2022 Assessment of the ISO New England Electricity Markets

Prepared By:

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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 2022 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 2022.

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 the electricity needs of New England. These markets provide substantial benefits to the region by coordinating the commitment and dispatch of the region's 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 averaged $84.92 per MWh at the New England Hub, up 89 percent from 2021. The primary driver was the 101 percent increase in natural gas prices from 2021 to 2022. This is consistent with our finding that the market performed competitively because energy offers should track input costs in a competitive market.
- Average load was very comparable to 2021, but the peak load fell by 4 percent despite two heat waves in the summer with above normal temperatures. 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 $4.63 per kW-month in the 2021/22 Capacity Commitment Period ("CCP") and $3.80 per kW-month in the 2022/23 CCP.
  - These relatively high levels reflect that the peak load forecasts for the Forward Capacity Auctions ("FCAs") held in 2018 and 2019 were significantly higher than the actual peak loads in 2021 and 2022.
  - Capacity prices will fall through FCA 14 (2023/24 CCP) to $2 per kW-month because of declining load forecasts and the retention of the Mystic CCs, before rising to roughly $2.60 per kW-month in the three CCPs after the Mystic cost-of-service agreement ends.

The IMM report provides detailed discussion of these trends and other market results in 2022. 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. This report evaluates energy mitigation, out-of-market commitments for operating reserves, pricing of operating reserves, incentives during reserve shortages, and capacity market design and accreditation.

2 See ISO New England's Internal Market Monitor 2022 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 New England faces unique challenges that distinguish it from many other RTOs, affecting 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. It also operates a network that is far less congested than most other RTO's, which affects its competitive performance, operating requirements, and reliability.

We compare several key market outcomes in the ISO-NE markets to comparable outcomes and metrics in other RTO markets in Section I of this report and find that:

Energy Prices ISO-NE generally exhibited the highest average energy prices among RTO markets in recent years because of its higher natural gas prices. However, ERCOT, which operates an "energy-only" market with shortage pricing as high as $9,000 per MWh, had much higher average prices in 2021 because of unusually lengthy shortages in February 2021.

Capacity Prices Capacity prices in New England have significantly exceeded the prices in other RTOs. This disparity can be attributed to 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 and associated capacity requirements.

Congestion ISO-NE experiences far less congestion than other RTOs, with an average congestion cost of roughly $0.37 per MWh of load. This is 10 to 20 percent of the average congestion levels in other RTO markets. This reflects that large transmission investments have been made over the past decade, resulting in transmission rates exceeding $22 per MWh in 2022 – more than double the average rates in other RTO markets.

Transmission investments in ISO-NE have been made primarily to satisfy relatively aggressive local reliability planning criteria. More recently, transmission investment has increased in ERCOT, MISO, and the 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, than MISO and the NYISO. The higher costs arise because: (a) ISO-NE's fuel costs tend to be higher, (b) it does not have 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 do MISO and the NYISO. Introducing day-ahead operating reserve markets will significantly reduce these costs.

Virtual Trading	The virtual trading levels in ISO-NE have been 30 to 40 percent of the levels in NYISO and MISO primarily because ISO-NE over-allocates real-time NCPC charges to virtual transactions and other real-time deviations. It is important to address this issue since virtual trading can play an important role in aligning the day-ahead and real-time market outcomes as the system's generation portfolio 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 the NYISO and between PJM and MISO. ISO-NE's process with the NYISO exhibits much higher bid liquidity, largely because of the RTOs' decision not to impose charges on CTS transactions and better price forecasting. However, we identify substantial room for improvement in the performance of CTS.
Shortage Pricing	ISO-NE has the most aggressive shortage pricing in the country, most of which is settled through the Pay-for-Performance ("PFP") framework rather than the energy market. The PFP framework generates outsized risks associated with modest shortages that generally do not raise substantial reliability concerns. We recommend ISO-NE address this by varying the penalty rate with the size of the shortage and capping the penalty rate based on a reasonable 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. Our evaluation of participant conduct also suggests that the markets performed competitively with no evidence of market power abuses or manipulation in 2022. 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 generally implemented consistent with Appendix A of Market Rule 1. However, we two issues with the current mitigation rules.

First, while the mitigation thresholds for local reliability are appropriately tight, suppliers have the incentive to operate in a higher-cost mode and receive higher NCPC payments as a result. In 2022, 47 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. In addition to inflating the NCPC costs, this over-commitment depresses prices in key load pockets and undermines incentives for flexible resources to be available. Hence, we recommend the ISO consider tariff changes as needed to expand its authority to address this concern. (See Recommendation #2014-5)

Second, we identify several deficiencies in the process for mitigating market power, which led to real-time mitigation of competitive offers during the cold weather on December 24, 2022. We recommend the following revisions to the current energy mitigation process (Recommendation #2022-2), which are in line with a Commission order related to the event:

- Implement hourly conduct and impact tests.
- Allow multiple Fuel Price Adjustments for calculating reference levels that vary over a resources' output range.
- Mitigate only offer segments that fail conduct test rather than the current practice of mitigating all offer segments to the reference level. This approach would ensure that the resource is not mitigated to a *higher* offer price level.

Out-of-Market Commitments and Operating Reserve Pricing

The ISO commits resources in the day-ahead market scheduling process to satisfy two types of reliability requirements:

- Ensure the ISO is able to reposition the system in certain local areas in response to the second largest contingency after the first largest contingency has occurred; and
- Satisfy system-level operating reserve requirements in the day-ahead market.

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 substantial additional net revenues, especially for flexible resources such as fast-start peaking units and battery storage units that are helpful 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 in 2022, nearly 50 percent of the day-ahead NCPC was incurred to satisfy the system-level 10-minute spinning reserve requirement or local second contingency requirements across nearly 3,000 hours. Resources that contribute to satisfying these requirements are generally undervalued as the cost of scheduling operating reserves is not reflected efficiently in either reserve prices or energy prices. We estimate that pricing these requirements in the day-ahead market would, based on the years from 2020 to 2022, result in additional revenue of:

- Up to \$4 to \$10 per kW-year for units in the areas with local second contingency protection requirements; and
- Up to \$15 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 \$80 to \$100 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 inflated because: (a) the ISO is often compelled to start combined-cycle resources in a multi-turbine configuration when its reliability needs could have been satisfied by starting them in a single-turbine configuration; and (b) the ISO does not allow firm energy imports to be counted towards satisfying local second contingency needs that determine local reserve requirements.

Given these findings, we make five recommendations to improve the scheduling and pricing of energy and operating reserves. We recommend that the ISO:

- Introduce co-optimized operating reserves in the day-ahead market that reflect the ISO's operational needs, such as the Flexible Response Services ("FRS") proposed under its *Day-Ahead Ancillary Services Initiative (DASI)* project (See Recommendation #2012-8)
- 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 need. (See Recommendation #2014-5)
- Consider allowing firm energy imports from neighboring areas to contribute towards satisfying local second contingency requirements. (See Recommendation #2020-1)
- Eliminate the Forward Reserve Market, which has resulted in inefficient economic signals and market costs. Implementation of day-ahead reserve markets further decreases any potential value this market may have offered. (See Recommendation #2014-7)

Lastly, we identify inefficient reserve prices in the fast-start pricing logic which tend to overstate the value of reserves under certain system conditions. To address this inefficiency, we recommend that the ISO modify the fast-start pricing logic to utilize the full capability of online resources for energy or reserves (Recommendation #2022-1). Specifically, the undispatched capacity below EcoMin of fast-start resources should be utilized to meet the 10-minute and 30-minute reserve requirements in the pricing pass of the real-time market. This will ensure that the reserve prices more accurately reflect the cost of maintaining operating reserves.

Assessment of Market Incentives during Capacity Scarcity Conditions

Winter Storm Elliot caused systemwide reserve shortages in late afternoon on December 24. We examined the market operations during the event and found that:

- There were 30-minute reserve shortages at the system level from 16:40 to 18:00, with an average magnitude of approximately 350 MW.
- There was only one brief systemwide 10-minute reserve shortage at 17:10, with a magnitude of less than 10 MW.
- These shortages were driven by two primary factors: (a) unplanned generator outages and deratings, which resulted in a total generating capacity loss of 2.1 GW; and (b) decreased levels of net imports, which fell 1.1 GW from day-ahead schedules in shortage hours.

- ISO-NE curtailed roughly 40 percent of scheduled exports to NYISO as it sought to minimize the magnitude and duration of shortages.

Although the curtailment actions to maintain system reliability were consistent with the operating rules, we identified inefficient market incentives in the PFP rules that simultaneously encouraged scheduling of imports and exports. Specifically, under the current PFP rules, importers have a large incentive of $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 to move 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 never be large relative to the overall ISO-NE market, this flaw undermines the efficiency of scheduling incentives during reserve deficiencies, which may undermine reliability or make reserve shortages more frequent. In addition, the costs and adverse incentives of this flaw will rise in the future if Capacity Scarcity Conditions become more frequent and because the PFP rate will rise to more than $9300/MWh in 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 the PFP rate so that market compensation 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)

Assessment of Forward Capacity Market Design

The capacity market is intended to satisfy ISO-NE's requirement to ensure a minimum level of reliability (i.e., load shedding no more than 1 day every 10 years). It will become more challenging to do this efficiently because of expected changes in New England's power sector. These include growing deployment of state-sponsored renewable resources and increased awareness of limitations faced by the generation fleet during extreme winter weather.

This report highlights several changes needed to ensure that the capacity market sends efficient signals to attract and retain resources needed for reliability under these new circumstances.

Incentives for Winter Reliability in the Capacity Market

Concerns regarding "energy adequacy" have become critical because of growing winter demand, tightening gas pipeline limitations, and retirement of fuel-secure resources. The capacity market must be enhanced to ensure energy adequacy by establishing efficient prices and accreditation for resources that improve reliability when seasonal fuel supplies are limited. Efficient capacity compensation will attract and retain firm imports, prevent inefficient retirements of dual fuel and oil units, encourage gas units to contract for LNG or firm gas, and promote investment in other resources that support reliability. However, it is necessary to accurately consider factors that drive winter reliability risks – including gas limitations and depletion of oil inventories – in the capacity market parameters. Otherwise, the market will provide inefficient signals.

In Section V.A, we analyze the adequacy of ISO-NE's portfolio in the next few years. On very cold days, nearly all interstate pipeline capacity is used by gas utilities, so very little is available for gas generators without firm transportation contracts. Cold weather periods can last for nearly two weeks and about 9 GW of capacity in ISO-NE can only burn natural gas. Historically, some of this capacity has been able to operate due to imports of LNG, but generators typically do not have LNG contracts. From a reliability planning perspective, it is unclear how much LNG will be available for generators in a severe cold period when gas utilities experience 'design day' conditions and fully utilize their own contracted supplies.

In recent years a significant amount of capacity with dedicated fuel supplies (including nuclear, coal and the Mystic 8 and 9 units) has retired or failed to obtain capacity supply obligations, so ISO-NE will be more dependent on stored fuels in upcoming winters. Around half of New England's qualified capacity (excluding gas-only generators) is from dual fuel and oil units. Consequently, serving load during a sustained period of low gas availability will depend on the oil inventories of those units and their ability to replenish them. Of the 11.5 GW of dual fuel and oil units with Capacity Supply Obligations ("CSOs") in 2026/27:

- 2.2 GW can run for less than 2 days,
- 5.1 GW can run for less than one week, and
- 7.7 GW can run for less than two weeks (based on maximum inventories).

To retain and attract the resources needed for winter reliability, it will be necessary to: (a) include the drivers of energy adequacy in ISO-NE's Resource Adequacy Model so they are reflected in the ICR, and (b) accredit capacity suppliers based on their marginal contribution to those requirements. Currently, the capacity market values gas and oil units based on their qualified capacity, so it does not meaningfully consider winter risk.

ISO-NE has proposed changes as part of its ongoing Resource Capacity Accreditation project that would include pipeline gas limitations and limited LNG supplies in the resource adequacy model. However, ISO-NE's proposal treats dual fuel and oil units with more than 40 hours of inventory (and gas-only resources with contracts that allow them to operate for 10 hours per day) as having unlimited fuel. While the proposal is an improvement, it substantially understates winter reliability risk because it does adequately model oil inventories during prolonged cold weather.

In Section V.A, we demonstrate that detailed modeling of stored energy supplies – including LNG and oil inventories – is needed for the capacity market to properly signal winter reliability needs. Our analysis shows that:

- Assuming dual fuel and oil units have unlimited fuel in the planning model artificially increases the estimated reliability of the system, causing reliability requirements to be underestimated by several gigawatts (or several BCF of LNG imports);
- Underestimating winter reliability needs will result in an artificial surplus in the capacity market, leading to depressed prices even when there is a need for more resources; and
- Realistic modeling of oil inventories is necessary to calculate appropriate accreditation values for many resource types. For example, the proposed modeling by ISO-NE will:
  - Over-accredit dual fuel and oil units with small tanks, gas-only resources without firm fuel contracts, and short duration energy storage; and
  - Under-accrediting units with medium and large oil tanks and wind generators.

Finally, good capacity market performance will avoid the need for out-of-market actions such as centralized procurement of LNG that could exacerbate these problems. For example, if an LNG reserve is procured out-of-market but oil inventory limitations are not adequately modeled, the additional LNG would result in an artificial surplus that could lead to under-procurement of lower-cost fuel-secure resources (e.g., dual fuel units and imports). Hence, we recommend that ISO-NE improve its resource adequacy modeling and accreditation as the primary means to address winter energy adequacy concerns.

Assessment of the Mandatory Forward Capacity Market

ISO-NE conducts its FCAs over three years before the associated capability period. Participation by loads in the three-year forward auction is mandatory, and it is the main avenue for suppliers to earn capacity revenues. We evaluate the efficacy of the mandatory three-year forward FCA and find that it has limited benefits and significant drawbacks compared to a "prompt" capacity market design in which auctions take place weeks or months before the capability period.

The main purported benefits of the FCA are that it provides revenue certainty to project developers and coordinates entry of exit of capacity in advance of when it is needed. However, any such benefits have diminished in recent years because ISO-NE no longer allows new resources to 'lock in' their initial FCA price for up to seven years. Hence, the FCA only provides price certainty for a single year, which does not significantly offset merchant risk for capital-intensive projects with amortization timeframes of twenty years or more.

The FCM has a dubious track record of coordinating timely entry of new resources even before the multi-year lock was eliminated. The FCM has facilitated only modest amounts of new investment, which has struggled to begin operation on time. Just 41 percent of capacity from new large projects with initial CSOs from 2016 to 2023 entered on time, while 30 percent entered 1-2 years late and 29 percent never entered. The uncertain development timeframes for a growing share of new resources, including offshore wind, causes the FCM to create inefficient financial risk for new resources that may become an economic barrier for new investment.

The three-year forward period of the FCA is increasingly disconnected from the development time of new projects, such as solar, storage and demand aggregations, which can often enter more quickly than three years and are inhibited from earning timely capacity revenues. This inefficiently reduces their investment incentives.

In addition to the limited benefits of the FCM in facilitating new investment, it also raises several other concerns compared to a prompt capacity market:

- A prompt market simply compensates new resources when they enter service without mandatory forward commitments, which reduces the inefficient risk described above.
- The FCA creates inefficient risk for old existing units that must commit to supplying capacity three to four years in the future. Unexpected issues can compel them to buy back their obligation at great cost and this risk may cause some resources to retire prematurely. A prompt market facilitates more efficient retirement decisions because the uncertainty regarding the condition and availability of older units is much lower.
- Key FCA parameters rely on resource mix assumptions that vary from the mix that actually clears the auction. This can cause the ICR and capacity credit values to become increasingly inaccurate. A prompt market allows more accurate assumptions regarding auction parameters because there is greater certainty about the resource mix.
- The FCA is conducted earlier than necessary for pipeline gas resources to firm up their capacity offers by contracting for LNG delivery. A prompt market would facilitate contracting for firm fuel at a time when such costs could be reflected in capacity offers.

To address all of these concerns, we recommend replacing the FCM and replacing it with a prompt capacity market (see Recommendation #2021-1). The prompt auction should be conducted on a seasonal basis ahead of each summer and winter period using capacity market demand curves that reflect the marginal value of capacity in each season. The seasonal approach would allow the market to address winter reliability issues more efficiently by creating incentives for suppliers to procure firm fuel and maintain fuel inventories.

To facilitate this transition, we recommend that ISO-NE postpone the forward capacity auctions, beginning with the upcoming FCA18 auction for 2027/28 scheduled to take place in February 2024 (see Recommendation #2022-4). This would provide time and resources to: develop enhancements to the capacity accreditation rules (see Recommendation 2020-2) and design the prompt seasonal capacity market (see Recommendation 2021-1). This will afford nearly four years for a prompt auction framework to be developed and implemented for the Summer 2027 capability period. Continuing to hold FCAs will delay the benefits these improvements.

Finally, the descending clock auction format adds unnecessary complications to the capacity auction process that may preclude other potential market enhancements such as: (a) a more efficient representation of transmission interfaces that separate individual capacity zones, and/or (b) more accurate determinations of the marginal reliability value of specific resource types. A sealed bid format would likely facilitate these and other potential market enhancements. Hence, we recommend the ISO transition to a sealed-bid auction. (See Recommendation #2015-7)

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 and those that can be implemented relatively quickly.

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[3]	Feasible in ST[4]	Report Reference
Reliability Commitments and NCPC Allocation				
2020-1	Consider allowing firm energy imports from neighboring areas to satisfy local second contingency requirements.		✓	Section III.B
2010-4	Modify allocation of "Economic" NCPC charges to make it consistent with a "cost causation" principle.		✓	2018 Report Section III
2014-5	Utilize the lowest-cost configuration for multi-unit generators when committed for local reliability.		✓	Section III.B
Energy and Operating Reserve Markets				
2022-1	Allow fast-start pricing model to utilize the full capability of online units for energy or reserves.			Section III.C
2019-3	Dynamically define a full set of local operating reserve requirements in the day-ahead and real-time markets.	✓		Section III.B
2014-7	Eliminate the forward reserve market.		✓	2014 Report Section I.B
2012-8	Introduce co-optimized operating reserves in the day-ahead market reflecting forecasted system needs.	✓		Section III.A

3 Recommendation will likely produce considerable efficiency benefits.

4 Complexity and required software modifications are likely limited.

Energy Market Mitigation				
2022-2	Implement energy mitigation reforms including (a) hourly conduct and impact tests, (b) mitigation of only conduct-failing offer ranges, and (c) fuel-price adjustments that vary by output level.			Section II.D
Capacity Market				
2022-3	Charge exporters at the PFP rate during reserve shortages.		✓	Section IV.C
2022-4	Postpone to forward capacity auction to support the transition to a prompt capacity market.	✓	✓	Section V.B
2021-1	Replace the forward capacity market with a prompt seasonal capacity market.	✓		Section V.B
2021-2	Include the effects of MOPR elimination on investment risk when establishing the net CONE for the demand curve.		✓	Section V.B
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.	✓		Section V.A-B
2020-3	Account for energy efficiency as a reduction in load instead of as a supply resource in the FCM.		✓	2020 Report Section V
2018-7	Modify the PPR to rise with the reserve shortage level, and not implement the remaining planned increase in the payment rate.	✓	✓	2019 Report Section V
2015-7	Replace the descending clock auction with a sealed-bid auction to improve competition in the FCA.			2017 Report Section IV.A

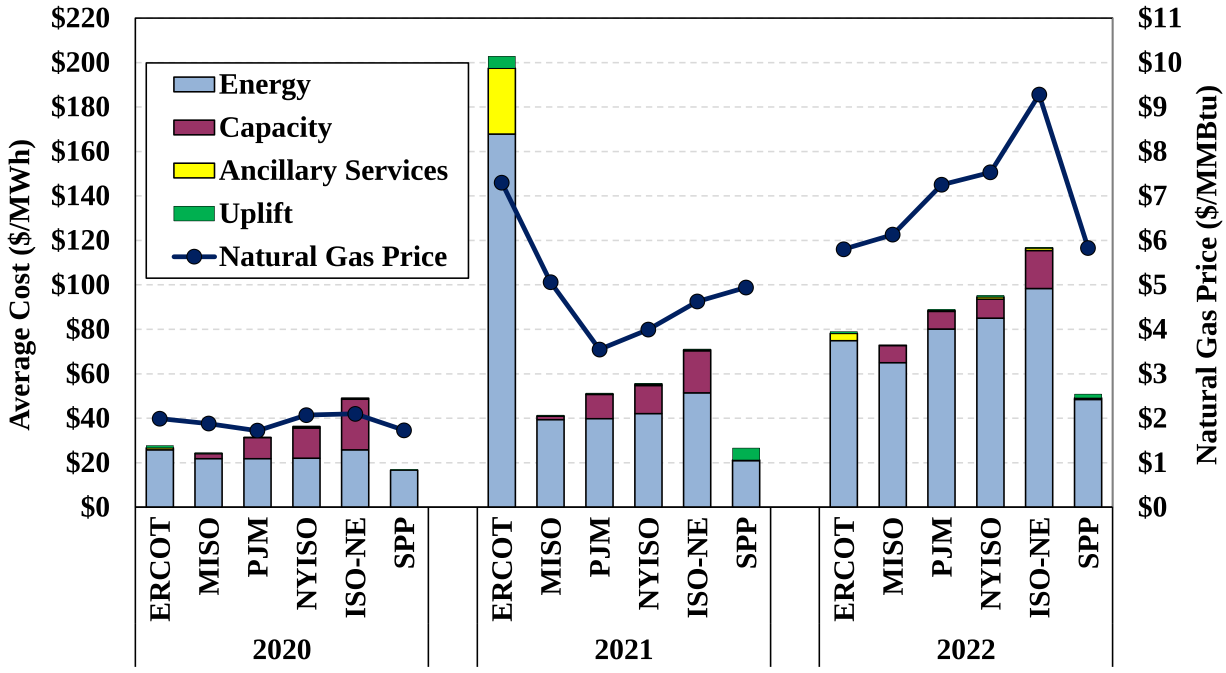
I. Comparing Key ISO-NE Market Metrics to Other RTOs

The 2022 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 2022. Rather than duplicating this discussion, we place the key market outcomes into perspective in this section by comparing them to outcomes and metrics in other RTO markets.

A. Market Prices and Costs

While the RTOs in the US have converged to similar market designs, including Locational Marginal Pricing (LMP) energy markets, operating reserves and regulation markets, and capacity markets (with the exception of ERCOT and SPP), the details of the market rules can vary substantially. In addition, the market prices and costs in different RTOs are affected by the types and vintages of the generation, state policies to support specific technologies, input fuel markets and availability, and differences in the capability of the transmission network. To compare the overall prices and costs between RTOs, we produce the "all-in price" of electricity in Figure 1.

Figure 1: All-In Prices in RTO Markets[5]
2020 – 2022



5 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 is a measure of the total cost of serving load. The all-in price 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 between these markets. ISO-NE has exhibited the highest energy prices of these markets with the exception of ERCOT. The relatively high energy costs in New England are primarily attributable to higher natural gas prices at pipeline delivery locations in New England. The high energy costs in ERCOT result from a combination of: (a) more frequent operating reserve shortages because its "energy-only" market that has produced relatively low planning reserve margins, (b) high operating reserve demand curves that result in high shortage pricing, and (c) extraordinary shortages that occurred during Winter Storm Uri in February 2021. Other key factors that affect relative energy costs in New England include:

- *Carbon Emission Costs.* ISO-NE energy prices are affected more than other regions by the costs of complying with state programs to limit greenhouse gas emissions. In 2022, compliance added an average of approximately $9 to $14 per MWh to the production costs of gas-fired combined cycle generators in Massachusetts and $5 to $7 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. In contrast, there are no such programs for generators in ERCOT, MISO, or SPP. RGGI compliance costs are included in a small number of PJM states.
- *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 substantially higher than in the other RTOs. The capacity costs for NYISO were lower because of its larger capacity surplus, which has resulted partly because: (a) New York state has retained large amounts of nuclear capacity through out-of-market subsidies called Zero Emission Credits (b) falling load forecasts have had more immediate effects in New York's prompt capacity market design than in New England's forward capacity market over these three years. Load forecasts have played a key role in the outcomes of these two markets:

- Both markets have experienced significant reductions in their load forecasts in recent years because of continued growth of energy efficiency programs and behind-the-meter ("BTM") solar installations. By the end of 2022, BTM solar installations reached 4.3 GW in New York compared to 5.5 GW in New England.

- ISO-NE's 4-year ahead load forecast used to determine the capacity requirement in each FCA fell from 26.8 GW for the summer of 2020 to 25.0 GW for the summer of 2022, resulting in a decline of 7 percent and contributing to the decline in capacity prices. Over the same period, NYISO's load forecast, which is set six months ahead, fell by just 2 percent from the summer of 2020 to 2022.
- The NYISO's downward revisions in its load forecasts are recognized immediately in the NYISO's prompt capacity market design. On the other hand, ISO-NE has made larger downward revisions and they are recognized with a four-year delay in New England's forward capacity market. This load forecast change has been a key contributor to the 44 percent decline in the FCM capacity compensation rate from the 2021/22 Capability Year to the 2025/26 Capability Year.

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 was not designed to reveal the true value of capacity. As a result, capacity prices have been understated and do not provide efficient long-term incentives. A large quantity of generation owned by unregulated companies in MISO have retired uneconomically in recent years and MISO was short of capacity in its Midwest region in the 2022/2023 planning year.

ERCOT and SPP both operate an "energy-only" market (i.e., no capacity market) with a shortage price of $9000 and $1100, respectively. Shortage pricing had a substantial impact on energy prices when ERCOT experienced reserve shortages. Several *days* of shortage in February 2021 during severe winter weather caused annual average energy and reserve costs in ERCOT to exceed $200 per MWh.

After Winter Storm Uri, the Public Utility Commission of Texas approved changes to ERCOTs ORDC that increased shortage revenues in 2022 by more than $1.5 billion. ERCOT relies primarily on shortage pricing to provide long-term incentives to facilitate investment and retirement decisions. 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 amount of congestion revenue collected through the day-ahead markets in a number of RTO markets in the U.S. To account for the very different sizes of these RTOs, we show the total amount of day-ahead congestion revenues divided by actual load in the top panel of the figure.

Figure 2: Day-Ahead Congestion Revenues
2020-2022

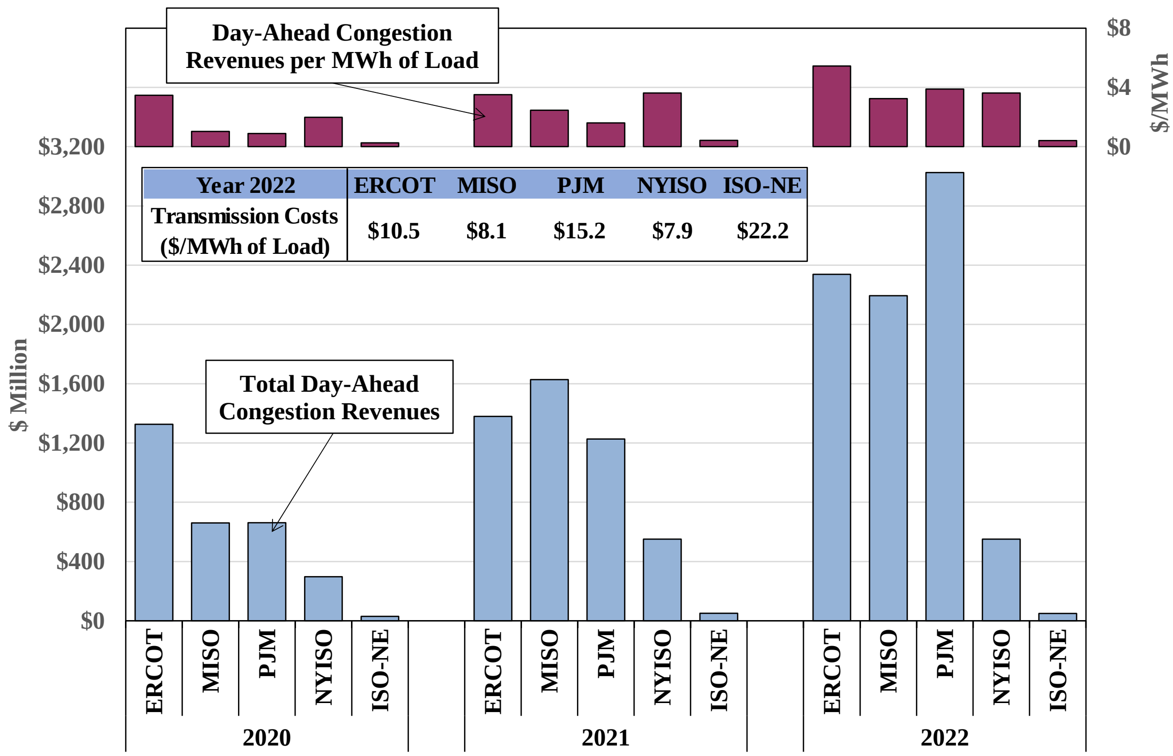


Figure 2 shows that ISO-NE experienced far less congestion than any of these other RTOs, with an average of $0.37 per MWh over the past three years. In contrast, congestion levels in the other RTOs were five to ten times higher than in New England on this basis. The low level of congestion in New England can be attributed to the substantial transmission investments made over the past decade. These investments have led transmission rates to be over $22 per MWh in 2022, which are more than double the average rates in the other RTO areas shown in the figure.

The transmission rates in other RTO areas are much lower than in New England, even given the billions in incremental transmission costs that have been incurred in 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 west Texas and the load centers in eastern Texas, while MISO began investing in transmission projects anticipated to exceed $15 billion to integrate renewable resources throughout MISO.

Likewise, the NYISO and New York State have approved over $17 billion in transmission projects since 2019. Construction started on some components in 2019, and the majority of construction costs will be incurred over the next few years. The financial impact on ratepayers will be spread over the next 25 to 30 years. The primary objective of these transmission upgrades is to facilitate the delivery of renewable energy from upstate New York to load centers in New York City and Long Island. Additionally, the NYISO is finalizing a major solicitation for transmission to move offshore wind output from Long Island to other areas of the state at a proposed cost of approximately $3 billion.

Hence, the primary reasons for transmission expansion in ERCOT, MISO, and NYISO have been to increase the deliverability of renewable resources to consumers. In contrast, the transmission investments in ISO-NE have generally been made for different reasons:

- 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 made to satisfy ISO New England's planning requirements to ensure the ISO can maintain reliability in the face of generation retirements throughout this area.

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. The cumulative investment in New England to maintain reliability was $11.8 billion from 2002 to March 2023, and another $1.3 billion is planned by 2031.[6]

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 transmission 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

NCPC costs (generally referred to as "uplift costs" industry-wide) typically account for a small share of wholesale market costs. However, they are important because they usually occur when the market requirements are not fully aligned with the actual system reliability needs or when prices are otherwise not fully efficient. Ultimately, this undermines the economic signals that govern behavior in the day-ahead and real-time markets in the short-term and investment and retirement decisions in the long-term. Thus, we evaluate the causes of NCPC payments to identify potential inefficiencies.

6 See *RSP Project List and Asset Condition List – March 2023 Update*, Planning Advisory Committee Meeting, March 16, 2023

Table 1 summarizes the total day-ahead and real-time NCPC charges in ISO-NE over the past three years, and it shows the comparable 2022 uplift charges for both NYISO and MISO. Because the size of the ISOs varies substantially, the table also shows these costs per MWh of load. Recognizing that some RTOs differ in the extent to which they make 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 to facilitate cross-market comparisons.

Table 1: Summary of Uplift by RTO

		ISO-NE			NYISO	MISO
		2020	**2021**	**2022**	**2022**	**2022**
Real-Time Uplift						
Total	**Local Reliability ($M)**	$1	$2	$1	$19	$3
	Market-Wide ($M)	$15	$19	$37	$29	$151
Per MWh of Load	**Local Reliability ($/MWh)**	$0.01	$0.01	$0.01	$0.13	$0.00
	Market-Wide ($/MWh)	$0.13	$0.16	$0.32	$0.19	$0.22
Day-Ahead Uplift						
Total	**Local Reliability ($M)**	$4	$6	$1	$41	$56
	Market-Wide ($M)	$5	$9	$13	$5	$35
Per MWh of Load	**Local Reliability ($/MWh)**	$0.04	$0.05	$0.01	$0.27	$0.08
	Market-Wide ($/MWh)	$0.05	$0.08	$0.11	$0.03	$0.05
Total Uplift						
Total	**Local Reliability ($M)**	$5	$8	$2	$60	$58
	Market-Wide ($M)	$21	$28	$50	$34	$187
Per MWh of Load	**Local Reliability ($/MWh)**	**$0.05**	**$0.07**	**$0.02**	**$0.39**	**$0.09**
	Market-Wide ($/MWh)	**$0.18**	**$0.24**	**$0.43**	**$0.22**	**$0.28**
	All Uplift ($/MWh)	**$0.22**	**$0.31**	**$0.45**	**$0.62**	**$0.36**

Market-Wide Uplift. Table 1 shows that ISO-NE incurred more market-wide uplift costs than the other two markets, adjusted for its size. In 2022, uplift charges increased in all three regions as a result of higher natural gas prices, although ISO-NE's market-wide NCPC uplift was 72 percent higher than 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, lower market-wide costs for NYISO and MISO are partly attributable to 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. We discuss these factors in more detail in Section III.
- Second, while all three markets have rules for compensating a generator whose 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.

Local Reliability Uplift. Table 1 also shows that local reliability NCPC uplift has been very low in the past three years. This reflects low levels of supplemental commitments in the load pockets because of transmission upgrades and new entry in key areas. Uplift for local reliability was much smaller than in the other regions, particularly in the NYISO where a large amount of generation is committed for local second contingency protection in New York City and several other load pockets. In addition, oil-fired peaking resources are often dispatched out-of-merit on Long Island in real-time to manage local voltage needs. These local transmission security and reliability requirements are not adequately reflected in the NYISO energy and reserve markets, leading to inefficient market 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 the uplift costs, the allocation of the uplift costs also varies substantially among the RTOs. ISO-NE allocated a significant portion of the real-time NCPC charges to real-time deviations, including virtual transactions. However, most of the NCPC charges that are allocated to real-time deviations are not caused by them. This misallocation distorts market incentives to engage in efficiency-enhancing transactions. Unfortunately, this distortion is compounded by the fact that NCPC charges are allocated to real-time deviations that actually reduce NCPC charges, such as virtual load and over-scheduling load in the day-ahead market.

Over-allocating NCPC charges to real-time deviations has resulted in higher costs for virtual transactions in New England than in other RTO markets, which reduces their participation in the market and overall market liquidity. This is undesirable because in organized wholesale power markets, virtual trading plays a key role in the day-ahead market by providing liquidity and improving price convergence between day-ahead and real-time markets.

Table 2 shows the average volume of virtual supply and demand that cleared the three eastern RTOs we monitor as a percent of total load, as well as the gross profitability of virtual purchases and sales. Gross profitability is the difference between the day-ahead and real-time energy prices used to settle the energy that was bought or sold by the virtual trader. The profitability does not account for uplift costs allocated to virtual transactions, which are shown separately.

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	2019	2.3%	-$1.20	4.9%	$1.26	$0.40
	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
NYISO	2022	5.9%	$2.40	5.8%	$1.28	< $0.1
MISO	2022	14.9%	-$0.07	15.5%	$0.94	$0.37

Table 2 shows that virtual trading was generally profitable, indicating that it has helped improve price convergence between the day-ahead and real-time markets. The gross volume of cleared virtual transactions (including both virtual load and virtual supply) averaged around 7.5 percent of load in the ISO-NE market each year from 2019 to 2022. This is significantly lower than the 12 percent in the NYISO market and the 22 percent in the MISO market observed in 2022.

We believe this substantial difference is largely due to the relatively high amount of uplift costs allocated to virtual transactions under ISO-NE's NCPC allocation methodology, which raises significant concerns. In spite of the decrease in recent years, the NCPC charges remain higher and more uncertain than the charges imposed by the other RTOs. Additionally, it results in large NCPC cost allocations to virtual load even though virtual load generally *reduces* NCPC costs. This provides a substantial disincentive for firms to engage in virtual trading, ultimately reducing liquidity in the day-ahead market. This explains why the gross profitability of virtual transactions is usually larger in ISO-NE than the other RTOs (i.e., the day-ahead and real-time prices are not as well arbitraged).

Hence, we continue to recommend the ISO modify the allocation of Economic NCPC charges to be consistent with "cost causation" principles, which 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). This will be necessary when the ISO implements day-ahead ancillary services markets and addressing both recommendations together would be reasonable.

D. Coordinated Transaction Scheduling

Coordinated Transaction Scheduling (CTS) is a process where neighboring RTOs exchange real-time market information to schedule external transactions more efficiently. CTS is very important because it allows the large interface between markets to be more fully utilized, which lowers costs and improves reliability in both areas. As intermittent generation grows, CTS will become even more important for RTOs to efficiently balance supply and demand.

Figure 3 compares CTS performance of the ISONE-NYISO process with the PJM-NYISO and MISO-PJM processes. In the lower panel, it shows annual average quantities of price-sensitive CTS bids and schedules from 2018 to 2022.[7] 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. In the upper panel, it shows the market efficiency gains from CTS measured by production cost savings, excluding estimates for the PJM-MISO process because of very limited participation.

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

Figure 3: CTS Scheduling and Efficiency
2018 – 2022

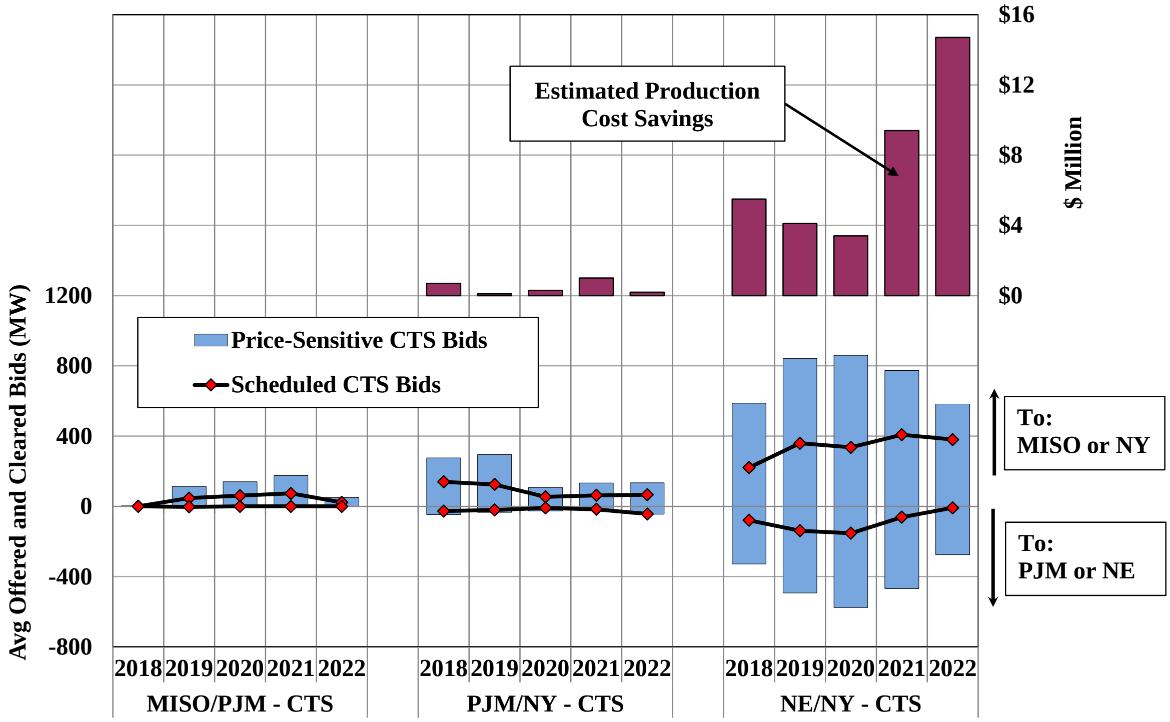


Figure 3 shows that the NE/NY interface had significantly higher CTS participation, with much larger amounts of price-sensitive bids offered and cleared, compared to the PJM/NY and PJM/MISO interfaces. These differences can be attributed to the substantial transaction fees imposed at both the PJM/NY and PJM/MISO interfaces, while there are no significant transmission or uplift charges at the NE/NY interface. For example, CTS transactions from NYISO to PJM incur charges typically ranging from $6 to $8 per MWh, while CTS transactions from MISO to PJM incur reservation charges of $0.75 per MWh based on the offered quantity and an additional $1.75 per MWh based on the cleared quantity. Accordingly, very few price-sensitive CTS transactions were offered and scheduled from NYISO or MISO to PJM.

Additionally, CTS transactions from PJM to MISO or NYISO typically incur a smaller charge ($1 to $2/MWh) than CTS transactions in the other direction, leading to much more activity in that direction. These results show that these charges are an economic barrier to achieving the benefits of CTS because they deter participants from submitting efficient CTS offers.

The estimated production cost savings from the CTS process between New England and New York totaled $37 million in the five-year period from 2018 to 2022, while the estimated savings were just over $2 million at the PJM/NY interface.[8] In addition to higher price-sensitive bids, better price forecasting was another key contributor to higher savings at the NE/NY interface.

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8 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.

ISO-NE's price forecasting is generally more accurate than PJM's, partly because ISO-NE forecasts a supply curve with 7 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 that 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 the savings that have been achieved by any of the current CTS processes and may justify consideration for New England and New York.

E. Net Revenues for New Entrants

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

This section compares the incentives for new investment in ISO-NE to three other markets by estimating the net revenue new generating units would have earned from both 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 facility from various market products and state and federal incentives.[9] For comparison, 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 2021 and 2022.

Incentives for New Combustion Turbines (CT)

Net revenues for a CT from the energy and reserve markets increased in 2021 and 2022 compared to previous years in all markets because of higher natural gas prices and electricity demand after the pandemic year of 2020. New CT investments in ISO-NE and NYISO are also heavily reliant on capacity revenues, which have been falling in both markets.

9 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.

Figure 4: Net Revenues Produced in ISO-NE and Other RTO Markets
2021 – 2022

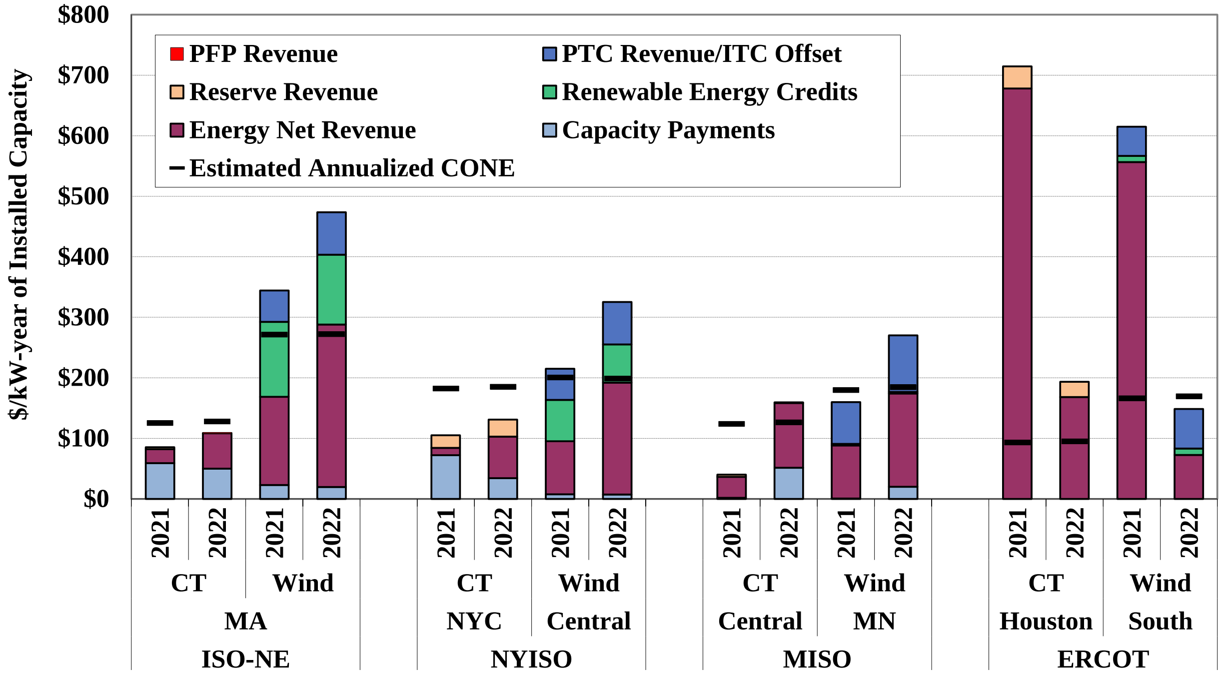

Figure 4 provides the following insights regarding incentives to invest in CTs in each market:

- *New England*. The capacity and energy prices over the last two years in ISO-NE would generally not support investment in new CTs. This is efficient for a market with surplus capacity, where new entry is likely to occur only if a resource has specific advantages (e.g., cost savings due to repowering, access to cheaper gas, etc.). The capacity surplus and associated decline in capacity prices will continue through at least 2026/27 CCP.
- *New York City*. Energy and reserve revenues also increased in 2022 due to more frequent transmission outages that raised prices in eastern New York. However, capacity prices fell to historically low levels in 2022 due to a decline in the Locational Capacity Requirement (LCR) in New York City. Capacity prices in New York City will be much higher in 2023 due to the retirement of a large amount of peaking capacity for environmental permitting reasons.
- *ERCOT*. The net revenues of a CT in ERCOT were much higher than in other markets in 2021. Shortage pricing at $9,000 per MWh for several *days* in February 2021 led net energy and reserve revenues to rise to more than seven times the estimated net CONE in 2021. Capturing these net revenues would have required resources to be online or selling reserves, but many of ERCOT's gas-fired resources could not run during this event because of the effects of the cold temperatures or fuel availability. Revenues in ERCOT remained high in 2022 due to tight supply conditions and shortage pricing changes order by the Public Utility Commission of Texas.
- *MISO*. In 2021 and earlier, a CT in MISO had the lowest estimated net revenue among regions analyzed because of MISO's sizeable capacity surplus and because the vertical capacity demand curves used in MISO led to inefficiently low capacity prices. In 2022,

MISO's capacity auction was unable to procure enough capacity to satisfy its requirements in the Midwest region, causing the price to clear at the CONE level of first time in that area. As a result, a CT in MISO's Central region would have recovered its Net CONE in 2022.

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.[10]

ii. ISO-NE has stop-loss provisions that limit, on a monthly and annual basis, the losses that a capacity resource could incur due to poor performance in PFP events.[11] These provisions limit the financial risk to generators while generally maintaining significant supplier incentives to perform during shortages. Aside from PFP, the operating reserve demand curves can set energy and reserve clearing prices above $2,500 per MWh.

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

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

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

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

Incentives for New Wind Projects

The net revenues for a land-based wind unit in New England exceeded its CONE in 2021 and 2022 because of higher energy revenues. State and federal incentives were still a major source for revenues, accounting for 51 percent of total net revenues in 2021 and 39 percent in 2022. Market revenues are also important because they provide critical price signals that differentiate

10 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.

11 "Under the monthly stop-loss limit, in any one month, the maximum amount that can be subtracted from a resource's Capacity Base Payment for that month is the resource's Capacity Supply Obligation quantity times the FCA starting price. Under the annual stop-loss limit, the maximum amount that a capacity resource can lose is equal to three times the resource's maximum monthly potential net loss." See pp 42 of FERC Order on May 30, 2014 in Docket Nos. ER14-1050-000, ER14-1050-001 and EL14-52-000.

the value of resources based on the needs of the power system. Wholesale markets complement state policies by guiding investment towards more efficient technologies and locations, enabling the more economic resources to win policy-driven solicitations. The prices of Class I RECs in New England have been high and volatile for several years.

Figure 4 shows that the incentive to invest in wind resources varies widely in other markets. Resources in New York receive significant REC revenues and further benefit from long-term contracts for 20 years with NYSERDA, which contributes to them being economic in New York.[12] Renewable resources in most of MISO and ERCOT had lower total revenues (with the exception of 2021 in ERCOT) because they receive much smaller state incentives in those markets, despite that fact that the resource potential in MISO and ERCOT is generally 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.

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

- Long-term PPAs are the dominant mechanism for stabilizing revenues for renewable resources in ISO-NE and NYISO.
- ERCOT has been transitioning from long-term PPAs to private financial hedges.

Incentive Effects of Bundled REC PPAs. These PPAs (typically with utilities) generally involve a fixed-price for the electricity and environmental attributes of 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 to be curtailed if other offer at lower prices.

It is not ideal for these risks to be assumed by consumers because they typically have very little control over where the project is sited, the technology used in the project, and 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

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

the environmental attributes of every MWh generated an amount 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.[13]

Under this design, the developer is partially insulated from wholesale energy price volatility driven by variations in key factors such as natural gas prices. However, the developer retains the key risks that arise in a system with high intermittent renewable penetration, which include basis risk, volumetric risk, and cannibalization risk.

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 opportunities for PPAs with state agencies or regulated utilities. Under a typical hedge, the wind project owner sells a certain amount of energy subject to a strike price that is based on the price at a pre-determined location.[14]

Overall, owners of projects that are financed using hedges are exposed to the basis risk and volumetric risk that projects with traditional PPAs do not face. This is good because the wind unit owner/operator is in the best position to manage these risks. For example, several wind unit owners in ERCOT that could not perform during the arctic event in February 2021 have reported significant financial losses, unit foreclosures, and/or a change in their hedging strategy.[15] 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.[16]

Even though financing new wind resources with financial hedges is effective and efficient, the availability of attractive PPAs offered by state agencies or regulated utilities will inhibit hedging with private counterparties. Additionally, long-term PPAs can create large shocks in renewable supply that lead to volatility of tradable REC prices, capacity prices, and energy prices, which would further inhibit hedging with private counterparties.

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13 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 energy revenue of $15/MWh.

14 If the locational price is lower than the strike price, the hedge provider pays the difference to the owner. If the hub price is higher than the strike price, the owner pays the difference to the hedge provider. The duration of the hedges is 10-13 years and these agreements usually do not cover the full output of the unit.

15 For instance, see articles in trade press about impact of hedges on Innergex and RWE, and multiple wind generators requesting the Texas PUC to reprice power to avoid "severe financial losses".

16 Since the PFP payments/ penalties are transfers between generators, to the extent that the production from the underperforming asset was required to meet load, ratepayers will see spot prices that include the RCPF adders, but not the Performance Payment Rate (PPR). The PPR for FCA-16 is set at nearly $8900 per MWh, while the RCPF for TMOR is $1000 per MWh.

II. Competitive Assessment of the Energy Market

This section evaluates the competitive performance of the ISO-NE energy market in 2022. Although LMP markets increase overall system efficiency, they may provide incentives for exercising market power in areas with limited generation resources or transmission capability. Most market power in wholesale electricity markets is 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 with market power may still have the incentive to exercise market power at levels that would not warrant mitigation.

Based on the analysis presented 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 measuring and analyzing potential withholding that was developed in prior assessments of the competitive performance in the ISO-NE markets.[17] 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.

A. Market Power and Withholding

Supplier market power can be defined as the ability to profitably raise prices above competitive levels. In electricity markets, this is generally done by either economically or physically withholding generating capacity. Economic withholding occurs when a resource is offered at prices above competitive levels to reduce its output or otherwise raise the market 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. Withholding will be profitable when the benefit of selling its remaining supply at prices above the competitive level is greater than the lost profits on the withheld output. In other words, withholding is only profitable when the price impact exceeds the opportunity cost of lost 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.

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

There are several additional factors (other than size) that affect whether a market participant has market power, including:

- The sensitivity of real-time prices to withholding, which can be very high during high-load conditions or high in a local area when the system is congested;
- Forward power sales that reduce a large supplier's incentive to raise prices in the spot market;[18] and
- The availability of information that would allow a large supplier to predict when the market may be vulnerable to withholding.

When we evaluate the competitiveness of the market or the conduct of the market participants, we consider each of these factors, some of which are included in the analyses in this report.

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 is a standard measure of market concentration 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 has the ability to unilaterally raise the spot market prices by raising its offer prices or by physically withholding.

The first two structural indicators focus exclusively on the supply side. Although they are 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 to evaluate the competitiveness of energy markets because it recognizes the importance of both supply and demand. Whether a supplier is pivotal depends on the size of the supplier as well as 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 substantial market power abuse. This does not mean that all pivotal suppliers should be deemed to have market power. Suppliers must have both the ***ability*** and ***incentive*** to raise prices in order to have market power. A supplier must also be able to foresee when it will

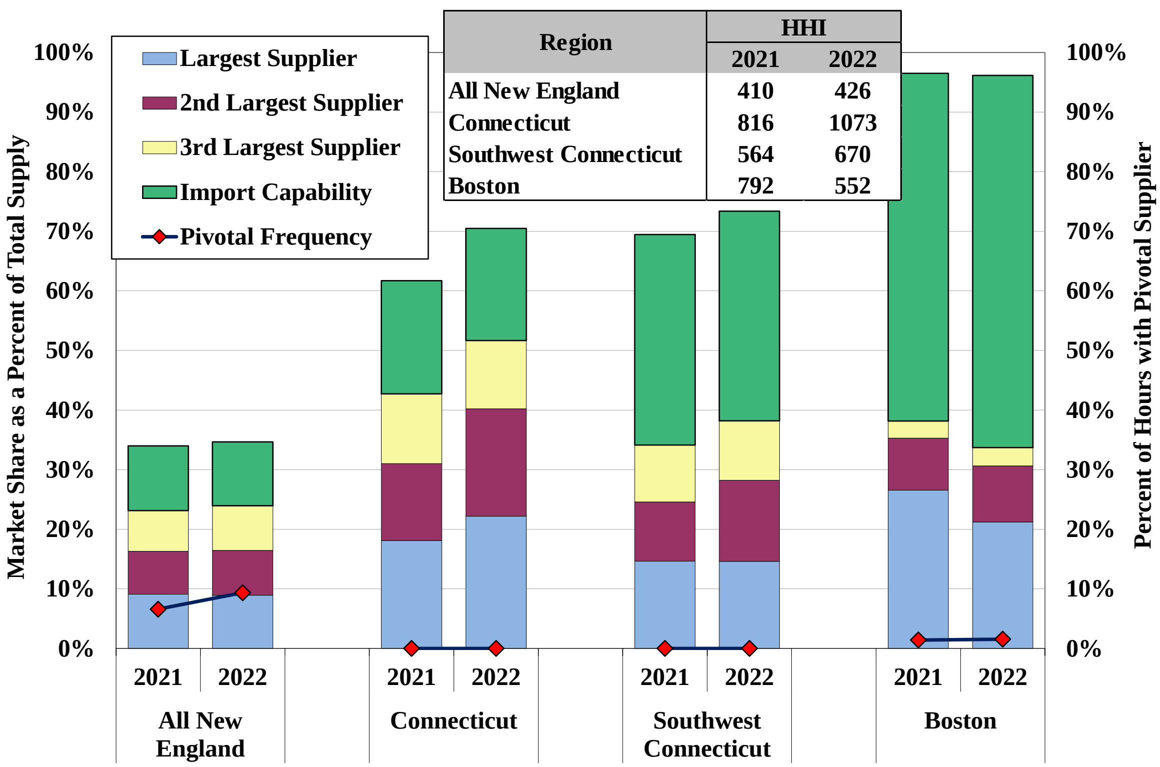
18 When a supplier's forward power sales exceed the supplier's real-time production level, the supplier is a net buyer in the real-time spot market, and thus, benefits from low rather than high prices. However, some incentive still exists because spot prices will eventually affect prices in the forward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

be pivotal to exercise market power. In general, the more often a supplier is pivotal, the easier for it to foresee circumstances when it can profitably raise market clearing prices. For the supplier to have the incentive to raise prices, it must have other unwithheld supply that would benefit from higher prices.

Figure 5 shows the three structural market power indicators for four regions in 2021 and 2022. First, the figure shows the market shares of the largest three suppliers and the import capability in each region in the stacked bars.[19,20] The remainder of supply to each region comes from smaller suppliers. The inset table shows the HHI for each region. We assume imports are highly competitive, so we treat the market share of imports as zero in our HHI calculation. The red diamonds indicate the portion of hours where one or more suppliers were pivotal in each region. We exclude potential withholding from nuclear units because they typically cannot ramp down substantially and would be costly to withhold due to their low marginal costs.

Figure 5: Structural Market Power Indicators

2021 – 2022



Region	HHI 2021	HHI 2022
All New England	410	426
Connecticut	816	1073
Southwest Connecticut	564	670
Boston	792	552

19 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.

20 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.

Figure 5 indicates that the market concentration of internal generation fluctuated from 2021 to 2022 because of changes in generating supply and asset ownership. ArcLight acquired NRG's portfolio in December 2021 and PSEG's portfolio in February 2022.[21] These acquisitions made ArcLight one of the top three suppliers in New England, Connecticut, and Southwest Connecticut, leading to a modest increase in the HHI in these regions. Conversely, the market share of the largest supplier in Boston declined due to the retirement of the Mystic Steam Turbine, resulting in a lower HHI in that area.

The 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 a portion of the total supply into the area), 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 New England to 62 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 the 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 2022, which indicates that:

- There were almost no hours with a pivotal supplier in Southwest Connecticut and Connecticut.
- In Boston, although one single supplier owned 57 percent of the internal capacity, it was pivotal in less than 2 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 9 percent of hours.[22]

The pivotal supplier frequency rose modestly from 2021 to 2022 due to at least two factors:

- Net imports continued to fall from 2021 to 2022, primarily across the interfaces with New York. In 2022, NYISO experienced unprecedented congestion across its Central-East interface because of transmission outages taken to facilitate transmission upgrades. As a result, importing power from New York became more expensive.
- Out-of-market commitments for second contingency protection in local areas declined in 2022, resulting in a decrease in average surplus capacity at the system level.

21 On December 1st, 2021, Generation Bridge, a wholly owned subsidiary of ArcLight Energy Partners closed an acquisition of a 4.9 GW power generating portfolio from NRG Energy, including 1.6 GW in New England. On February 23rd, 2022, Generation Bridge II, another wholly owned subsidiary of ArcLight Energy Partners closed an acquisition of a 1.9 GW power generating portfolio from PSEG, including 1 GW in New England.

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, December 7, 2018.

Despite the modest increase in 2022, the pivotal supplier frequency remained low. Nonetheless, we review the conduct of suppliers in the Boston and all New England areas in the next section because these areas have the highest pivotal supplier frequencies.

C. Economic and Physical Withholding

Suppliers that have market power can exercise it by economically or physically withholding resources as described above. We measure potential economic and physical withholding by 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.[23]
- ***Physical withholding:*** we focus on short-term deratings and outages because they are most likely to reflect attempts to physically withhold, since it is generally less costly to withhold a resource for a short period of time. Long-term outages typically result in larger lost profits in hours when the supplier does not have market power.

The following analysis shows the output gap results and short-term physical deratings relative to load and participant characteristics. The objective is to determine whether the output gap and/or short-term physical deratings increase when factors prevail that increase suppliers' ability and incentive to exercise market power. This allows us to test whether the output gap and short-term physical deratings vary in a manner consistent with attempts to exercise market power.

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:

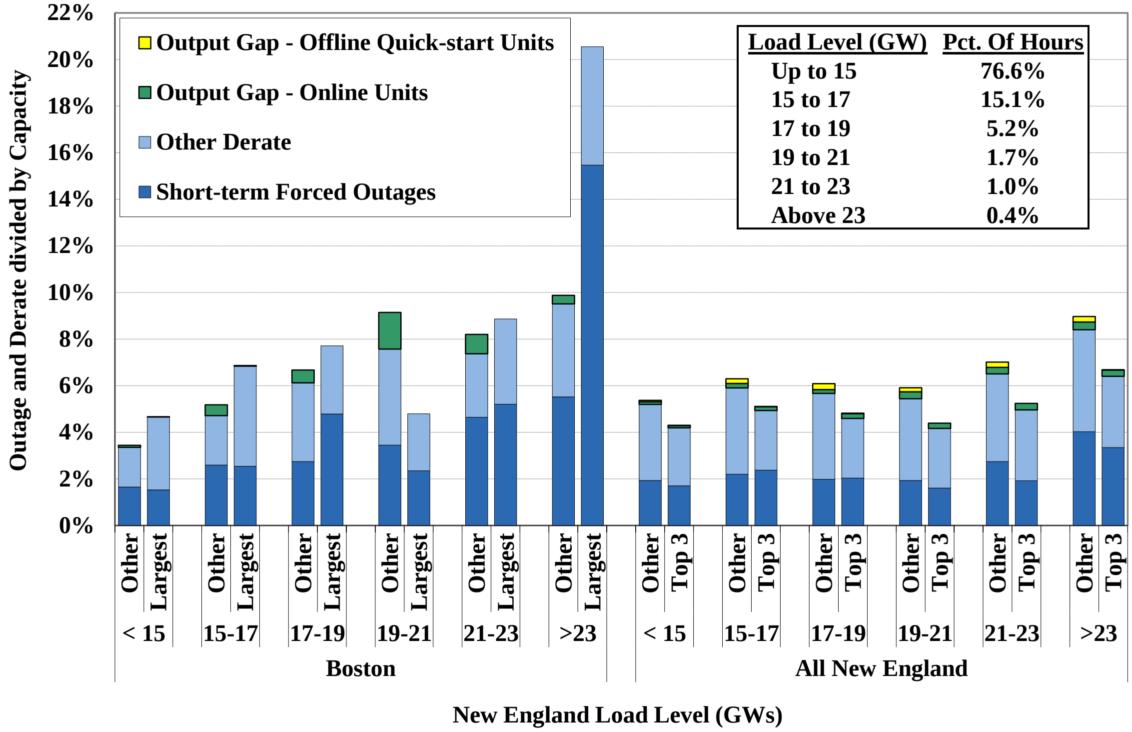
- ***Short-term forced outages*** that typically last less than one week; and
- ***Other derates*** that includes reductions in the hourly capability of a unit that is not logged as a forced or planned outage. This can be the result of ambient temperature changes or other legitimate factors.

The results in Figure 6 are shown as a percentage of suppliers' portfolio size for the largest suppliers versus the other suppliers. In Boston, we include only the largest supplier that own 57

[23] 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.

percent of generation in 2022. In all New England, we compare the three largest suppliers, who collectively owned 27 percent of internal generating capacity in 2022, to all other suppliers.

Figure 6: Average Output Gap and Deratings by Load Level and Type of Supplier
Boston and All New England, 2022



The figure shows that the amount of "Other Derate" was usually high. This was primarily because some combined-cycle capacity was often offered and operated in a configuration with reduced capability during off-peak hours. This is generally efficient and does not raise significant competitive concerns. Additionally, the "Other Derate" category rose modestly for all classes of suppliers during the highest load hours (above 23 GW), which is a very small number of high-temperature hours during the summer that tend to reduce the ratings of thermal generators.

Excluding the contributions of the "Other Derates", the overall output gap and deratings were not significant as a share of the total capacity in all New England during 2022. Compared to small suppliers, the largest suppliers generally exhibited lower levels of overall output gap and short-term deratings, particularly at higher load levels when prices are most sensitive to withholding. This is an indication that large suppliers' conduct was generally competitive.

In Boston, however, the largest supplier exhibited significant short-term deratings and outages during the highest load hours, raising concerns about potential physical withholding. Upon investigation, we found no significant competitive concerns because:

- The resources in question failed to start due to equipment issues but were able to come online later in the day or the following day.

- During these high load hours, congestion in Boston was minimal, and there were no suppliers in Boston that held pivotal positions because of sufficient import capability. This alleviates concerns regarding the excise of market power in local areas.
- Furthermore, this supplier was not a pivotal supplier in all New England either, alleviating concerns regarding the excise of market power at the system level.

It is also noted that small suppliers exhibited slightly higher output gap during high load conditions, most of which was associated with the duct-firing ranges of combined-cycle capacity whose operating characteristics vary under high summer load conditions. However, this did not raise competitive concerns because (a) it was from suppliers with small market shares in the area; and (b) it generally did not result in congestion and higher prices during these periods. The output gap continues to be very low across a wide range of conditions. Overall, these results indicate that the energy market performed competitively in 2022 and did not raise 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 applies a conduct-impact test that can result in mitigation of a participant's supply offers (i.e., incremental energy offers, start-up and no-load offers). The mitigation measures are only imposed when suppliers' conduct exceeds well-defined conduct thresholds above a unit's reference levels and when the effect of that conduct on market outcomes exceeds well-defined market impact thresholds. This framework prevents mitigation when it is not necessary to address market power, while allowing high prices during legitimate periods of shortage.

The market can be substantially more concentrated in import-constrained areas, so more restrictive conduct and impact thresholds are employed in these areas than 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: [24]

- 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.

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

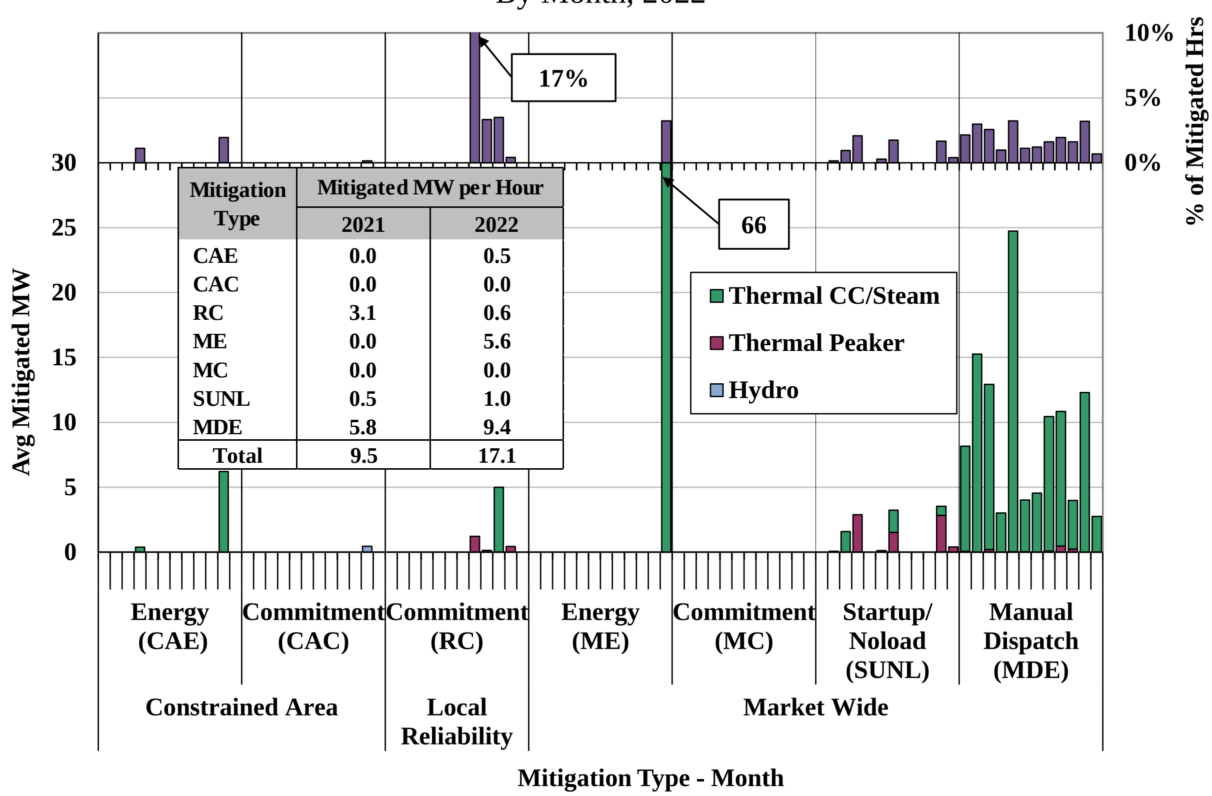
- Local Reliability Commitment Mitigation (RC) – RC mitigation is applied to a resource that is committed or kept online for local reliability.
- Start-up and No-load Mitigation (SUNL) – SUNL mitigation is applied to any resource that is committed in the market.
- Manual Dispatch Mitigation (MDE) – MDE mitigation is applied to resources that are dispatched out of merit above their Economic Minimum Limit levels.

There are no impact tests for the SUNL mitigation, the MDE mitigation, and the three types of commitment mitigation (i.e., MC, CAC, and RC), so suppliers are mitigated if they fail the conduct test in these five categories. This is reasonable because this mitigation normally only affects uplift payments, which usually rise as offer prices rise, so, in essence, the conduct test is serving as an impact test as well for these categories. When a generator is mitigated, all offer cost parameters are set to their reference levels for the entire hour.

Summary of Real-Time Mitigation

Figure 7 examines the frequency and quantity of mitigation in the real-time market during each month of 2022. Any mitigation changes made after the automated mitigation process were not included in this analysis (because these constitute a very small share of the overall mitigation).

Figure 7: Frequency of Real-Time Mitigation by Mitigation Type and Unit Type
By Month, 2022



Mitigation Type	Mitigated MW per Hour	
	2021	2022
CAE	0.0	0.5
CAC	0.0	0.0
RC	3.1	0.6
ME	0.0	5.6
MC	0.0	0.0
SUNL	0.5	1.0
MDE	5.8	9.4
Total	9.5	17.1

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 in the figure. The lower portion of the figure shows the average mitigated capacity in each month (i.e., total mitigated MWh divided by total numbers of 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 mitigation type between 2021 and 2022.

Mitigation has been infrequent in recent years, occurring in 5 percent of all hours in 2022, comparable to 2021. The vast majority of mitigation in the real-time market was for manual dispatch energy and local reliability commitment. A high proportion of mitigation in these categories is expected because local reliability areas raise the most significant potential market power concerns and are mitigated under the tightest thresholds. These two categories of mitigation typically only affect NCPC payments and have little impact on energy or ancillary service prices. The occurrence of manual dispatch energy mitigation rose modestly from 2021 to 2022, the vast majority of which was on combined-cycle units that were typically instructed to provide regulation service or dispatched manually to address transient issues on the network.

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 in the single-turbine configuration when they are likely to be needed for local reliability. By offering in 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 the issue.

The appropriateness of mitigation depends on accurate generator cost estimates (i.e., "reference levels"). If reference levels are too high, suppliers may be able to inflate prices and/or NCPC payments above competitive levels. If reference levels are too low, suppliers may be mitigated below cost, which could suppress prices below efficient levels. It can be difficult to estimate costs accurately for several types of generators, including:

- *Energy-limited hydroelectric resources*. The units' costs are almost entirely opportunity costs (the trade-off of producing more now and less later). These costs are generally difficult to accurately reflect.
- *Oil-fired resources during periods of tight gas supply*. They become economic when gas prices rise above oil prices. But when they have limited on-site oil inventory, the suppliers may raise their offer prices to conserve the available oil in order to produce during the periods with potentially the highest LMPs.
- *Gas-fired resources during periods of tight gas supply*. Volatile natural gas prices in the winter create uncertainty regarding fuel costs that can be difficult to reflect accurately in

offers and reference levels. The uncertainty is increased by the fact that offers and reference levels for the day-ahead market must be determined by 10 am on the prior day.

Appropriately recognizing opportunity costs in resources' reference levels reduces the potential for inappropriate mitigation of competitive offers, helps the region conserve limited fuel supplies, and improves the overall efficiency of scheduling for fuel-limited resources. ISO-NE uses a model to estimate an opportunity cost 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 on December 24, 2022

Although market wide energy mitigation has been rare in past years, it was applied to relatively large amounts of generating capacity in December 2022, as shown in Figure 7. On December 24, specifically, nine resources in one Lead Market Participant's portfolio were mitigated. The mitigation began in intervals within the hour ending at 1:00 when the lead market participant was identified as a pivotal supplier and the resources failed both conduct and impact tests. The mitigation remained in effect for all nine resources until 19:00 when the lead market participant was no longer pivotal. We reviewed the mitigation in this instance and, while the mitigation was conducted in accordance with the tariff, we identified several aspects of the mitigation measures that resulted in inefficient market outcomes. These are discussed in detail below.

During the Christmas holiday weekend, the New England states were hit by severe winter weather caused by Winter Storm Elliott. The region experienced blizzard conditions, strong winds, and extremely cold temperatures. Consequently, the supply of natural gas became very limited for power plants and the gas price indexes rose above $30/MMBtu. Figure 8 shows the market wide energy mitigation, referred to as General Threshold Energy ("GTE") mitigation, for one of the nine resources. The figure shows three relevant incremental energy curves:

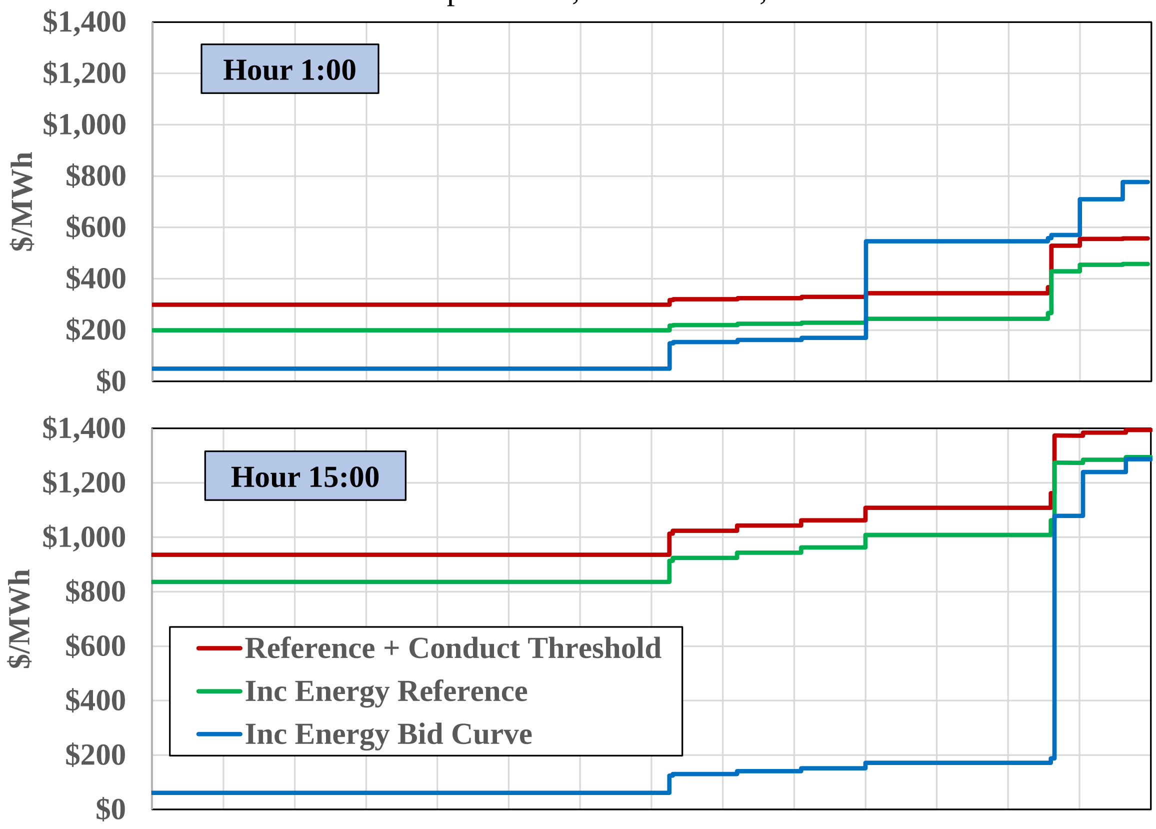
- *Inc Energy Bid Curve* (blue line): This curve represents the hourly incremental energy offer curve submitted by the resource.
- *Inc Energy Reference* (green line): This curve represents the hourly incremental energy reference curve used by the ISO for mitigation.
- *Reference + Conduct Threshold* (red line):[25] This curve serves as the benchmark in the conduct test. The resource fails the conduct test if any portion of its incremental energy bid curve exceeds this benchmark curve (i.e., when the blue line is above the red line).

The figure only shows the price level of these curves, with MW segments hidden to maintain resource confidentiality. The figure presents these curves for two specific hours, Hour 1:00 (i.e.,

25 The GTE mitigation uses a threshold equal to the lower of 300% or $100/MWh above the reference level, whichever is lower. See Market Rule 1, Appendix A, Section III.A.5.5.1.2.

hour-ending 2) in the upper panel and Hour 15:00 (i.e., hour-ending 16) in the lower panel. These hours correspond to different periods when distinct Fuel Price Adjustments ("FPAs") were used for calculating the reference level. The first period spans from HE 1 to 10 with an FPA of $35/MMBtu, while the second period covers HE 11 to 19 with an FPA of $150/MMBtu.

Figure 8: Incremental Energy Offer vs. Reference Curve During Mitigation
Two Sample Hours, December 24, 2022



During HE 1, the upper 30 percent of the incremental bid curve failed the conduct test, indicated by the portion of the blue line above the red line in the figure. As the resource's lead participant was identified as a pivotal supplier and the resource failed the price impact test, the resource was mitigated. As per Section III.A.5.6 of the Tariff, GTE mitigation continues until there is one complete hour where the lead market participant is no longer pivotal. Consequently, the resource remained mitigated until HE 19, as the lead market participant remained pivotal in each hour during this period. It is worth noting that, during HE 11 to HE 19, the mitigation remained in effect even though the supply offer did not exceed the reference level after a higher FPA of $150/MMBtu was approved, as shown in Hour 15:00 in the figure.

This instance of mitigation highlights several inefficiencies in the process. First, the current process lacks hourly conduct and impact tests after GTE mitigation starts, leading the nine resources to remain mitigated during the period from HE 11 to HE 19, even without ongoing conduct and impact violations. Additionally, the supply offer was mitigated *up* to a higher reference level, as shown in Hour 15:00 in the figure, which is not consistent with the purposes of market power mitigation rules to limit economic withholding.

Second, offer segments that do not violate conduct test are still mitigated, sometimes resulting in *higher* offer prices. During Hour 1:00, although the upper 30 percent of the offer curve was mitigated *down* because of conduct violation, the lower 70 percent was mitigated *up* to the reference level, despite not violating the conduct threshold. Similarly, during Hour 15:00, the entire offer curve was mitigated *up* to the reference level.

Third, FPAs are applied uniformly to all offer segments even though the natural gas price can vary substantially based on the amount purchased during illiquid gas market conditions. This can lead to both understated and overstated reference levels. On days with tight gas supply, resources often face increasing gas prices for different output levels. Dispatches above day-ahead schedules may require additional gas purchases at much higher intra-day prices. While a resource can reflect rising gas costs in different segments of its offer curve, the calculation of the reference level only allows for a single gas price for the entire range. Consequently, on days with high and volatile gas prices:

- An FPA reflecting purchase costs of day-ahead awards may *understate* the cost for the offer segments above day-ahead awards (e.g., Hour 1:00 in the figure).
- An FPA reflecting the highest gas purchase cost tends to *overstate* the reference level for a significant portion of the output range (e.g., Hour 15:00 in the figure).

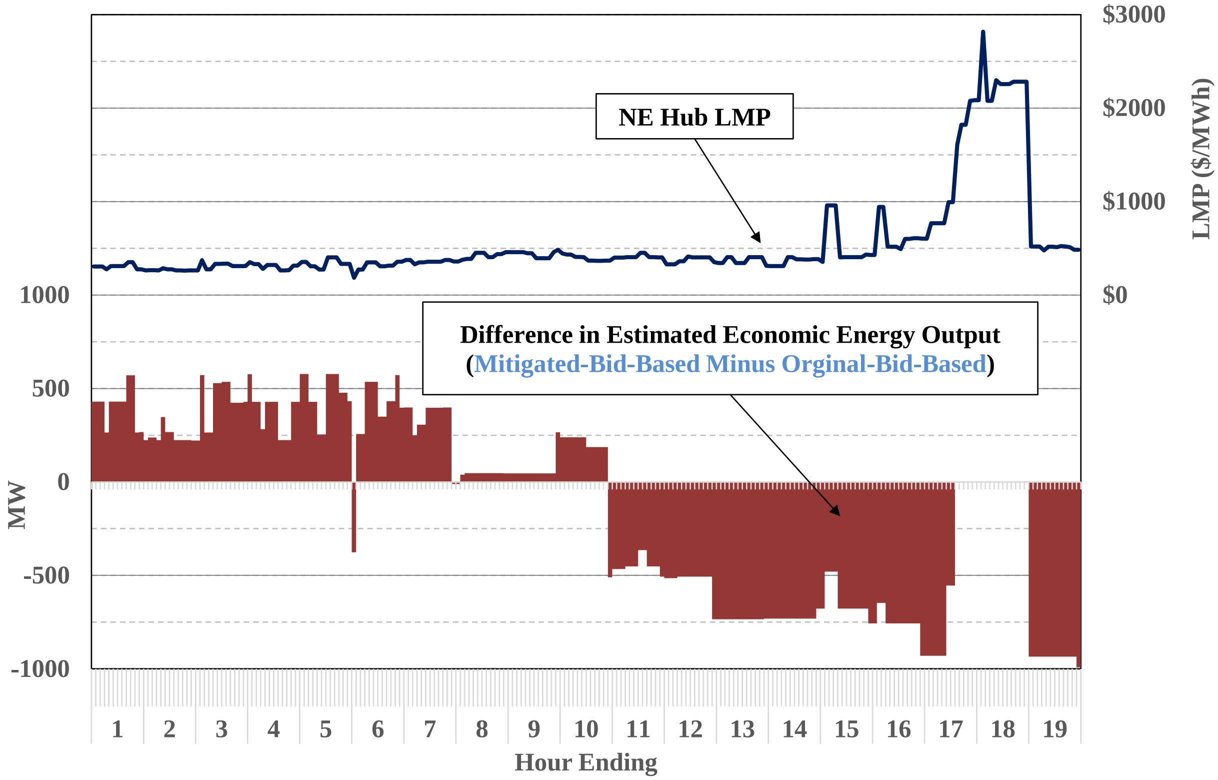
These inefficiencies can lead supply offers to be mitigated to levels that do not reflect their marginal costs, leading to inefficient real-time market outcomes.

Figure 9 shows our estimated difference in economic energy dispatch of the nine resources before and after the GTE mitigation. The upper portion of the figure displays the 5-minute LMPs at the New England Hub during the mitigation period. The economic energy dispatch of the resources is estimated by comparing their original and mitigated bids with the hub LMPs. The lower portion shows the difference between the two estimated economic dispatch levels.

Figure 9 shows that during the early morning hours (HE 1-10), the mitigated resources were dispatched *up* by an average of roughly 300 MW compared to the economic dispatch under their original bid curve. Some of this additional output incurred higher gas costs than the FPA range of $35-$40/MMBtu. Conversely, in the afternoon hours (HE 11-19), the mitigated resources were dispatched *down* by an average of nearly 600 MW as the FPA of $150/MMBtu overstated resource costs for a large portion of the output range.[26] However, this mitigation did not affect resource scheduling and pricing during shortage intervals in HE 17 and HE 18 as the clearing prices were much higher than both the incremental energy offer level and the reference level.

[26] It is important to note that these quantities are rough estimates and should not be considered precise representations of the actual impact on economic dispatch levels caused by the GTE mitigation.

Figure 9: Potential Difference in Economic Energy Dispatch by GTE Mitigation
December 24, 2022



To address these inefficiencies, we recommend the ISO implement the following revisions to the current energy mitigation process (Recommendation #2022-2):

- *Implement hourly conduct and impact tests*: Resources should only be mitigated in hours when they violate both conduct and impact tests, which is only when it is warranted.
- *Allow multiple FPAs for calculating reference levels*: Enabling the use of multiple FPAs to calculate reference levels for different output ranges will allow for 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 avoid inappropriate mitigation.
- *Mitigate only offer segments that fail the conduct test*: Instead of mitigating all offer segments, only mitigate the offer segments that exceed the conduct threshold (although the offer prices of other segments might still be reduced to ensure that an offer is monotonic). This would ensure that no resource is mitigated to a *higher* offer price.

By implementing these revisions, the ISO can enhance the energy mitigation process, reducing inefficiencies and improving the accuracy of dispatch and pricing outcomes. The Commission recently recognized the need for these three enhancements in its order in response to a complaint related to the mitigation that occurred on December 24, 2022. [27]

[27] See *Order Granting Cost Recovery Request In Part and Denying In Part and Establishing a Show Cause Proceeding*, dated May 5, 2023, Docket Nos. EL23-62-000 and ER23-1261-000, P. 39.

E. Competitive Performance Conclusions

The pivotal supplier analysis suggests that structural market power concerns have diminished noticeably in Boston and in all New England since 2018 because of:

- The new entry of more than 2.5 GW of generating capacity since 2018;
- Transmission upgrades in Boston; and
- Downward-trending load levels due to energy efficiency improvements and behind-the-meter solar generation.

Overall, we find little evidence of structural market power in New England, either overall 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 2022.

Although we find that 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 may not have been fully effective. This relates to resources that are frequently committed for local reliability. Although the mitigation thresholds are tight for these resources, the 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 identify several inefficiencies in the mitigation process and recommend the following revisions to the current energy mitigation process (Recommendation #2022-2):

- Implement hourly conduct and impact tests.
- Allow multiple FPAs for calculating reference levels that vary over a resources' output range.
- Mitigate only offer segments that fail conduct test rather than the current practice of mitigating all offer segments to the reference level. This approach would ensure that the resource is not mitigated to a *higher* offer price level.

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

To maintain system reliability, sufficient resources must be available in the operating day to satisfy load and operating reserve requirements, both at the system level and in local areas. The day-ahead market is intended to provide incentives for market participants to make resources available to meet these requirements 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.

The ISO commits resources through the day-ahead market process to satisfy two types of reliability requirements not embodied in the day-ahead market products. They are to:

- Ensure the ISO is able to reposition the system in key areas in response to the second largest contingency after the first largest contingency has occurred; and
- Satisfy system-level operating reserve requirements.

Although these commitments are primarily made through the day-ahead market, they are not reflected in ISO-NE's market pricing process, causing the clearing prices of energy (and reserves) are understated because they do not reflect the costs of satisfying these requirements. When resources are scheduled at clearing prices that are not sufficient 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 the overall market costs, they are important because they usually occur when the market requirements are not fully aligned with the system's reliability needs, or when prices are otherwise not fully efficient. This alignment is key for causing the wholesale market to provide efficient short-term operating incentives and long-term investment incentives to satisfy the system's needs. Efficient incentives for flexible low-cost providers of operating reserves will be increasingly important as the penetration of intermittent renewable generations increases over the coming decade.

The general concern associated with out-of-market commitments and NCPC is that prices will be understated, but we have identified an issue that can cause them to be overstated in some cases (i.e., inefficiently high relative to the costs of satisfying short-term system needs). This issue relates to the fact that the fast-start pricing model does not count some available capacity of online fast-start resources towards satisfying the operating reserve requirements. We discuss this issue later in this section and recommend improvements to address it.

This section evaluates commitments to maintain operating reserves in the day-ahead market, the pricing of reserves in the real-time markets, and implications for market efficiency. It is divided into subsections that address: (a) commitment for system-level operating reserve requirements; (b) commitment 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 in addition to bid load. However, these reserve requirements are not enforced as a market product 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.

Table 3 summarizes the additional commitments to satisfy the system-level 10-minute spinning reserve requirements in the past three years by showing our estimates of:

- The total number of hours in each year during which such commitments occurred;
- The average capacity (i.e., the Economic Max of the unit) committed in these hours;
- The total amount of NCPC uplift charges incurred; 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
2020 - 2022

Year	# Hours	Average Capacity Committed per Hour (MW)	DA NCPC (Million $)	Average Reserve Value ($/MWh)
2020	4054	571	$3.8	$1.68
2021	3389	514	$5.4	$1.94
2022	2450	496	$5.8	$1.81

The table shows that additional generating capacity was committed to satisfy the system-level 10-minute spinning reserve requirement in 28 to 46 percent of hours in each of the past three years. This was the second largest contributor to the NCPC uplift charges in the day-ahead market during the period. Co-optimized procurement and pricing of this reserve product in the day-ahead market would improve the pricing of 10-minute spinning reserves and energy since this would lead the opportunity cost of not providing reserves to be reflected in 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 $1.8 per MWh over the past three years.[28] We also estimate that pricing such a product would increase the energy and ancillary services net revenues for a 4-hour battery storage unit by $15 per kW-year.

28 These estimates quantify the direct effect of modeling the reserve requirements in the day-ahead market. However, the increase in day-ahead LMPs would attract additional virtual supply, which would reduce the LMP effect, while increasing the effect on 10-minute spinning reserve prices.

Setting more efficient prices for energy and spinning reserves would provide better incentives for reliable performance, flexibility, and availability. Under-compensating generators that have flexible characteristics will be increasingly undesirable as the penetration of intermittent renewable generation increases over the coming decade because these resources will be essential to complement the 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. These local commitments have been the largest contributor to NCPC charges in the day-ahead market in recent years.

Table 4 summarizes the commitments for local second contingency protection in the day-ahead market from 2020 to 2022 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 most notable results in this table over the past three years are in two areas:

- *Eastern New England.* Day-ahead commitments for local second contingency protection in the broader region east of the New England West-to-East interface were most frequent, occurring on an average of 40 days (480 hours) per year and accounting for 46 percent of this type of NCPC uplift. Most of these commitments occurred in periods when planned transmission outages reduced the transfer capability across the West-to-East interface.

[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 $14.66/kW-year in 2021 ($8.11 of NH-to-Maine plus $6.55 of NE West-to-East).

- *Maine*. Although Maine generally exports to other areas, operating reserves are still required to ensure local reliability in case two large contingencies occur. Reliability commitments in this area were frequent as well, often occurring in the shoulder months when transmission maintenance outages reduced import capability from New Hampshire.

Table 4: Day-Ahead Commitment for Local Second Contingency and NCPC Charges
2020 – 2022

		# LSCP Days	#LSCP Hours	Average LSCP Capacity per Hour (MW)	DA NCPC (Million $)	Average Uplift Rate ($/MWh)	Implied Marginal Reserve Value ($/kW-Year)
2020	**NH Seacoast**	3	38	45	$0.04	$21.91	$0.80
	NH-to-Maine	28	401	298	$2.0	$16.92	$8.24
	NEMA/Boston	7	72	672	$0.7	$14.27	$0.97
	Lw. SEMA & East RI	24	245	232	$0.2	$4.28	$1.72
	NE West-to-East	51	553	373	$0.8	$3.85	$3.03
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

The table also shows that day-ahead commitments for local second contingency protection fell in 2022 from prior years, largely because of reliability transmission upgrades in these areas. For example, local second contingency protection commitments in the combined area of Lower SEMA and Eastern Rhode Island have fallen from 51 days in 2019 to just 1 day in 2022. This is attributable to completed transmission upgrades associated with the Southeast Massachusetts/Rhode Island Reliability Project.

In 2022, although total uplift cost associated with these reliability commitments was small, the uplift cost per MWh of committed capacity was significant, ranging from nearly $6 per MWh in the broader region east of the New England West-to-East interface to roughly $23 per MWh in the NEMA/Boston load pocket. These results raise two significant efficiency concerns:

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

These two inefficiencies distort economic incentives in favor of higher-cost, less flexible units and reduce prices received by 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 period by:

- Roughly $3.7 per kW-year in eastern New England (east of the West-to-East interface); and
- Nearly $9.6 per kW-year in Maine.

The frequent use of 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 to commit resources out-of-market in the local areas that currently receive sizable NCPC payments. These concerns are exacerbated by two issues that lead excessive amounts of capacity to be committed for local second contingency protection when additional reserves are needed.

Multi-Turbine Configuration. Some generators that are frequently committed for local second contingency protection offer as a multi-turbine group, requiring the ISO to commit multiple turbines when one turbine would be sufficient. Needlessly committing the multi-turbine configuration displaces other more efficient generating capacity. In 2022, multi-turbine combined-cycle commitments accounted for: (a) roughly 47 percent of the capacity committed for local reliability in the day-ahead market; and (b) roughly 50 percent of day-ahead local second contingency NCPC payments.

The ISO could avoid excess commitment by modifying its tariff to require capacity suppliers to offer multiple unit configurations to allow the ISO the option of committing just one turbine at a multi-turbine group. This would improve market incentives for flexibility and availability.

Treatment of Imports. Day-ahead scheduled energy imports from neighboring areas are currently not counted towards satisfying local second contingency protection needs in the same manner as energy scheduled on internal resources—even if the import is associated with a CSO.

- In 2022, an average of 195 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.
- Allowing these imports to satisfy local second contingency requirements would have reduced the need for LSCP commitments by 25 percent.
- However, given the lack of a day-ahead reserve market with a comprehensive set of local requirements, firm import 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 they are not continuously dispatchable from zero to their maximum output level. 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 to enable fast-start resources to set prices when their output displaces output from more expensive resources. Such units include fast-start generators and certain types of demand response resources.

The real-time energy market is cleared using an optimization model that determines the quantity of production from each resource that minimizes the overall as-offered production cost across the market given transmission constraints and operating constraints of individual units. After this physical scheduling step or “physical pass” occurs, the fast-start pricing logic is implemented in the “pricing pass” . While the physical dispatch accurately reflects all of 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 the unit to “set the price” for energy. In addition, the energy offer of the fast-starting resources are 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.

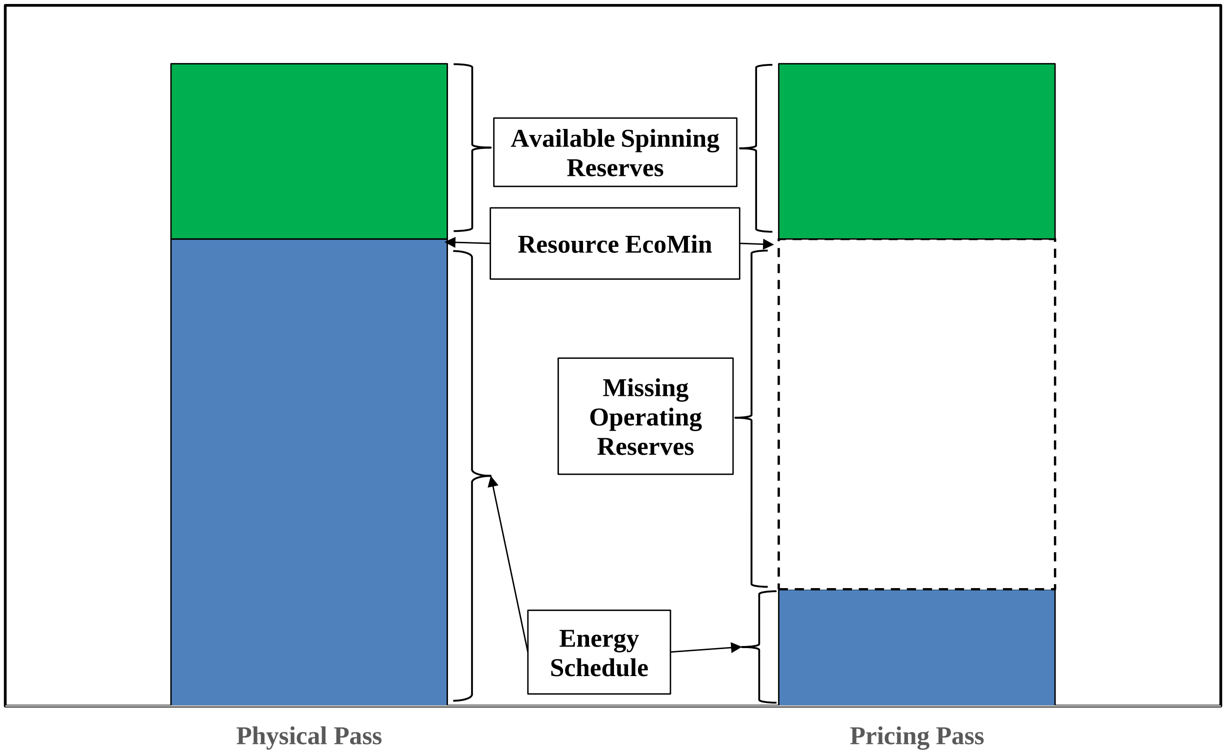
However, we have identified the following problem with the fast-start pricing logic, which results in inefficient reserve pricing under some conditions.

- The pricing pass does not allow fast-start units to hold operating 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 the available operating reserves often raises reserve and energy prices inefficiently.

The loss in available reserves is illustrated in Figure 10 below. This illustration assumes that in the physical pass, a fast-start unit is dispatched at its physical EcoMin level and the head room above its EcoMin is allocated for spinning reserves. In the pricing pass, the fast-start unit is dispatched below its physical EcoMin level because the EcoMin is relaxed to zero, and the unit becomes marginal for setting prices. The pricing pass still considers the head room above the unit’s physical EcoMin for spinning reserves but excludes the undispatched portion below its physical EcoMin for providing reserves, which is represented by the white dashed box and labeled as “missing operating reserves” in the figure.

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, freeing up other online capacity for additional operating reserves. This inconsistency does not cause inefficient prices in the vast majority of intervals because the system usually has surplus reserves. However, under certain system conditions when the margin on operating reserves is small, this issue will cause reserve prices to be overstated.

Figure 10: Illustration of Available Reserves in Physical Pass and Pricing Pass



To show cases where this issue affected prices, Figure 11 and Figure 12 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. The upper portion of each figure compares shadow prices of reserve requirement constraints between the two passes in side-by-side bars. The shadow price is the marginal cost of satisfying the reserve requirement and contributes to setting the price for the 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. The system has surplus reserves when the dashed line is above the requirement line or a shortage when the dashed line is below the requirement line. These figures show that in the 243 intervals with binding reserve constraints:

- The physical pass consistently exhibited an equal or greater amount of available reserves. On average, the physical pass had 110 MW and 330 MW more available 10-minute and 30-minute reserves, respectively.
- Shadow prices of the reserves were often much higher in the pricing pass than in the physical pass. The clearing reserve prices averaged $216/MWh and $318/MWh for 30-minute and 10-minute reserves, respectively, compared with only $92/MWh and $148/MWh in the physical pass.

Figure 11: Available 10-Minute Reserves in UDS
Physical Pass vs. Pricing Pass, 2022

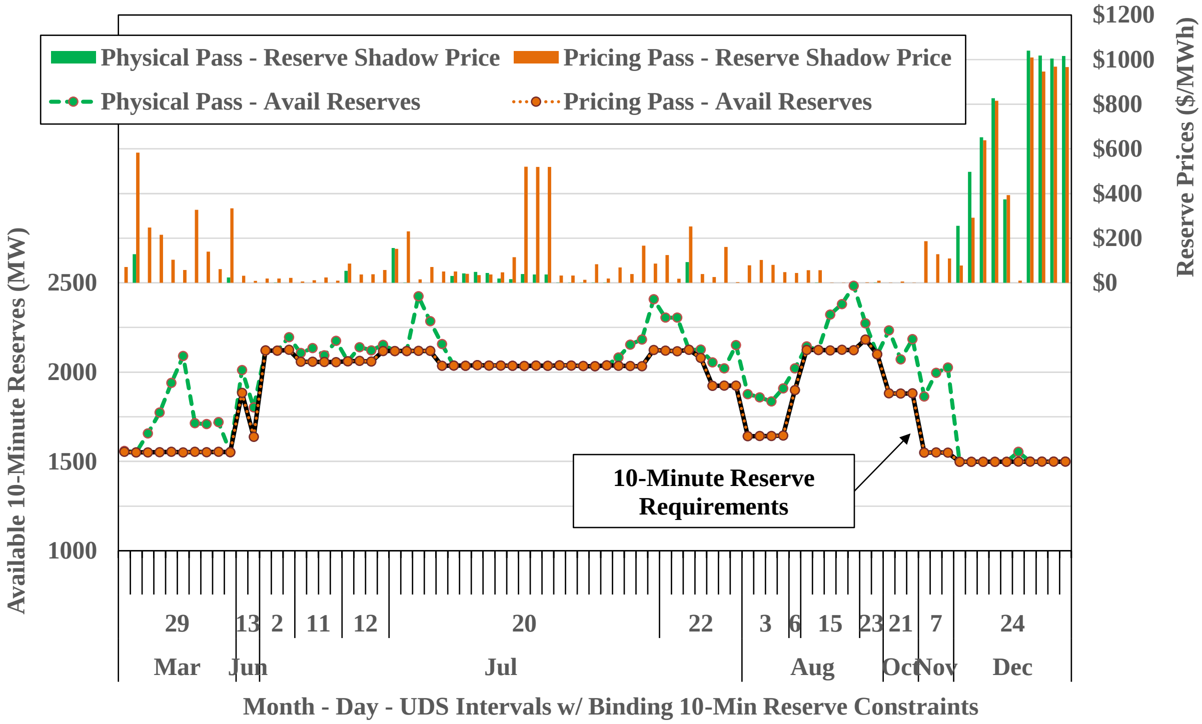
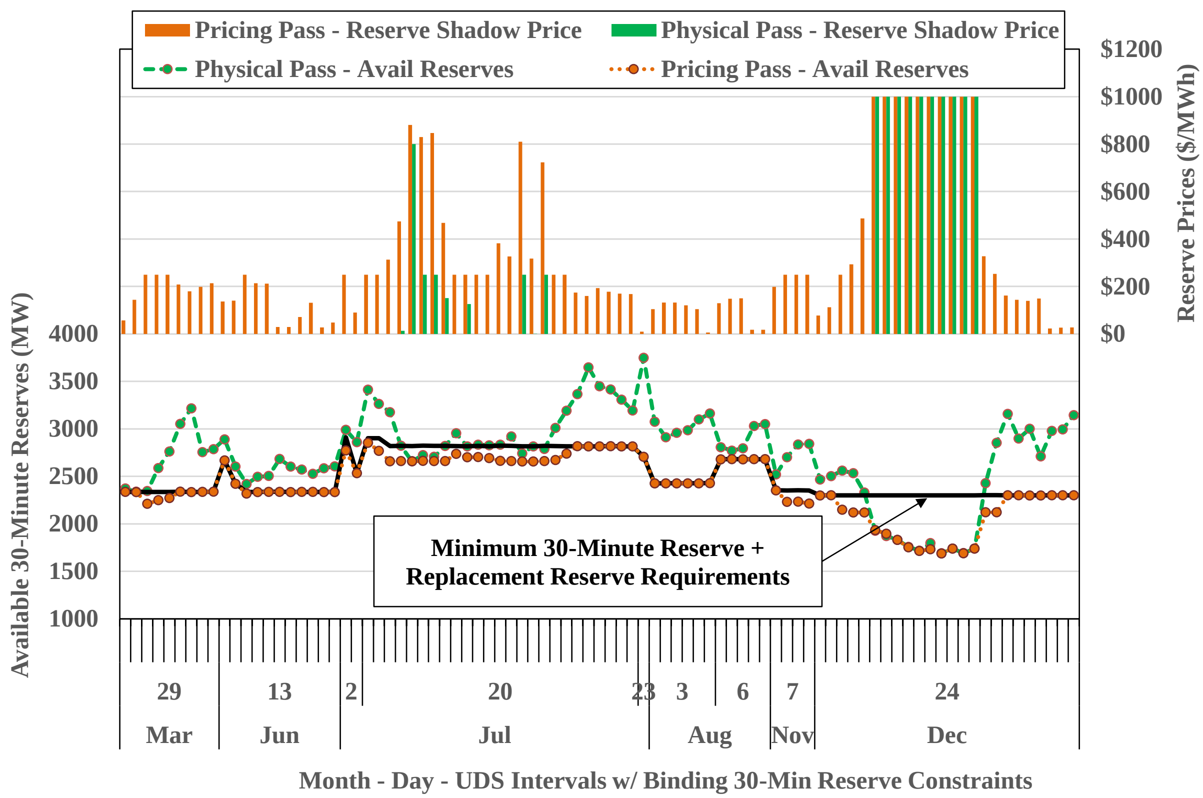


Figure 12: Available 30-Minute Reserves in UDS
Physical Pass vs. Pricing Pass, 2022



The reduction in available reserves in the pricing pass represents a flaw in the fast-start pricing algorithm that sometimes produces overstated clearing prices for both 10-minute and 30-minute reserves. There are two scenarios when this occurs most commonly:

- When the look-ahead model commits an excessive number of fast-start resources because demand or another key input was over-forecasted, some or all of the fast-start resources will be uneconomic relative to the marginal resource(s) in the real-time market. In this case, the pricing pass will tend to dispatch them to zero for energy. Consequently, a potentially large amount of capacity below EcoMin on these resources is excluded from providing operating reserves in the pricing pass.

- 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 correct 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 utilized to meet the 10-minute and 30-minute reserve requirements in the pricing pass of the real-time market. This will ensure that the reserve prices more accurately reflect the cost of maintaining operating reserves.

D. Conclusions and Recommendations

In our assessment of day-ahead reliability commitment in 2022, we found that nearly 50 percent of the day-ahead NCPC or almost $7 million was incurred to satisfy the system-level 10-minute spinning reserve requirement or local second contingency requirements in nearly 3,000 hours. Because the commitments to satisfy these requirements are not reflected in the pricing software, the day-ahead energy prices are generally understated, which require NCPC payments to cover these commitment costs.

As a result, resources that contribute to satisfying these reserve needs are undervalued, as is energy more broadly. Because the ISO does not procure the reserves it will need in the day-ahead market, a large share of its operating reserves needed to satisfy NERC and NPCC criteria are supplied by resources receiving no day-ahead reserve schedules or related compensation – "latent reserves". This is problematic because:

- The cost of the marginal resource that is committed in the day-ahead market to provide spinning reserves is not fully reflected in the marginal clearing prices.
- Many of the resources counted on for reserves have energy limitations that would prevent them from converting reserves to energy for significant 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 our recommendation for the ISO to implement operating reserve requirements in the day-ahead market that are co-optimized with energy. This should include operating reserves needed to satisfy both the local second contingency requirements and systemwide forecasted energy and reserve requirements.[30] Procuring and pricing these requirements in the day-ahead market would result in substantial additional net revenues, especially for the flexible resources needed to integrate intermittent renewable generation. The ISO is developing potential solutions that will address this recommendation in its *Day-Ahead Ancillary Services Initiative (DASI)* project. To address its local reliability needs, it should consider approaches that would allow it to dynamically define new reserve zones as second contingency protection requirements arise in different areas.

In addition, we continue to find that out-of-market commitment and NCPC costs are inflated because: (a) the ISO is often compelled to start combined-cycle resources in a multi-turbine configuration when its reliability needs could have been satisfied by starting them in a single-turbine configuration; and (b) the ISO does not allow firm energy imports to satisfy local second contingency requirements and thereby reduce the associated local reserve requirements. To address these concerns, we recommend that the ISO:

- Expand its authority to commit combined-cycle units in a single-turbine configuration when that will satisfy its reliability need (Recommendation #2014-5); and
- Consider allowing firm energy imports from neighboring areas to contribute towards satisfying local second contingency requirements, since these requirements can be met with capacity that is expected to provide energy. (Recommendation #2020-1).

Lastly, we identify inefficient reserve prices in the fast-start pricing logic that tend to overstate the value of reserves under certain system conditions. To address this inefficiency, we recommend that the ISO modify the fast-start pricing logic to utilize the full capability of online resources for reserves (Recommendation #2022-1). Specifically, the undispatched capacity below EcoMin from fast-start resources should be utilized to meet the 10-minute (only for 10-minute fast-start units) and 30-minute reserve requirements (for both 10-minute and 30-minute fast-start units) in the pricing pass of the real-time market. This will ensure that the reserve prices more accurately reflect the cost of maintaining operating reserves.

[30] Recommendation #2012-8 would co-optimized reserves in the day-ahead market, while Recommendation #2019-3 implement a full set of local operating reserve requirements in the day-ahead and real-time markets.

IV. Assessment of Capacity Scarcity Event on December 24

Winter Storm Elliot hit the Northeast region of the US from December 23 to December 27, 2022, causing heavy snowfall, strong winds, and freezing temperatures. The extreme weather conditions put a significant strain on the power system in the region. ISO-NE market operations were greatly affected by the blizzard conditions and rapid temperature drops, resulting in extended periods of systemwide reserve shortages on December 24.

ISO-NE implemented the Pay-for-Performance ("PFP") rule in 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.[31] This section examines market operations during the capacity scarcity event on December 24 and discusses the incentives provided by the PFP rule and shortage pricing levels. This section: (a) summarizes the supply-demand margin during the event; (b) analyzes bids and schedules of external transactions; and (c) assesses overall market incentives. The final subsection summarizes the conclusions and recommendations derived from the evaluation.

A. Summary of Systemwide Supply Margin on December 24

Winter Storm Elliot had a significant impact on the market operations of RTO/ISOs in the northeast region. The extreme weather conditions caused numerous generator outages due to equipment failures, and natural gas supplies were limited by a surge in demand for heating. As a result, the supply-demand balance was tight, leading to volatile prices and reserve shortages.

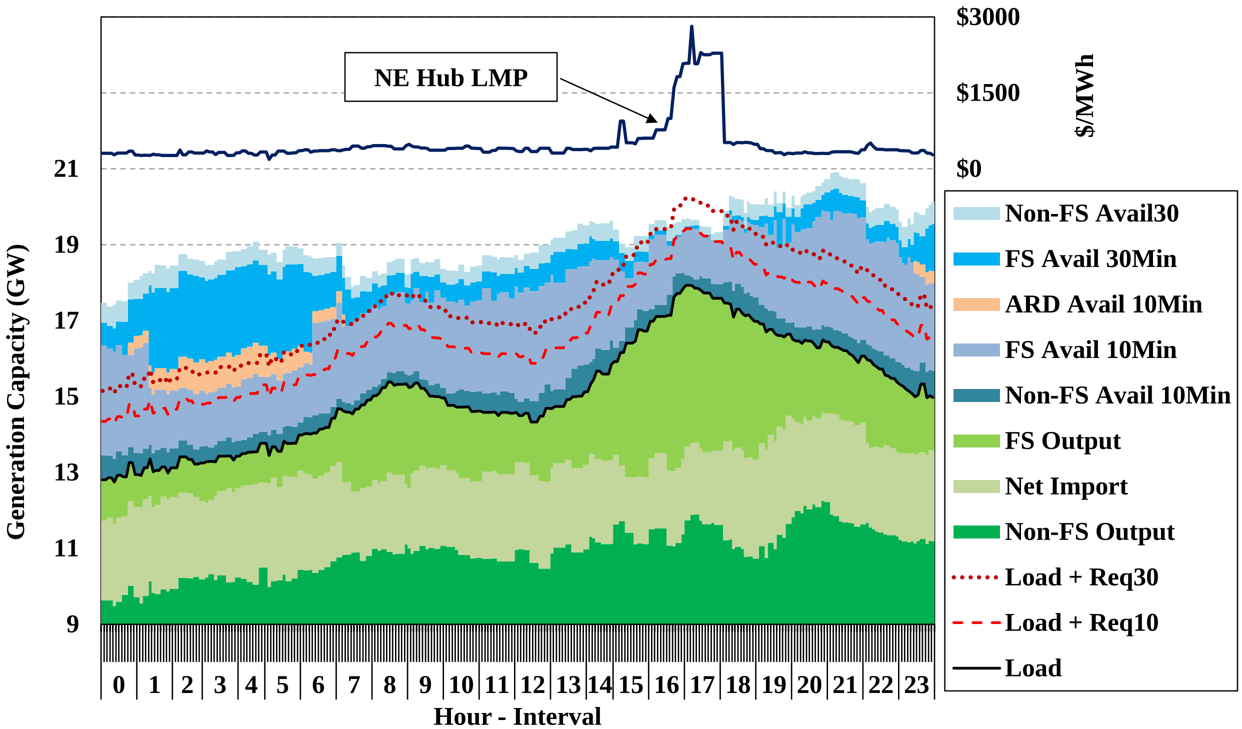
Of the three northeastern wholesale markets, PJM experienced the longest period of reserve shortages, lasting for a total of 23 hours on December 23 and 24. NYISO experienced 8 hours of reserve shortages on the same days. In comparison, ISO-NE was less affected and experienced shortages for less than two hours on December 24. Figure 13 summarizes available supply versus demand and reserve requirements in the ISO-NE market in each 5-minute interval on December 24. The figures show the following demand categories: (a) Load in ISO-NE, (b) Load + system-wide 10-minute reserve requirement ("Req10"), and (c) Load + system-wide 30-minute reserve requirement ("Req30"). The figures also show the following supply categories:

- *Non-FS Output* – the total scheduled generation outputs from internal non-fast start resources, including conventional slow-start thermal resources and renewable resources.
- *Net Import* – the amount of net imports across all interfaces between ISO-NE and neighboring areas, representing net external supply.

31 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.

- *FS Output* – the total scheduled generation outputs from internal fast start resources, including gas turbines and flexible hydro units that can start up within 10 or 30 minutes.
- *Non-FS Avail 10Min & 30Min* – the amount of available 10-minute and 30-minute spinning reserves from non-fast start resources that are already online and dispatchable.
- *FS Avail 10Min & 30Min* – the amount of available 10-minute and 30-minutes reserves from fast-start resources.
- *ARD Avail 10Min* – the amount of available 10-minute reserves from Asset-Related Demand Response ("ARD") resources.

Figure 13: Available Resource vs. Load and Reserve Requirement
5-Minute Intervals, December 24, 2022



The figure shows the available supply resources in each 5-minute interval on December 24. The bottom three categories reflect energy output and sum to the system load. The next three categories are available 10-minute reserves – systemwide 10-minute reserve shortages are observed when the "Load+Req10" line exceeds the top of the three 10-minute reserve categories. The available 30-minute reserve offers are the last categories stacked on top, so systemwide 30-minute reserve shortages are observed when the "Load+Req30" line exceeds the top of all the areas. The figure shows that:

- There were 30-minute reserve shortages at the system level from 16:40 to 18:00.[32] In this period, there was only one brief systemwide 10-minute reserve shortage at 17:10.

32 There were no reserve shortages in local areas on December 24.

- The magnitude of the 30-minute reserve shortages varied, ranging from roughly 190 to 430 MW, averaging of roughly 350 MW for the event. The pricing for both reserves and energy was determined by the $1000 RCPF of systemwide 30-minute reserves.
- The 10-minute reserve shortage was shallow with a magnitude of less than 10 MW. Nonetheless, the pricing for reserves and energy during this particular shortage interval was set by the $1500 RCPF.
- Consequently, LMPs at New England Hub ranged between $2,000 and $3000 per MWh during the reserve shortages. In addition, resources operating during these shortage intervals were subject to a PFP-related incentive of $3500 per MWh.

There were two primary causes of the reserve shortages. First, unplanned generator outages occurred before the shortage hours, resulting in a net loss of approximately 1 GW of capacity. During the shortage hours, an additional 1.1 GW was lost. However, these outages were partly offset by self-schedules and OOM commitments by the ISO that totaled roughly 650 MW.

Second, real-time net imports were much lower than the day-ahead scheduled levels, ranging from roughly 500 to 1500 MW lower on an hourly basis. During the shortage hours, real-time net imports were lower than day-ahead scheduled levels by roughly 1100 MW.

Offline quick-start resources were committed to satisfy demand (which is evident from the quantity of 'FS Output'), thereby reducing the quantities of 'FS Avail 10Min' and 'FS Avail 30Min'. In addition, the ISO curtailed exports to maintain reserves, including 800 MW of exports to NYISO in the 16:00 hour and by roughly 500 MW in next hour. The next subsection evaluates the incentives for scheduling external transactions during the event.

B. Bidding and Scheduling of External Transactions

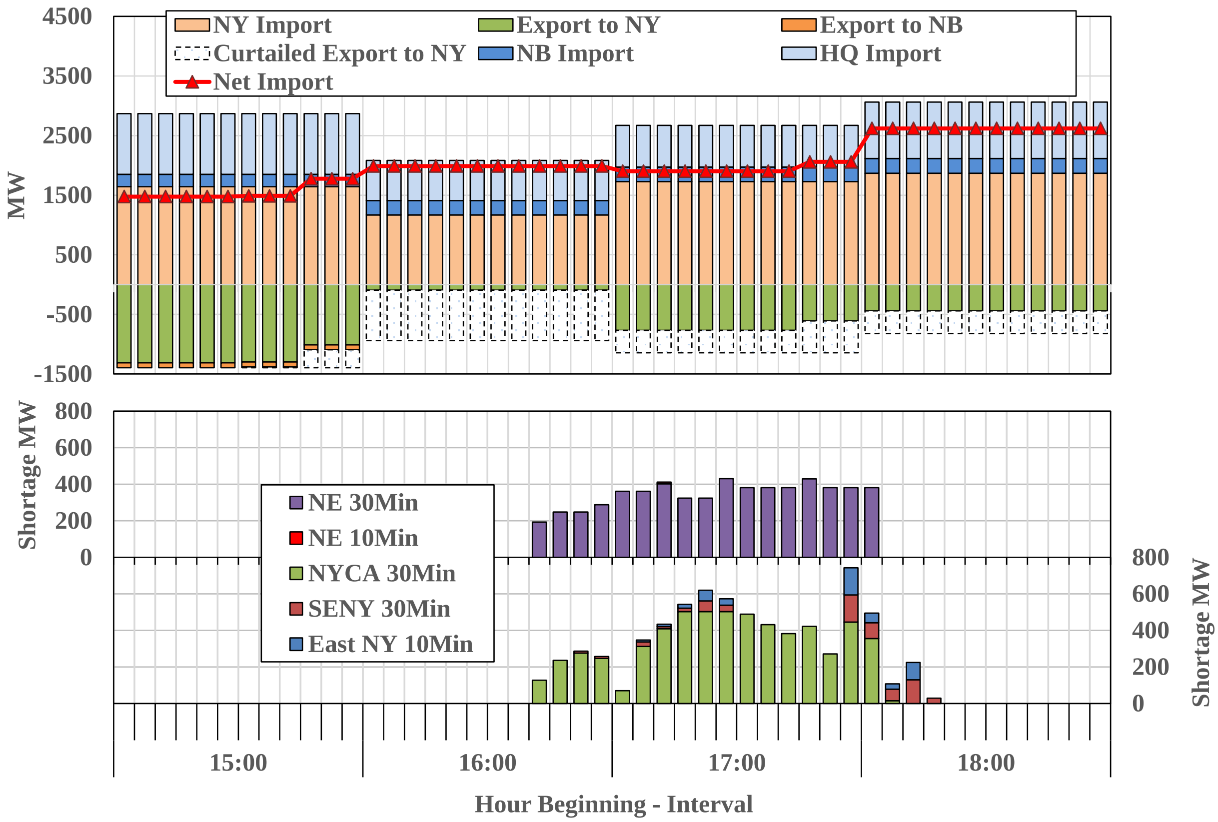
Wholesale markets facilitate the efficient use of transmission interfaces between control areas, allowing low-cost resources in one area to serve consumers in another area and allowing ISOs to access neighboring systems for emergency power and reserves, ensuring reliability standards are met in each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

ISO-NE imports and exports substantial amounts of power from three adjacent control areas: New York, Hydro Quebec, and New Brunswick. The total import capability is large relative to New England load, making it important to schedule the interfaces efficiently. During reserve shortages, efficient scheduling enables ISOs to optimize the utilization of resources across different regions and minimize the overall cost of maintaining grid reliability.

Imports and Exports Scheduled During the Shortage Hours

Figure 14 examines the scheduling of external transactions with neighboring areas during the capacity scarcity conditions on December 24. 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.

Figure 14: Scheduling of External Transaction During Reserve Shortages
December 24, 2022



The lower panel of the figure displays the types of reserve shortages and their respective magnitudes in the ISO-NE market, compared to the NYISO market. 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] Likewise, in the NYISO market, the magnitude of 30-minute reserve shortages is measured against the minimum requirement of 1965 MW, which has a demand curve value of $750.[34] This panel compares the reserve shortages in the ISO-NE and NYISO markets, allowing for an assessment of the differences in their respective shortage situations.

33 This excludes the 180 MW of replacement reserve requirement, which has a much lower RCPF of $250.

34 NYISO procures 2620 MW of 30-minute reserves equivalent to the size of two largest contingencies. For shortages less than 655 MW, the demand curve value ranges between $40 and $625 depending on the magnitude of the shortage.

In shortage hours, ISO-NE scheduled slightly over 1 GW of imports across the interfaces with Hydro Quebec and New Brunswick. Conversely, ISO-NE was a net importer from New York over in the shortage hours, scheduling nearly 1.6 GW of imports on average and 1 GW of exports. However, in hour 15, ISO-NE began curtailing exports to maintain reserves. ISO-NE curtailed 840 MW in the 16:00 hour and 530 MW in the 17:00 hour. Consequently, only about 100 MW and 770 MW of exports remained un-curtailed in the two hours, respectively.

In ISO-NE, systemwide 30-minute reserve shortages occurred between 16:40 and 18:00, ranging from 190 to 430 MW and averaging 347 MW. The NYISO also experienced systemwide 30-minute reserve shortages that were more variable but similarly averaged 352 MW. Additionally, in the NYISO, there were several small local 30-minute reserve shortages in the Southeast New York region and 10-minute reserve shortages in the East New York region.

ISO-NE did not curtail all exports to avoid 30-minute reserve shortages likely because the NYISO was also larger facing 30-minute reserve shortages and further curtailments by ISO-NE would have resulted in more severe shortages in the NYISO market. This underscores a key principle governing interchange scheduling between ISO-NE and NYISO – *one area should avoid actions to preserve operating reserves that would lead the other area to be deficient of a higher-quality reserve*.[35] This principle has two key implications:

- When two neighboring areas experience similar reserve deficiencies, operators should avoid curtailments or other unilateral actions that make one area more reliable at the greater expense of the other; and
- When one area is experiences a more severe reserve deficiency, it becomes appropriate to shift interchange toward that area.

We believe adhered to this principle by appropriately limiting its export curtailments. Additional curtailments would have created much deeper shortages in New York and undermined reliability of the overall region or prompting the NYISO to issue curtailments of ISO-NE's imports.

Scheduling of Imports and Exports During Shortages

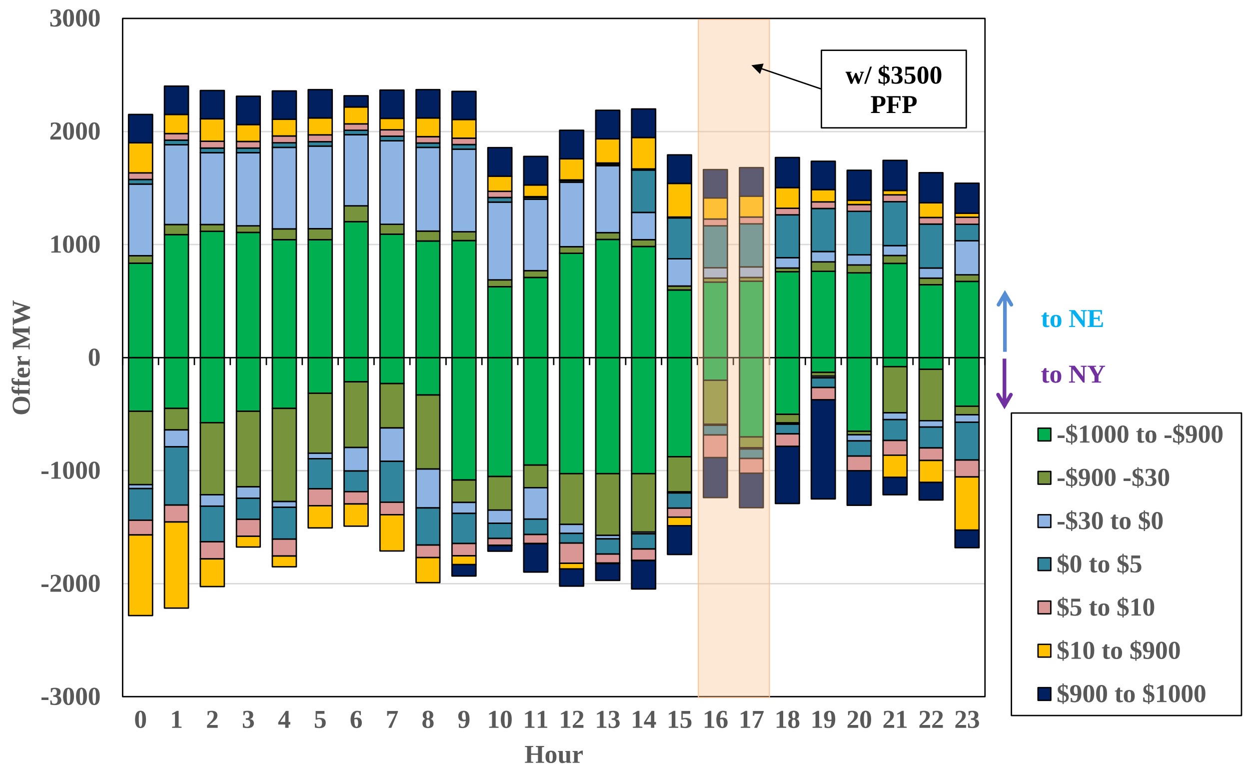
Given the effects of imports and exports on reliability during reserve shortages, it is important to evaluate the scheduling of transactions under these conditions. Many transactions are scheduled through the Coordinated Transaction Scheduling ("CTS") process in the real-time market. Figure 15 provides an overview of the CTS bids submitted at the primary NE/NY interface for each hour of December 24. These bids reflect the participants' preferences and willingness to schedule power flows in either direction throughout the day. Stacked bars represent the amounts of CTS spread bids submitted in seven specific price ranges from -$1000 and $1000 per MWh.

35 Section 5.2.2 of the NY- ISO_NE Joint operating agreement states: "If one Control Area experiences an Operating Reserve deficiency, the other Control Area is not obligated to go deficient in its reserves of the same or a higher quality product, but may go deficient in a lower-quality reserve product in order to prevent an Operating Reserve deficiency of a higher quality reserve product in the other Control Area."

Positive bars indicate import offers to New England while negative bars represent export bids to New York. NYISO's RTC model schedules a CTS import to ISO-NE if the forecasted price in NYISO is less than the sum of: (a) the bid price and (b) ISO-NE's forecasted price at the border. Conversely, RTC schedules a CTS export from ISO-NE if the forecasted price in NYISO exceeds: (a) ISO-NE's forecasted price at the border less (b) the bid price.

In the figure, the bids at the bottom of each import and export stack are considered "the least expensive" and will be cleared first. Hours 16 and 17 are highlighted because reserve shortages occurred in the ISO-NE market during the two hours.

Figure 15: CTS Bids at the Primary NE/NY Interface
December 24, 2022



The figure illustrates that during the afternoon hours (HB 15-20), there were no significant changes in CTS import bids. However, it shows a surge in bids to export from ISO-NE. In HB 18 and HB 19, a large quantity of exports increased their spread bid to the bid cap level of $1000 per MWh. The delayed response in bid patterns is likely attributable to the 75-minute bid lock window. For instance, the deadline for submitting CTS bids for HB 18 was 16:45, just after the reserve shortages started to occur in the ISO-NE market. By 17:45, as the shortage conditions persisted, more bids were adjusted to the bid cap level. By 18:45, when the shortage conditions disappeared, export bids adjusted downward once again.

However, not all exports responded in the same way. There were still significant amounts of export bids that were offered at very low prices, indicating a preference for exporting. This preference was likely due to reserve shortages occurring in multiple regions within the NYISO market during the same period. The additive pricing effects for multiple shortages resulted in higher energy prices in the New York market. Specifically, during the shortage hours, energy prices in the Capital Zone were on average $300/MWh higher than at the New England Hub. This price differential made it profitable to export energy from New England to New York. However paradoxically, it was also profitable to import energy from New York to New England at this time because importers receive the PFP rate of $3500 per MWh.

Therefore, the PFP rule incentivized imports to New England during the reserve shortages, while the higher energy prices in the NYISO market provided incentives to export, creating a situation where transactions in both directions became simultaneously profitable. This outcome was clearly inefficient, since efficient markets should reward firms for scheduling power to the area with a *greater* reliability need. This is discussed in more detail in the next subsections.

C. Pay-for-Performance Incentives During Reserve Shortages

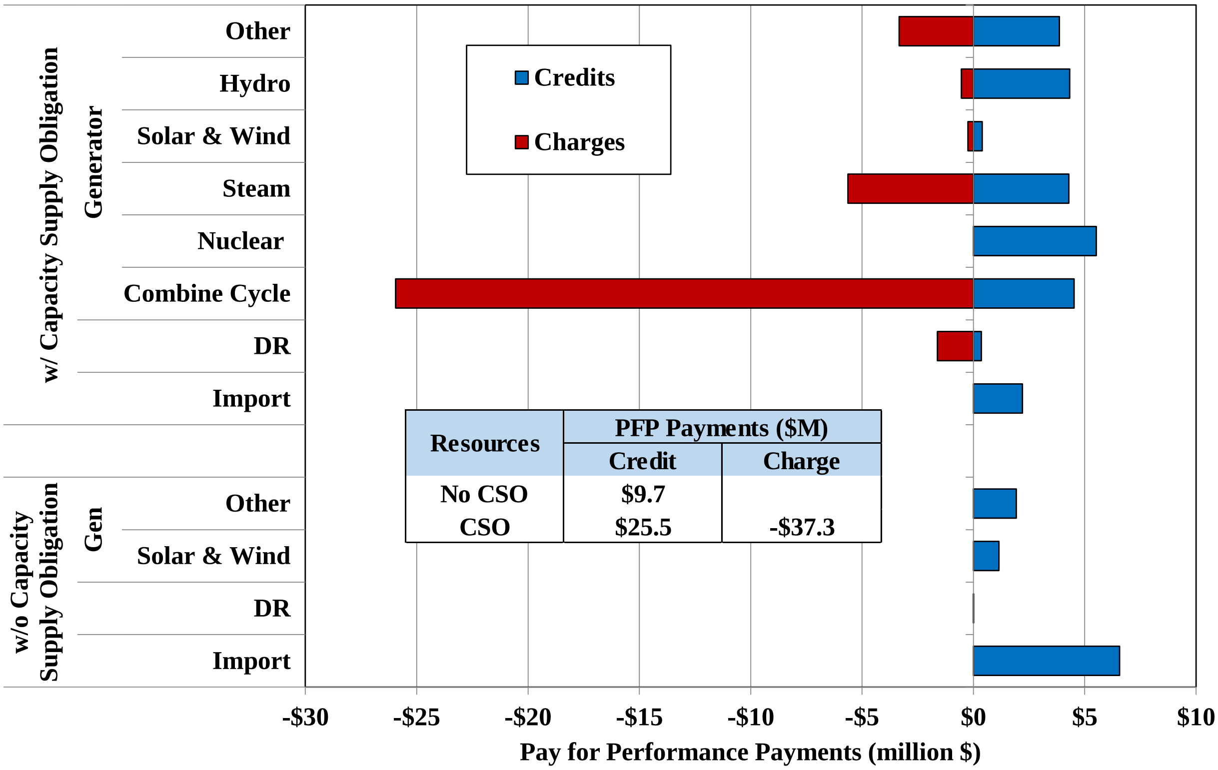
In the ISO-NE market, the PFP rules play a strong role in ensuring grid reliability in key ways. First, it reduces the likelihood, duration, and severity of system-wide emergencies by encouraging resources to be more reliable and available. Second, it provides financial incentives to invest in building new resources and maintaining existing resources that enhance reliability.

Under the PFP rules, resources that fail to deliver energy during scarcity events or experience significant outages may face financial penalties (i.e., PFP charges). On the other hand, resources that perform well and contribute to system reliability are rewarded (with PFP credits). Figure 3 summarizes the PFP credits and charges during the scarcity event on December 24. Resources are grouped based on whether they had Capacity Supply Obligations ("CSOs") and by type of resource. PFP credits and charges were calculated using the penalty rate of $3,500/MWh.

Figure 3 shows that resources with CSOs that performed poorly during the scarcity event incurred more than $37 million of PFP charges. Conventional slow-start generators, including steam turbines and combined-cycle units, accounted for 85 percent of the total charges. Many of these units were not committed in the day-ahead market because they were not anticipated to be needed or because natural gas was in limited supply, while others experienced forced outages or deratings. This underscores the significant PFP risk faced by units with longer lead times and/or uncertain fuel supplies from unforeseen real-time shortage events.

A total of $35 million in PFP credits was allocated, with generators receiving nearly 75 percent of the performance payments. Importers received the majority of remaining credits, totaling almost $9 million, of which 75 percent was paid to importers without CSOs. 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 that provides inefficient incentives and encourages gaming.

Figure 16: PFP Credits and Charges
December 24, 2022



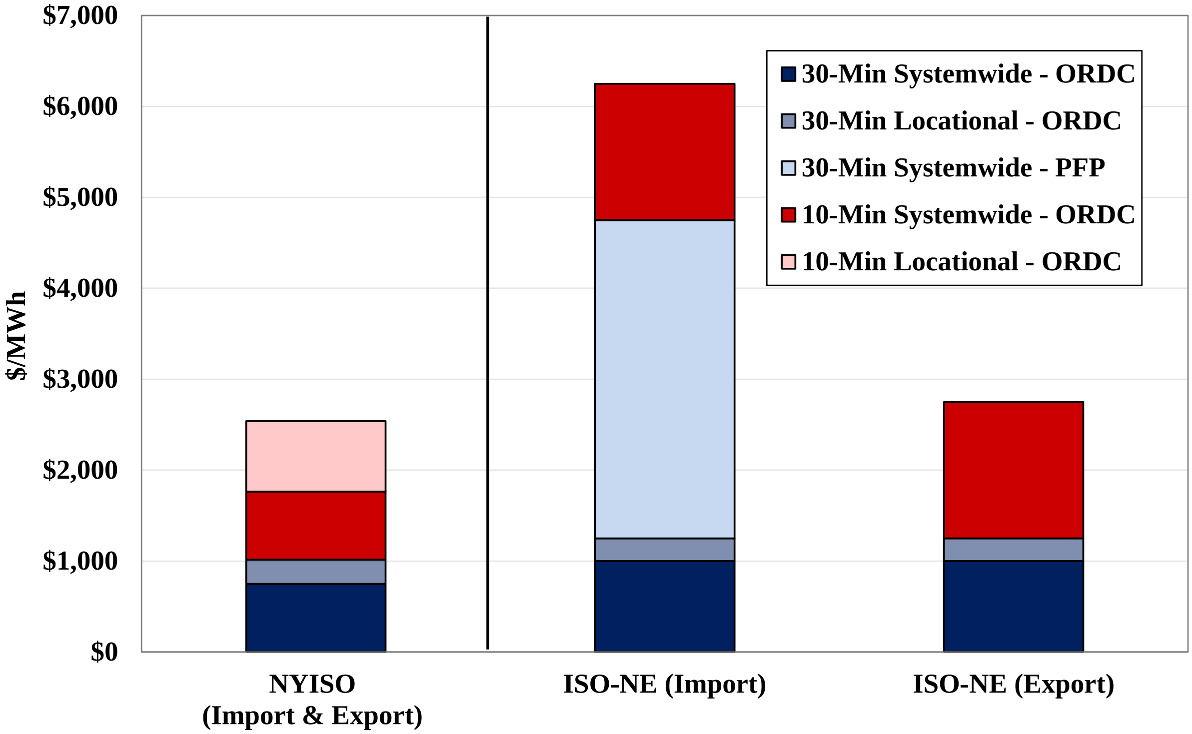
Resources	PFP Payments ($M)	
	Credit	Charge
No CSO	$9.7	
CSO	$25.5	-$37.3

One potential gaming strategy involves a participant, through different bidding entities, scheduling an equal amount of imports and exports at the NE/NY border simultaneously. This pair of transaction would result in no actual power transfers between the two markets and would carry no settlement risk since the settlements would offset with one exception. The imports would receive a PFP credit at a rate of $3500/MWh, while exports would not be charged. It is important to note that although we did not observe such behavior from any individual participants during the scarcity event on December 24, it remains a significant gaming concern.

Even though no participants appear to have engaged in the specific gaming strategy mentioned above, imports and exports were simultaneously scheduled by different participants during the scarcity event. Although ISO-NE subsequently curtailed roughly 40 percent of the scheduled exports during the reserve deficiency, there were still 100 MW of exports in the 16:00 hour and 770 MW in the 17:00 hour that were 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 17 illustrates the current disparity in PFP incentives for imports and exports by comparing the shortage pricing incentives between the NYISO and ISO-NE markets.

Figure 17: Market Incentive for Imports and Exports During Reserve Shortages
At the NE/NY border



The figure summarizes the incentives faced by importers and exporters at the NE/NY border, including applicable 10-minute and 30-minute operating reserve RCPFs (or demand curve values for the NYISO market) and from the PFP rate.[36] A resource faces a total incentive that is based on the sum of each of these sources when multiple reserve product shortages and/or PFP scarcity conditions are in effect simultaneously. The figure shows that,

- In ISO-NE, the current PFP rate is $3500/MWh,[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. During reserve shortages, these results in an overall incentive of $6250/MWh for importers and $2750/MWh for exporters.

- In the NYISO, 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.

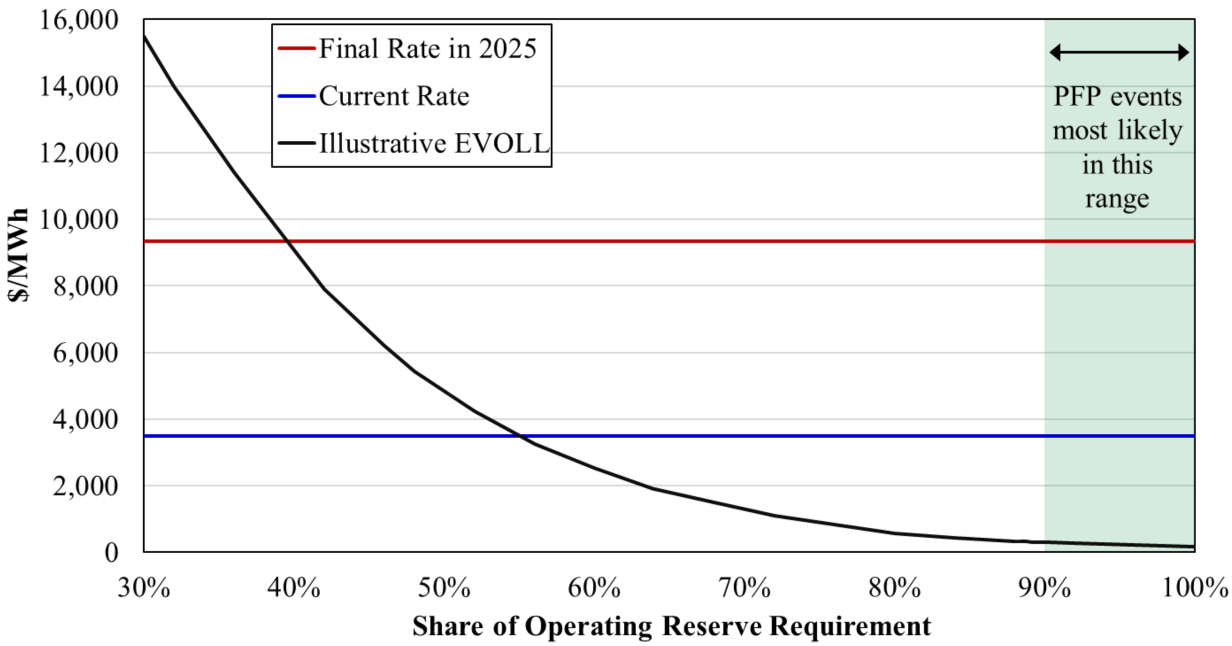
36 Locational prices for ISO-NE refer to Connecticut. Locational prices for NYISO include the full value of East 30-minute and East 10-minute shadow prices and assign 45 percent weight to the SENY 30-minute shadow price.

37 The PFP rate will rise to $5455/MWh in 2024 and $9337/MWh in in 2025.

The disparity in incentives for imports and exports at the NE/NY border can lead to situations where transactions in both directions become simultaneously profitable. This creates inefficient market incentives, which leads to the scheduling of transactions that are profitable but provide no value, requiring more frequent intervention in the market by the operators. Hence, we recommend that the ISO revise the PFP settlement rules to charge exporters at the PFP rate during Capacity Scarcity Conditions. (Recommendation #2022-3)

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 $6300 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 18 illustrates the EVOLL as reserve levels fall and shows the current PFP Rate and the higher PFP Rate to be implemented in 2025.

Figure 18: PFP Rates and the Value of Lost Load



As shown in Figure 18, constant PFP rate applied for all reserve shortage quantities tends to over-value of 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 show the full magnitude of the potential problem with overstated prices because it does not show the shortage pricing in the energy market that can be as high as an additional $2750 per MWh.

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

- The PFP rates are planned to increase to more than $9300 per MWh over the next few years are implemented; and
- Growing uncertainties associated with fuel supply and increasing reliance on intermittent resources will likely result in more frequent and unpredictable shortages in the future.

While very strong performance incentives may be appealing, massively overstating them can create inefficient risk for less flexible resources that can facilitate poor retirement decisions.

Hence, we recommend that the ISO modify its PFP rate to levels that are generally in line with a reasonable estimate VOLL and the likelihood that various operating reserve shortage levels could result in load shedding. 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 on December 24), 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.

D. Conclusions and Recommendations

Winter Storm Elliot greatly affected the ISO-NE energy market, resulting in extended periods of systemwide reserve shortages on December 24. We examined the market operations during the scarcity event and found that:

- There were 30-minute reserve shortages at the system level from 16:40 to 18:00, with an average magnitude of approximately 350 MW.
- There was only one brief systemwide 10-minute reserve shortage at 17:10, with a magnitude of less than 10 MW.
- These shortages were driven by two primary factors: (a) unplanned generator outages and deratings, which resulted in a total generating capacity loss of 2.1 GW, and (b) decreased net imports, which were 1.1 GW lower than day-ahead schedules during shortage hours.
- ISO-NE curtailed roughly 40 percent of scheduled exports to NYISO as it sought to minimize the magnitude and duration of shortages.

Although the curtailment actions to maintain system reliability were consistent with the operating rules, we identified inefficient market incentives in the PFP rules that simultaneously encouraged scheduling of imports and exports, thereby increasing the quantity of transactions that had to be curtailed.

In evaluating the settlements and incentives provided by the PFP framework, we found:

- The application of the PFP rate to settlements with importers but not exporters is a significant flaw that creates gaming opportunities. It undermines the efficiency of scheduling incentives during reserve deficiencies and may undermine reliability.
- Importers received $9 million of PFP credits. If the exports were charged at the PFP rate, it would have lowered costs to New England customers by roughly $3 million and many of the exports curtailed by the ISO may not have been scheduled (or been reduced) by the participants themselves.
- The constant PFP rate that is applied in all reserve shortages, and that is slated to increase substantially in the coming years, will result in overstated settlements and inefficient incentives under most conditions. The effects of these incentives will grow as the PFP rate escalates and if shortages become more frequent in the future.

Therefore, to address these inefficient incentive structures, 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 the reserve shortages grow deeper. (Recommendation #2018-7)

V. Assessment of Forward Capacity Market Design

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 framework in which suppliers compete to obtain capacity supply obligations (CSOs) in exchange for payments at the auction clearing price. The capacity market provides incentives for efficient entry of new capacity that is needed for reliability and the retirement of surplus capacity.

New England's power sector is experiencing profound changes that will make the task of efficiently satisfying resource adequacy requirements more challenging, including:

- Large-scale entry of state-sponsored resources that receive a combination of wholesale market revenues and out-of-market revenues,
- Growing reliance on intermittent and energy-limited resources with complex characteristics that limit their availability, and
- Increased awareness of limitations faced by the generation fleet during extreme weather, especially in winter months.

In response to these drivers, we have recommended that ISO-NE pursue improvements to its resource adequacy model and capacity accreditation so that suppliers are efficiently compensated for the marginal reliability benefit they provide. Over the past two years, ISO-NE has developed a proposal to implement accreditation based on marginal reliability value through its Resource Capacity Accreditation project. ISO-NE's proposal would accredit each resource considering forced outage rates, intermittency, energy storage limitations, fuel supply limitations, and unit size. These would be major improvements, but additional refinements will be needed to address winter reliability issues. In this chapter:

- Section A discusses how efficient capacity market signals can address concerns about fuel supplies needed to ensure winter reliability ("energy adequacy") and the need for further resource adequacy model enhancements.
- Section B assesses the forward capacity market framework that requires loads to procure capacity over three years in advance. This section discusses why the FCA is not structured to satisfy reliability needs efficiently and contrasts it with a "prompt" market framework that would procure capacity closer to the commitment period.
- Section C provides a summary of our conclusions and recommendations for improving capacity market design.

A. Incentives for Winter Reliability in the Capacity Market

Winter reliability has become a critical concern in New England due to growing winter demand, increased awareness of winter gas limitations, and retirement of fuel-secure resources. In this context, *resource adequacy* is now often contrasted with *energy adequacy*. Resource adequacy is traditionally assessed based on the availability of capacity in a few peak demand hours, while energy adequacy considers the total energy available from resources, including those with limited fuel inventories, over all periods when reliability may be threatened. In reality, energy adequacy has always been the reliability objective, but conditions and technologies allowed the industry to simplify the analysis by focusing only on peak hours. Energy limitations, fuel issues, and intermittent resources now compel a more sophisticated planning analysis of "energy adequacy" that accurately models these factors.

This Section A examines New England's current reliance on stored or contracted fuels in the winter and discusses how the capacity market can be improved to efficiently signal energy adequacy needs. In particular, the two subsections below discuss:

- The value of stored fuels and fuel-secure imports during prolonged winter cold periods, which will increase in the coming years, and the shortcomings of the current market in capturing winter reliability needs. We also discuss concerns with ISO-NE's proposed rule changes intended to address resource compensation for winter reliability.
- The importance of detailed modeling of winter reliability needs, including adequately considering oil inventory limitations, which is essential even when other drivers of winter risk are modeled (i.e., pipeline gas and LNG storage limitations as in the ISO's proposal). We discuss the adverse effects on incentives, the markets, and reliability of failing to model winter reliability needs and resource characteristics accurately.

1. *Reliance on Stored Fuels for Winter Reliability*

Figure 19 shows historical daily generation by fuel type in ISO-NE in December 2017 and January 2018. The 2017-2018 winter included a prolonged period of unusually cold weather and high load, from approximately December 27 through January 7, with a subsequent period of cold temperatures on January 14 and 15. We classify historical generation as follows:

- The 'Retired Nuclear/Coal/Mystic' category includes resources with dedicated fuel supplies that were in service in January 2017 but have since retired or failed to secure obligations in the latest FCA for 2026-27. These include the 1.7 GW Mystic 8 and 9 units, the 680 MW Pilgrim nuclear plant, and over 1.5 GW of coal-fired generators.
- We classify gas-fired generation (excluding Mystic 8 and 9) as pipeline gas or LNG using the ratio of daily LNG imports into New England to total generator gas consumption.[38]
- Other sources include nuclear, renewables, biomass, and waste-to-energy.
- Imports are from the neighboring New York, Quebec and New Brunswick systems.

[38] We estimate LNG imports based on reported pipeline inflows from the Everett and Northeast Gateway LNG terminals and from the Maritimes & Northeast Pipeline into New England (assumed to be sourced from the Saint John LNG terminal in New Brunswick). We estimate total generator gas consumption based on EPA emissions monitoring data.

Figure 19: ISO-NE Generation by Fuel Type, December 2017 – January 2018

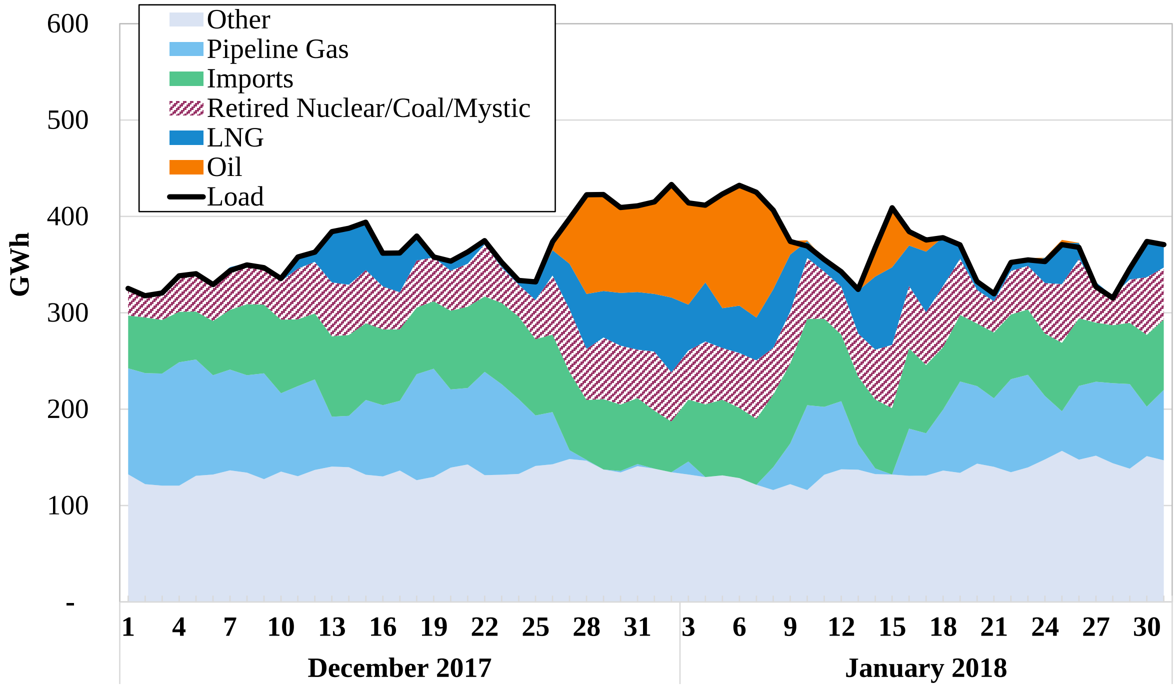


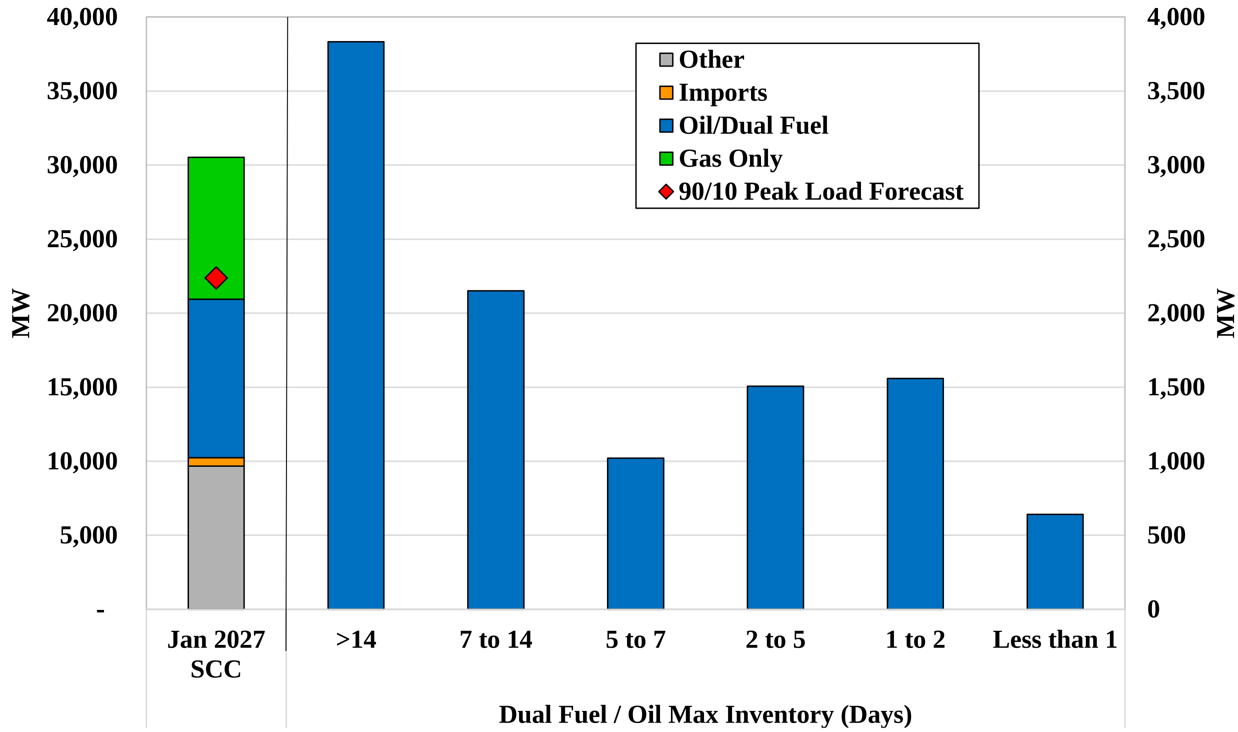
Figure 19 illustrates several key points about New England's generation supply during periods of prolonged cold weather:

- Gas available for generators from interstate pipelines is extremely limited on very cold winter days when demand from gas utilities is high.[39]
- New England is highly dependent on stored or contracted fuel inventories – including LNG and oil – as well as imports from other areas.
- New England has relied on significant output by nuclear, coal and the Mystic 8 and 9 units (backed by a dedicated LNG terminal) that will not be available in future winters.
- Historical levels of imports may not be available in the future without firm capacity commitments as neighboring areas also face growing winter reliability concerns.

Figure 20 shows the Seasonal Claimed Capability (SCC) of resources with CSOs for January 2027, based on the results of the last forward capacity auction (FCA17). The left portion shows the total SCC by fuel type. The right portion shows the capacity of dual fuel and oil resources based on the maximum days of output assuming a full oil tank and no replenishment. Roughly 800 MW of capacity on dual fuel units is classified as "gas-only" because it is not available to run on oil because of duct firing limitations or reduced upper operating limits when burning oil.

39 ISO-NE and its consultants have showed that significant quantities of gas could be available for generators on cold days. See presentation "Natural Gas Demand Forecast through 2032 and Natural Gas Topology Tool" presented by ICF at March 15, 2023 NEPOOL Reliability Committee (available here). ICF's analysis of available gas include expected LNG imports, which we present separately to show available pipeline gas *in the absence* of LNG. ICF's results that compare pipeline imports from the Tennessee, Algonquin, Iroquois and Portland pipelines to LDC firm demand imply that very little gas will be available for generators.

Figure 20: January 2027 Seasonal Claimed Capability and Maximum Oil Inventories



Total qualified capacity greatly exceeds the 1-in-10 year winter peak load forecast. However, as shown in Figure 19, very little pipeline gas is likely to be available for generators without firm transport contracts on high-load winter days and the availability of firm gas transport will be limited. Hence, the availability of the 9.5 GW of gas-only generation largely depends on whether additional LNG is available. About half of New England's qualified capacity (excluding gas-only generators) is from dual fuel and oil units. As a result, the system's ability to serve load during a sustained period of low gas availability depends on the fuel inventories of those units and their ability to replenish them. Of the 10.7 GW of dual fuel and oil units with CSOs, 2.2 GW can run for less than 2 days, 4.7 GW can run for less than one week, and 6.9 GW can run for less than two weeks (based on maximum inventories).

Figure 20 suggests that ISO-NE's winter capacity surplus is currently greatly overestimated, because the qualified capacity of gas-only, dual fuel and oil units doesn't reflect their fuel and inventory limitations. ISO-NE's ongoing Resource Capacity Accreditation project has developed proposals to improve consideration of winter reliability risks in the capacity market. These include:

- Improved modeling of winter load profiles reflecting historic prolonged cold periods;[40]

40 ISO-NE has proposed to use a winter load profile based on the 2013/14 winter (which included a Polar Vortex cold weather event) in its resource adequacy modeling. See February 14, 2023, NEPOOL presentation "Resource Capacity Accreditation in the Forward Capacity Market".

- Modeling limited quantities of LNG available for generators based on a stochastic forecast that considers historical LNG deliveries and LDC usage;
- Modeling limits on systemwide pipeline gas availability in winter when setting the ICR and accreditation, derived from analysis of pipeline limits, gas LDC demand, and resources that are operationally limited by the pipeline system;[41] and
- Qualification requirements for units with firm gas contracts, LNG contracts, and stored oil inventories. For dual-fuel and oil-fired units, ISO-NE proposes to treat resources with tanks large enough to run for 40 hours or more as having no fuel limitations.[42] Similarly, ISO-NE proposes to treat gas resources with firm fuel contracts allowing them to operate 10 hours per day for at least 11 days per season as having no fuel limits.

ISO-NE's proposal would improve the market's ability to detect winter reliability risk and reflect it in the ICR. The ISO's analysis found (in a scenario based on FCA16 incorporating the proposed improvements), just 29 percent of LOLE and 10 percent of expected unserved energy (EUE) would take place in the winter, compared to zero percent without the improvements.[43]

Even with the ISO's proposed improvements, winter reliability risk will be underestimated significantly because they do not include adequate modeling of oil inventories during prolonged cold weather. As shown in Figure 19 and Figure 20, significant oil generation has historically been needed for periods of up to two weeks, accounting for a very large portion of ISO-NE's usable capacity when gas pipelines are constrained.

As such, an oil resource capable of running for 40 hours (equivalent to the ISO's proposed daily requirement of 10 hours per day over 4 days) is likely unable to operate indefinitely in an extreme scenario as the proposal assumes. The next subsection discusses how modeling oil unit inventories in greater detail would affect reliability and market outcomes.

2. *Analysis of Capacity Market Signals for Energy Adequacy*

This subsection demonstrates that detailed modeling of stored energy supplies – including LNG and oil inventories – is necessary for the capacity market to appropriately signal winter reliability needs. If this is not done, the market will struggle to attract and retain the internal resources and

41 While modeling of gas pipeline limitations is critical, we find that ISO-NE's current proposal for how this will be used for *accreditation* of gas-only resources will lead to inefficient market outcomes. ISO-NE has proposed to accredit non-firm gas units using an 'equivalencing' method that calculates the quantity of non-fuel limited capacity that could replace the entire gas fleet while holding reliability constant. The ISO has characterized this approach as representing the marginal capacity value of non-firm gas resources. We disagree with this characterization, because an incremental unit of non-firm gas capacity that does not increase the total gas supply will result in minimal marginal benefit for system reliability. See section "Review of Proposed Gas Resource MRI" in April 2023 NEPOOL presentation "Resource Capacity Accreditation in the Forward Capacity Market – Winter Gas Modeling and Accreditation."

42 See March 7, 2023, NEPOOL presentation by Levitan & Associates, Inc., "Firm Fuel Requirement Values".

43 See April 2023 NEPOOL presentation "Resource Capacity Accreditation in the Forward Capacity Market – FCA16 Baseline Case Accreditation".

imports needed for energy adequacy. This is true even (and perhaps especially) if out-of-market mechanisms are used to bolster LNG supplies.

ISO-NE establishes its Installed Capacity Requirement (ICR) using the resource adequacy model GE-MARS, which probabilistically simulates the supply of generation available to meet load. The ICR is set so that the system's Loss of Load Expectation (LOLE) equals its target criteria level of 0.1 days per year if the total sale of Qualified Capacity (QC) equals the ICR.

In principle, this framework can incentivize investments needed to maintain energy adequacy (because a shortfall of fuel inventories relative to modeled demand would cause a higher ICR and strong marginal capacity values for fuel-secure resources). However, the key drivers of energy adequacy risk (e.g., oil inventory depletion and replenishment) must be modeled in the planning model or they will not be reflected in the ICR and capacity accreditation.

Winter Resource Adequacy Modeling

Reliability planning studies are designed to assess whether the system has adequate resources to meet specific reliability criteria typically under stressed conditions. Planning models should use mechanisms for deploying available resources that result in realistic deployment given the conditions being modeled (which are often extreme given the purpose of planning studies). Planners should be careful to avoid counting on resources that have been available historically, but which are not contracted to their system, because such resources are less likely to be available during the sort of stressed conditions for which planning models are designed.

In past winters, New England has enjoyed high levels of pipeline gas imports, LNG imports, and electricity imports that were not contractually obligated to ISO-NE. However, the ISO must plan for extreme weather conditions when gas LDCs consume pipeline gas under 'design day' conditions, LNG shipments are attracted to foreign markets, and electricity imports fall because neighboring areas are experiencing similar weather. We consider these factors when making assumptions about resource availability in our resource adequacy analysis discussed below.

We analyzed the impact of oil and LNG inventory limits on winter reliability using a simplified resource adequacy model ("RA Model"). Our RA Model simulates hourly chronological load and generation, similar to GE-MARS. It calculates the total amount of expected unserved energy ("UE") resulting from a given resource mix. Resource adequacy analysis is used to determine capacity requirements needed to satisfy the strict 0.1 day per year LOLE criteria. As such, our RA Model employs assumptions that represent stressed system conditions that will not occur in a typical year. The RA Model uses the following assumptions:

- *Resource Mix* – The resource mix includes all resources with CSOs for January 2027 and existing renewable resources without CSOs. This includes the Vineyard Wind and Revolution Wind offshore wind projects.

- *Load* – Hourly load is based on load shapes for the 2013/14, 2014/15 and 2017/18 winters, adjusted using the 2023 CELT forecast of total energy demand and 90th percentile peak load for the 2026/27 winter.[44]
- *Generator model* – Intermittent renewables are modeled using hourly capacity factor profiles. Fossil resources are modeled at their qualified capacity with a 5 percent average derate applied. Pumped hydro and battery storage resources are modeled as discharging in peak hours and charging when surplus generation is available.
- *Pipeline Gas* – Pipeline gas available each day is modeled based on the historical relationship between winter load and pipeline gas generation in New England. We presented analysis of this relationship in our 2021 annual report on ISO-NE.[45]
- *Oil Inventories* – We assumed that units with limited inventories run when needed until their inventories are depleted and units with smaller inventories are generally deployed after units with larger inventories. This ordering is consistent with the observed dispatch in historic events with inventory-limited units because inventory-limited units generally increase their offer prices to conserve their remaining fuel. We considered replenishment of spent oil inventories after a given number of days in each scenario.
- *LNG* – We modeled a fixed amount of LNG in each scenario available over the entire season. The RA model generally deploys dual fuel and oil units that are capable of replenishment before LNG. However, LNG is used before oil units with low amounts of remaining inventory (e.g., six hours or less) in order to maximize available capacity. This ordering is consistent with the tendency for facilities with lower fuel inventories to increase their offer prices to conserve their available fuel and avoid PFP penalties. We limit the maximum hourly LNG-fired gas output to 6.3 GW based on the quantity of gas that could be ratably injected by the Saint John facility.
- *Imports* – We assume up to 3 GW of available imports on low-load days, but regional supply shortages reduce non-firm imports on cold winter days. On the coldest days when pipeline gas availability would be reduced to zero, we assume only 646 MW of imports (based on the winter tie benefits assumed in ISO-NE's Future Grid Reliability Study), excluding additional firm imports that might be secured through the capacity market.[46]

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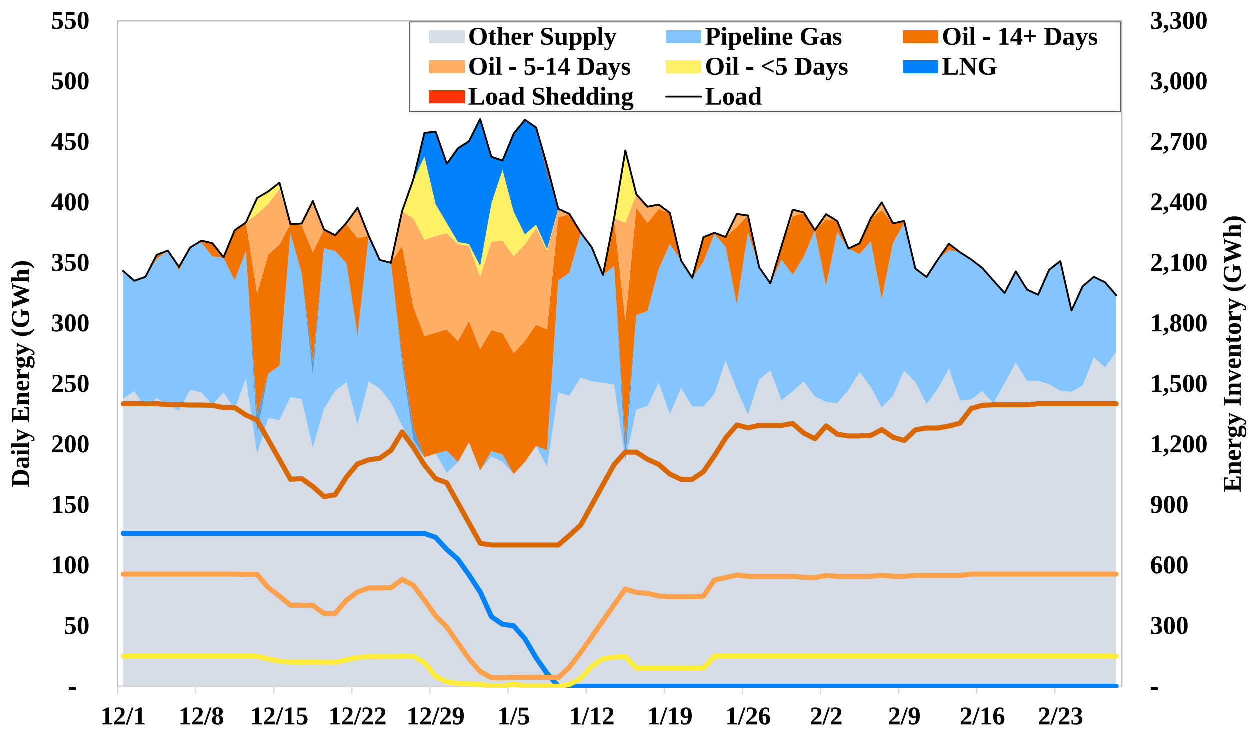
44 These are the winters with the most severe and prolonged cold weather periods in the last decade. We scaled each hour of each historical load shape using a scaling factor calculated as (1) the ratio of the 2026/27 load forecast from the latest CELT report to the actual load in the base year times (2) the ratio of the forecast load in the base year (from the same year CELT forecast) to actual load. For days where peak demand was at least 90 percent of the seasonal peak we used forecasted 90th percentile peak load in the scaling factor calculation, and for other days we used the seasonal total energy load forecast. The purpose of these adjustments is to develop load profiles with shapes similar to the 2013/14, 2014/15 and 2017/18 winters but matching the 90/10 peak demand and total winter energy demand for 2026/27 from the CELT forecast.

45 See our 2021 Assessment of the ISO New England Electricity Markets, section IV.B, available here.

46 See September 22, 2021, NEPOOL presentation "Resource Adequacy Screen and Probabilistic Resource Availability Analysis", at slide 18. In our modeling, non-firm imports up to 3,000 MW are assumed available on days with peak load up to approximately 18 GW, declining to 646 MW on days with peak loads of approximately 21.5 GW.

The purpose of Figure 21 is to illustrate how our RA Model would deploy resources under stressed system conditions. The figure shows generation and load by fuel type in the RA Model (aggregated by day) for a winter scenario including a prolonged cold period with load shape based on the 2017-18 winter. This scenario includes over 600 GWh of available LNG supply (approximately 5 million Bcf) and assumes that oil drawn from inventories is replenished 7 days after use. The scenario is set to a target level of UE intended to reflect a system at the target criteria level of reliability.[47] The target level of UE is reached by adjusting the amount of capacity imports. Figure 21 shows the dispatch and remaining inventory of LNG and dual fuel / oil resources classified by maximum days of inventory.

Figure 21: Illustration of Fuel Utilization in RA Model



The scenario depicted in Figure 21 demonstrates the complex relationship between energy adequacy and resource adequacy. Because it reflects a system at reliability criteria, it results in a small amount of UE, but this does not take place on the day with the highest peak load (January 5). Instead, it takes place on January 8 because inventories of LNG and oil units with small tank sizes have been depleted by that point. Additional LNG supplies, faster replenishment of oil inventories, or increased supply from other sources (such as renewables or imports) would reduce unserved energy. Because reliability is primarily constrained by energy supplies (versus

47 We use a target EUE level of 200 MWh per year in our RA Model to represent at-criteria conditions. We do not use a LOLE target because our simplified model performs a limited number of replications. A target of 200 MWh is consistent with the published amount of EUE associated with the 0.1 days per year LOLE target in the similarly sized NYISO system. Since we simulate only years with 1-in-10 peak load, we divide the UE produced by the RA Model by ten to estimate EUE.

total capacity), supply sources that allow LNG or oil to be conserved earlier in the cold period can improve reliability even if their output doesn't coincide with the timing of load shedding.

Given that the purpose of the analysis depicted in Figure 21 is to evaluate the planning needs of New England, the pattern of fuel consumption shown in Figure 21 reflects a more limited supply of LNG than observed in historical winters. LNG has often been burned by generators before significant oil consumption has occurred (see Figure 19). Historical winters have also seen more imports on cold days than we assume in the RA Model. LNG has historically been made available to generators that did not contract for it because the amounts contracted by gas utilities to meet their planning criteria exceeded their actual demand. Our analysis assumes a limited quantity of contracted LNG will be available with a relatively high opportunity cost and is generally reserved until it is needed. One could assume an amount of LNG injections on cold winter days that would defer the need to consume oil, but this would likely only occur in an extremely cold winter if price of natural gas in overseas markets decreased substantially.

Impact of Oil and LNG Inventory Modeling on the Capacity Requirement

The following analysis uses our RA Model to examine how different combinations of LNG supply, oil supply, and firm capacity imports can be used to ensure resource and energy adequacy. The analysis quantifies the amount of additional imports or LNG supply that would be required to satisfy reliability criteria, depending on whether depletion of existing dual fuel and oil units' inventories is explicitly considered. Ultimately, the overall need for resources should be reflected in the ICR so that the capacity market procures adequate resources and provides efficient incentives for investment.

Figure 22 shows the amount of "firm capacity" or LNG needed to satisfy reliability criteria in our RA Model, *in addition* to resources with January 2027 CSOs.[48] Firm capacity represents a fixed MW-level of continuous output, which might correspond to a fuel-secure resource or an import backed by one. We calculate the amount of firm capacity or LNG required to maintain UE at the target level depending on replenishment rates of dual fuel and oil units. For example, if dual fuel and oil units replenish spent fuel in 7 days, over 3 GW of firm capacity or almost 6 million Dth of LNG would be needed (in addition to FCA17 resources) to meet reliability criteria. In the "Instantaneous Replenishment" case, we model no depletion of dual fuel and oil unit inventories, but derate units with maximum inventories of less than 40 hours proportionally.

Figure 22 shows that when the resource adequacy model assumes slower replenishment of oil inventories, a larger amount of firm capacity or LNG is needed to satisfy reliability criteria. If oil inventories are replenished instantaneously, about 2.1 GW of firm capacity *or* 1.0 million Dth of LNG will be sufficient to satisfy reliability criteria. If inventory depletion is modeled with

48 Note that the RA Model does not include all features of GE MARS and the results presented in this section should be interpreted directionally, rather than as a prediction of precise requirements.

replenishment occurring 7 days later, the additional resources needed to satisfy reliability criteria increase to 3.2 GW of firm capacity *or* 5.7 million DTh of LNG. If inventory depletion is modeled with relatively slow (14-day) replenishment, then the required resources rise to 4.3 GW of firm capacity *or* 10.2 million Dth of LNG.

Figure 22: Firm Capacity or LNG Needed to Satisfy Reliability Criteria

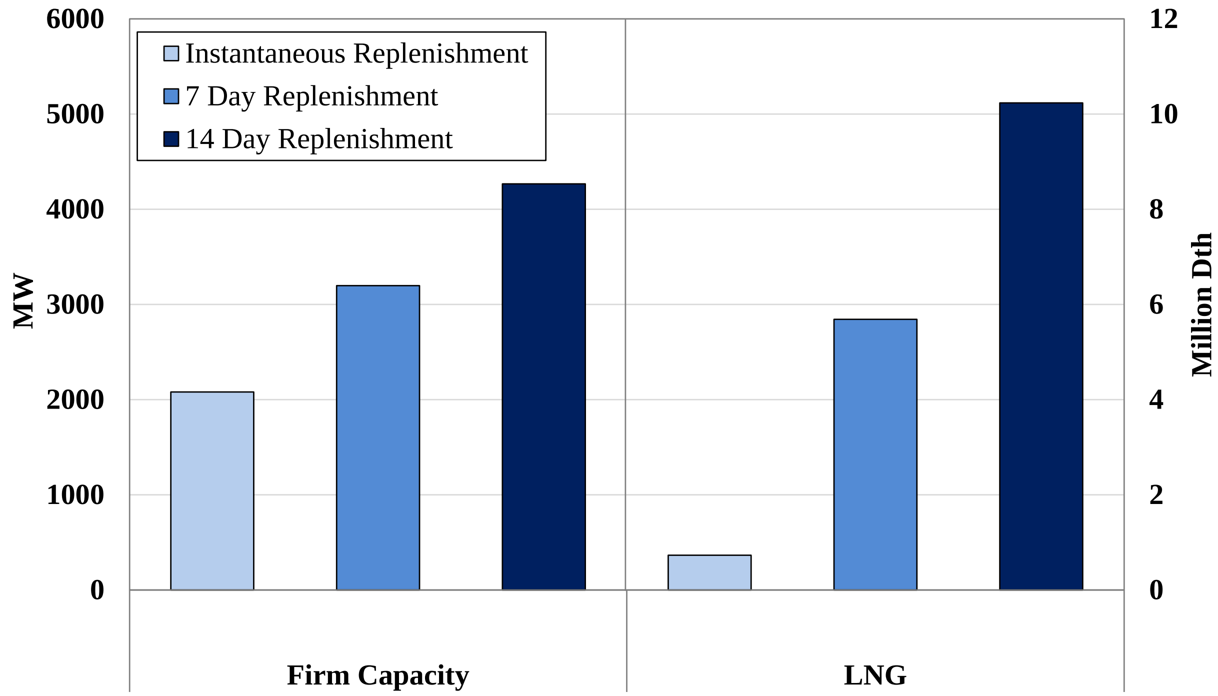


Figure 22 illustrates two key points:

- The amount of LNG required to meet seasonal energy adequacy needs is highly dependent on the replenishment rate of oil inventories. If dual fuel and oil units never have to expend more than 40 hours of fuel before they are replenished (as ISO-NE's current proposal implicitly assumes), very little LNG is needed because most of the existing oil and dual fuel capacity effectively has an unlimited assumed fuel supply.
- Failing to model the pace of oil inventory replenishment could cause the ICR (or the amount of LNG supply targeted by policymakers) to be set inefficiently low, creating a false impression that the region has a capacity surplus.

The following figure summarizes our analysis of inefficiently low ICRs is evaluated in the following analysis. Figure 23 shows the "artificial surplus" in the capacity market under the ISO's current proposal that assumes oil inventories larger than 40 hours are replenished instantaneously. In each scenario, we assume 5 million Dth of seasonal LNG supply and adjust the actual rate of oil inventory replenishment. The "artificial" capacity surplus is the amount by which the ICR is understated if the actual rate of replenish is slower than the rate assumed in the RA Model.

Figure 23: Artificial Surplus from Assuming Instantaneous Replenishment

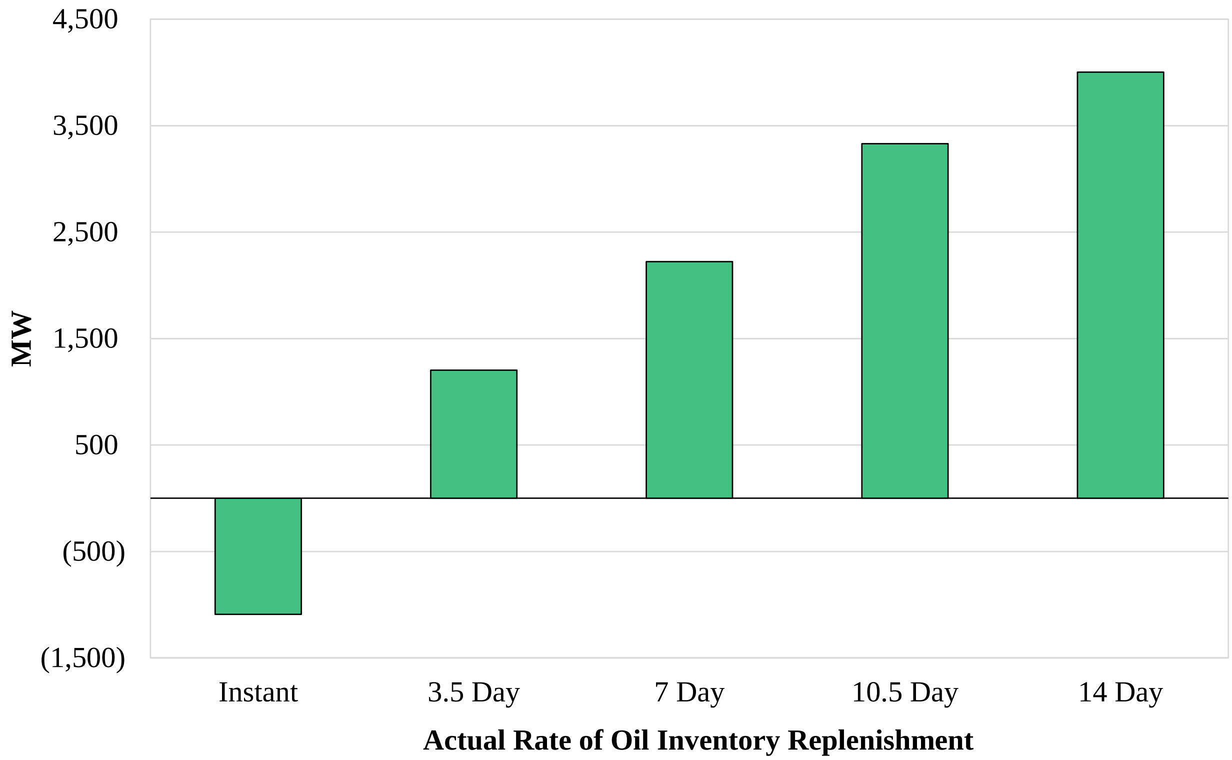


Figure 23 demonstrates that:

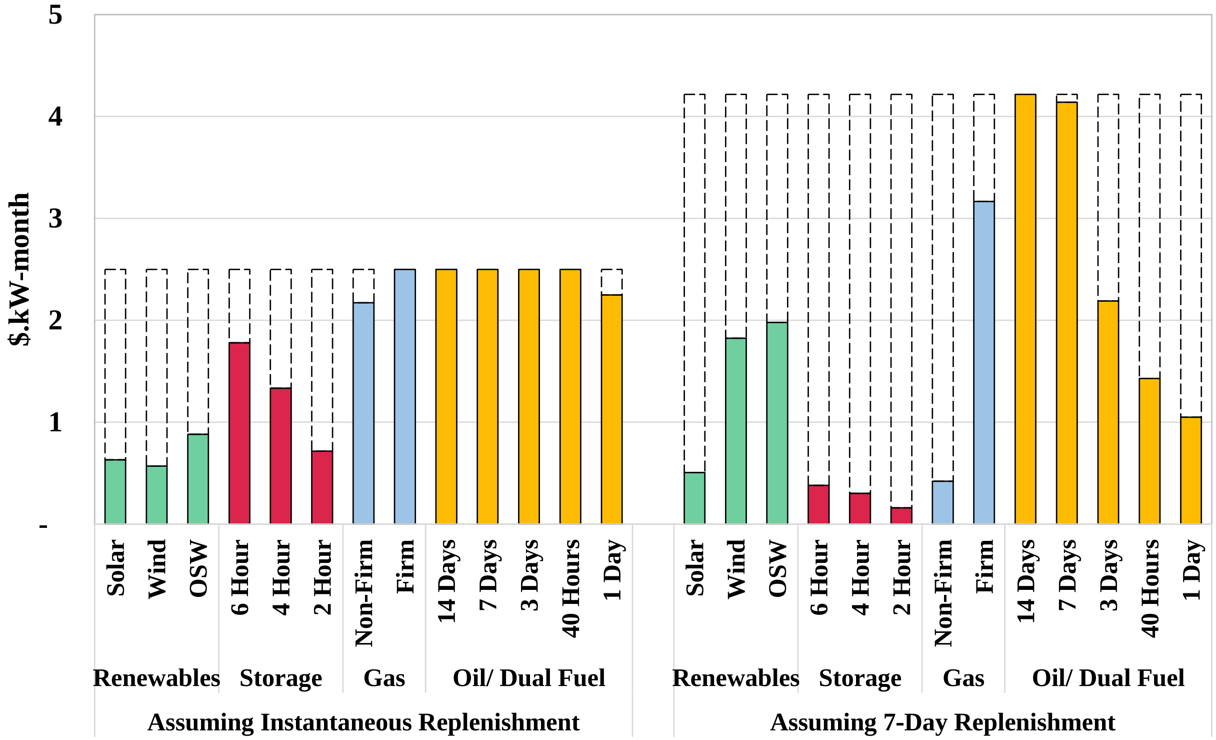
- The capacity market could perceive large artificial surpluses under the ISO proposed assumption that oil inventories of greater than 40 hours are instantaneously replenished.
- For example, if the actual rate of oil inventory replenishment is 7 days, Figure 23 indicates the capacity market will have an artificial surplus of 2.2 GW.
- This could cause capacity prices to be inefficiently low when reliability risk is high. As a result, the market will provide weak incentives for investments in resources that enhance winter reliability such as: importing firm capacity, contracting for firm gas transportation, importing LNG, retaining existing oil and dual fuel units, and arranging for rapid replenishment of oil inventories.

Impact of Oil and LNG Inventory Modeling on Capacity Market Compensation

Figure 24 shows simulated capacity accreditation and payment outcomes for a system with 5 million Dth of seasonal LNG and 7-day replenishment of oil inventories, based on the results of the RA Model. In the "Instantaneous Replenishment" case (in which no depletion is modeled for dual fuel and oil units with greater than 40 hours of inventory), the system has significant artificial surplus and a low price (assumed to be equal to the FCA17 price of $2.5 per kW-month). The "7-day Replenishment" reflects a more realistic assessment of the same system with oil inventory depletion modeled, resulting in greater perceived reliability risk.

We calculate a higher price in the “7-day Replenishment” case such that total consumer payments for capacity remains constant between the two cases after accounting for changes in resources' accreditation. We calculate capacity credit values as a weighted average of summer and winter marginal reliability impact relative to a unit of firm capacity (equivalent to the “rMRI” term in ISO-NE’s proposal), assuming approximately 25 percent weight to winter risk in the “Instantaneous Replenishment” case and 90 percent weight to winter risk in the “7-day Replenishment” case.[49]

Figure 24: Capacity Market Accreditation and Compensation Outcomes [50]



We draw the following key observations from Figure 24:

- Modeling oil inventory depletion causes the capacity credit (i.e., rMRI) of dual fuel and oil units with 7 days or less of maximum inventory to decline. This is because a resource’s rMRI is driven by its ability to defer the region’s consumption of LNG when reliability risk is driven by energy adequacy. Thus, an oil unit that depletes its fuel supply before replenishment has a lower rMRI than one that can run indefinitely.

49 Recent analysis by ISO-NE found that 75 percent of hours contributing to the MRI of a perfect capacity resource would take place in summer, for a scenario based on FCA16 with pipeline gas limitations and LNG imports modeled but without detailed modeling of oil inventories. Because we observe a large increase in the capacity requirement when oil inventory depletion is modeled, we assume that the share of MRI hours taking place in winter would increase significantly.

50 Compensation is shown per kW-month of installed capacity (e.g., per unit of nameplate capacity for intermittent resources). It does not include the impacts of individual unit size and forced outage rates which would cause compensation to most fossil units to be lower than the values shown.

- Although capacity credit falls, modeling slower rates of oil inventory replenishment causes the compensation of most dual fuel and oil units to rise. This is because the capacity price in this case is higher than the inefficiently-low price in the "Instantaneous Replenishment" case that reflects an artificial surplus.
- Accreditation and compensation of non-firm gas-only units is much lower in the "7-Day Replenishment" case. This case primarily reflects winter reliability risk and the marginal benefit of gas-only units without firm fuel is very low in the winter). We also modeled the rMRI of a "Firm Gas" unit with a burn profile based on historical data.[51] The accreditation difference between the Firm and Non-Firm gas units is much higher in the "7-Day Replenishment" case, resulting in much stronger incentives to procure firm fuel.
- Accreditation and compensation of wind units rises in the "7-Day Replenishment" case because the high capacity factor of wind allows the region to defer consumption of LNG and oil inventories. This suggests that investments in wind can help to improve winter energy adequacy and appropriate modeling of risks would support such investment.
- Accreditation and compensation of storage units falls in the "7-Day Replenishment" case. This is because recharging such units during multi-day cold periods requires depletion of LNG and oil inventories, so they provide little improvement to energy adequacy.

Conclusions about Winter Reliability in the Capacity Market

New England's reliability needs are increasingly driven by winter energy adequacy and these needs are not reflected in the current market. This is true even after considering the improvements that ISO-NE has currently proposed. The capacity market framework can support energy adequacy by establishing efficient prices and accreditation for resources that improve reliability when seasonal fuel supplies are limited. Efficient capacity prices and payments are needed to attract and retain firm imports, to prevent inefficient retirements of dual fuel and oil units, to encourage gas units to contract for LNG or firm gas, and to promote investment in renewables that contribute to reliability.

The results in the section demonstrate that realistic modeling of oil inventory depletion and replenishment is essential. It will provide more efficient incentives for gas-only suppliers to procure firm fuel. It is also necessary to avoid over-compensating or under-compensating resources relative to their value in satisfying the regions' energy adequacy needs.

Out-of-market actions ostensibly made to improve energy adequacy, such as centralized procurement of LNG, could exacerbate winter reliability risks by undermining incentives for firms to maintain and replenish oil inventories. Further, failing to model realistic rates of oil inventory replenishment will cause artificial surpluses to increase, leading to premature retirement of dual fuel and oil units or lack of incentives for imports. Hence, we recommend that ISO-NE improve its resource adequacy modeling and accreditation (Recommendation 2020-2).

51 The modeled winter burn profile is based on average gas burn profiles on the 15 highest-load winter days in the period Dec 2017 to Feb 2022. The modeled profile has an average winter capacity factor of 73 percent, ranging from approximately 50 percent in the early morning hours to 100 percent in the evening hours.

B. Assessment of the Mandatory Forward Capacity Market

ISO-NE procures capacity to satisfy resource adequacy requirements through the FCAs conducted over three years before the associated CCP. The processes to develop auction parameters and qualify participating resources take place over the course of approximately a year before each FCA. Participation by load-serving entities in the FCA is mandatory. The FCA is the main avenue for new resources to obtain a CSO and receive capacity revenues. The ISO also conducts annual reconfiguration auctions ("ARAs") that allow resources to gain or shed a CSO closer to the commitment period. However, the role of the ARAs is limited due to the mandatory nature of the FCA.

In this subsection, we evaluate the efficacy of the mandatory three-year forward FCA, contrasting the forward framework with a prompt capacity market that conducts auctions shortly before the commitment period (e.g., weeks or months). Both forward and prompt frameworks require load-serving entities to satisfy their procurement obligations; the difference is in the timing of the procurement relative to the CCP.

Role of FCA in Coordinating Investment

The main alleged benefit of a mandatory forward capacity market is that it provides price certainty for investors seeking to finance new projects or invest in existing capacity. This would reduce investors' market risk and make them more likely to bring forward new projects. The FCA is also purported to facilitate planning by ensuring that there is sufficient available supply in advance of when it is needed. We discuss each of these assumed benefits below.

Price Certainty. The FCA no longer provides significant price certainty for major projects. In late 2020, FERC ordered ISO-NE to end its practice allowing a new resource to 'lock in' the price it received in its first FCA for up to seven years.[52] Resources that receive a CSO now receive the prevailing capacity price for only a single CCP. One year of guaranteed capacity revenue is unlikely to cover a meaningful portion of a resource's investment costs, which typically have project amortization periods of 20 years or more. Even with prices clearing at the FCA 16 Net CONE of $7.4/kW-month, a single-year CSO would cover less than 11 percent of the capital cost of a new gas peaking unit or 7.6 percent of a new four-hour battery. Hence, developers must already rely on expected future revenues or forward contracts.

Evidence from other regions does not support the notion that a mandatory forward capacity market is necessary to encourage merchant investment when it is needed. For example, 2.3 GW of merchant generation has been financed and built in the past decade in New York ISO, which

52 This practice, while providing significant revenue certainty for new resources, was discriminatory in favor of new projects and in some cases inefficiently allowed resources to lock in capacity payments that were much higher than the value of that capacity in subsequent years. See FERC Docket EL20-54.

operates a prompt capacity market immediately prior to the capability period. Developers of these projects have mitigated their revenue risks through bilateral hedges such as revenues puts.[53] Spot markets provide a basis for investors to enter forward contracts with loads or financial intermediaries, even when loads are not mandated to buy capacity on a forward basis. Since a prompt capacity market would facilitate such contracts, a forward capacity market is neither needed nor effective in providing the price certainty developers claim they need.

New Entry in the FCA. The FCA provides a small amount of revenue certainty if the project enters service on time. However, the FCM had a dubious track record of coordinating timely entry of new resources even before the multi-year lock-in was eliminated. Figure 25 shows new generation projects that received CSOs of at least 50 MW for the CCPs beginning June 2016 through June 2023.

Figure 25: New Generation with Initial Capacity Obligation above 50 MW

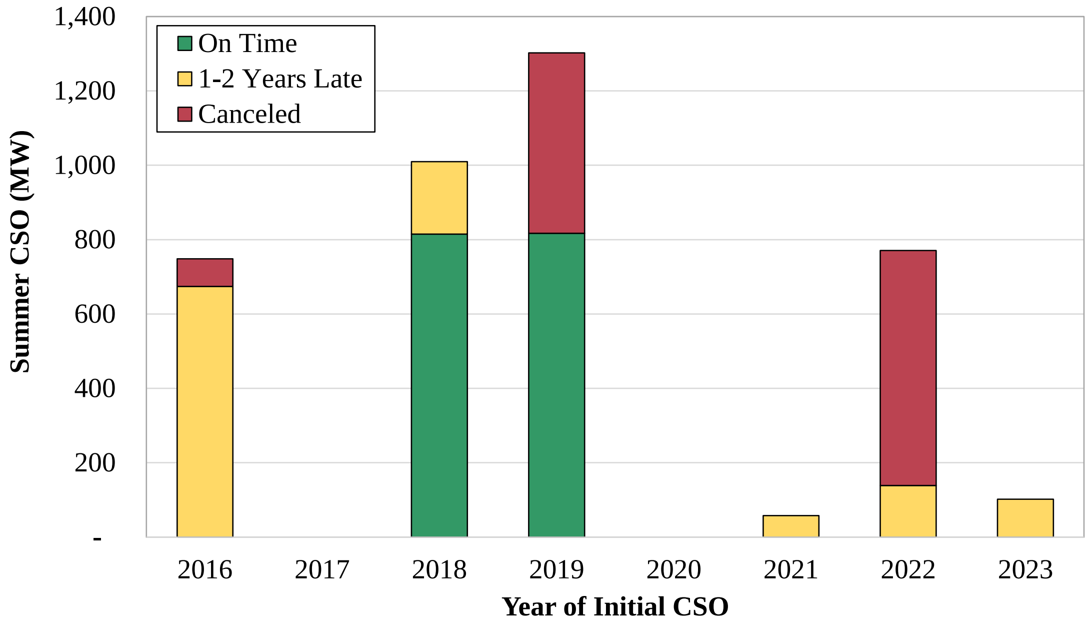


Figure 25 shows that out of 4.0 GW of such projects, just 1.6 GW (41 percent) entered service on time to satisfy their initial CSO, 1.2 GW (30 percent) entered (or are expected to enter) later than the summer of their initial CSO, and 1.2 GW (29 percent) never delivered their CSO because the project was canceled or failed to meet development milestones.[54] The projects that entered on time all opted to receive multi-year price guarantees, an option which is no longer available.

53 For example, owners of the 1.1 GW Cricket Valley Energy Center and 680 MW CPV Valley Energy Center have publicly indicated that they obtained voluntary revenue hedging agreements for the first five years of plant operations.

54 The Vineyard Wind offshore energy project had a CSO of 54 MW beginning in June 2022 and an additional 102 MW beginning in June 2023. Other projects with initial CSOs in 2022 include Killingly Energy Center, which had its CSO terminated for failing to meet milestones, and Three Corners Solar, which is under construction as of June 2023 and is expected in service in late 2023 or early 2024.

The three-year forward term of the FCA is not aligned with development timeframes for a growing share of projects in ISO-NE. Three years was originally thought to correspond to the construction period for a new fossil peaking plant. However, a large share of new capacity now comes from projects with different characteristics:

- Of the 1.9 GW of new generation capacity that received CSOs in the past three FCAs, 1.4 GW (77 percent) was from solar and battery projects, both of which can often be constructed in significantly less than three years.
- Over 530 MW of new demand resources cleared in the last three FCAs, including energy efficiency, active demand response and load reductions provided by behind-the-meter solar and storage.[55] These projects are typically aggregations of devices installed by individual end-users and do not require lengthy construction timelines.

The FCM may actually inhibit resources with fast development timeframes from receiving capacity payments as soon as they are able to support reliability. For example, approximately 875 MW (nameplate) solar and storage resources that entered service between January 2016 and April 2023 first participated in an FCA whose CCP was much later than the project's actual in-service date. While these resources can in principle secure a CSO through an ARA or bilateral trade, volumes and prices in these auctions are typically much lower than in the FCA.

Disadvantages of Mandatory Forward Capacity Market

The previous subsection demonstrates that the three-year forward FCA is less important for coordinating new investment than has often been assumed. However, the FCA has significant disadvantages compared to a prompt capacity market.

Higher Financial Risks. Developers that earn a CSO through the FCA but are not in service by the commitment period face financial penalties. Projects that are up to two years late or cannot fully satisfy their CSO must buy capacity to make up their obligation. Projects that are more delayed may have their CSO canceled, face significant penalties by forfeiting financial assurance, and must restart the qualification process in order to sell capacity in a subsequent auction. This creates the following development risks for resources that sell capacity:

- Large projects such as offshore wind face uncertain development timeframes and may fail to be in service by the date associated with their CSO. For example, the Vineyard Wind project off the coast of Massachusetts received a CSO beginning in June 2022 has just recently started construction as of May 2023.
- Small-scale clean energy projects (including most solar and storage projects) often do not have EPC contracts and other project details finalized three to four years in advance. As a result, these projects may have to submit FCA offers before they have certainty

[55] We have recommended that energy efficiency be removed from the supply side of the capacity market and treated as a load reduction instead. See our 2020 Assessment of the ISO-NE Markets. If treated as a load reduction, EE resources would still produce more timely cost savings under a prompt auction framework.

regarding the costs of major components such as batteries and solar panels and when development of the project may be uncertain even if a CSO is awarded. Alternatively, some projects may choose not to sell in the FCA until these details are more certain, causing them to forego capacity revenues in the first year or two of operation.

- Large conventional projects may similarly encounter delays due to both regulatory and construction risk.[56] In a prompt market, developers can manage these risks by delaying or discontinuing the project, but these actions are more costly in a forward market.
- Demand resources backed by aggregations of small consumers (including aggregations of behind-the-meter solar and storage) typically do not sign contracts with customers over three years in advance. In order to participate in the FCA, these providers must estimate potential future sales and face the risk of not providing enough demand reduction to satisfy their CSO. This is one reason why EE providers routinely offer less capacity in the FCA than they actually install.[57]

A prompt capacity market avoids these risks because project owners simply offer their capacity in prompt auctions once the project is in service or nearly complete. This aligns the timing of capacity payments with each resource's actual in-service date.

Poor Facilitation of Retirement Decisions. The forward market also creates significant financial risks for existing older generators. This is because retirement of older units is often prompted by unforeseen equipment failure that is not economic to repair (as opposed to planned retirement mediated through the FCA). Such units must accept a CSO that ends more than four years after the FCA. This raises two significant concerns:

- The FCM structure can cause resource owners to be unable to satisfy a CSO if it suffers equipment failure that is not economic to repair. This possibility creates a substantial risk for older existing generators that are marginally economic.
- This risk can cause older resources to retire prematurely. If the capability of an old unit 3 to 4 years in the future is sufficiently uncertain, it may be rational for the supplier to simply decide not to accept a CSO and retire the unit.

FCM increases the Misalignment Between Planning Models and the Capacity Market. It will become increasingly challenging for the FCA to value capacity accurately as the resource mix becomes more diverse and as winter risks take precedence. This is because the FCA must rely on planning models that assume a resource mix that is different from what is actually procured in the auction. With an evolving resource mix, projects face financial risks as their capacity value is updated between the FCA and capability period. This subsection further explains this issue.

56 For example, the Footprint Combined Cycle project entered service two summers later than its original CSO after significant delays and ultimate termination of its first EPC contract. This led to a $236 million arbitration judgment against the developer for wrongful contract termination in March 2022.

57 See ISO-NE filing letter in FERC Docket ER20-2869

A key difference between forward and prompt capacity markets is the degree of uncertainty regarding the supply mix prior to the auction. Before a prompt auction, there is a high degree of certainty about the mix of resources that will clear because participants are already in service or near completion. In a forward auction, a range of potential new resources and retirement offers may be selected, and resources that obtain CSOs might ultimately fail to enter by the CCP. The longer the forward term of the auction, the greater the uncertainty regarding the resource mix.

This uncertainty is problematic because it causes assumptions underpinning key auction parameters to differ from actual market outcomes. ISO-NE uses its resource adequacy model to calculate the ICR before the FCA is conducted, but the results of the resource adequacy model depend on the assumed resource mix. For example, assuming a large amount of wind will produce a different ICR and marginal capacity credit values than assuming a small amount.

Large amounts of new capacity from intermittent renewables and storage will enter the market in the coming years. Hence, in its resource adequacy model, the ISO will either underestimate the penetration of these technologies or apply speculative assumptions about which technologies will clear before the auction.[58] This will have the following effects:

- The ICR used in the FCA will not correspond to the level of capacity that satisfies the 1-in-10 reliability target because it will be based on an inaccurate resource mix, and
- Capacity credit values used in the FCA will be over- or under-estimated for resources whose marginal value depends on their penetration.

These issues will increase the cost to consumers. For example, suppose a large amount of new short-duration storage clears in the FCA. Before the auction, the capacity credit of the storage will have been overestimated and the ICR will have been underestimated because these resources will have been excluded from the resource adequacy model. When the resource mix is updated, the capacity value of storage units will be reduced.

The current ISO proposal will protect capacity sellers from this risk by allowing them to retain the capacity credit value from the FCA qualification process. However, this simply shifts these financial risks from developers to consumers, leading to inefficient incentives and increased consumer costs as additional capacity must be procured to make up for resources that were overvalued in the FCA.

These problems are significantly reduced or eliminated in a prompt capacity market because there is much less uncertainty about the supply mix that will clear. A prompt capacity auction

58 Currently, only existing resources and projects that have already cleared in a prior auction are included in the resource adequacy model for the FCA. Changes to inclusion rules in the resource adequacy model are not likely to resolve this issue as long as there is a range of potential outcomes for the resource mix that clears the FCA. In the example provided for FCA15, inclusion of all qualified storage projects in the model would have over-estimated the penetration of storage by 1.1 GW instead of underestimating it.

would tend to produce values for capacity credit and the ICR that are consistent with the mix of technologies in the corresponding capability period.

Misalignment with Fuel Contracting Opportunities. The capacity credit of pipeline gas generators should depend on whether they contract for firm transportation and/or LNG deliveries. However, the capacity credit of resources participating in the FCA will be determined nearly four years in advance of the winter portion of the CCP.[59] This would require resources to arrange for firm fuel supply far in advance of the delivery date to improve their capacity credit in the FCA, which is likely infeasible or undesirable for most resource owners. Alternatively, some pipeline gas resources may accept low credit in the FCA even if fuel contracts are economically available closer to the CCP, causing the FCA to under-procure fuel-secure capacity for winter reliability needs.

In a prompt market, the auction is conducted closer to the timeframe when generators are likely to sign contracts for firm fuel supplies for the coming winter season. This is particularly true if the prompt market is conducted on a seasonal basis (e.g., summer and winter capacity auctions). This would facilitate generators choosing the optimal amount of firm fuel contracts based on expectations of revenues in the prompt market.[60]

C. Conclusions and Recommendations

Rapid change in New England’s power sector will require capacity market design enhancements in order to efficiently facilitate investment and retirement. This section discusses the following concerns with ISO-NE’s current forward capacity market:

- Detailed modeling of factors driving energy adequacy, including depletion and replenishment of oil inventories, is needed for the capacity market to attract and retain resources needed for winter reliability;
- The mandatory three-year forward nature of the FCA is no longer useful for coordinating new investment and will inhibit efforts to implement efficient capacity accreditation;
- The FCA timeframe undermines generators’ ability to make efficient retirement decisions for old resources whose availability is uncertain three to four years in the future; and
- The FCA timeframe is misaligned with market contracting timelines for firm gas transport and LNG.

To address these concerns, we recommend the following key changes to the FCM:

59 The FCA is usually conducted in February and the associated CCP begins in June three years later. Hence, the portion of a resource’s CSO that begins in December is approximately 46 months after the FCA.

60 For example, if reliable winter supply is expected to far exceed peak load, prompt winter capacity prices would be low, and all pipeline gas generators need not incur the cost of obtaining firm fuel. On the other hand, if winter reliability risk is expected to be high, winter capacity prices would be high and generators would face incentives to firm up as much supply as possible to receive higher capacity payments.

Recommendation #2020-2: We recommend that ISO-NE improve its capacity accreditation 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. Specifically, we recommend that ISO-NE: (a) implement detailed modeling of dual fuel and oil unit inventory depletion and replenishment, and (b) accredit non-firm gas-only resources based on the marginal reliability benefit they provide.

Recommendation #2021-1: We recommend replacing the mandatory forward capacity auction with a mandatory prompt seasonal capacity auction. As is the case today, the ISO would determine an Installed Capacity Requirement and procure capacity using its MRI-based demand curve. Load-serving entities would still be required to purchase capacity corresponding to their load-ratio share of the ICR. However, LSEs would not be required to purchase capacity three years in advance and would instead be responsible for purchasing it in the prompt auction prior to each capability period. Hence, 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 associated capability period;[61]
- 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;
- Eliminate the annual reconfiguration auctions (ARAs), which will not be necessary in the absence of mandatory three-year forward auction; and
- Simplify the capacity qualification process to account for a shorter lag between qualification and the CCP.

61 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.

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. Significant effort will be necessary to develop new processes for batching and sequencing interconnection studies, assignment of cost allocation and financial assurance for transmission upgrades, and determination of capacity sales rights.

However, switching from a forward to a prompt FCA 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 #2022-4: We recommend that ISO-NE postpone the future forward capacity auction as soon as practicable, beginning with the upcoming FCA18 auction in February 2024 but no later than FCA19 in February 2025. This delay would be beneficial because it would accelerate the implementation of a seasonal prompt market and allow time for implementation of Recommendations 2020-2 before another FCA is conducted. Holding the auction before these recommendations are fully addressed poses the following risks:

- The ICR and accreditation values used in the FCA may significantly underestimate winter reliability risk because oil unit inventories are not currently modeled in MARS. This could result in artificially low prices and premature retirement of dual fuel and oil units and/or failure to procure imports needed for reliability;
- The FCA is likely conducted too far in advance for gas generators to economically procure firm gas transport and/or LNG in order to qualify for the auction; and
- The FCA is likely to result in inefficient outcomes because there is no means to ensure that resources will be accredited at values consistent with the cleared resource mix.

We do not expect delaying the FCA will have a negative impact on the ISO-NE markets because capacity supply obligations through May 2027 have already been secured. If the ISO signals its intent to delay the auction soon, this affords nearly four years for a prompt auction framework to be developed and implemented for the Summer 2027 capability period. On the other hand, continuing to hold FCAs would lock-in prices and obligations based on flawed results for additional years into the future.

Recommendation #2021-2: We recommend that ISO-NE explicitly consider the impact of eliminating the Minimum Offer Price Rule (MOPR) on merchant generators' cost of capital when establishing the Net CONE value used in its capacity market demand curve. In the short term, it may be necessary to direct ISO-NE's demand curve consultant to estimate an appropriate risk adjustment based on expected changes in market volatility due to elimination of the MOPR. In the long term, the widespread removal of MOPR provisions in U.S. capacity markets will be reflected in financial market data and such an adjustment may not be necessary.

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.

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.[62] 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. Hence, we recommend the ISO transition to a sealed-bid auction.

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

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.[63]
- Fuel costs assume transportation and other charges of $0.27 per MMBtu for gas and $2 per MMBtu for oil on top of the day-ahead index price. Intraday gas purchases are assumed to be at a 20% premium due to gas market illiquidity and balancing charges, while intraday gas sales are assumed to be at a 20% discount for these reasons. Regional Greenhouse Gas Initiative (RGGI) compliance costs are included, if applicable.
- The 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 5:

Table 5: 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

63 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.[64] For estimating net revenues, we used the generation profiles that were assumed in the 2019 Economic Study.
- 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.[65]
- We estimated the REC revenues for land-based wind using a 4-year average of the MA Class I REC Index for 2020 and 2021 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 and ORTP study.[66]
- For estimating the cost for entry, we utilized the cost trajectory from inputs to the NREL's ReEDS model.[67]

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.[68] 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.

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64 For NREL data, see link.

65 See report on the ISO-NE Net CONE and ORTP Analysis. See Brattle study for Ney York for OSW capacity value assumptions.

66 See report on the ISO-NE Net CONE and ORTP Analysis, available at link

67 The capital costs for land-based wind units are based on the ISO-NE Net CONE and ORTP Analysis. We assumed 'Class 7-low' projections for adjusting the land-based wind costs. Fixed O&M costs for land-based wind units are based on the ISO-NE Net CONE and ORTP study. Region specific cost multipliers were applied to convert the US average costs reported by NREL.

68 See figure in the *2021 State of The Market Report for The New York ISO Markets*.

- The energy produced by these units is calculated using location-specific hourly capacity factors. We considered capacity factor for recent wind installations in MISO and ERCOT, and the capacity factor information presented in 2021 NREL ATB for our assumption regarding the capacity factor for land-based wind in these regions.
- We estimated the value of RECs produced by the wind unit in ERCOT using a 4-year average of the Texas REC Index for 2020 and 2021 vintages from S&P Global Market Intelligence. For MISO, we utilized publicly available information on the REC prices in Minnesota.[69]
- Consistent with the assumption for other markets, we assumed full PTC revenues for the land-based wind plants in ERCOT and MISO regions.

Table 6: Land-based Wind Parameters for Net Revenue Estimates[70]

Parameter	ERCOT (South)	MISO
Investment Cost (2021$/kW)	$1,402	$1,430
Fixed O&M ($/kW-yr)	$44	$45
Federal Incentives	PTC	
Project Life	20 years	
Depreciation Schedule	5-years MACRS	
Average Annual Capacity Factor	35%	46%

69 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.

70 The Fixed O&M and Investment costs are sourced from NREL ATB 2021, available at link. We assumed TRG-3 specific costs for the MISO wind unit, and TRG-7 costs for the ERCOT unit. Region specific cost multipliers were applied to derive the location specific costs from the US average costs reported by NREL.