides so that investment is directed towards the most beneficial resources.

G. Improvements to Winter Reliability Models and Processes

In the previous subsection, we demonstrated that winter reliability risk can be managed by market participant actions with market incentives. This subsection discusses the significance of key assumptions in winter reliability risk models and how these will affect market incentives if the capacity market is enhanced to account for winter fuel limitations. We highlight key modeling choices, including: (1) the amount of LNG brought into the pipeline system in New England in cold weather, (2) the treatment of opportunity costs in the dispatch logic for resources with limited fuel inventories, and (3) consideration of fuel inventory limitations in models used to determine accreditation values.

The capacity market is designed to procure resources needed to satisfy reliability criteria. Since extreme conditions that test the system's reliability do not occur every year, the market relies on probabilistic models to quantify the level of reliability risk and resources' efficacy at reducing it. A higher level of modeled risk will result in a higher ICR, causing the market to clear at higher prices indicating a need to attract or retain capacity. Higher modeled winter risk should also result in higher payments to fuel-secure resources and lower payments to non-fuel secure resources. Figure 20 illustrates this relationship.

Figure 20: Relationship Between Reliability Model and Market Outcomes



The assumptions made in reliability models are therefore very important for the market's ability to manage winter risk. Unrealistic or excessively optimistic assumptions will result in weak incentives to attract and retain the *amount* and *type* of capacity and fuel arrangements needed to support reliability. The remainder of this subsection discusses several critical assumptions.

1. LNG Available to Generators in Extreme Conditions

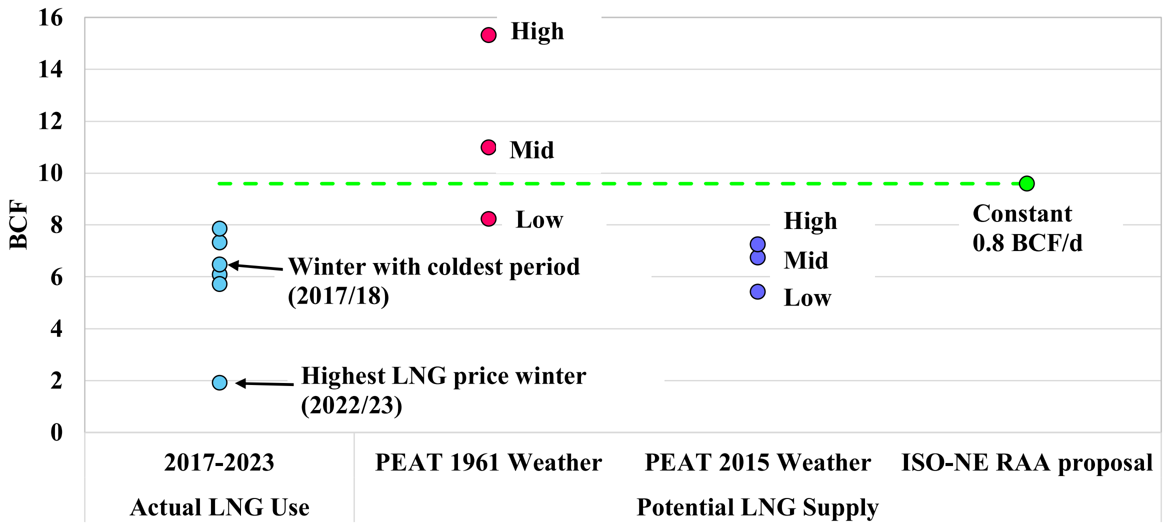
In very cold weather, there is insufficient pipeline gas capacity to meet demand in New England and the region relies on LNG imported to the Everett, Northeast Gateway, and Saint John terminals. Since most pipeline transport capacity is held by gas utilities, the ability of generators to operate on gas depends on the amount of LNG available on a given day. Historically, most generators have not signed contracts for LNG deliveries and instead have accessed LNG indirectly that is made available to the market. Hence, the amount of "secondary LNG" assumed to be available in risk models is a major determinant of winter reliability risk.

ISO-NE developed secondary LNG assumptions for its Resource Adequacy Assessment (to be used for the capacity market) and PEAT study (to be used for long-term planning assessments) using two different approaches. The proposed RAA approach includes no secondary LNG from Everett or Northeast Gateway but assumes that the full 0.8 BCF/day transport capacity of the Maritimes and Northeast pipeline is used to carry gas from the Saint John terminal throughout any cold event.[42] This is enough to support approximately 4.8 GW of average gas-fired generation output. The PEAT study developed Low, Mid, and High schedules of LNG deliveries for each simulated winter event based on historic data.

42 See ISO-NE January 16, 2024, Reliability Committee presentation "Resource Capacity Accreditation in the Forward Capacity Market - Gas and Oil Modeling for the Seasonal Risk Assessment".

Figure 21 below compares the proposed RAA and PEAT assumptions of LNG over a 12-day window to the maximum 12-day sendout of gas from LNG terminals to pipelines serving New England in recent winters. We use a 12-day window because it is reflective of the most severe recent continuous cold period as well as the most stressed sub-period in the PEAT study.

Figure 21: Comparison of 12-Day LNG in Reliability Models and Historic Data



The chart above shows that historic LNG sendout to the pipeline system has generally been lower than the levels assumed to be available in the RAA proposal and the 1961 weather year of the PEAT study (the most stressful weather pattern included in the study). However, low sendout in a historic period does not necessarily imply that additional LNG *inventory* was not available. We examine the drivers of LNG supply to New England in the Figure 22 below.

In Figure 22, the bottom panel compares total winter LNG imports to all three terminals (less LNG imports to Everett used by the Mystic 8 and 9 units) along with the "sendout" to pipelines, which supports gas withdrawals from the pipelines. The top panel shows factors that drive LNG imports and utilization in each winter:

- the maximum number of heating degree days (HDDs) in excess of 40 over a two-week period in each winter (a measure of the most severe extended cold event).
- The difference between futures prices for Dutch TTF LNG (a major global index) and Algonquin Citygate, based on trades for the winter period during the prior summer and fall. This provides a measure of the relative value of LNG elsewhere vs. New England.

Figure 22 shows that there has been major variation in the total amount of LNG imports arriving to the region because of global market conditions. Total imports fell from an average of 27 BCF in the 2017-2020 winters to 10 BCF in the past two winters, with only 7 to 8 BCF through the end of January.

Figure 22: Historic LNG Deliveries, Sendout, Prices and Cold Weather

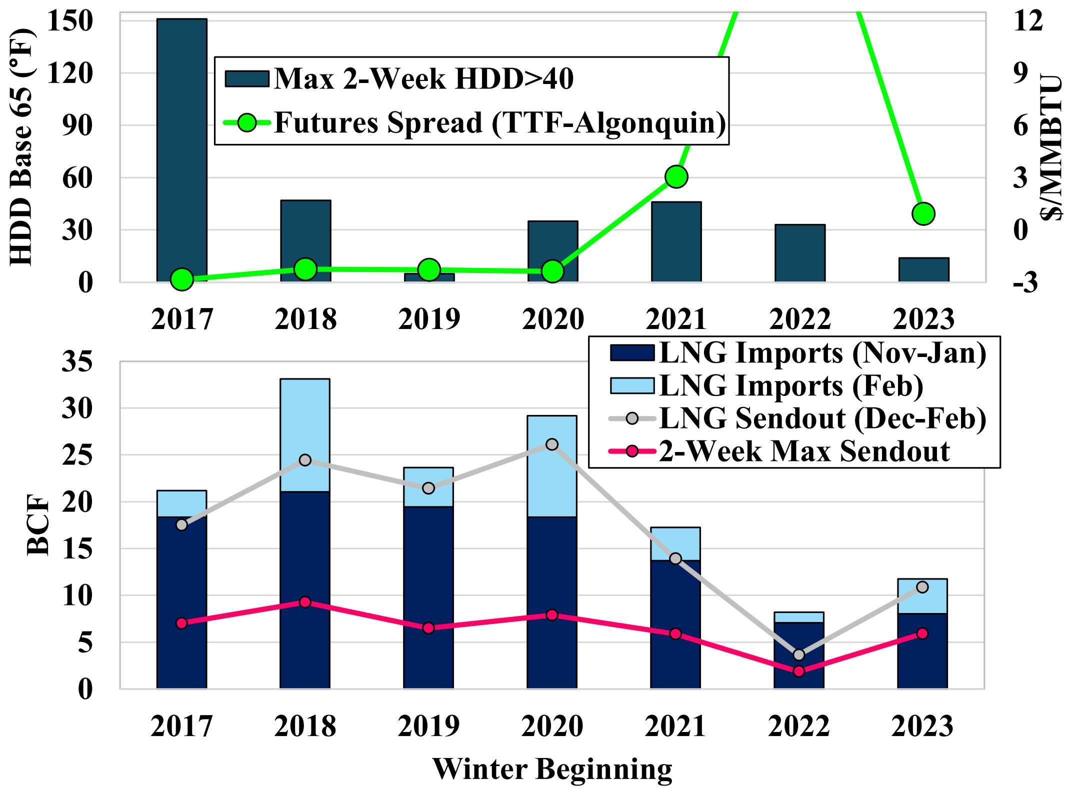
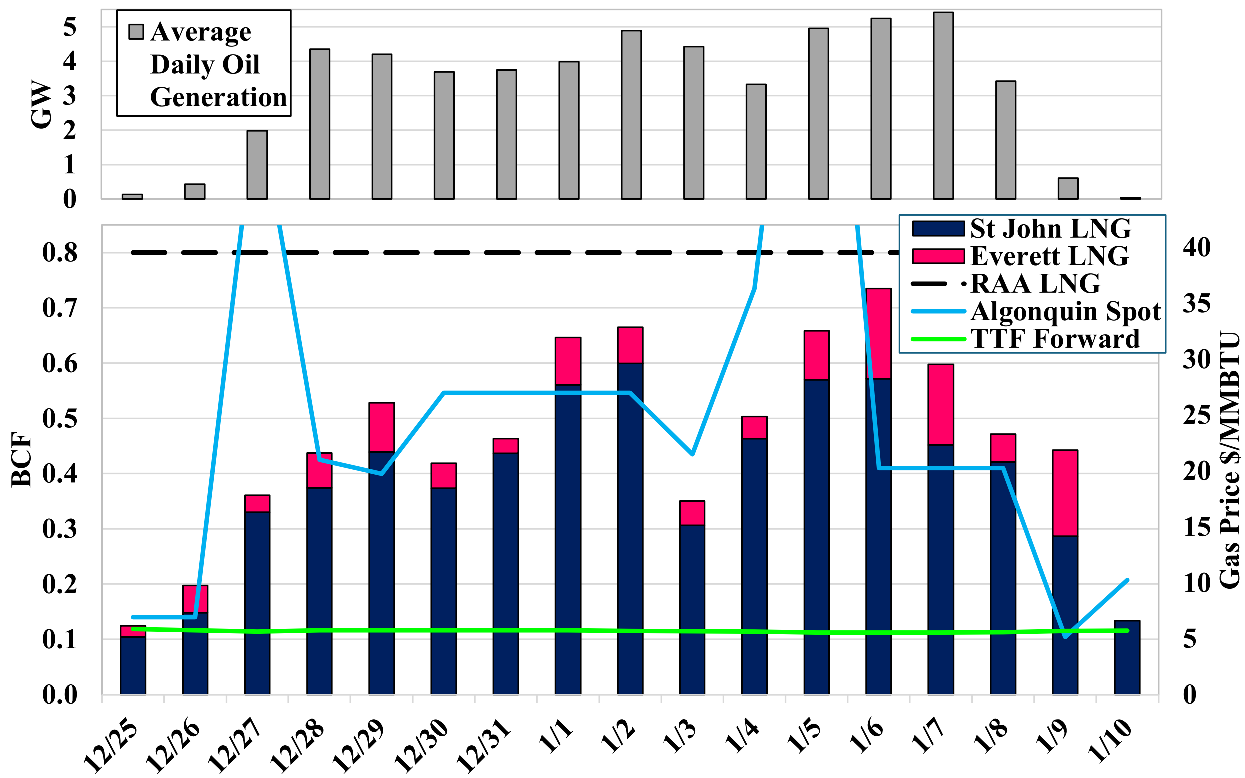


Figure 22 also indicates that colder temperatures in New England do not appear to attract larger quantities of LNG sendout to pipelines. Instead, LNG sendout to pipelines is limited by the total amount of imports minus the amount used by gas utilities for other purposes. This suggests that total LNG available to generators in any given cold event is limited by the need to ration a limited quantity of supply over the winter season.

Figure 23 provides additional evidence that there is very limited flexibility to increase LNG supply within a winter. It shows LNG sendout to pipelines during the cold event from late December 2017 to early January 2018. During this period, New England experienced nearly two consecutive weeks of very cold weather. The bottom panel compares the LNG delivered from the Saint John and Everett facilities in this period to the 0.8 BCF per day assumed by ISO-NE's RAA proposal. The bottom panel also shows the daily Algonquin Citygate spot natural gas price and the month-ahead Dutch TTF LNG index. The top panel shows the average generation level from oil on each day.

Figure 23 shows that pipeline sendout of LNG was well below ISO-NE's proposed RAA assumption of a continuous 0.8 BCF per day from the Saint John facility for much of this period. Total LNG supplied to the interstate pipelines averaged 0.5 BCF/day from December 27 through January 8. Neither the Saint John or Everett facility sent out gas at its maximum vaporization rate for a sustained period, despite Algonquin spot gas prices exceeding near term forward LNG prices by an average of $25/MMBTU and significant oil-fired generation occurring. The owners of LNG stored at these facilities chose to preserve their inventories despite large potential profits from increasing LNG sendout while contracting for short term LNG shipments. The most likely explanation for this behavior is that they would not have been able to obtain shipments quickly if a subsequent cold snap occurred.

Figure 23: LNG Sendout and Prices in 2017/18 Winter Cold Event



These support the following conclusions regarding secondary LNG available for generation:

- LNG import volumes vary widely with global market conditions, and additional supplies do not necessarily become available in-season even when economics appear to support it;
- Historic LNG sendout during the most recent severe cold event was significantly lower than the amount assumed by ISO-NE's RAA proposal;
- Optimistic assumptions of LNG availability will lower modeled winter reliability risk, greatly reducing incentives for generators to contract for firm fuel supplies.
- Hence, a conservative approach to the amount of secondary LNG included in reliability planning models is warranted, considering historic variability;

2. Dispatch Logic for Resources with Limited Inventories

When modeling winter reliability risk, the sequencing of inventory-limited units in the dispatch order (i.e., which resources are used first in the 'merit order' of the model logic) can have a large impact on the results. The risk model should use assumptions that reflect opportunity costs, which provide incentives for generators to conserve fuel for the most valuable periods. While an unrealistically optimal use of fuel over a long period will understate reliability risk, an unrealistically short-sighted approach will overstate risk.

The PEAT model recently developed by ISO-NE employed an approach that largely dispatches resources in ascending order of marginal cost based on externally determined fuel prices, ignoring opportunity costs. While this logic is reasonable for simulating normal operations, it does not realistically account for fuel inventory limitations as fuel becomes scarce. A more realistic dispatch logic would consider the following:

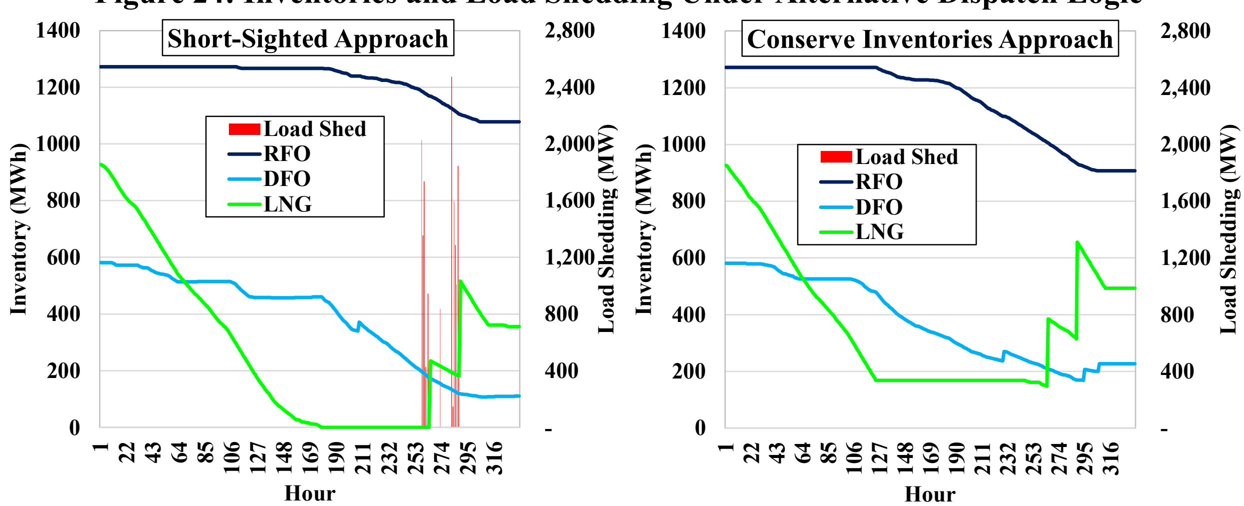
- LNG terminals have historically conserved inventories rather than maximizing sendout even during cold weather when gas prices were very high, as discussed in the previous subsection. Hence, it is more realistic to assume that LNG terminals will not completely deplete their inventories when other sources (such as oil units) are available to serve load.
- Oil and dual fuel units have strong incentives to avoid complete depletion of inventories. Being unable to operate because of insufficient fuel during a cold event would leave the unit exposed to large pay-for-performance penalties. We expect that units with low inventories would conserve fuel by including higher opportunity costs in their energy market offers, even if they have comparatively-low variable costs;

By not considering incentives to conserve inventories, the logic used in the PEAT study will overestimate reliability risk. Figure 24 below illustrates this by comparing fuel inventories and EUE in a scenario using two approaches:

- Short-Sighted Approach – Replicates the sequencing of resources in the PEAT study.
- Conserve Inventories Approach – This uses the logic of our PE-RAM to reflect opportunity costs as described earlier in this section.

In this scenario, load shedding is caused by premature complete depletion of LNG inventory in the "short-sighted" case, while this is avoided in the "conserve inventories" case. Because the inventories are not depleted, more resources are available to run in the conserve inventories case.

Figure 24: Inventories and Load Shedding Under Alternative Dispatch Logic



In addition to overestimating winter risk, an short-sighted dispatch logic may fail to identify which types of solutions improve or harm reliability. For example, the PEAT study found that the ISO-NE system faced significantly *more* risk if Everett Marine Terminal remained in service, because additional LNG sendout capability resulted in regional LNG inventory being prematurely depleted at a faster rate. In contrast, we found that Everett Marine Terminal would consistently provide some reliability benefit, even if it does not increase the quantity of LNG available to the region. Hence, we recommend refining the winter risk models used for planning and accreditation to more realistically account for the incentives to conserve inventories.

3. Modeling Inventory Depletion When Determining Marginal Accreditation Values

In Section F, we showed that winter reliability risk in the coming decade largely depends on market participant decisions regarding fuel procurement, retirements, and new entry. To provide efficient incentives to facilitate these decisions, it is important to calculate the marginal capacity values that accurately reflect each resources' contribution towards the system's reliability needs.

In a summer peaking system, a resource's marginal capacity value has depended on its expected availability during the highest peak net load hours. However, when reliability needs are driven by energy adequacy over a prolonged period such as a severe cold weather event, a resource's net energy contribution may be higher or lower than its peak availability (relative to a perfect resource). For example, assume that in the peak net load hour during the winter, a wind unit that has low expected output and a battery storage resource has high expected availability. The wind resource may still provide substantially more winter reliability because:

- If the wind unit can generate at high capacity factors throughout the cold period, it will defer consumption of scarce stored fuels.
- The battery storage resource will do little to support reliability over a sustained winter period because they do not produce a significant amount of energy.

The relative importance of availability during peak net load hours and contributions to energy adequacy will vary based on many factors including the load profile, resource mix, and systemwide fuel procurements. To ensure that marginal capacity credit values reflect (1) the most critical attributes needed to support the system's needs and (2) the amount of those attributes each resource provides, capacity credit should be calculated based on a model that includes all potential reliability risks facing the system, including inventory limitations.

ISO-NE's proposed method to determine capacity credit values under the Resource Capacity Accreditation (RCA) framework would inaccurately value some resource types when energy adequacy is the key driver of reliability risk. ISO-NE proposed to calculate winter capacity credit in two steps.[43] First, a Seasonal Risk Assessment determines the level of winter reliability

[43] See ISO-NE January 16, 2024, Reliability Committee presentation "Resource Capacity Accreditation in the Forward Capacity Market - Gas and Oil Modeling for the Seasonal Risk Assessment".

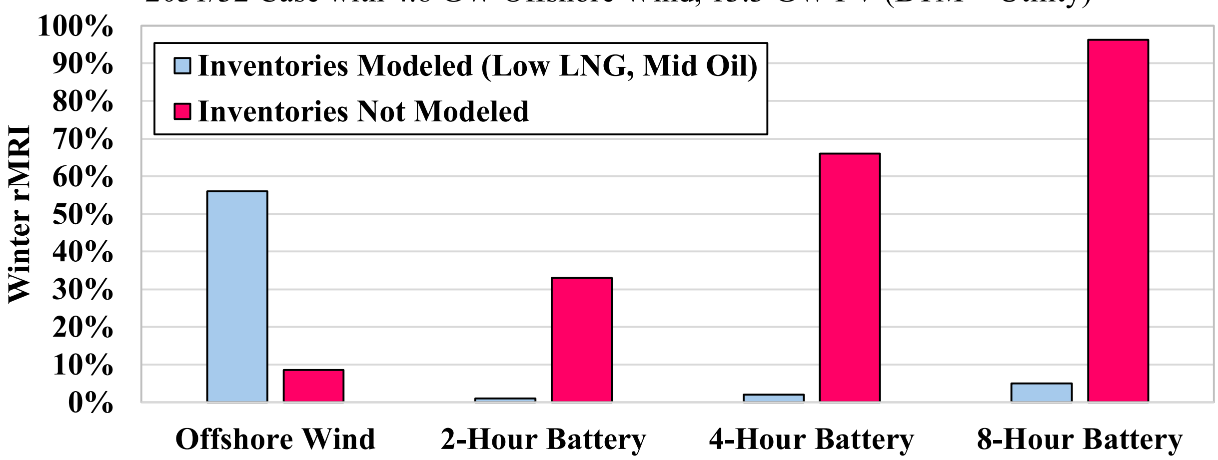
risk, modeling depletion of limited fuel inventories for oil units. Second, the Resource Adequacy Assessment using GE MARS is calibrated to the same total risk level from the Seasonal Risk Assessment by adjusting load, and then GE MARS is used to calculate the Marginal Reliability Impact (MRI) of each resource.

However, the Resource Adequacy Assessment does not explicitly model depletion of fuel inventories – instead, oil units are simply derated based on an externally determined heuristic. As a result, the MRI values for all other resource types will reflect their expected availability in the peak net load hours, *even if energy adequacy is the primary driver of winter reliability*.

Figure 25 shows our estimates of marginal capacity value for various resources using an "inventories modeled" and "inventories not modeled" approach, using our PE-RAM model. When depletion of inventories is modeled explicitly, offshore wind has a much higher capacity value and battery storage has a much lower capacity value. Hence, to ensure that the incentives provided by the market are aligned with the reliability each type of resource provides, we believe it is essential to calculate marginal capacity accreditation values using a model that explicitly represents fuel inventory limits.

Figure 25: Marginal Capacity Value Under Alternative Modeling Approaches [44]

2031/32 Case with 4.8 GW Offshore Wind, 13.3 GW PV (BTM + Utility)



H. Conclusions and Recommendations

In this section, we assess winter reliability risk to the ISO-NE system using our PE-RAM model, discuss how capacity market incentives can manage this risk, and suggested improvements to recent winter reliability models and processes proposed by ISO-NE.

44 The results are presented in terms of "rMRI", or the reduction in load shedding provided by an additional 50 MW of each resource type relative to 50 MW of perfectly available capacity. Note that the results for the Inventories Not Modeled case differ from recent indicative results for FCA19 presented by ISO-NE because of differences in models and assumptions. The rMRI values for battery storage in the Inventories Not Modeled case were supported by the high levels of solar included in the 2031/32 scenario.

Our analysis has the following key takeaways:

- *Winter reliability risks are driven by limited fuel inventories* – The ISO-NE system faces elevated reliability risk in winter in the coming decade. Reliability risk is driven by low-probability, high severity events where stored fuel inventories were insufficient to preserve reliability through cold waves lasting approximately 12 days or longer.
- *Multiple resource combinations can limit winter reliability risk to acceptable levels* – Actions that had a major impact on reliability in our model included: LNG quantities available to gas generators, fuel inventory levels of oil and dual fuel units, entry of wind generation, and retirements of fuel-secure units (including coal and oil units with large tanks). Entry of battery storage did not substantially mitigate winter reliability risks.
- *Everett Marine Terminal is beneficial but not essential for winter reliability* – Scenarios that modeled the Everett LNG terminal as retired generally resulted in higher winter reliability risk, but this was manageable in all cases by holding larger oil inventories and/or more LNG from the Saint John terminal.
- *Well-designed risk models and capacity market rules are essential.* This is because they will: accurately signaling the value of procuring firm fuel, avoid premature retirements of fuel-secure units, and attract entry of resources that contribute to winter fuel security. To do this, reliability models used for setting requirements and accreditation will need to accurately represent the key drivers of winter reliability risk. We identified the following areas where improvements to planning models and processes are needed:
    - *Secondary Available LNG*: The amount of uncontracted LNG available to gas-only generators is a critical assumption in the reliability models. Optimistic assumptions of LNG availability will understate winter risk, negate incentives for generators to procure fuel and incentivize premature retirements. The assumptions used in recent ISO-NE studies may not account for variability in year-to-year LNG imports and in-season inflexibility.
    - *Including Opportunity Costs in the Dispatch Logic*: Reliability models should account for economic incentives for holders of stored fuels (including oil and LNG) to avoid premature depletion of inventories during long cold events. Failure to do so may result in unrealistically high estimated reliability risks and distort the estimated value of potential solutions.
    - *Inventory Representation in Accreditation Models*: Models used to determine capacity credit should explicitly represent depletion of LNG and oil inventories. This will allow marginal accreditation values to accurately reflect each resource's contribution to winter reliability risk that is driven by energy adequacy.

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.

ISO-NE is currently pursuing major changes to its resource adequacy modeling and accreditation methods in order to accredit resources based on the marginal reliability benefit they provide. We generally support these changes and also highlight the need for further improvements in the modeling of factors affecting winter reliability and resulting accreditation, discussed above and throughout this section.

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;[45]
- 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.

If the ISO transitions to a prompt market framework, we recognize that it will require significant conforming changes to the interconnection and reliability planning processes. However, it would generate the following substantial benefits:

- Reduce development risk associated with FCA participation by awarding a CSO only when a resource is in service or nearly complete;
- Facilitate more efficient investment in resources with fast development timelines by allowing them to receive capacity payments more quickly after entry;
- Align assumptions underlying GE-MARS with the actual resource mix so that the ICR and capacity credit ratings are determined accurately;
- Efficiently compensate resources that provide different summer and winter capacity;
- Facilitate efficient retirement decisions by old existing generating resources by eliminating the risk of accepting CSOs three to four years in advance.
- Permit a greater range of capacity cost hedging options by load-serving entities instead of requiring all obligations to be satisfied three years in advance; and

45 This recommendation would not preclude the ISO from running a non-mandatory forward market which would facilitate voluntary hedging by buyers and sellers of capacity.

- Simplify administration of the capacity market by eliminating the need to rely on multi-year forecasts of auction parameters and closely monitor the progress of new projects.

Recommendation #2020-3: 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 a supply resource. It would also be substantially less administratively burdensome and would produce more efficient incentives to invest in EE technologies.[46]

Recommendation #2015-7: We recommend replacing the descending clock auction with a sealed-bid auction. We have detailed in previous reports that ISO-NE's DCA process inadvertently provides information that may help suppliers with market power influence auction prices.[47] A sealed bid auction would eliminate such information and improve the incentives for suppliers to submit competitive offers. In addition, the DCA format adds unnecessary complications that may interfere with other enhancements recommended in this section, including accurate determinations of resources' marginal reliability value and the effects of changes in the resource mix on the ICR.

Appendix: Key Assumptions and Inputs for the Winter Reliability Assessment

Table 5 provides a summary of the case inputs for the winter reliability assessment.

Table 5: Summary of Assumptions for Winter Risk Cases

2024 CELT Forecast FCA18 Case (2031/32 Winter)	
Load Shapes	PEAT Study 1961 and 2015
LNG and Oil Inputs	PEAT Study assumptions
Pipeline Gas Profile	PEAT Study assumptions
Electrification	2024 CELT
21-Day Peak / Average Load	25.7 GW / 18.1 GW (1961), 24.2 GW / 17.0 GW (2015)
Fuel Secure Retirements	Mystic 8 & 9 + 1.7 GW
Offshore Wind	4.8 GW
Utility Scale Solar	1.3 GW
Behind the Meter Solar	12 GW
Battery Storage	1.9 GW (2 hour)
NECEC Line	In Service
Sensitivity Cases	
Delayed OSW Case	3.2 GW OSW
Delayed OSW + Low Retirements	3.2 GW OSW, 0.8 GW Retirements (plus Mystic 8 & 9)
Delayed OSW + ESR	3.2 GW OSW, 3.5 GW Battery

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

47 See our 2014, 2015 and 2017 Assessment of the ISO New England Electricity Markets.

We modeled load shapes based on the 21-day 1961 and 2015 winter events developed for the PEAT study. We increased load to account for the electrification forecast in the 2024 CELT.

We modeled fossil units that failed to obtain obligations in FCA18 as unavailable, including the Middletown steam, Montville, and Merrimack units. We modeled additional battery storage capacity based on the results of FCA18. We also ran sensitivity cases reflecting delayed completion of offshore wind included in the PEAT study (assuming Vineyard Wind and Revolution Wind plus half of the 3.2 GW with currently canceled contracts enter service by 2031/32), retention of the Merrimack and Montville units, and additional energy storage capacity in place of offshore wind.

Figure 26 summarizes inventory assumptions for oil and dual fuel units. We use unit-level assumptions from the PEAT study based on historic generator survey data. The light blue bar shows the maximum replenishment that may occur in a 14-day period based on unit-level inputs from the PEAT study. Actual replenishment in an individual model run year may be lower.

Figure 26: Oil Inventory Assumptions

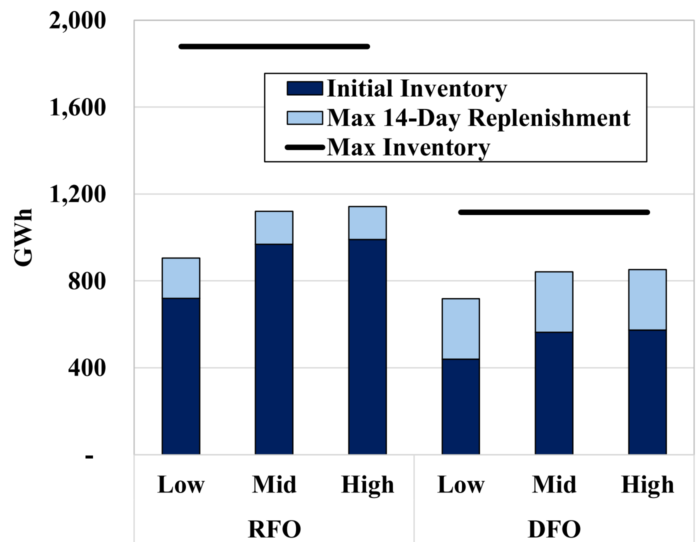
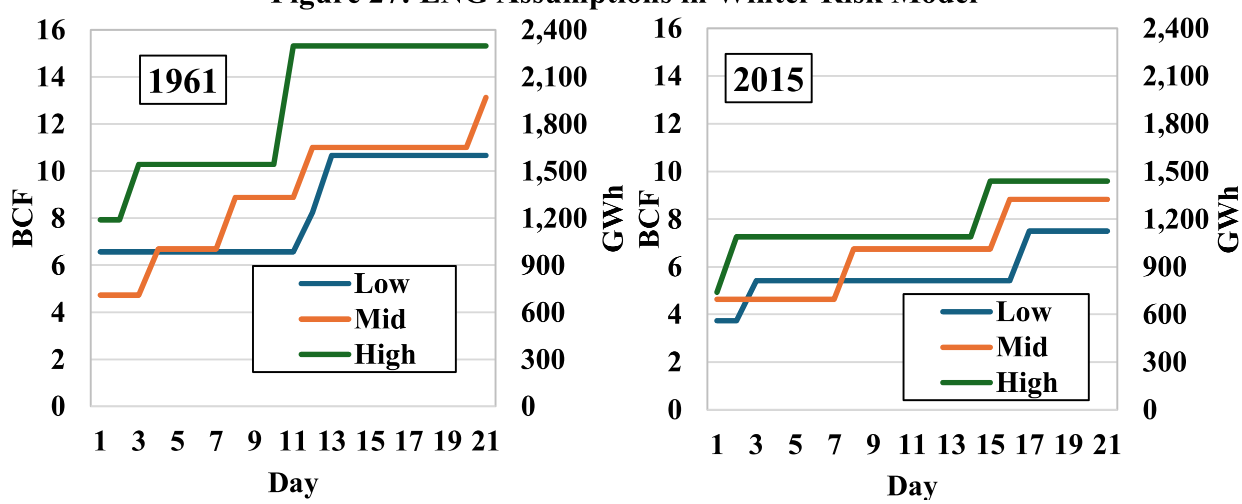


Figure 27 summarizes LNG inventory assumptions derived from the PEAT study. LNG deliveries are assumed to arrive at the Saint John and Everett terminals over the course of the 21-day period. We estimate the equivalent gigawatt-hours of generation using a 7 MMBtu per MWh heat rate.

Figure 27: LNG Assumptions in Winter Risk Model



VI. APPENDIX: 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.[48]
- 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 because of 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 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.
- The assumed operating parameters for combustion units are shown in Table 6:

Table 6: Unit Parameters for Net Revenue Estimates of Combustion Turbine Units

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

48 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 2022 and 2023 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.[49]
- Capital and operating costs are based on NREL's 2023 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.[50] 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 the capacity factor for recent wind installations in MISO and ERCOT, and the capacity factor information presented in 2023 NREL ATB for our assumption regarding the capacity factor for land-based wind in these regions.

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49 See Norton Rose Fulbright Cost of Capital: 2024 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 2023, we calculate an ATWACC of 8.7 percent for wind.

50 See Section III and Appendix VII of our 2023 report on the New York ISO markets, available here.

- 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.[51]
- 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.

51 We used $1.10 per REC price based on the reported price range in the "Minnesota Renewable Energy Standard: UTILITY COMPLIANCE" document, available at: link.