2021 Assessment of the ISO New England Electricity Markets

Prepared By:

POTOMAC ECONOMICS

External Market Monitor for ISO-NE

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PREFACE

Potomac Economics serves as the External Market Monitor for ISO-NE. In this role, we are responsible for evaluating the competitive performance, design, and operation of the wholesale electricity markets operated by ISO-NE.[1] In this assessment, we provide our annual evaluation of the ISO's markets for 2021 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 2021.

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 during the year, which shows:[2]

- Real time energy prices averaged $44.84 per MWh at the New England Hub, up 92 percent from the historic lows in 2020. The primary driver was the 120 percent increase in natural gas prices from 2020 to 2021. This correlation is consistent with our finding that the market performed competitively because energy offers should track input costs in a competitive market.
- Average load rose roughly 2 percent in 2021, reflecting more frequent peaking conditions in the winter and summer months because of weather and dissipation of the effects of the COVID-19 pandemic. Nonetheless, load levels have been on a downward trend in recent years because of continued energy efficiency and behind-the-meter solar generation.
- The market was never short of operating reserves in 2021 because of the availability of sufficient surplus capacity, so no Pay-for-Performance (PFP) events occurred.
- The capacity compensation rate was $5.30 per kW-month in the 2020/21 Capacity Commitment Period (CCP) and $4.63 per kW-month in the 2021/22 CCP.
  - These relatively high levels reflect that the peak load forecasts for the FCAs held in 2017 and 2018 were significantly higher than the actual peak loads in 2020 and 2021.
  - 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 modestly to roughly $2.60 per kW-month in FCAs 15 and16 (the 2024/25 and 2025/26 CCPs) after the Mystic cost-of-service agreement ends.

The IMM report provides detailed discussion of these trends and other market results in 2021. This report complements the IMM report, comparing key market outcomes with other RTO markets, assessing the competitive performance of the markets, and evaluating market design issues. This report addresses long-term economic incentives, out-of-market commitments, winter operations and reliability, and capacity market design and accreditation.

[2] See ISO New England's Internal Market Monitor 2021 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 very different challenges than many other RTOs, which affect the structure and performance of its markets. In particular, ISO-NE is located at the end of a number of interstate pipelines whose aggregate capability 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 Sections 0 of this report and find that:

Energy Prices ISO-NE generally exhibited the highest average energy prices of the 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, averaged higher prices in 2021 because of unusually high energy prices during several days of shortages in February 2021.

Capacity Prices Capacity prices in New England were substantially higher than in the other RTOs. Lower capacity prices in other markets have generally been due to higher surpluses in those areas and MISO's poor market design. Additionally, over-forecasted peak loads and associated capacity requirements can only be slowly addressed (over three years) in ISO-NEs forward capacity market.

Congestion ISO-NE experiences far less congestion than other RTOs. As per MWh of load, the average congestion cost in New England was less than $0.38 per MWh – roughly 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 costs of nearly $22 per MWh in 2021 – 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, while the primary reasons for transmission expansion in ERCOT, MISO, and the NYISO have been 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. Introduction of 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. (See Recommendation #2010-4) 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.

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, forecast errors still limit the potential benefits of CTS, so the ISO should continue to improve the forecasts or consider using real-time prices. (See Recommendation #2016-5)

Shortage Pricing ISO-NE has the most aggressive shortage pricing in the country, most of which is settled through the PFP framework rather than the energy market. The PFP framework reduces the potential financial risks in several key ways, but 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 the ISO-NE's wholesale electricity markets contained in Section II of this report, we find that the markets performed competitively in 2021. Our pivotal supplier analysis suggests that structural market power concerns diminished noticeably in Boston and New England since 2018 because of:

- The entry of more than 2.5 GW of generation;
- Transmission upgrades in Boston; and
- Falling load levels due to combined effects of continued energy efficiency improvements, growth of behind-the-meter solar generation, and the effects of the COVID-19 pandemic.

Our analyses of potential economic and physical withholding also indicates that the markets performed competitively with little evidence of significant market power abuses or manipulation in 2021. 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. The automated mitigation process helps ensure the competitiveness of market outcomes by mitigating attempts to exercise market power in the real-time market software before it can affect the market outcomes.

The only area where the mitigation measures may not have been fully effective is in their application to resources frequently committed for local reliability. Although the mitigation thresholds are tight, suppliers have the incentive to operate in a higher-cost mode and receive higher NCPC payments as a result. In 2021, 46 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)

Out-of-Market Commitments and Operating Reserve Markets

The ISO commits resources within 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.

However, these local and system-level reserves are not procured or priced in the day-ahead market. Consequently, the price of energy is often understated when such commitments occur because the costs of satisfying these reserve requirements are not reflected in the prices. Procuring and pricing these requirements in the day-ahead market would result in substantial additional net revenues, especially for flexible resources such as fast-starting peaking units and battery storage units that will be 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. Our assessment of day-ahead reliability commitments in 2021 showed they occurred in more than half the hours:

- Commitment for local second contingency protection occurred in roughly 1,250 hours and accounted for 40 percent of the day-ahead NCPC.
- Commitments to satisfy the system's 10-minute spinning reserve requirement occurred in roughly 3,400 hours and accounted for 35 percent of the day-ahead NCPC.

The 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 result in an additional revenue of:

- Up to \$6 to \$15 per kW-year for units in the areas with local second contingency protection requirements; and

- Up to $18 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 Improvements* 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 satisfy 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)

Generator Operations during January 2022 Cold Weather

New England has become vulnerable to natural gas supply limitations during cold weather conditions over the past decade with the retirement of older oil-fired, dual-fuel, and nuclear generation. ISO-NE is considering capacity market enhancements to procure resources needed to maintain reliability during periods of extreme natural gas scarcity. Nonetheless, ISO will continue to rely on its energy and ancillary services markets to coordinate the efficient commitment and dispatch of all of its resources, and to provide efficient incentives to procure fuel and perform reliably. Conditions in January 2022 provided an opportunity to evaluate the market's performance cold weather conditions and the incentives they provide to be available.

The report shows that natural gas pipeline limitations led day-ahead gas prices to rise near the delivered prices of ultra-low sulfur diesel ("ULSD") as many generators burned a mix of oil and gas during the period. Although gas prices were relatively high in January, they never rose far above delivered ULSD prices because large amounts of gas were available throughout the month. No day averaged less than 3.5 GW of gas-fired output compared to conditions in the Winter of 2017/18 when pipeline gas-fired generation fell to as little as 1.5 GW on day and gas prices exceeded $100 per MMbtu. Oil-fired generation was modest, although it rose as high as 3 GW on the highest-load days when the spread between gas and oil prices was highest.

Economic Oil Utilization. Although oil-fired generation increased as it became more economic than natural gas, we found that it averaged just 41 percent of the amount we estimate would have been economic in January. Actual oil-fired output averaged 41 percent of the capacity that we estimate would have been economic to burn fuel oil on these days. In some cases, these resources burned natural gas instead and in other cases they did not run as we explain below.

27 percent of the economic oil-fired output was produced by burning natural gas because:

- *Favorable Gas Costs*. Most of the output from gas (84 percent) came from either baseloaded cogeneration plants or plants that are situated favorably upstream of key pipeline constraints that often have better access to gas at potentially lower prices.
- *Operational Benefits*. The choice of fuel may affect the operational characteristics of the generator. For example, burning oil may restrict access to duct-firing ranges on a combined-cycle unit and lower its potential output.
- *Oil Inventory Management*. Generators with limited oil inventories may burn natural gas to conserve their oil, although this was not likely a significant factor during this period.
- *Total Emissions Limits*. Air permit restrictions may limit a generator's number of oil-fired hours per year, which was also not likely binding in January 2022.

The remaining 32 percent of estimated economic oil-fired output was not produced because of:

- *Forced outages and deratings*. Led an average of 860 MW to be unavailable over the period and over 2.3 GW from January 29 to 31.
- *Inventory-limited units*. Accounted for an estimated 450 MW of unutilized capacity.
- *Emission rate limitations*. Accounted for 360 MW from generators that had difficulty keeping their emissions within the tolerances required by their air permits.

Economic Gas Utilization. Our evaluation of actual gas burn showed a relatively weak relationship between the estimated production costs of gas-fired resources and the generation costs implied by their actual operation. On most days, actual gas-fired generation was *lower* than our estimated economic level (by almost 30 percent on average) primarily because additional gas burn would either have been limited by pipeline restrictions or because additional gas would only have been available at a premium. However, on a substantial number of days, actual gas-fired generation was much *higher* than our estimated economic level because gas often became available at a lower price intraday than was available day-ahead. This happens when actual consumption by core natural gas demand is lower than LDCs' forecasts, making more gas available to generators after the timely window has closed.

Overall, this section of the report demonstrates that generators do respond to the economic signals provided by the fuel markets and electricity markets. This underscores that producing efficient day-ahead and real-time energy and ancillary services prices is of paramount importance. This response by generators is not always easy to predict because they must consider an array of factors and limitations in making fuel procurement and burn decisions. Real-time gas availability and cost can be highly uncertain, which will affect generators' fuel burn decisions, particularly under tight conditions.

In the longer-term, efficient energy and ancillary service prices along with the incentives provided by the capacity market reforms discussed below should motivate generators to efficient fuel procurement and inventory decisions in advance of the winter season. This will be increasingly important as maintaining reliability in the winter season becomes much more challenging for the ISO.

Assessment of Forward Capacity Market Design

The capacity market is the primary market mechanism for satisfying 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 complex and challenging to do this efficiently because of the expected changes in New England's power sector 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 availability characteristics, and
- Increased awareness of limitations faced by the generation fleet during extreme weather, especially in winter months.

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

Resource Adequacy Modeling and Efficient Capacity Accreditation

Capacity accreditation is the number of megawatts a resource may sell in the capacity market. An efficient capacity market provides the same level of compensation to all resources that provide comparable reliability benefits.

A resource's capacity credit should reflect its marginal reliability value, which is how much system reliability would change if an increment of that resource type were to enter the market or retire. Marginal capacity accreditation provides efficient incentives to invest in resources that complement each other (such as pairing renewables with storage) and retire surplus resources that provide little reliability value.

Current capacity accreditation methods over-value several resource types, including:

- Intermittent Resources – Qualified capacity of intermittent resources such as wind and solar is based on their median output at certain times of the day and doesn't consider correlation of resources' output which will affect the timing of reliability needs.
- Energy Storage – These are accredited up to 100 percent of their installed capacity if they can discharge for at least two hours. This substantially over-compensates low-duration batteries relative to their reliability value.
- Pipeline Gas-Dependence – Generators that rely on pipeline gas and lack backup fuel are accredited as if fuel is always available to them, but in practice these generators have limited availability during the winter.
- Large Resources or Resources with Correlated Outages – Large individual units provide reduced reliability value because all their capacity can be lost in a single outage, but this is not reflected in their capacity credit. Likewise, multiple units that can be lost in a single contingency provide less reliability than ones whose outages are uncorrelated.
- Low Flexibility – Some units require lengthy startup notification times, such as older steam turbines. They are less likely to be able to support reliability during critical periods that arise unexpectedly.

Hence, we recommend that the ISO develop capacity accreditation rules based on each resource's marginal reliability value (See Recommendation #2020-2a).

ISO-NE uses a resource adequacy model to determine its Installed Capacity Requirement (ICR). Hence, it is important to model each resource type accurately so that the ICR is high enough to maintain reliability and the accreditation of each resource type is consistent with its marginal reliability contribution. This will require the ISO to enhance the resource adequacy model to properly consider the limitations and availability of the five resource categories listed above. Hence, we recommend that the ISO modify how various resource types are modeled in MARS (See Recommendation #2020-2b).

Efficient Accreditation of Pipeline Gas Generators

ISO-NE awarded CSOs to 8 GW of generators that rely on fuel from natural gas pipelines and lack dual fuel capability in the most recent FCA. Hence, this is currently the largest class of resources whose marginal reliability value may significantly differ from the credit they are assigned in the FCM. In this report, we discuss a potential approach to determine the capacity value of these resources.

New England relies on imports of natural gas via the interstate pipeline system to supply fuel for winter heating, power generation, and other uses. On cold winter days, there is not enough interstate pipeline capacity to supply all of ISO-NE's gas generators after the heating demands of gas utilities are met. In recent winters, imports of liquefied natural gas (LNG) have allowed a portion of gas-only generators to operate. However, few generators have contracted for firm LNG deliveries, and it is unknown how much LNG will be available in future cold conditions.

We used a simplified resource adequacy model to simulate the marginal capacity value of pipeline gas-only resources that do not contract for firm LNG. Our model restricts the combined output of these resources on very cold days based on historical data showing that generation sourced from pipeline gas has been limited in peak winter conditions. We find that:

- The marginal value of gas-only capacity depends on whether reliability needs are concentrated in winter or summer. Gas-only resources have high marginal value for meeting reliability needs in summer when the pipeline system is not constrained. However, their value in the winter will depend on whether they can secure contracts to firm-up their gas supply.
- We estimate that if more than 5 to 6 GW of gas-only generation does not contract for firm fuel supply in the near future, the marginal value of these resources will be very low, which will increase winter reliability risks. Accordingly, marginal accreditation rules are needed to ensure that a sufficient portion of these resources are motivated to contract for firm fuel supply.

Our analysis underscores the importance of using a marginal approach to determine capacity credit. An alternative 'average' capacity value approach would provide approximately 70 percent capacity value even when the incremental value of these resources is zero, providing weak incentives to acquire firm fuel supplies or retire.

Assessment of the Mandatory Forward Capacity Market

ISO-NE conducts its Forward Capacity Auction (FCA) 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 FCA has a dubious track record of coordinating timely entry of new resources even before the multi-year lock was eliminated. Just 42 percent of capacity from new large projects with initial CSOs from 2016 to 2022 entered on time, while 27 percent entered 1-2 years late and 31 percent never entered. 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 are sometimes inhibited from earning timely capacity revenues by the forward market.

The three-year forward FCA has several disadvantages compared to a prompt capacity market:

- Participation in the FCA poses risk of financial penalties for a growing share of resources. These include large resources with uncertain development timeframes such as offshore wind and small resources such as distributed resource aggregations that lack certainty in the amount of capacity they can install three years in advance. A prompt market would simply begin compensating these resources as soon as they enter service without mandatory forward commitments.
- 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 can 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, increasing the financial risk for projects whose capacity credit could change after the FCA. 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.

Hence, we recommend eliminating the mandatory forward capacity auction and replacing it with a mandatory prompt capacity auction (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.

Financial Risk for New Capacity Investment

In early 2022, ISO-NE filed tariff changes to eliminate its Minimum Offer Price Rule (MOPR) beginning in the FCA19 auction to be held in 2025. An important consequence of eliminating the MOPR is that it will increase the financial risk for merchant resource owners. This may make it more difficult to attract new investment when it is needed for reliability.

Hence, 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 (See Recommendation #2021-2).

Other Capacity Market Design Enhancements

The purpose of the capacity market is to provide a market mechanism to facilitate long-term investment and retirement decisions that ensure sufficient resources to satisfy the planning reliability requirements of New England. We evaluate potential market design improvements to facilitate competition in the auction and to enhance the incentives it provides.

Improving the Competitive Performance of the FCA

In our previous Annual Market Reports, we evaluated the supply and demand in the FCA and concluded that: a) Limited competition can enable a single supplier to unilaterally raise the capacity clearing price by a substantial amount; and that publishing information on qualified capacity and the Descending Clock Auction format help suppliers recognize when they can benefit by raising capacity prices.[3] Most of the pre-auction information available to auction participants regarding the existing, new and retiring resources either needs to be published for other purposes or is available from sources that are outside the ISO's purview. However, the ISO's DCA process provides key information on other suppliers offers that is not relevant for constructing competitive offers, and instead would allow a resource to raise its offer above competitive levels. A sealed bid auction would eliminate such information and improve the incentives for suppliers to submit competitive offers.

In addition, 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 than 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.

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

Recommendation Number and Description		High Benefit[4]	Feasible in ST[5]	Report Reference
Reliability Commitments and NCPC Allocation				
2010-4	Modify allocation of “Economic” NCPC charges to make it consistent with a “cost causation” principle.		✓	2018 Report Section III
2020-1	Consider allowing firm energy imports from neighboring areas to satisfy local second contingency requirements.		✓	Section III.B
2014-5	Utilize the lowest-cost configuration for multi-unit generators when committed for local reliability.		✓	Section III.B
Reserve Markets				
2012-8	Introduce co-optimized operating reserves in the day-ahead market reflecting forecasted system needs.	✓		Section III.A
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.
External Transactions				
2016-5	Pursue improvements to the price forecasting or other reforms to improve Coordinated Transaction Scheduling.			2017 Report Section VI.C
Capacity Market				
2015-7	Replace the descending clock auction with a sealed-bid auction to improve competition in the FCA.			2017 Report Section IV.A
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
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 IV.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
2021-1	Replace the forward capacity market with a prompt seasonal capacity market.	✓		Section IV.C
2021-2	Include the effects of MOPR elimination on investment risk when establishing the net CONE for the demand curve.		✓	Section IV.D

4 Recommendation will likely produce considerable efficiency benefits.

5 Complexity and required software modifications are likely limited.

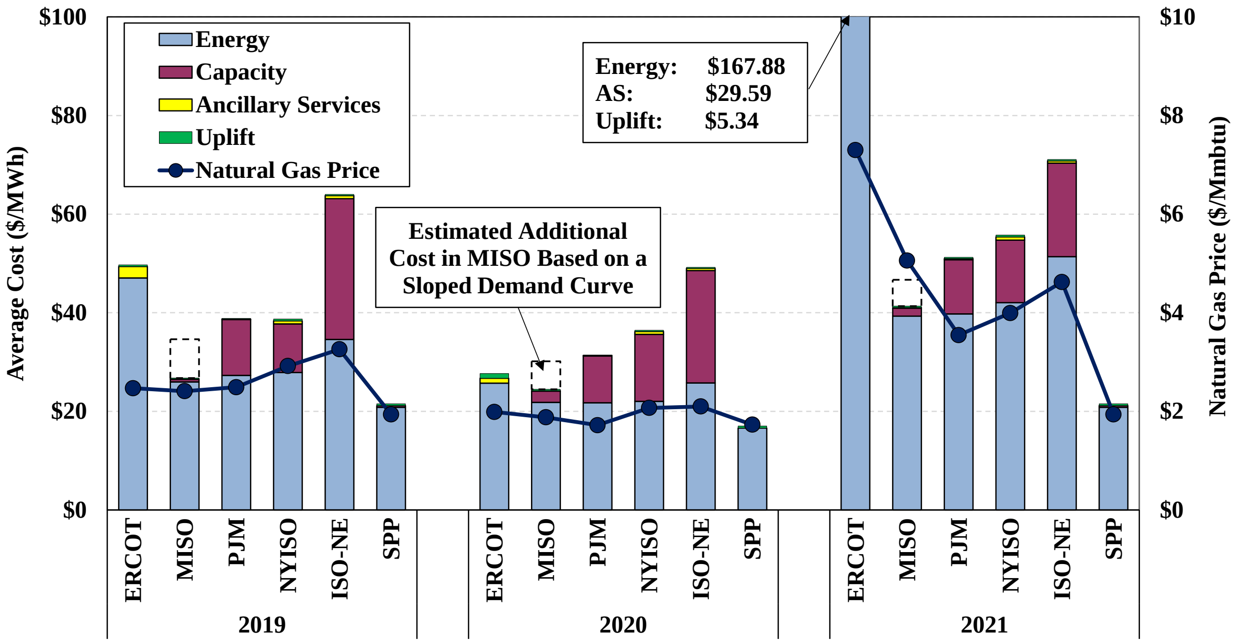
I. Comparing Key ISO-NE Market Metrics to Other RTOs

The 2021 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 2021. Rather than duplicating this discussion, we attempt to 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), the details of the market rules can vary substantially. In addition, the market prices and costs in different RTOs can be significantly affected by the types and vintages of the generation, the 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[6]
2019 – 2021



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

6 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.

production guarantee uplift (referred to as "make-whole uplift" 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 some clear 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 2021, compliance added an average of approximately $8 to 10 per MWh to the production costs of gas-fired combined cycle generators in Massachusetts and $4 to $5 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 in 2021.
- *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 and (b) falling load forecasts have had more immediate effects in New York's "prompt market" design than in New England's "forward market" design over these three years. Load forecasts have played a key role in the differences in the outcomes between these two markets:

- Both markets have experienced significant declines in their load forecasts in recent years because of continued growth of energy efficiency programs and behind-the-meter solar installations, as well as changing consumption patterns.
- ISO-NE's load forecast for the summer of 2021 fell from 26.2 GW in the forecast performed in 2017 that was used to develop inputs for FCA 12 to 24.8 GW in the 2021

CELT Report, a reduction of 5 percent. The NYISO's load forecast for the summer of 2021 fell by only 2 percent over the same period.[7]

- 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 on with 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, which have resulted from a larger amount of available of capacity imports and lower generation development costs. Low capacity costs in MISO are attributable to its poor market design and surpluses generally produced by its regulated utilities. MISO operates a capacity auction with a vertical demand curve that is not designed to reveal the true value of capacity. As a result, capacity prices are understated (as shown by the skeleton bar in the figure) and do not provide efficient long-term incentives. This is not a problem for the regulated entities in MISO because they receive revenues from retail ratepayers. However, a large quantity of generation owned by unregulated companies in MISO have retired uneconomically in recent years and MISO is now short of capacity in its Midwest region beginning in the 2022/2023 planning year. The figure shows that if MISO were to adopt an efficient sloped demand curve, the all-in prices would increase to a level that is closer to the levels in NYISO and PJM.

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 hours of shortage in the summer of 2019 raised annual average energy and reserve costs in ERCOT well above those costs in other markets in 2019, while several *days* of shortage in February 2021 during severe winter weather caused annual average energy and reserve costs in ERCOT to move off the chart. ERCOT relies primarily on shortage pricing to provide long-term incentives to facilitate investment and retirement decisions. This is only feasible in ERCOT because it does not enforce planning reserve requirements, unlike the other ISOs shown in this figure. Although SPP does not operate a capacity market, it enforces a 12 percent planning reserve requirement.

Uplift Costs. The final result 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. The largest outlier in this area is ERCOT who adopted extremely conservative operating procedures

[7] See NYCA Summer Peak Demand Baseline forecast in the 2017 and 2021 *Load & Capacity Data "Gold Book"* reports.

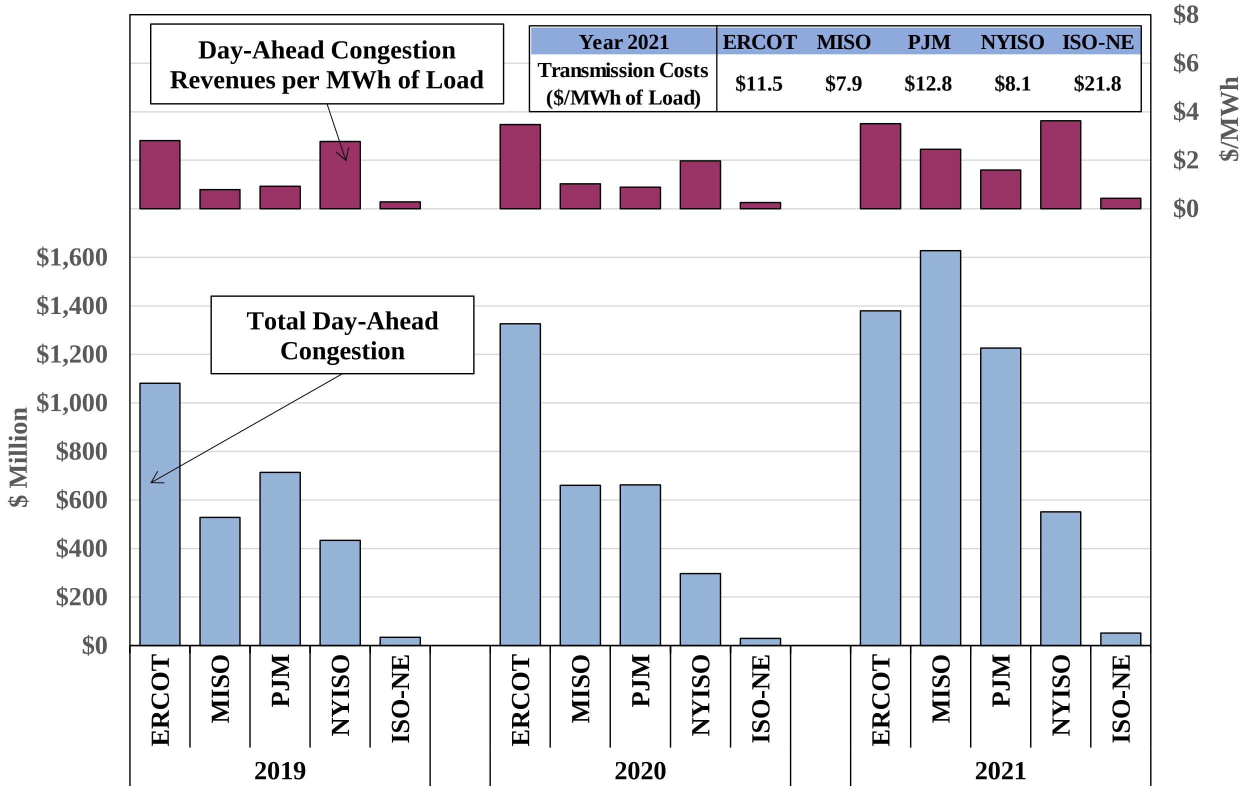
beginning in July 2021, which has resulted in substantial out-of-market actions and uplift costs exceeding $5 per MWh of load. We discuss uplift in more detail in Subsection C.

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 shows that ISO-NE experiences far less congestion than any of these other RTOs, averaging less than $0.38 per MWh. On this basis, congestion levels in the other RTOs are five to ten times larger than in New England. The low level of congestion in New England is not a surprise given the substantial transmission investments that were made over the past decade. These investments have led transmission rates to be nearly $22 per MWh in 2021, which are more than double the average rates in the other RTO areas shown in the figure.

Figure 2: Day-Ahead Congestion Revenues
2019-2021



Year 2021	ERCOT	MISO	PJM	NYISO	ISO-NE
Transmission Costs ($/MWh of Load)	$11.5	$7.9	$12.8	$8.1	$21.8

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 $13 billion in transmission projects. Construction started on some components in 2019, but the vast majority of construction costs will be incurred over the next five years, while the impact to ratepayers will be spread over the next 25 to 30 years. These transmission upgrades principally focus on delivering renewable energy from upstate New York to load centers in New York City and Long Island, although the NYISO is currently conducting a major solicitation for transmission to move offshore wind output from Long Island to other areas of the state.

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 much more stringent than the reliability planning criteria used in the other three markets. A total of 834 project components have been placed in service across the region since 2002 and another 47 project components are either under construction or planned or proposed over the planning horizon. The estimated investment in New England to maintain reliability was $11.7 billion from 2002 to March 2022, and another $1.1 billion is planned by 2030.

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 $0.32 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

Although NCPC costs (generally referred to as "Make-Whole Uplift Charges" industry-wide) generally account for a small share of the overall wholesale market costs, 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. The cost of satisfying some needs will be reflected in NCPC payments rather than in market-clearing prices. 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.

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 2021 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
		2019	2020	2021	2021	2021
Real-Time Uplift						
Total	**Local Reliability ($M)**	$2	$1	$2	$11	$2
	Market-Wide ($M)	$16	$15	$19	$12	$127
Per MWh of Load	**Local Reliability ($/MWh)**	$0.01	$0.01	$0.01	$0.07	$0.00
	Market-Wide ($/MWh)	$0.14	$0.13	$0.16	$0.08	$0.19
Day-Ahead Uplift						
Total	**Local Reliability ($M)**	$7	$4	$6	$28	$44
	Market-Wide ($M)	$6	$5	$9	$3	$26
Per MWh of Load	**Local Reliability ($/MWh)**	$0.06	$0.04	$0.05	$0.18	$0.07
	Market-Wide ($/MWh)	$0.05	$0.05	$0.08	$0.02	$0.04
Total Uplift						
Total	**Local Reliability ($M)**	$9	$5	$8	$39	$46
	Market-Wide ($M)	$22	$21	$28	$15	$153
Per MWh of Load	**Local Reliability ($/MWh)**	**$0.07**	**$0.05**	**$0.07**	**$0.25**	**$0.07**
	Market-Wide ($/MWh)	**$0.19**	**$0.18**	**$0.24**	**$0.10**	**$0.23**
	All Uplift ($/MWh)	**$0.26**	**$0.22**	**$0.31**	**$0.35**	**$0.30**

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 2021, uplift charges increased in all three regions as a result of higher natural gas prices and load levels following the pandemic, although ISO-NE's market-wide NCPC uplift was more than double the cost per MWh of load incurred by NYISO and slightly higher than that in MISO. MISO saw a substantial increase in uplifts because of substantial increase in out-of-market commitments that were have been investigating.

The higher uplift costs in New England are attributable to at least two factors:

- 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 some circumstances when the 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 relatively low in the past three years. This reflects low levels of supplemental commitments in the load pockets because of transmission upgrades and new market entries in these areas. Uplift for local reliability in ISO-NE was generally in line with the MISO market, but was much smaller than in the NYISO. In the NYISO, a large amount of generation is committed in the day-ahead market for local second contingency protection in several the load pockets across the state, primarily in New York City. In addition, oil-fired peaking resources are often dispatched out-of-merit on Long Island in real-time to manage local voltage needs or congestion on the 69 kV network. 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 approximately half 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 of NCPC charges distorts market incentives to engage in scheduling that can lead to real-time deviations. Unfortunately, this distortion is compounded by the fact that NCPC charges are allocated to real-time deviations that actually help 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 tends to reduce their participation in the market and the 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	2018	2.7%	$1.10	4.5%	$2.69	$0.94
	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
NYISO	2021	6.2%	$0.95	9.7%	$0.73	< $0.1
MISO	2021	11.3%	$0.75	11.7%	$1.64	$0.37

Table 2 shows that virtual trading was generally profitable, indicating that it has generally 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 percent of load in the ISO-NE market each year from 2018 to 2021. This is much lower than the 16 percent in the NYISO market and the 23 percent in the MISO market observed in 2021.

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.

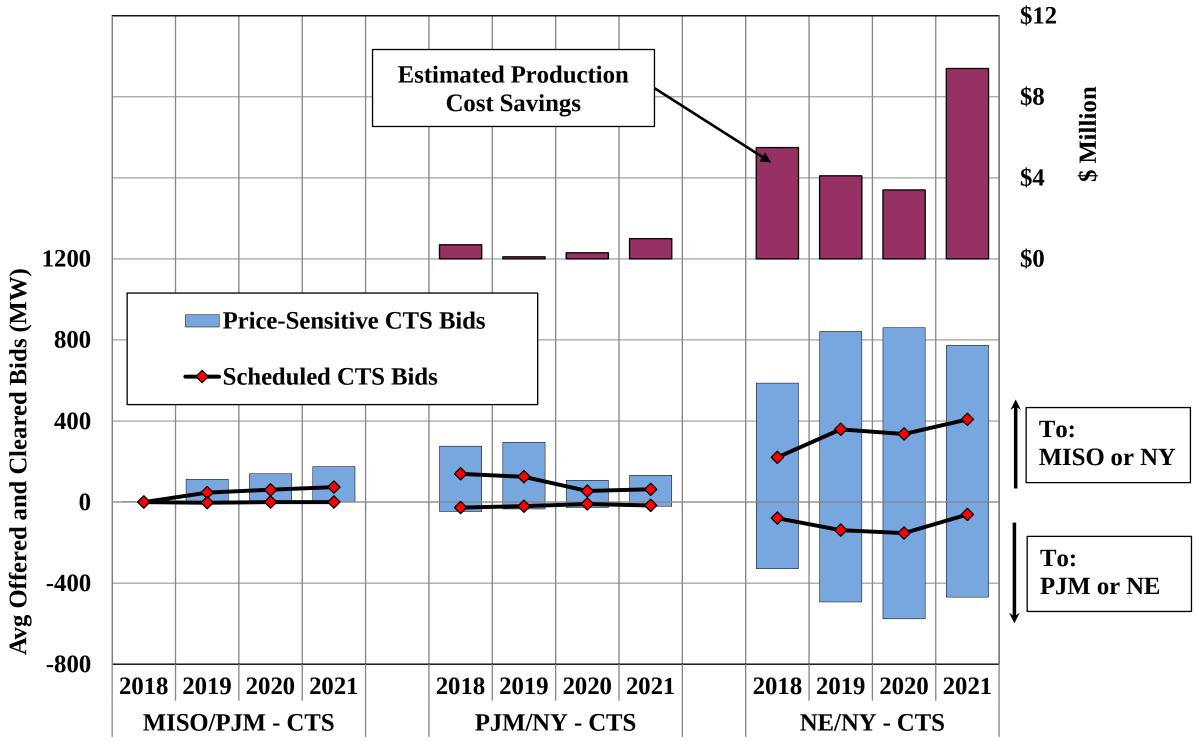
D. Coordinated Transaction Scheduling

Coordinated Transaction Scheduling (CTS) is a market process whereby two 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. The benefits of CTS are likely to grow in the future as the addition of intermittent generation makes it more difficult for RTOs to balance supply and demand.

Figure 3 compares the performance of the CTS scheduling process between ISO-NE and NYISO with the CTS processes between PJM and NYISO and between MISO and PJM. The bottom portion of the figure shows annual average quantities of price-sensitivity of CTS bids and schedules from 2018 to 2021.[8] Positive numbers indicate transactions offered and scheduled from neighboring markets to the NYISO or MISO markets, while negative numbers represent transactions offered and scheduled from neighboring markets to the PJM or New England markets. The upper portion of the figure shows the market efficiency gains (and losses) from CTS, which is measured by production cost savings. However, we did not estimate the cost savings for the process between PJM and MISO because of very limited participation.

Figure 3: CTS Scheduling and Efficiency

2018 – 2021



The results in Figure 3 show that the participation of CTS has been much more robust at the NE/NY interface than at the PJM/NY and PJM/MISO interfaces. The average amount of price-sensitive bids that were offered and cleared was significantly larger at the NE/NY interface because large transaction fees are imposed at both the PJM/NY and PJM/MISO interfaces while there are no substantial transmission charges or uplift charges on transactions 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.

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

On the other hand, CTS transactions from PJM to MISO or NYISO typically incur a smaller charge (between $1 and $2 per MWh) than CTS transactions in the opposite direction, leading to significantly more activity in that direction. These results demonstrate that these charges are a significant economic barrier to achieving the potential benefits from the CTS process 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 over $22 million in the four-year period from 2018 to 2021, while the estimated savings were just $2 million at the PJM/NY interface.[9] In addition to higher price-sensitive bids, better price forecasting was another key contributor to higher savings at the NE/NY interface.

ISO-NE's price forecasting is generally more accurate than PJM's price forecasting. This is partly because ISO-NE forecasts a supply curve (with 7 points representing different interchange levels at the interface), while PJM only forecasts a single price point at one assumed interchange level. Nonetheless, our evaluation of the price forecasting errors at the NE/NY interface have indicated that further improvements in price forecasting are possible.10 If the ISOs can address these areas and further improve the price forecasts that underlie the CTS prices, it should ultimately allow the process to achieve larger savings. Therefore, there is ample opportunity to improve the performance of the CTS process at the NE/NY interface.

Available improvements to the forecasts 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 each interval 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. Wholesale prices motivate firms to invest in new resources, maintain existing generation, and/or retire older units. 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 possible 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 the overall profitability of most projects.

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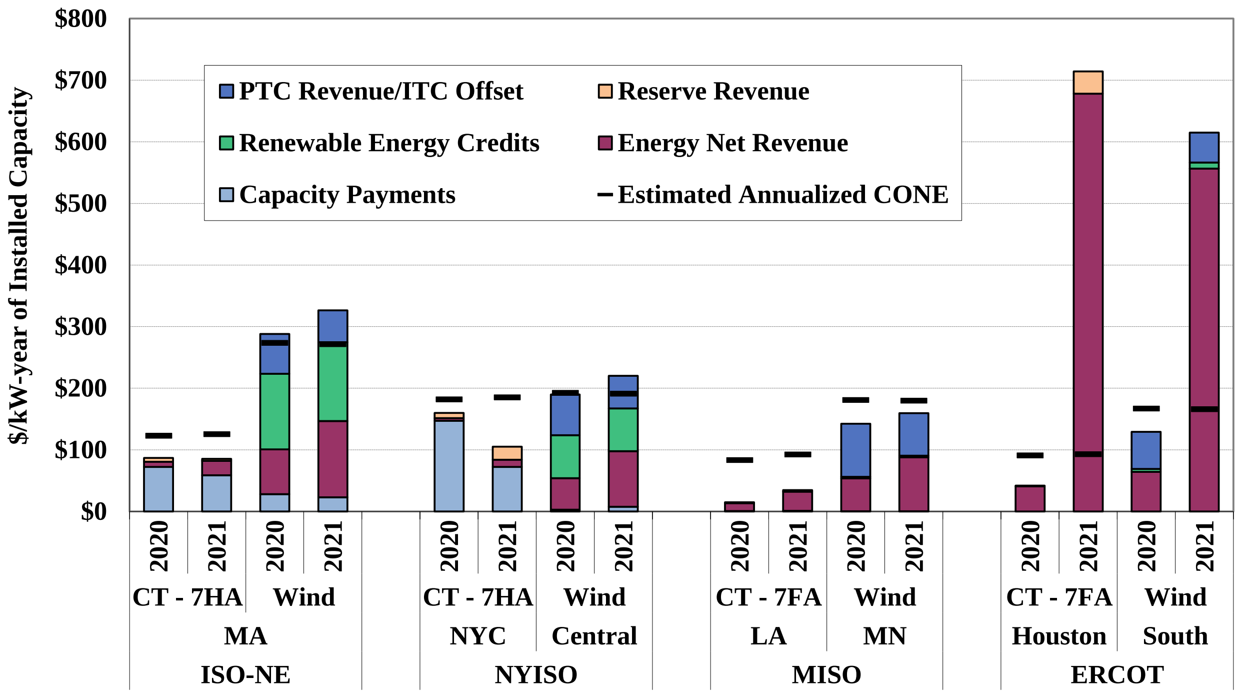
9 Production cost savings are calculated relative to our estimates of scheduling that would have occurred under the previous hourly scheduling process. To estimate the adjustment in the interchange schedule attributable to the intra-hour CTS scheduling process, we compare the final CTS schedule to advisory schedules in NYISO's RTC model that are determined 30 minutes before each hour.

10 See Section VI.C in our *2017 Assessment of the ISO New England Electricity Markets*.

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 the wholesale market and the applicable state and federal incentives. Figure 4 shows the estimated net revenues for a new combustion turbine and a land-based wind facility divided into the following categories: (a) energy net revenues based on spot prices, (b) capacity payments based on auction clearing prices and pay-for-performance incentives, (c) operating reserve net revenues, (d) federal production tax credits, and (e) state renewable energy credits.[11] 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 2020 and 2021.

Figure 4: Net Revenues Produced in ISO-NE and Other RTO Markets
2020 – 2021



Incentives for New Combustion Turbines (CT)

New CT investments in ISO-NE and NYISO are heavily reliant on capacity revenues. In ISO-NE, the capacity and energy prices over the last two years would generally not incent new entry of 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, usage of a more advanced technology, etc.). The capacity surplus and associated decline in capacity prices will continue through at least 2025/26 CCP.

11 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.

Net revenues for a CT from the energy and reserve markets increased in 2021 in all markets because of natural gas prices and electricity demand returning to more normal levels after the pandemic year of 2020.

- *New York City*. The only location where total net revenues decreased in 2021 was New York City, where capacity prices fell primarily because of a shift of the locational capacity requirements from New York City to other areas starting in the summer of 2021.
- *ERCOT*. The net revenues of a CT in ERCOT rose substantially from 2020. Shortage pricing at $9,000 per MWh for several *days* in February led net energy and reserve revenues to rise to more than seven times the estimated net CONE in 2021. However, capturing these net revenues would have required resources to be online or selling reserves and unfortunately many ERCOT's gas-fired resources could not run during this event because of the effects of the cold temperatures or fuel availability.
- *MISO South*. Of the locations analyzed, a CT in Louisiana exhibited the lowest estimated net revenue because of the region's sizeable capacity surplus and because the vertical capacity demand curves used in MISO lead to inefficiently low capacity prices. Adopting a sloped demand curve would have substantially increased capacity net revenue and reduced the shortfall in the annual revenue requirement of the CT.

Although shortage pricing is a very important component of the expected revenues in both ISO-NE and ERCOT, a large share of ISO-NE's shortage pricing is settled through its PFP framework. This PFP approach alters the financial risks to consumers and suppliers under extreme conditions in at least five ways:

i. The performance payments are a transfer from underperforming to overperforming resources. Hence, there is no direct increase in consumer payments.[12]

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.[13] 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.

12 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.

13 "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.

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, although there are similarities in pricing and supplier incentives during shortage events, 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 like ERCOT.

Incentives for New Wind Projects

The net revenues for a land-based wind unit in New England exceeded its CONE in 2021 because of higher energy revenues. State and federal incentives were still the primary source for revenues, accounting for 55 percent of total net revenues in 2021. Market revenues are also important because they provide critical price signals that differentiate 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 market for Class I RECs in New England continued to be tight in 2021. High prices in 2021 were likely driven by (i) increases in state RPS requirements (which increases the demand), and (ii) delays in the anticipated completion of offshore wind projects (which reduces the supply).[14] Although prices in the past two years have been high, REC prices have historically been volatile.

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.[15] However, renewable resources in most of MISO and ERCOT do not receive significant REC revenues. This contributed to the resources not receiving sufficient net revenue to be economic in recent years (with the exception of 2021 in ERCOT), despite that fact that the resource potential in MISO and ERCOT is normally better than in New England and New York.

Ultimately, however, the investment incentives in wind resources will 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.[16]

14 See April 13, 2021 market update from Power Advisory LLC.

15 The figure shows the average Tier 1 REC sale price posted by NYSERDA, whereas NE price is based on MA Class I REC broker quotes as reported by S&P Financial.

16 In recent years, Virtual PPAs of wind projects with a corporate off taker has also grown, with total amounts in 2021 comparable to the amount of capacity with traditional PPAs. See articles from S&P Global.

Incentive Effects of PPAs. PPAs (typically with utilities) generally involve a fixed-price for every MWh generated by the project and tend to be 20-years long. The buyers in such contracts (ultimately consumers) generally assume two key risks:

- Basis risk (i.e., risk of congestion between the wind node and the hub); and
- Volumetric risk (i.e., risk of underperformance which would require buyers to purchase any shortfall at spot prices).

This is not ideal because consumers typically have very little control over where the project is sited, the technology used in the project, and project operation and maintenance. Hence, project owners are in a better position to manage these risks when compared to off takers.

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.[17]

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.[18] If units under PPAs underperform, it is the ratepayers, rather than the wind unit owner, that would generally bear the costs of the poor performance.[19]

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.

17 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.

18 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”.

19 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 2021. 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.[20] 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.

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20 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;[21] 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.

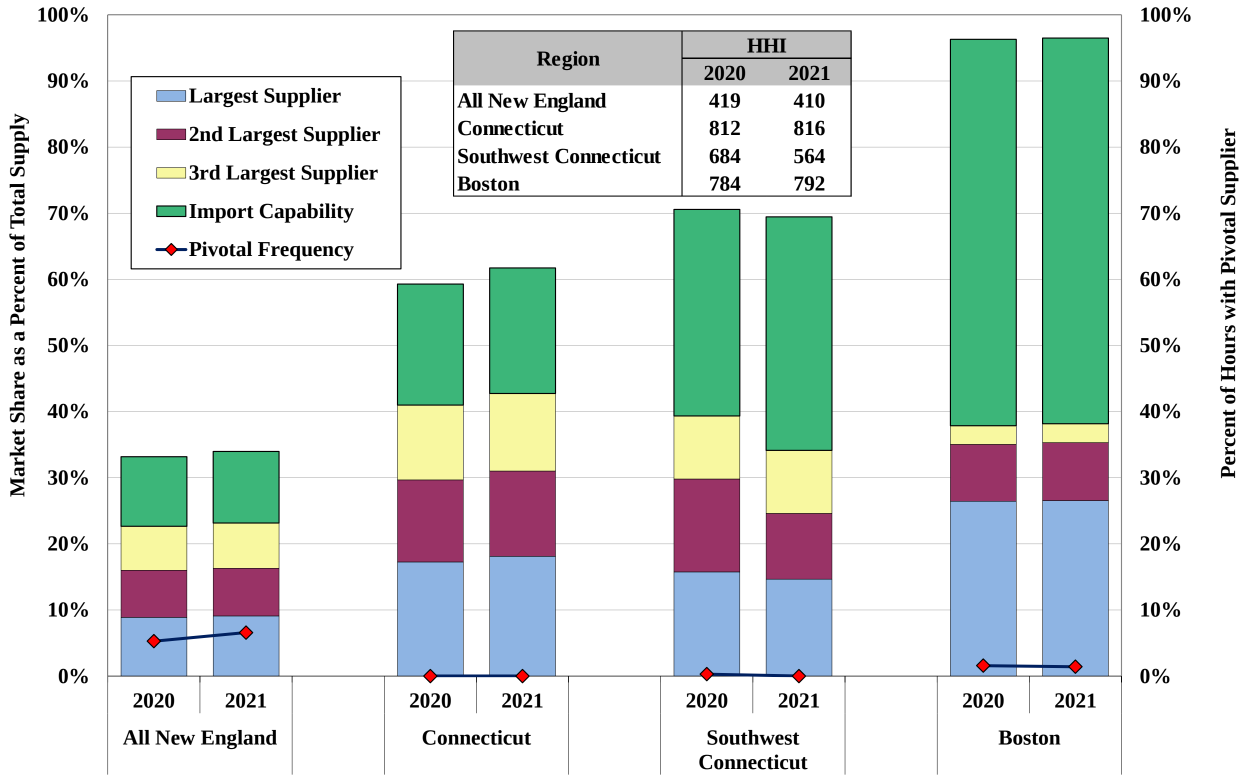
The Pivotal Supplier Test is a more reliable means to evaluate the competitiveness of energy markets because it recognizes the importance of both supply and demand. Whether a supplier is pivotal depends on the size of the supplier as well as the amount of excess supply (above the demand) held by other 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

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

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 2020 and 2021. First, the figure shows the market shares of the largest three suppliers and the import capability in each region in the stacked bars.[22,23] 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
2020 – 2021



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

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

Figure 5 indicates that market concentration of internal generation did not change significantly in most regions from 2020 to 2021. The portfolio sizes of the three largest suppliers remained similar from 2020 to 2021 in Boston, Connecticut, and all New England. However, the market share of the largest suppliers fell in Southwest Connecticut as PSEG retired its final coal-fired power plant, Bridgeport Harbor Station Unit 3, on June 1, 2021. In addition, the import capability into Southwest Connecticut increased modestly from 2020 to 2021 as a result of completed transmission upgrades n the 115 kV system.[24] Consequently, the HHI fell in that area.

There were variations in market concentrations among the largest internal suppliers in the four regions. In 2021, Boston had one supplier with a large market share of 27 percent (including import capability as a portion of the total supply into the area), while all New England had three suppliers with similar market shares of less than 10 percent each. Import capability accounted for a significant share of total supply in each region, ranging from 11 percent in all New England to 58 percent in Boston in 2021. Consequently, the market concentration (measured by the HHI) was relatively low, well under 1000 in all of the four areas. In general, HHI values above 1800 are considered highly concentrated by the U.S. Antitrust Agencies and the FERC for purposes of evaluating the competitive effects of mergers. However, this does not establish that there are no market power concerns. These concerns are most accurately assessed in our pivotal supplier analysis for 2021, which indicates that:

- In Southwest Connecticut and Connecticut, there were almost no hours when a supplier was pivotal.
- In Boston, although one supplier owned 64 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 7 percent of hours.[25]

The pivotal supplier frequency rose modestly from 2020 to 2021 largely because of higher load levels and lower net imports. Both average and peak load levels rose by roughly 1.6 percent from 2020 to 2021, reflecting continued demand recovery from the COVID-19 pandemic and more frequent weather-driven summer and winter peaking conditions. Net imports fell notably from 2020 to 2021 primarily across the interfaces with New York. The NYISO experienced substantially higher congestion across its Central-East interface in 2021 because of transmission outages and the retirement of the Indian Point nuclear facility, making it more costly to import

24 Southwest Connecticut 2022 Upgrades were all placed in service by February 2021, which included rebuilding and reconductoring lines, installing new lines, rebuilding two substations, and adding reactive support to maintain voltage, all on the 115kV network.

25 The pivotal supplier results are conservative for "All New England" compared to those evaluated by the IMM primarily because of our differences in: (a) treatment of portfolios with nuclear generation; (b) assumptions about supply availability; 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.

power from New York. In addition, Long Island had further elevated energy prices because of major transmission outages of its tie lines with upstate New York, attracting more imports from Connecticut. These resulted in an average reduction of roughly 530 MW in net imports from New York in 2021.

Despite the slight increase in 2021, the pivotal supplier frequency has been falling in recent years. New market entry was a key driver in all New England, including more than 1.5 GW in 2018 and over 1 GW in 2019. In addition, price-responsive demand resources have been able to participate in the energy market since June 2018, satisfying a significant portion of reserve requirements. In Boston, the pivotal supplier frequency fell to less than 2 percent in both 2020 and 2021, much lower than the 28 percent in 2017. The entry of the Footprint power plant in 2018 has led to less frequent commitments of the Mystic facilities in the portfolio of the largest supplier in Boston. The increase in the import capability because of the Greater Boston Reliability Project upgrades has further reduced the reliance on the internal generation. Going forward, the three Mystic units (one steam turbine and two combined-cycle units) are expected to retire in the next couple of years, which will reduce internal supply for the Boston area. Although the reliability concern of these upcoming retirements has been studied and addressed through the transmission upgrades in the Boston Area Optimized Solution project, the pivotal supplier frequency in this area would likely rise.

In spite of the low pivotal supplier frequency in 2021, the results in Boston and all New England still warrant further review to identify potential withholding by suppliers in these regions. This review is provided in the following section, which examines the behavior of pivotal suppliers under various market conditions to assess whether the conduct has been consistent with competitive expectations.

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.[26] This may overstate the potential economic withholding because some of the offers included in the output gap may reflect legitimate supplier responses to operating conditions, risks, or uncertainties.

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

- ***Physical withholding:*** we focus on short-term deratings and outages because they are more likely to reflect attempts to physically withhold than other types of deratings, 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.

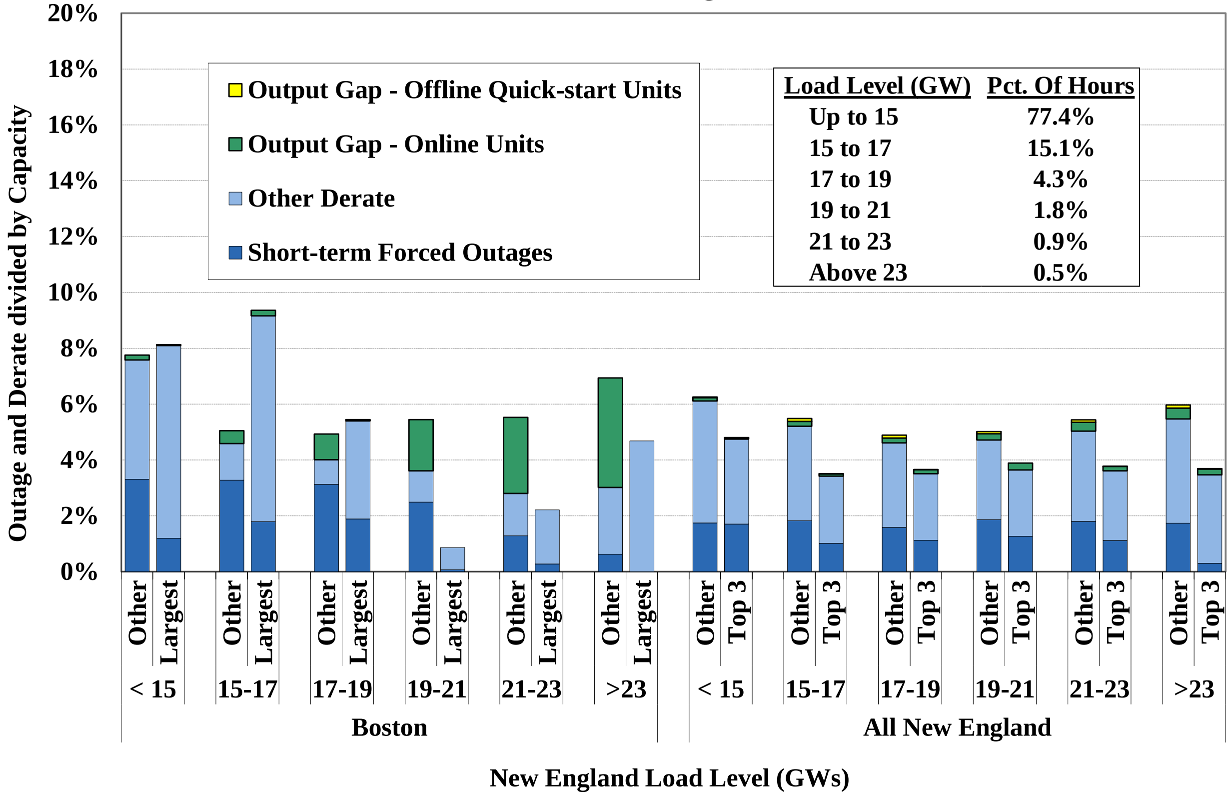
Our short-term physical withholding analyses examine:

- ***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 in this comparison, who owned 64 percent of internal generating capacity in 2021. In all New England, we compare the three largest suppliers, who collectively owned 26 percent of internal generating capacity in 2021, to all other suppliers.

Figure 6 shows that the amount of "Other Derate" was usually higher than other categories. This was primarily because some combined-cycle capacity was often offered and operated in a reduced configuration 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 supplier during the highest load hours (above 23 GW). This was a very small number of hours during the summer when very high ambient temperatures tended to reduce the ratings of thermal generators.

Figure 6: Average Output Gap and Deratings by Load Level and Type of Supplier
Boston and All New England, 2021



Excluding the contributions of the "Other Derates" for the reasons described above, the overall output gap and deratings were not significant as a share of the total capacity in either Boston or all New England during 2021. The total amount of output gap and short-term deratings generally fell as load levels increased to the highest levels, which is a good indication that suppliers tried to make more capacity available when the capacity needs were the highest. In addition, the largest suppliers in all New England generally exhibited lower levels of overall output gap and deratings, particularly at higher load levels when prices are most sensitive to potential withholding.

In Boston, the small suppliers exhibited an increased 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 did not result in congestion and higher prices in Boston 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 2021 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: [27]

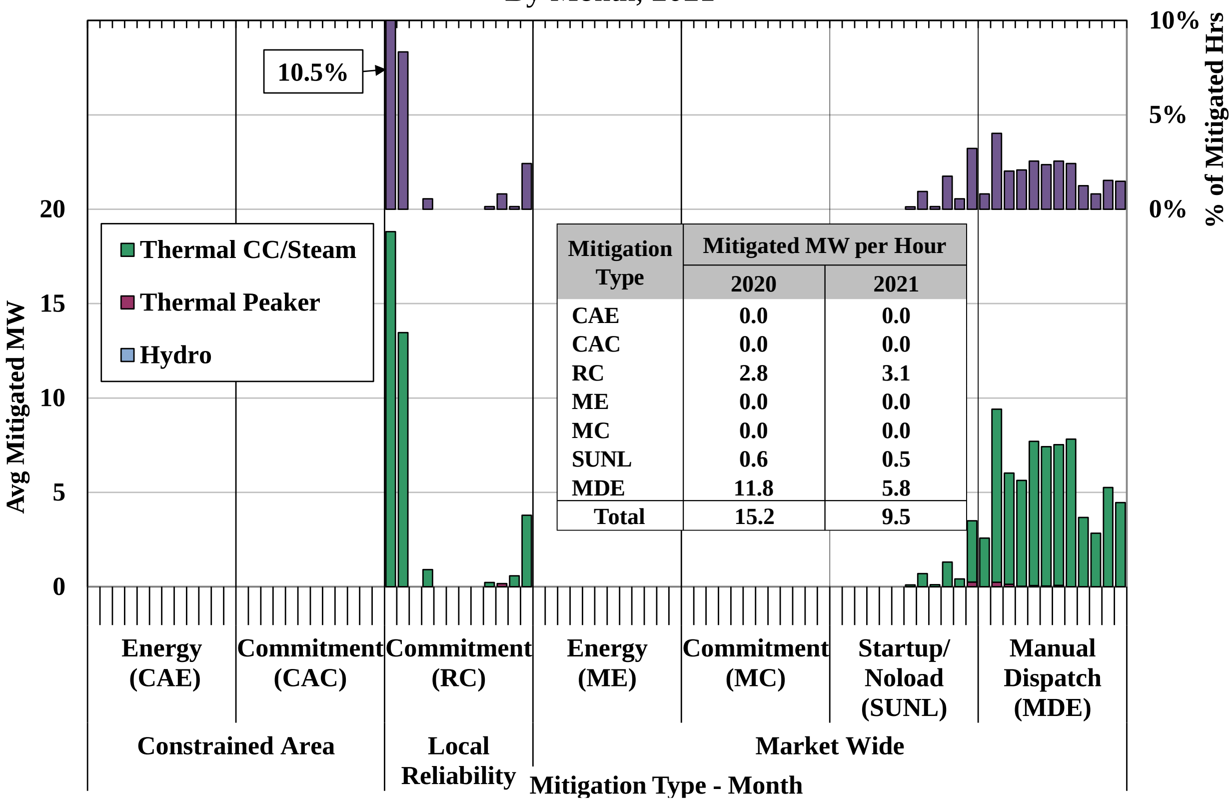
- Market-Wide Energy Mitigation (ME) – ME mitigation evaluates the incremental energy offers of online resources. This is applied to any resource whose Market Participant is a pivotal supplier.
- Market-Wide Commitment Mitigation (MC) – MC mitigation evaluates commitment offers (i.e., start-up and no-load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

There are no 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.

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

Figure 7 examines the frequency and quantity of mitigation in the real-time energy market during each month of 2021. 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). 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 2020 and 2021.

Figure 7: Frequency of Real-Time Mitigation by Mitigation Type and Unit Type
By Month, 2021



Mitigation has been infrequent in recent years, occurring in less than 4 percent of all hours in 2021, down modestly from 2020. Nearly all mitigation in the real-time market was for either local reliability commitment or manual dispatch energy. The 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.

In general, these two categories of mitigation only affect NCPC payments and have little impact on energy or ancillary service prices. The occurrence of manual dispatch energy mitigation fell from 2020 to 2021, the vast majority of which was on combined-cycle units that were typically instructed to provide regulation service or to address transient issues on the transmission grid.

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 latitude and incentive to operate in a more costly mode and receive larger NCPC payments as a result. For example, combined-cycle units needed for reliability that can offer in a multi-turbine configuration or in a 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*. 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, particularly 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.

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. Relatively mild weather conditions and the effects of the COVID-19 pandemic also contributed to falling load levels.

Overall, we find little evidence of structural market power in all of New England or in individual sub-regions. Our analyses of potential economic and physical withholding also find that the markets performed competitively with no significant evidence of market power abuses or manipulation in 2021.

In addition, we find that the market power mitigation rules have generally been effective in preventing the exercise of market power in the New England markets. The automated mitigation process helps ensure the competitiveness of market outcomes by mitigating attempts to exercise market power in the market software before it can affect the market outcomes. To ensure competitive offers are not mitigated, generators can proactively request reference level adjustments when they experience input cost changes due to fuel price volatility or other factors. Hourly offers enable generators to modify their offers to reflect changes in their marginal costs and for the ISO to set reference levels that properly reflect these costs.

Nonetheless, 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 I. Hence, we recommend the ISO require resources to operate in the lowest-cost configuration when they are committed for local reliability.

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

To maintain system reliability, sufficient resources must be available in the operating day to satisfy forecasted load and operating reserve requirements, both at the system level and in local load pockets. 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 affect which resources should be committed economically in the day-ahead market.

The ISO commits resources within the day-ahead market scheduling 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.

These commitments are made outside of the market (OOM) because they are not reflected in ISO-NE's market products, 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.

This section evaluates these reliability commitments and resultant NCPC charges and discusses implications for market efficiency. It is divided into subsections that address commitment for: a) system-level operating reserve requirements, and b) local second contingency protection requirements. The final subsection summarizes of our conclusions and recommendations.

A. Day-Ahead Commitment for System-Level Operating Reserve Requirements

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 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
2019 - 2021

Year	# Hours	Average Capacity Committed per Hour (MW)	DA NCPC (Million $)	Average Reserve Value ($/MWh)
2019	3774	580	$4.2	$2.21
2020	4054	571	$3.8	$1.68
2021	3389	514	$5.4	$1.94

The table shows that additional generating capacity was committed to satisfy the system-level 10-minute spinning reserve requirement in 39 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 both 10-minute spinning reserves and energy since this would lead the opportunity cost of not providing reserves to be reflected in the price of energy. We estimate that the absence of a day-ahead 10-minute spinning reserve product reduced energy prices across the system by an average of nearly $2 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 $18 per kW-year.[29]

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

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.

29 See Section IV.B of our 2020 SOM Annual Report.

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 the recent years.

Table 4 summarizes the commitments for local second contingency protection in the day-ahead market from 2019 to 2021 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.

Table 4: Day-Ahead Commitment for Local Second Contingency and NCPC Charges
2019 – 2021

Year	LSCP Region	# LSCP Days	#LSCP Hours	Average LSCP Capacity per Hour (MW)	DA NCPC (Million $)	Average Uplift Rate ($/MWh)	Implied Marginal Reserve Value ($/kW-Year)
2019	**NH Seacoast**	33	296	46	$0.4	$28.93	$8.57
	NH-to-Maine	68	1035	370	$2.5	$6.58	$9.21
	NEMA/Boston	4	42	600	$0.2	$7.37	$0.31
	Lw. SEMA & East RI	51	696	292	$2.6	$12.94	$11.74
	WMASS Springfield	5	38	273	$0.2	$15.84	$0.60
	NE West-to-East	15	164	355	$0.2	$3.00	$0.62
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

The table above 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.[30] The most notable results over the past two 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 in 2021, occurring on 52 days (nearly 700 hours) and accounting for 56 percent of NCPC uplift in this category. Most of these commitments occurred during periods when planned transmission outages reduced the transfer capability across the West-to-East interface.
- *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 reduce import capability from New Hampshire.

Day-ahead commitments for local second contingency protection in other areas have fallen in recent years, largely because 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 9 days in 2021. This is attributable to recent transmission upgrades associated with the Southeast Massachusetts/Rhode Island Reliability Project. Similarly, the reliability commitments for the small Seacoast load pocket in New Hampshire rarely occurred in 2020 and 2021 because of transmission upgrades associated with the New Hampshire Solution – Seacoast Reliability Project.

In 2021, the uplift cost per MWh of committed capacity ranged from roughly $7 per MWh in the combined area of Lower SEMA and Eastern Rhode Island to $14 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 higher-cost and less flexible, systematically receive more revenues than lower-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 lower 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 net revenue received by a fast start unit in 2021 by:

- Over $6.5 per kW-year in eastern New England (east of the West-to-East interface); and

30 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).

- Nearly $15 per kW-year in Maine.

These values represent a sizable increase in net revenue given that such units earned an estimated $26 per kW-year under the current markets in 2021. 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 2021, multi-turbine combined-cycle commitments accounted for: (a) roughly 46 percent of the capacity committed for local reliability in the day-ahead market; and (b) roughly 57 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 2021, an average of 182 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 11 percent.

- However, given the lack of a day-ahead reserve market with a comprehensive set of local requirements, firm importers that satisfy local requirements are not compensated efficiently.

C. Conclusions and Recommendations

In our assessment of day-ahead reliability commitment in 2021, we found that 75 percent of the day-ahead NCPC or almost $12 million was incurred to satisfy the system-level 10-minute spinning reserve requirement or local second contingency requirements in more than 4600 hours.

Because the commitments to satisfy these requirements are made outside of the market, they depress day-ahead energy prices and require NCPC payments to cover their costs.

As a result, resources that contribute to satisfying these 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:

- Many of these resources 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.

Therefore, we recommend that the ISO 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.[31] Procuring and pricing these requirements in the day-ahead market would result in substantial additional net revenues, especially for flexible resources such as fast-starting peaking units and battery storage units that will be helpful for integrating intermittent renewable generation. The ISO is evaluating potential solutions to this recommendation in its *Day-Ahead Ancillary Services Improvements* project, and we strongly support this effort. 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.

Lastly, 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 imports from neighboring areas to contribute towards satisfying local second contingency requirements (Recommendation #2020-1).

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

IV. Assessment of Forward Capacity Market Design

The capacity market is the primary market-based mechanism for satisfying resource 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.

Current capacity market rules were designed assuming that the vast majority of capacity would be supplied by conventional generators that are available year-round at all hours of the day, and that entry and exit would be mainly driven by market prices. However, as the characteristics and incentives for new generation investment change, the capacity market rules must evolve accordingly. This section highlights several features of the capacity market that should be adapted to these new circumstances:

- Section A discusses the need to update ISO-NE's reliability planning models and the capacity credit assigned to suppliers, so that capacity payments accurately reflect the marginal value of reliability provided by each resource.
- Section B analyzes how efficient capacity accreditation techniques might be applied to generators that rely on pipeline gas during peak winter conditions and discusses the need for market signals to differentiate between the value of capacity in summer and winter seasons.
- Section C assesses the forward capacity market framework, in which loads must 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 D evaluates the need to revise the Net CONE value used in the capacity demand curve to account for financial risks to merchant suppliers that are posed by state policies.
- Section E provides a summary of our conclusions and recommendations for improving capacity market design.

A. Resource Adequacy Modeling and Efficient Capacity Accreditation

ISO-NE's current practices do not accurately assess the reliability contributions of individual resources or the resource adequacy of the system as a whole. This is because: (1) simplistic methods are used to determine resources' capacity credit that do not reflect the marginal reliability benefit they provide, and (2) ISO-NE relies on a resource adequacy model that assumes an excessively high availability for some resources during tight conditions. These issues are closely related because efficient capacity accreditation requires an accurate resource adequacy model. As a consequence, the FCA does not send efficient signals for resources to enter and exit the market and may fail to procure the resources needed for reliability.

Efficient Capacity Accreditation

Capacity credit refers to the amount of megawatts a resource may offer and be compensated for in capacity market auctions. In ISO-NE, a resource that participates in the Forward Capacity Market may obtain a Capacity Supply Obligation (CSO) up to its Qualified Capacity (QC) rating. Generally, this rating is determined based on the resource's tested maximum output (for conventional generators) or its seasonal median output during certain hours of the day (for intermittent resources).[32]

In an efficient market, capacity credit reflects a resource's marginal contribution to reliability. This is equivalent to the impact that an incremental quantity of that resource type would have on the system's reliability. Capacity credit based on marginal value provides efficient incentives by paying each resource in proportion to the change in system reliability that would occur if the resource were to enter the market or retire. Alternative approaches that deviate from marginal value (such as simple heuristics or 'average' accreditation) are inefficient because they misalign resource owners' compensation from the impacts of their actions.[33]

ISO-NE's methods to determine QC largely rely on simple heuristics and are likely to significantly differ from marginal reliability contribution for the following resource types:

Intermittent Resources: The QC of intermittent generators such as wind and solar is determined based on their median output across certain hours each day in the winter and summer seasons.[34] This reflects typical output in the timeframes when peak loads have historically occurred.

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32 For most resource types, maximum Qualified Capacity is based on Seasonal Claimed Capability (SCC). See ISO-NE, *Having a Capacity Supply Obligation Lesson 2C: Introduction to Capacity Resources*.

33 We discuss the difference between capacity accreditation based on marginal value and alternative approaches that have been proposed in other markets (such as average or portfolio ELCC) in the Appendix Section VII.

34 Output is measures during hour ending 14 through 18 in the Summer season (June through September), and hour ending 18 through 19 in the Winter season (October through May), plus any reserve shortage hours.

However, it does not account for correlation of output from resources of the same technology or location. As penetration of these resources grows, the timing of reliability needs will shift to hours when they are less likely to be available. As a result, the current approach to determine their QC will increasingly overestimate their marginal reliability value.

Energy Storage: Energy limited resources, such as battery storage, can produce output for a limited period of time. As a result, the reliability value of such resources is lower than that of a resource that can generate indefinitely. The marginal reliability value of storage depends on the number of hours it can run, the penetration levels of other storage resources with various durations, and factors such as penetration of intermittent renewables (which tends to increase the marginal reliability value of storage).

Under current rules, storage that can discharge for at least two hours may offer QC up to 100 percent of its installed capacity in the FCM. This allows low-duration batteries (such as two-hour systems) to receive compensation that far exceeds their true reliability value.[35] As a result, the FCM provides little incentive for developers to choose longer-duration storage projects (which are more reliable but more costly) over short-duration batteries with diminishing benefits.

Pipeline Gas Dependency: Units that rely on common fuel supplies (such as a single shared pipeline) and do not have alternative backup fuels provide less reliability value than units that are not dependent on a common fuel source in two ways. First, extreme weather could limit the total fuel available to a group of units with no alternative fuel source, reducing the available output from the group. Second, an outage of gas pipeline equipment could result in several units being unavailable simultaneously from a single contingency. Currently, these risks are not accounted for in the determination of QC, which is based on Seasonal Claimed Capability (tested maximum output) for thermal generators.

Large Size: A large individual unit provides less reliability value than several smaller units that add up to the capacity of the large unit. This is because several small units are unlikely to experience forced outages simultaneously, while the outage of a large unit is more likely to affect reliability.[36] Currently, this is not accounted for in the QC of individual resources.

Low Flexibility: Some units (e.g., older steam turbines) require lengthy advanced notice because of long startup lead times that reduce operational flexibility. If such a unit is not already online or committed, it may not be able to provide output if a period of critical system need occurs with short notice. Hence, inflexible units with low capacity factors have less reliability value than more flexible units. This is not accounted for in a unit's QC.

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35 For example, in a past report analyzing the NYISO system, we found that the capacity value of a 2-hour battery storage resource was 66 to 68 percent when the overall penetration of storage resources is 500 MW, declining to 38 to 41 percent at 2,000 MW of penetration.

36 See Section V.C of our 2019 Assessment of the ISO-NE Electricity Markets.

Shortcomings of Resource Adequacy Model

ISO-NE uses the resource adequacy model GE-MARS to determine its Installed Capacity Requirement (ICR). Hence, each resource type should be modeled accurately in MARS so that the ICR satisfies the target level of reliability. Furthermore, accurate representation in MARS will be needed to calculate the marginal reliability contributions of individual resource types.

MARS is used to assess system reliability, measured in terms of Loss of Load Expectation (LOLE). It performs a probabilistic Monte Carlo simulation of resources' availability to serve load in each hour of the year, considering uncertainty in the annual load forecast and random outages of individual units. If the resource mix is less reliable on average, this process will result in a higher ICR to account for uncertainty in resources' availability. When running MARS to determine the ICR, ISO-NE assumes that all capacity suppliers are available up to their Qualified Capacity unless experiencing a random outage or scheduled maintenance. MARS assumes all available capacity is fully committed at all times and, therefore, does not account for the ISO's actual chronological commitment decisions or day-ahead forecast uncertainty.

The availability of several resource types is currently overestimated in MARS. The table below describes the current modeling of these resource types and potential improvements:

Table 5: Modeling Issues for Resource Types in MARS

Resource Type	Current modeling approach	Improved modeling approach
Intermittent resources	Available up to QC rating in all hours, no variation in hourly output	Model hourly resource profile reflecting weather patterns and technology characteristics. Align with weather year underlying load profile
Pipeline gas generators	Available up to QC rating in all hours unless experiencing random forced outage	Limit output of pipeline gas generators based on maximum shared gas availability in winter
Energy limited resources	Storage modeled as energy limited resource, deployed to prevent load shedding if other resources are unavailable	Consider realistic timing of storage deployment in sequence of emergency operating procedure (EOP) steps such as external assistance and reserves
Inflexible generators	Available up to QC rating in all hours unless experiencing random forced outage[37]	Model unit commitment separately from dispatch with stochastic net load forecast errors between stages; treat unit as unavailable if not committed

[37] Modeling commitment separately from dispatch may require fundamental changes to MARS. We encourage ISO-NE to explore whether this is possible but note that inflexible generators are especially vulnerable to pay-for-performance (PFP) penalties when flexibility-driven reserve shortages occur.

B. Efficient Capacity Accreditation for Non-Firm Gas Generators

Generators that rely on pipeline gas and lack dual fuel capability ("gas-only") are not modeled accurately in ISO-NE's resource adequacy model and are not assigned capacity values consistent with their marginal reliability value. In the most recent FCA for the capability period 2025-26, ISO-NE awarded CSOs to 8 GW of gas-only generators. Hence, this is currently the largest class of resources whose marginal reliability value may significantly differ from the credit they are assigned in the FCM. This subsection analyzes the historical output of pipeline gas generators during winter peak conditions and the factors affecting their marginal reliability value.

Marginal Reliability Value of Pipeline Gas-Dependent Generation

New England does not produce natural gas locally and relies on gas imported through interstate pipelines to supply fuel for winter heating, power generation, and other uses. Most firm transportation rights on the interstate pipelines are held by local gas distribution utilities (LDCs), so there is limited spare capacity available to supply power plants after gas heating demand is satisfied. Additional gas is available to generators from three liquified natural gas (LNG) import facilities which connect to the pipeline system serving New England (Everett and Northeast Gateway in Massachusetts and Saint John in New Brunswick, Canada). However, LNG import deliveries must be arranged far in advance and are not generally available on a spot basis.

Figure 8 estimates generators' use of gas delivered on interstate pipelines (which excludes gas from LNG imports). It shows the 30 winter days with the highest peak loads from December 2017 to February 2022. The gray shaded bars show injections of LNG into the New England pipeline system.[38] We assume that on winter days, gas is first used for LDCs' heating demand and that generators are served by any leftover pipeline gas and LNG. Hence, we estimate the pipeline gas used by power generators as their total gas consumption minus LNG imports. The days shown in Figure 8 are arranged in descending order of peak load, shown in the top panel. For the analyses in this subsection, gas consumption and LNG import values exclude LNG consumption by the Mystic 8 and 9 units, which obtain it directly via the Everett terminal.

Figure 8 shows that on the highest load days, the vast majority of power plant gas consumption has been made possible by LNG imports. On the top ten highest-load days in the past five winters, LNG accounted for nearly all gas-fired generation. The total amount of LNG imports varied on these days (with higher injections in 2019/2020 and lower injections in 2017/2018), corresponding to variations in the total amount of gas consumption by power plants.

38 LNG imports show the injections from the Everett, Northeast Gateway, and the St. John terminal after netting gas consumption in Canada. The bars show imports via the Everett and Northeast Gateway to the Algonquin Pipeline but do not include LNG provided directly to the Mystic plant and other local off-takers. Net imports from the St. John facility in New Brunswick reflect flows into New England via the Maritimes and Northeast Pipeline at the Baileyville station in Maine (deducting gas consumption in Canada). Pipeline receipt data was obtained from S&P Global.

Figure 8: Power Plant Gas and LNG Consumption on High Load Winter Days
December 2017 – February 2022

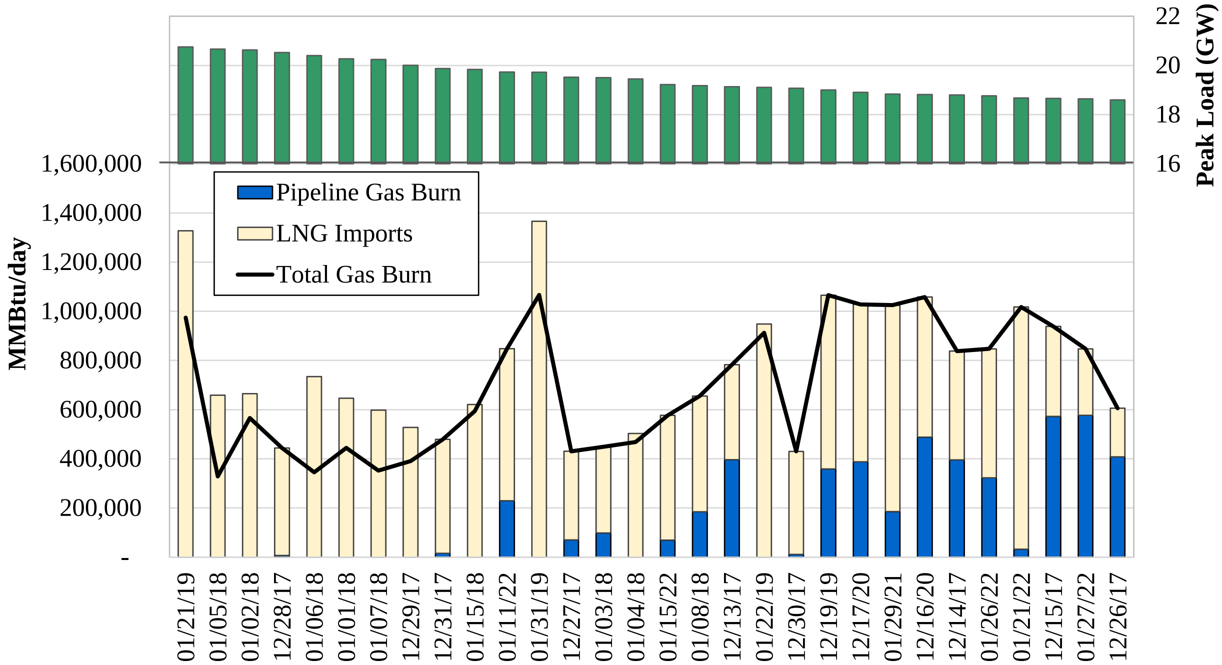
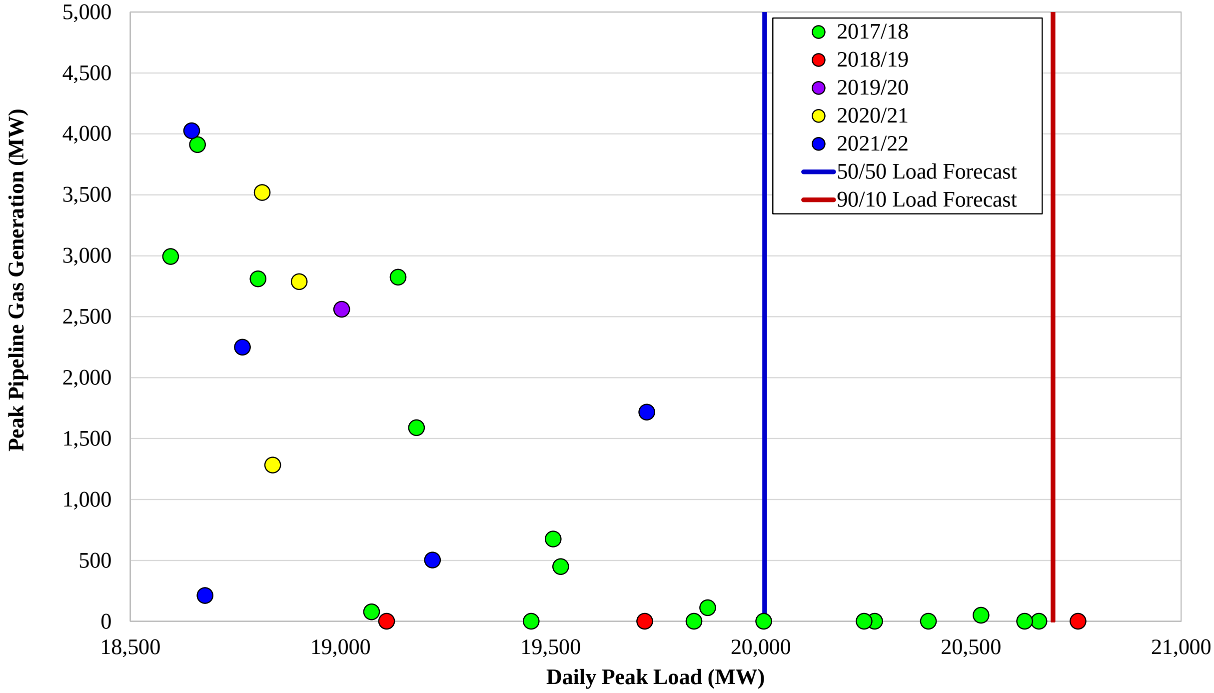


Figure 9 compares daily peak load with peak-hour generation from pipeline gas (excluding generation fueled by LNG) for the same 30 days as in Figure 8. Peak-hour pipeline gas generation is estimated as total peak output by gas-fired generators multiplied by the ratio of pipeline gas burn to total gas burn (including LNG) on that day. The orange and black lines show the forecasted 50/50 and 90/10 net peak load forecast for Winter 2022/23 from the 2022 CELT report (indicating that peak load has a 50 percent and 10 percent chance of exceeding these values, respectively).

Figure 9 shows that on high-load winter days there has been a negative relationship between peak load and generation supplied by pipeline gas (excluding LNG).[39] On days when load exceeded the 2022 CELT's winter load forecast of 20.0 GW, generation supplied by pipeline gas was minimal. This suggests a large portion of New England's gas-dependent generation will be unable to operate under the tightest winter conditions unless LNG imports are available. LNG has enabled some of these resources to operate in past winters as peak-hour gas generation on the top ten winter days has ranged from 2.7 GW to 7.1 GW. However, most gas generators do not secure contracts for firm LNG deliveries, and it is unknown how much LNG will be available in future cold weather events (beyond what LDCs need to satisfy their own planning criteria).

39 Note that changes in factors such as load patterns and energy efficiency over time may alter the peak load that would occur at a given temperature, potentially changing the relationship between load and available gas generation. Hence, this analysis is indicative, and a more robust calculation would make adjustments for forecasted changes in the relationships between temperature, load and heating gas demand.

Figure 9: Winter Peak Load vs. Pipeline Gas Generation
December 2017 – February 2022



The importance of these findings related to gas availability depends on whether tight gas system conditions coincide with the periods when the electric system conditions are tightest. Since its creation, ISO New England has been a summer peaking system, so the capacity market is designed to procure sufficient resources for the summer and, as a byproduct, this has also satisfied system needs during other seasons. However, as winter demand increases relative to summer demand and the generation mix includes more resources that are less available in the winter (e.g., solar and gas-only units), it will become more important to consider gas availability in the compensation of capacity resources. The following figure analyzes the value of these resources as New England shifts from a summer-peaking to a winter-peaking system.

Figure 10 shows two measures of capacity value for pipeline gas generators – marginal reliability improvement (MRI) and average effective load carry capability (ELCC). The quantity on the X-axis is the amount of pipeline gas-only capacity that does not have a contract for delivery of LNG. We estimated the MRI and ELCC values on the Y-axis using a simplified resource adequacy model that simulates expected unserved energy (EUE). At each level of pipeline-gas-dependent generation, the system is adjusted so that total EUE is equal to a criteria level (similar to the procedure used to determine the ICR).

Pipeline gas capacity that is not backed by LNG is assumed to be limited on high-load winter days, using a relationship based on the data shown in Figure 9. The bottom panel shows the percentage of annual EUE that occurs in winter months if the supply mix contains a given level of pipeline gas generation. This analysis only considers joint unavailability of pipeline gas generators due to constraints on the maximum amount of gas that can be transported through the interstate pipeline system. As noted in Section A, there is also a risk that pipeline gas resources will be jointly unavailable due to outage of gas infrastructure serving multiple plants. Accounting for this risk in the resource adequacy model would require assumptions regarding the probability of gas system contingencies.

Figure 10: Capacity Value Curve for Non-Firm Pipeline Gas Generators

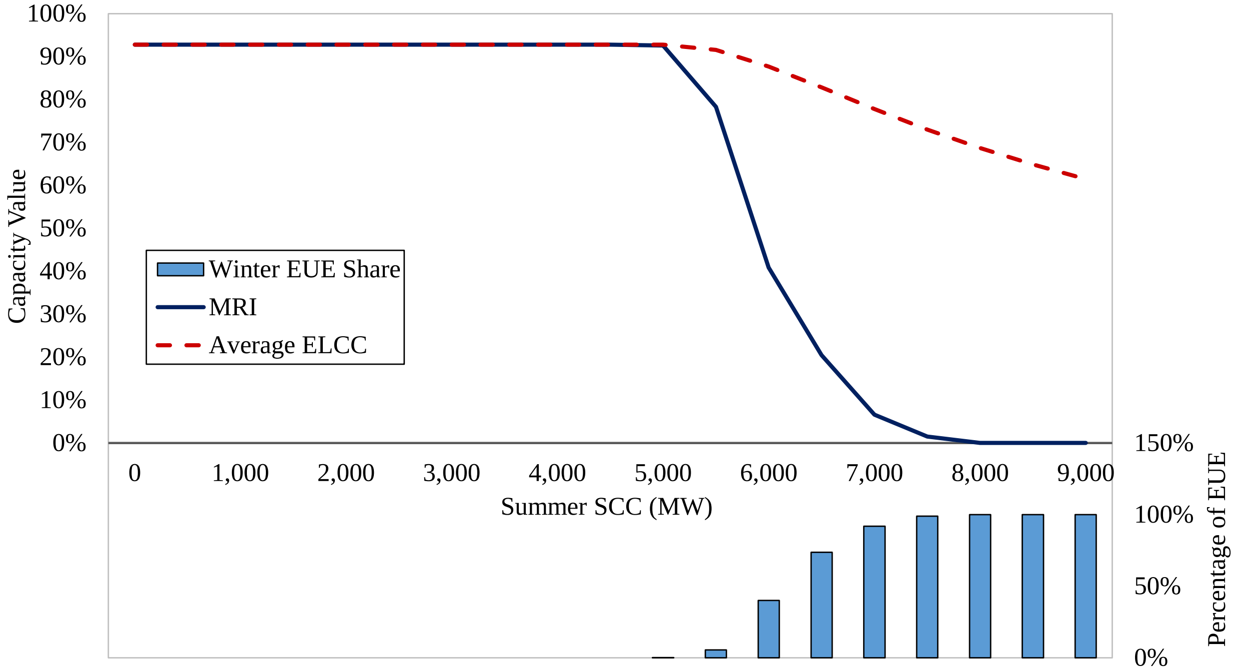


Figure 10 shows that when there is a large amount of pipeline gas capacity not backed by LNG, its marginal reliability value declines rapidly:

- For 8.0 GW of pipeline gas capacity without LNG, we estimate an MRI of **zero** percent.
- However, if the system was dependent on a smaller amount of pipeline gas generation (or if a significant portion of it was backed by LNG), its MRI would be much higher – over 90 percent at total penetrations of 5.0 GW or less.

Figure 10 also shows that the share of EUE taking place in winter months increases at higher penetrations of pipeline gas. In other words, reliability risks are increasingly concentrated in winter when the system's dependence on pipeline gas capacity is higher.[40]

This figure demonstrates that the marginal value of pipeline gas capacity is closely related to the proportion of load-shedding risk that takes place in winter. Pipeline gas generators have a high

40 It is important to note that this analysis does not necessarily imply that ISO-NE is currently at a heightened risk of load shedding in winter months. We calculated MRI and ELCC values 'at criteria' (e.g., assuming there is no capacity surplus beyond what is needed to satisfy minimum reliability requirements). When ISO-NE has surplus capacity, load shedding risk in all seasons is lower than at criteria conditions.

marginal reliability value in summer, when the gas system is not constrained. The 2022 CELT 90/10 summer load forecast for 2025 is 5.2 GW higher than the winter load forecast. Hence, if only a small amount of capacity faces winter fuel risks, load shedding risk is likely to be concentrated almost exclusively in summer months. This is because the capacity needed to meet summer peak load is more than enough to reliably meet winter peak load. In this case, resources facing winter fuel restrictions still have high marginal capacity value because they are reliable in the period when capacity is most valuable (summer). By contrast, if a large portion of the system's capacity faces winter fuel limitations, winter months will exhibit a greater reliability risk despite having lower peak load and the marginal value of these resources will be low.

Efficient Accreditation of Pipeline Gas-Dependent Generation

Figure 10 illustrates why a marginal capacity accreditation approach will provide efficient incentives to address winter reliability issues and an average accreditation approach will not. When load shedding risk is concentrated in winter, pipeline gas resources without LNG will receive very low capacity payments under an MRI-based approach because they do not improve winter reliability. The owners of these resources will then have strong incentives to procure firm LNG deliveries or invest in dual fuel capability because these actions would increase their capacity payment by up to 100 percent of the capacity price. We recognize that some of these responses may be limited by states' willingness to permit dual fuel infrastructure or by the 3-year ahead timeframe of the FCM. The latter issue can be addressed by transitioning to a prompt capacity market, which we discuss in the next subsection. The portion of resources that cannot take these actions will face incentives to retire and be replaced by more reliable capacity.

Under an average accreditation approach, pipeline gas generators that provide no marginal value would still receive relatively high capacity payments. In Figure 10, 8 GW of pipeline gas-dependent capacity without LNG would have an average ELCC of 69 percent despite having *no* marginal value. This is because the average value includes the amount of pipeline gas capacity that is valuable for meeting summer load before winter reliability risk increases. Such an approach would significantly overpay these resources since the average value of all 8 GW is immaterial to a given resource's value when the system is over-saturated with pipeline gas generators. As a result, average accreditation would not provide efficient incentives for resources without firm fuel to take actions to improve their winter reliability or retire.

Differences Between Summer and Winter Capacity Market Parameters

Our analysis of pipeline gas generation highlights the need to consider how the value of capacity differs between summer and winter seasons. Historically, most resources could provide similar amounts of capacity in summer and winter, so resource adequacy planning centered on procuring sufficient capacity to meet peak summer load. However, there are now large amounts of capacity that have higher availability in summer than winter, including:

- 8 GW of gas-only generation cleared in FCA16, a large portion of which may be unavailable on peak winter days if not backed by LNG;
- Gas-fired generators that have oil as a backup fuel are often unable to use duct burners and other output ranges when running on oil. As a result, approximately 800 MW of qualified capacity may be unavailable when these resources switch to oil in cold weather;
- 1.5 GW (nameplate) of solar PV cleared in FCA16, and solar is a fast-growing resource in New England. Solar PV resources listed in the 2022 CELT report have an average summer SCC of 41 percent and an average winter SCC of less than 1 percent.

The FCA is designed to procure the same amount of qualified capacity in all months of the year. ISO-NE conducts a single FCA each year covering a capacity commitment period (CCP) from June through May. Most resources with different levels of summer and winter QC may only offer the minimum QC that they can provide for the entire CCP. Alternatively, pairs of resources may form ‘composite offers’ that have the same aggregate summer and winter QC. Resources that receive a CSO through the FCA earn the same capacity price in each month of the CCP.

The FCA is not currently designed to recognize differences in seasonal reliability needs and compensate suppliers accordingly. As weather-driven renewables enter the market and ISO-NE implements improved capacity accreditation methods, a growing portion of capacity is likely to have unequal seasonal capacity values. An efficient market would compensate capacity in each season based on its marginal value, which is determined by the level of surplus reliable capacity relative to peak demand in that season. The current practice of procuring the same amount of capacity in each season and setting a uniform price regardless of seasonal surplus levels may have the following consequences:

- The FCA may be unable to procure the optimal amount of capacity in each season. The optimal amount of procurement in summer and winter may vary because demand is lower in winter, but resource availability is also lower. Because summer and winter cleared capacity must be equal, the FCA may be unable to procure surplus summer capacity that could contribute to improved reliability and lower prices.
- The FCA may fail to compensate resources based on their marginal reliability value. For example, suppose a resource with high summer QC and a resource with high winter QC form a composite offer and obtain a CSO. Both resources receive the same price per kW-month, even if one member of the pair provides the vast majority of the reliability benefits. This reduces incentives to invest in resources that have higher marginal value when capacity is most needed.
- Conducting the FCA on an annual basis may limit the flexibility of resources to take actions targeting seasonal reliability needs, such as securing LNG supply ahead of a winter season. This concern is related to issues with the mandatory forward capacity market discussed in the next section.

C. Assessment of the Mandatory Forward Capacity Market

ISO-NE procures capacity to satisfy resource adequacy requirements primarily through the Forward Capacity Auction (FCA). The FCA is conducted over three years before the associated Capacity Commitment Period (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 Capacity Supply Obligation (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 procurement relative to the CCP.

Role of FCA in Coordinating Investment

The main purported benefit of a mandatory forward 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.[41] 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 Net Cost of New Entry (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

41 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.

of merchant generation has been financed and built in the past decade in New York ISO, which operates a prompt capacity market immediately prior the capability period. Developers of these projects have mitigated their revenue risks through bilateral hedges such as revenues puts.[42] Spot markets provide a basis for investors to enter into 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 FCA had a dubious track record of coordinating timely entry of new resources even before the multi-year lock-in was eliminated. Figure 11 shows new generation projects that received CSOs of at least 50 MW for the CCPs beginning June 2016 through June 2022.

Figure 11: New Generation Projects with Initial CSO above 50 MW

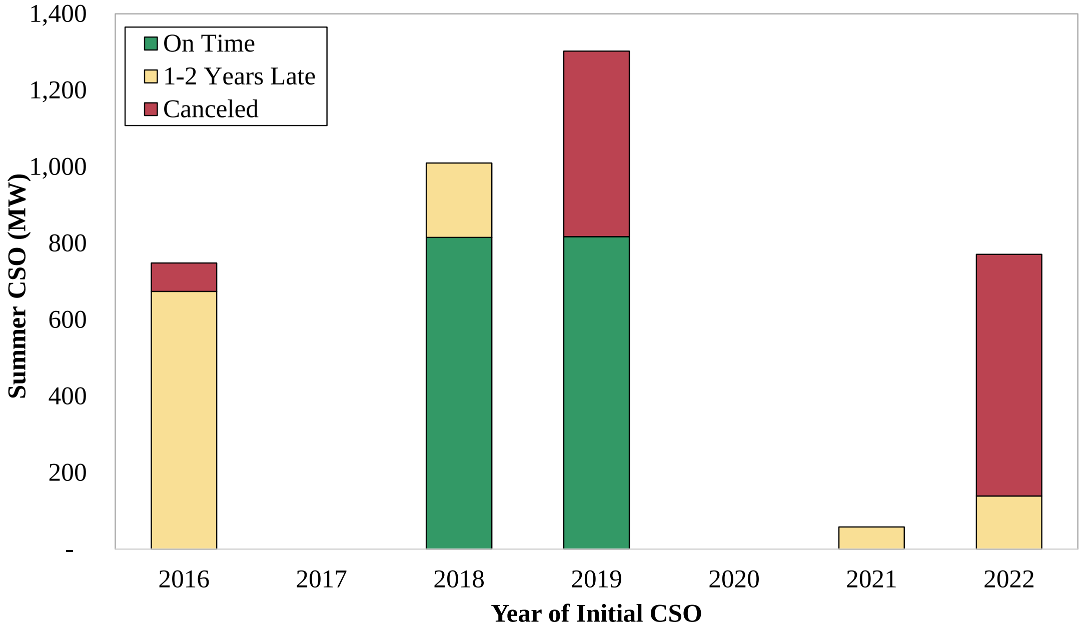


Figure 11 shows that out of 3.9 GW of such projects, 1.6 GW (42 percent) entered service on time to satisfy their initial CSO, 1.1 GW (27 percent) entered (or are expected to enter) later than the summer of their initial CSO, and 1.2 GW (31 percent) never delivered their CSO because the project was canceled or failed to meet development milestones.[43] The projects that entered on time all opted to receive multi-year price guarantees, an option which is no longer available.

42 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.

43 Projects with initial CSOs in 2022 include Killingly Energy Center, which had its CSO terminated for failing to meet milestones, as well as the Vineyard Wind and Three Corners Solar projects, which we

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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 1.6 GW of new generation capacity that received CSOs in the past three FCAs, 1.1 GW (72 percent) was from solar and battery projects, both of which can often be constructed in significantly less than three years.
- Over 700 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.[44] These projects are typically aggregations of devices installed by individual end-users and do not require lengthy construction timelines.

The FCA may actually inhibit resources with fast development timeframes from receiving capacity payments as soon as they are able to support reliability. For example, 848 MW (nameplate) solar and storage resources that entered service between January 2016 and April 2022 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 but will not be in service until at least 2023.[45]

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assume to be at least one year late due to publicly available information that they are not likely to be in service on time to meet their initial CSO in summer 2022.

44 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.

45 As of May 2022, Vineyard Wind's website states that it will first deliver power in 2023 and ISO-NE's interconnection queue lists its commercial operation date as October 2023.

- Large conventional projects may similarly encounter delays due to both regulatory and construction risk.[46] In a prompt market, developers can manage these risks by delaying or discontinuing the project, but these actions are more costly in forward market.
- 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 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.
- 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.[47]

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. 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

46 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. However, this led to a $236 million arbitration judgment against the developer for wrongful contract termination in March 2022.

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

resource mix, projects face financial risks as their capacity value is updated between the FCA and capability period. This subsection further explains this issue.

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.[48] 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 financial risks for some resource types selling capacity in the FCA. Capacity credit values and the ICR will change between the FCA and the capability period as the resource adequacy modeling assumptions become more accurate. 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 over-estimated and the ICR will have been under-estimated because these resources will have been excluded from the resource adequacy model. When the resource mix is updated for subsequent ARAs with the FCA results, the capacity value of storage units will be reduced, requiring them to buy out of part of their CSO at potentially high cost.[49]

48 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.

49 Under an alternative design, resources that clear the FCA might be permitted to lock in the capacity credit they were originally assigned. However, this would simply shift 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 in the supply mix that will clear. A prompt capacity auction 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 will depend on whether they contract for firm transportation and/or LNG deliveries if proposed improvements to capacity accreditation rules are adopted. However, the capacity credit of resources participating in the FCA will be determined nearly four years in advance of the winter portion of the associated CCP.[50] 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 undesirable for many 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 over-procure 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 new fuel contracts based on expectations of revenues in the prompt market.[51]

D. Rising Financial Risk for New Capacity Investment

In early 2022, ISO-NE filed tariff changes with FERC to eliminate its Minimum Offer Price Rule (MOPR) beginning in FCA19 auction to be held in 2025. Eliminating MOPR will lower barriers to participation in capacity markets by resources sponsored by New England states. However, an important consequence of eliminating the MOPR is an increase in financial risk for merchant resource owners. This is because resources that receive state contracts and other out-of-market revenues may enter regardless of market conditions, increasing the likelihood of extended capacity surpluses and correspondingly low capacity prices. The timing and quantities of future state-sponsored projects are uncertain, so projects that rely on capacity revenues (including clean energy technologies) face greater market risk in the absence of a MOPR than they would if new entry was governed only by wholesale market conditions.

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50 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.

51 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.

The capacity market plays a critical role in incentivizing entry of new resources to support reliability. The capacity market demand curve is designed so that the price will equal the net cost of new entry (CONE) of a new peaking unit when new capacity is needed to satisfy the installed capacity requirement (ICR).[52] The ISO periodically estimates the CONE based on a review of the costs of a new peaking plant, including the cost of capital that would be required by investors relying on risky merchant revenues to recover the costs of the plant.

In order to meet the capacity market's objectives, factors that increase the cost of capital for a merchant peaking plant should be considered in the CONE study. Otherwise, the demand curve will not provide enough revenue to encourage new entry when it is needed for reliability. This could lead to a chronic need to use out-of-market reliability agreements to prevent retirement of existing units instead of relying on efficient merchant entry.

Recent CONE studies have estimated the cost of capital of a new entrant based on a review of historical returns required by investors in power generation assets operating in regions with competitive wholesale markets. Each of these markets is either in a state jurisdiction with limited policy intervention or has limited the price effects of subsidized entry with a MOPR. Hence, the available historic data does not reflect the returns an investor would expect in a competitive power market without a MOPR and high levels of policy-driven investment. Hence, it is important to account for the effects of eliminating the MOPR provisions on the WACC.

We performed a study in 2021 of the potential impact of eliminating the MOPR on the cost of capital for merchant resources.[53] We used a Monte Carlo model to simulate revenues of a hypothetical peaking unit with and without elimination of the MOPR under a range of scenarios of policy-driven investment. We relied on studies conducted by state governments and other public information to develop a range of policy-driven entry levels for clean energy technologies. Our study found that the revenues of the peaking unit would be more volatile without the price-moderating effects of the MOPR.

This study estimated that eliminating the MOPR would cause the after-tax weighted cost of capital for the peaking resource to increase by 225 basis points, which corresponds to a 16 percent increase in the Net CONE. This study demonstrates that the ISO should explicitly consider the effects of state policies on merchant investment risk and the net CONE used to set the capacity market demand curve.

52 The new unit for which the CONE is estimated has generally been a natural gas-fired combustion turbine. This assumed technology may warrant re-evaluation in the future if fuel or regulatory limitations make such resources difficult to develop.

53 See "EMM Evaluation of Changes in MOPR Rules on Financial Risk in New England", available here.

E. 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:

- Current resource adequacy modeling and capacity accreditation techniques will not accurately assess the system's reliability or send efficient signals for investment;
- The lack of seasonal price signals and requirements will cause the capacity market to fail to procure the optimal amount of capacity or incent gas generators to obtain firm fuel;
- 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; and
- 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.
- The capacity market demand curves may fail to attract new capacity when needed for reliability if not adjusted to consider the effects of MOPR elimination.

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

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.

Under the recommended framework, each resource's compensation reflects: (a) the expected ability of the resource to provide output in critical hours based on the type and characteristics of the resource, and (b) the historic performance of the individual resource relative to other resources of the same type. The expected capacity value of a resource should be estimated by measuring how an incremental addition of that resource impacts a reliability metric (such as LOLE or MWhs of unserved load) in ISO-NE's resource adequacy model.[54]

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54 This is the Marginal Reliability Improvement (MRI) method. Marginal capacity value can also be calculated using the Marginal ELCC method. As explained in the Appendix Section VII, Marginal ELCC and MRI are likely to produce similar results. We expect that MRI is advantageous because it is less computationally intensive and is already used in ISO-NE's capacity demand curve.

ISO-NE will need to enhance its resource adequacy model to accurately assess the value of each resource type and the ICR needed to satisfy resource adequacy criteria. In particular, ISO-NE's GE-MARS model should be modified to consider the characteristics of intermittent resources, energy storage, generators with correlated fuel limitations (such as pipeline gas), and units with long startup lead times.[55]

Recommendation #2021-1: We recommend eliminating the mandatory forward capacity auction and replacing it 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 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 weeks or months prior to the associated capability period;[56]
- 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.

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;

[55] See Section VI.D of our 2020 Assessment of the New England Electricity Markets.

[56] 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.

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

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

V. Market Operations During January 2022

The markets in New England and eastern New York have become increasingly vulnerable to natural gas limitations during cold weather conditions over the past decade with the retirement of older oil-fired, dual-fuel, and nuclear generation. Additional generators have signaled their intent to retire, although the retirement of the Mystic combined cycle generators (which are supplied with LNG) has been deferred until June 2024. Given the current capacity surplus measured relative to the summer peak load conditions, additional retirements of oil-fired and dual-fuel generation appear likely.

In Section IV, we recommend that ISO-NE enhance its resource adequacy model and capacity market to provide efficient market incentives for addressing fuel security needs. However, even with these enhancements, the ISO will continue to rely on its energy and ancillary services markets to coordinate the efficient commitment and dispatch of oil-fired and gas-fired generation. Day-ahead and real-time prices must accurately reflect the marginal cost of the supply needed to satisfy system needs in order to provide efficient incentives to procure fuel and perform reliably. Therefore, it is important to assess whether the day-ahead and real-time markets function efficiently during winter weather conditions to ensure that suppliers have appropriate incentives to be available. Conditions in January 2022 provided an opportunity to evaluate this aspect of the markets' performance so in this section we review:

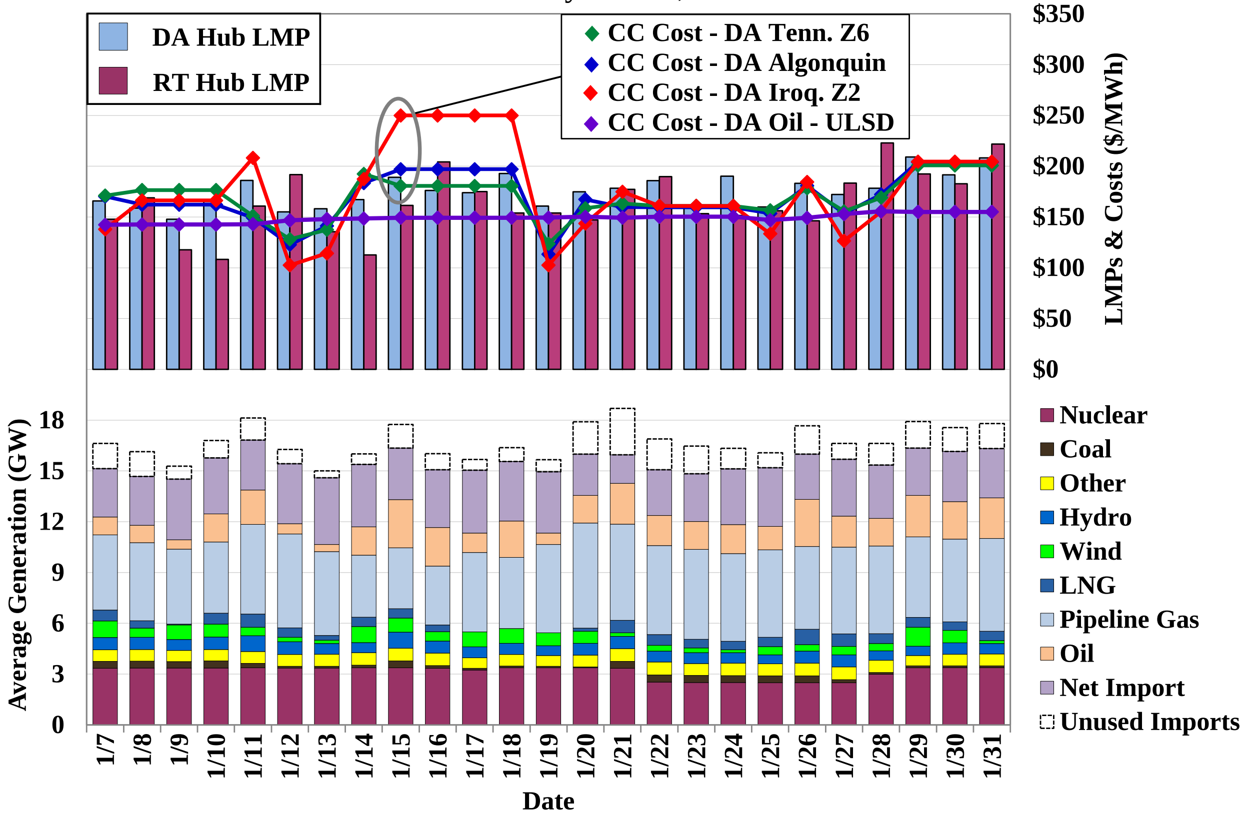
- Fuel and electricity prices to determine whether they were consistent with the commitment and scheduling of individual generators;
- Utilization of oil-fired and dual-fuel resources to identify factors that may have limited their availability;
- Production from gas-fired generation to determine how well day-ahead gas price indices reflected the cost of fuel to these units; and

These analyses provide insight about how well the day-ahead and real-time markets coordinate the utilization of resources with limited fuel inventories and reward suppliers that ensure fuel is available to run their plants. Our conclusions are provided at the end of the section.

A. Evaluation of the Supply Mix and the Prices for Fuel and Electricity

This subsection shows sources of supply that New England used on days with tight gas market conditions in January 2022. Our analysis evaluates the consistency of prices and energy output with the production costs of different types of units. The bottom panel in Figure 12 shows the amount of generation supplied by each fuel type during the period by date, the net imports to New England and the amount of unused import capability. The top panel shows the average daily day-ahead and real-time LMPs at the New England Hub compared to the variable production cost of hypothetical combined cycle resources with heat rates of 7.0 MMbtu per MWh burning natural gas procured day ahead from Algonquin, Iroquois Z2, and Tennessee Z6, and from Ultra-Low Sulfur Diesel ("ULSD"). The estimates include $3 per MWh of variable O&M, RGGI compliance costs, and $3 per MMbtu for ULSD delivery costs.

Figure 12: Generation by Fuel Type and Imports to New England
January 7 to 31, 2022



This evaluation provides several useful insights about market operations on days with very tight gas market conditions.

- Nuclear, coal, other (wood/refuse), hydro, and wind ran at high output levels and satisfied 4.5 to 6.3 GW (30 to 41 percent) of load on these days. The total from these categories has fallen from previous cold winters primarily because of retirements. For example, they accounted for an average of 7.1 GW in the 2017/18 cold spell.
- LNG-fired generation fell significantly from the 2017/18 winter cold spell, providing an average of 470 MW of supply on these days (down 45 percent). Tight conditions in global natural gas markets led to steep LNG price increases and reduced shipments to New England generators.[58]
- Oil-fired generation use was low (averaging 10 percent of load), especially given its apparent cost advantage relative to natural gas price indices on most days. In total, oil generation averaged 1.4 GW and rose as high as 3 GW on the highest load days when gas system conditions led to higher positive spreads between gas prices and oil prices.
- Net imports were substantial, accounting for an average of 3.2 GW on these days.

58 See "Winter Operations Recap Winter 2021-2022" by Mike Knowland at https://www.northeastgas.org.

- Pipeline-gas-fired generation was relatively consistent, providing an average of 4.8 GW of output on these days. However, this category fell to as low as 3.5 GW on the highest load days when the spread between gas and oil prices was highest.

These results raise two issues that are addressed later in this section. First, oil-fired output satisfied up to 17 percent of load on these days, which is substantial even though the winter was unusually cold. Nonetheless, some apparently economic oil-capable generation was not utilized to burn oil. Subsection B identifies factors that reduced utilization of economic oil generation. We evaluate these factors and assess whether they arise from a deficiency in the market or from normal issues that should be expected to occur in a well-functioning market. Second, pipeline-gas-fired generation was produced on many days when pipeline gas appeared to be uneconomic based on day-ahead gas index prices, which is evaluated in Subsection C. In particular, we discuss factors that led pipeline gas to be more or less expensive than would appear based on these index prices.

B. Utilization of Oil-Fired and Dual-Fuel Capacity

In a competitive market, dual-fueled generators are expected to use the most economic fuel to produce power. Generators offer into the day-ahead and real-time markets on the lowest cost fuel, and the ISO selects the most economic offers across the system to satisfy demand and reserve requirements. Through this process, the ISO coordinates the utilization of different fuels efficiently while maintaining reliability. When individual generators offer to use the fuel type that is apparently more expensive, it can be an indication of an operating constraint or market factor that could become more significant under more severe conditions.

This subsection evaluates the use of oil-fired and dual-fuel capacity during this period, eliminating the few days when gas prices were lower than ULSD prices.[59] We estimate the amount of capacity that would have been economic based on the variable cost of generating from fuel oil, assuming no logistical, mechanical, or environmental limitations other than explicit air permit restrictions. Of the 13.7 GW of winter capability listed in the CELT report as dual-fueled or oil-fired, approximately 6 percent (or 15 percent of the combined cycle total) is unable to operate on oil because of equipment limitations and/or air permit restrictions. Most of this is duct-firing equipment that is not permitted and/or not configured to burn oil on combined cycle units that are able to burn oil in the main combustion turbines.

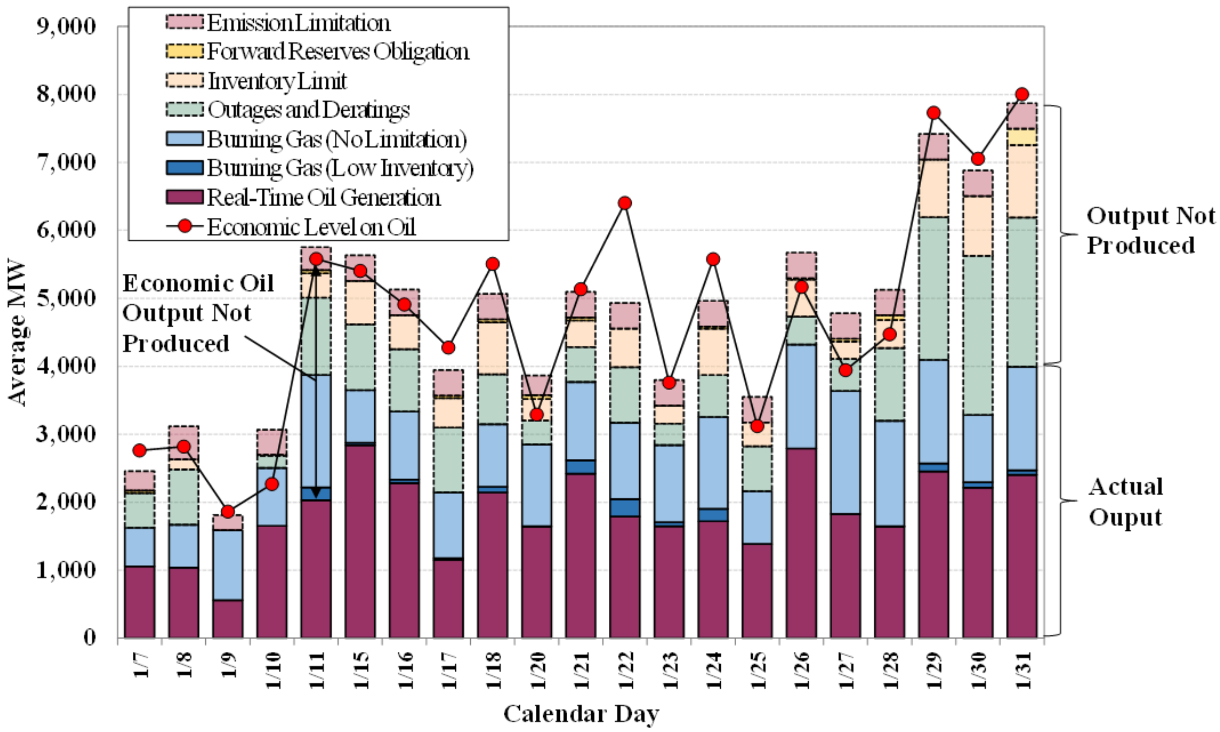
Figure 13 shows our estimates of the amount of oil-capable capacity that would have been economic to burn oil based on day-ahead and real-time clearing prices each day (the red circles).[60] The figure also shows the actual output produced from oil and natural gas in these

59 Gas prices for all three of the major indexes were lower than ULSD prices on each of Jan 12, 13, and 19. January 14 results were also excluded due to the mismatch in timing between electric and gas market days.

60 We assume economic commitment of fast-start generation is done in accordance with real-time prices while economic commitment of slow-start generation is done in accordance with day-ahead prices.

units along with the amount of economic oil output that was likely limited by four different factors.[61] This assessment provides key insight about how efficient markets should affect the availability of generation with firm fuel supply during periods of natural gas scarcity.

Figure 13: Utilization of Oil-Fired and Dual-Fuel Capacity
Selected Calendar Days in January 2022



Actual oil-fired output averaged 41 percent of the capacity that we estimate would have been economic to burn fuel oil on these days. Alternatively, 27 percent of the estimated economic oil-fired output was actually produced by burning natural gas for the following reasons:

- *Favorable Gas Costs*. Most of the output from gas (84 percent) came from either baseloaded cogeneration plants or plants that are situated favorably on the Tennessee and Algonquin pipelines in western Massachusetts or Connecticut. Generators upstream of key pipeline constraints often have better access to gas at potentially lower prices.
- *Operational Benefits*. The choice of fuel may affect the operational characteristics of the generator. For example, burning oil may restrict access to duct-firing ranges on a combined-cycle unit and lower its potential output.
- *Oil Inventory Management*. Generators with limited oil inventories may burn natural gas to conserve their oil, although this was not likely a significant factor during this period.
- *Total Emissions Limits*. Air permit restrictions may limit a generator's number of oil-fired hours per year, which was also not likely binding in January 2022.

61 Non-forced outages and deratings were not significant during this period. The ISO operators did not posture (i.e., hold a generator in reserve through an OOM action) any oil-fired units during the period.

The remaining 32 percent of estimated economic oil-fired output was not produced because of:

- *Forced outages and deratings*. Led an average of 860 MW to be unavailable over the period and over 2.3 GW from January 29 to 31.
- *Inventory-limited units*. Accounted for an estimated 450 MW of unutilized capacity.
- *Emission rate limitations*. Accounted for 360 MW from generators that had difficulty keeping their emissions within the tolerances required by their air permits.

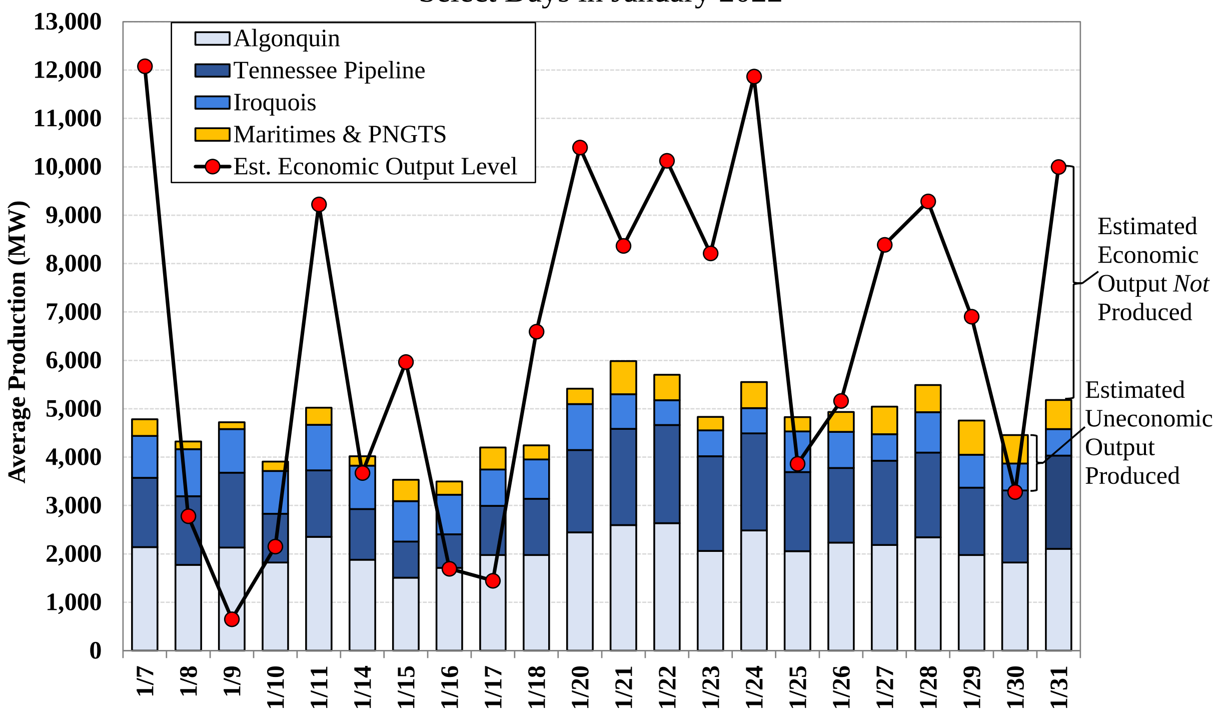
From January 29 to 31, the amount of generation economic to burn oil and oil-fired output both increased significantly partly because of forced outages and derates that raised prices and made higher cost oil-fired units economic. This highlights that when generators are incentivized through efficient day-ahead and real-time prices, they need not be compensated specifically for maintaining alternative fuel inventories. Efficient markets allow them to earn additional revenues by maintaining oil inventories and maximizing their resources' availability.

C. Analysis of Production by Pipeline-Gas-Fired Generation

This subsection evaluates the use of pipeline-gas-fired generation during this period to determine whether the marginal cost of these resources was efficiently reflected in clearing prices. This is important because it indicates whether the ISO-NE markets are providing economic signals to attract the necessary available supply under tight system conditions with limited gas availability. Figure 14 shows pipeline-gas-fired generation each day by pipeline relative to the generation we estimate would have been economic based on prevailing day-ahead gas prices for each pipeline.

Figure 14: Production by Pipeline-Gas-Fired Generation versus Wholesale Prices

Select Days in January 2022



Of the gas-fired generation that was economically scheduled during the period:

- 8 percent was supplied from the Maritimes and PNGTS pipeline;
- 16 percent was supplied from the Iroquois pipeline;
- 45 percent was supplied from the Algonquin pipeline; and
- 31 percent was supplied from the Tennessee pipeline.

The figure shows a relatively weak relationship between the production costs estimated from day-ahead gas price indices and other production input costs and wholesale prices. On twelve of the days shown, the estimated amount of economic gas-fired generation was at least 40 percent *higher* than actual gas-fired generation for several reasons:

- Some pipelines (especially Iroquois) require generators to burn a more consistent quantity across the day than would be optimal based on variations in power prices, reducing their profitability; and
- The day-ahead index prices generally reflect the prices of the gas transacted for these days, but additional quantities of gas may have been available only at a premium over the day-ahead prices published for the indices.

On five days, the estimated amount of economic gas-fired generation was *far lower* than the actual levels for related reasons. This reflects that gas sometimes becomes available at a lower price intraday than was available day-ahead. This can happen if actual consumption by core natural gas demand is lower than LDC's forecasts. For instance, generators on the Tennessee pipeline scheduled an average of nearly 50 percent more gas after the timely window on these days, while LDCs generally reduced their schedules after the timely window closed.

D. Conclusions

New England has become increasingly reliant on natural gas and vulnerable to disruptions in fuel supplies to the region. ISO-NE is considering capacity market enhancements to procure resources needed to maintain reliability during periods of extreme natural gas scarcity. Nonetheless, efficient day-ahead and real-time market performance will also help maintain reliability during winter conditions while minimizing costs to consumers. This section of the report evaluates market operations during cold weather conditions in January 2022. It demonstrates that:

- Generators do respond to the economic signals provided by the fuel markets and electricity markets. This underscores that producing efficient day-ahead and real-time energy and ancillary services prices is of paramount importance;
- This response by generators is not always easy to predict because they must consider an array of factors and limitations in making fuel procurement and burn decisions; and
- Real-time gas availability and cost can be highly uncertain, which will affect generators' fuel burn decisions, particularly under tight conditions.

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.[62]
- 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 6:

62 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.

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

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

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.[63] 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.[64]
- 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.[65]
- For estimating the cost for entry, we utilized the cost trajectory from inputs to the NREL's ReEDS model.[66]

63 For NREL data, see link.

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

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

66 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.

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.[67] Net revenues of wind units in MISO and ERCOT are based on the following assumptions:

- Net E&AS revenues are calculated using real time energy prices in the South zone in ERCOT and in Minnesota for MISO.
- The energy produced by these units is calculated using location-specific hourly capacity factors. We considered capacity factor for recent wind installations in MISO and ERCOT, and the capacity factor information presented in 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.[68]
- Consistent with the assumption for other markets, we assumed full PTC revenues for the land-based wind plants in ERCOT and MISO regions.

Table 7: Land-based Wind Parameters for Net Revenue Estimates[69]

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%

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

68 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.

69 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.

VII. APPENDIX: MRI AND ELCC METHODOLOGIES

In this report, we recommend accrediting capacity suppliers based on each resource's marginal reliability value. We recommend determining this value using the Marginal Reliability Improvement (MRI) method or marginal Effective Load Carrying Capacity (ELCC) method. These approaches differ from other methods that have been used for capacity accreditation, including 'average' ELCC and simple heuristic approaches. In this subsection, we explain the difference between MRI and ELCC approaches and discuss the advantages of marginal approaches in general and MRI in particular.

Approaches to Capacity Accreditation

In markets that procure a quantity of capacity based on a megawatt-requirement, capacity credit refers to the amount of megawatts a resource is allowed to offer and be compensated for in capacity market auctions. All frameworks to establish capacity credit use methods to either discount each resource's nameplate capacity or establish different prices for resources with different characteristics.

The concept of capacity credit is closely related to the system's reliability metric, which represents how reliable the system is. For example, ISO-NE targets a Loss of Load Expectation (LOLE) of 1 day in 10 years. This criterion is used to determine capacity market requirements (e.g., ICR), which are derived from simulations of LOLE that consider every resource's availability during hours when load shedding might occur. Ultimately, every resource's capacity credit should reflect its marginal impact on LOLE. Hence, a MW of accredited capacity from any resource type should correspond to a comparable impact on LOLE.

For some resource types, a random forced outage rate (EFORd) alone is not applicable or is not sufficient to reflect the resource's marginal impact on LOLE. Examples include intermittent renewables, energy-limited resources, long lead time or very large conventional generators, and generators that can experience a common loss of a limited fuel supply (such as a pipeline outage). One reason that EFORd alone does not accurately describe these resources' impact on reliability is that EFORd represents the probability of random uncorrelated forced outages. However, these resource types pose the risk of correlated outage or limited availability of a large amount of capacity under peak conditions.

There are multiple methods to assess the capacity credit of these resources. Capacity credit is often described relative to a hypothetical unit of 'perfect capacity' that is always available:

(a) Marginal Reliability Impact (MRI) – measures how an incremental amount of capacity of Resource X impacts LOLE or MWhs of expected unserved energy, relative to how the same amount of 'perfect capacity' impacts LOLE or MWhs of expected unserved energy.

(b) Effective Load Carrying Capacity (ELCC) – measures the MW quantity of 'perfect capacity' that would produce the same LOLE as a given quantity of Resource X.
   - ELCC approaches may be marginal or average, which is discussed further below.

(c) Heuristic approaches – estimate capacity credit based on rule-of-thumb approaches, such as a resource's average output in a predetermined set of hours.

Current ISO-NE Approach

ISO-NE's current approach to determining qualified capacity credit of intermittent and energy-limited resources relies on simple heuristics. The QC of intermittent generators, such as wind and solar, is determined based on their median output across certain hours each day in the winter and summer seasons.[70] Storage resources can offer QC up to 100 percent of their installed capacity if they can discharge for at least two hours. Our recommendation would eliminate these heuristic approaches and replace them with a common data-driven framework for all resource types.

ISO-NE currently does not adjust capacity credit for very large conventional generators or for units with common fuel security risks. The risk of a common outage affects their expected PFP risk, but there is no mechanism to preemptively reflect correlated risk of these units in their qualified capacity amount. Similarly, ISO-NE does not preemptively adjust capacity credit for units with long startup lead times, even though such units may perform poorly as a group during certain events (such as shortages that occur unexpectedly without sufficient notice for these offline units to be committed). ISO-NE is aware of these issues and evaluating potential solutions for addressing them.

Illustrative MRI and ELCC Approaches

MRI and ELCC approaches to capacity accreditation both rely on a probabilistic resource adequacy model that simulates LOLE or MWh of expected unserved energy. ISO-NE uses GE-MARS software to plan its capacity market requirements. MARS is a Monte Carlo model that inputs the system's resource mix and simulates a variety of load and resource outage conditions to estimate the likelihood of loss-of-load events.

Both MRI and ELCC approaches add or remove generation or load in MARS and simulate LOLE. The following are examples of generalized calculation approaches, although there are multiple variations of each approach:

Example MRI Approach. An example of an MRI calculation is as follows:

1. Begin with a base case simulation reflecting the expected system resource mix, with load increased so that LOLE = 0.1 days per year.
2. Add 50 MW of Resource X to (1). Calculate LOLE, which will be lower than 0.1 because the system will have more resources available.
3. Add 50 MW of perfect capacity to (1). Calculate LOLE, which will be lower than 0.1.

70 Output is measured during hour ending 14 through 18 in the Summer season (June through September), and hour ending 18 through 19 in the Winter season (October through May), plus any reserve shortage hours.

The MRI of Resource X is the ratio of the change in LOLE in step 2 to the change in LOLE in step 3: $MRI_X = (0.1 – LOLE_2) / (0.1 – LOLE_3)$. This will be less than or equal to 100 percent, because Resource X cannot be more reliable than perfect capacity.[71]

The same method may be employed if an alternative metric to LOLE, such as Expected Energy Not Served (EENS), is used. In this case, substitute EENS for LOLE in steps (2) and (3) and calculate the change in each step relative to EENS in step (1) accordingly.

Example ELCC Approach. ELCC methods determine how much load or perfect capacity could be replaced with a given quantity of Resource X while holding LOLE constant.[72] An example of an ELCC calculation, based on a recent proposal in PJM,[73] is as follows:

1. Begin with a base case simulation reflecting the expected system resource mix, including any MWs of Resource X. Increase load so that LOLE = 0.1 days per year.
2. Remove the capacity of Resource X from (1). LOLE will be above 0.1, because the system has less capacity and is therefore less reliable than (1).
3. Add perfect capacity to (2) until LOLE returns to 0.1.

The ELCC of Resource X is the quantity of perfect capacity added in (3) divided by the quantity of capacity of Resource X subtracted in (2). This percentage is less than or equal to 100 percent, because Resource X cannot be more reliable than perfect capacity.

A ***Marginal ELCC*** approach subtracts only a small quantity of Resource X in (2), while an ***Average ELCC*** approach subtracts all capacity of Resource X. For example, if 5,000 MW of Resource X already exists, marginal ELCC might consider how much load can be served by the next 50 to 100 MW of Resource X, while average ELCC would consider how much load can be served by all 5,000 MW. A 'portfolio ELCC' approach is similar to average ELCC but considers how much total load is served by a portfolio of multiple technologies simultaneously.

Comparison of MRI and ELCC Approaches

We recommend using MRI or Marginal ELCC to determine capacity accreditation. The key feature of these approaches is that they reflect a resource's marginal impact on LOLE, so they are consistent with ensuring reliability and with the principles of ISO-NE's capacity market.

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71 The number of resources added in the MRI simulation can vary but should be small enough so that it reflects an incremental change to the system as a whole. For example, our analysis of the NYISO market suggests that a size of 50 MW is small enough to calculate a marginal impact while producing an MRI function that is monotonic with the quantity of capacity in a given location.

72 There are many variations of ELCC methods, including whether the starting simulation is at or below criteria and the order in which the studied resource and perfect capacity or load are added/removed from the model. This section outlines one recent proposed approach. For a general description, see NERC, *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning*, March 2011.

73 This is a stylized simplification of PJM's proposal – see filings by PJM Interconnection L.L.C. in FERC Docket ER21-278-000, especially October 28, 2020 Affidavit of Dr. Patricio Rocha Garrido.

MRI and Marginal ELCC approaches are likely to produce very similar capacity credit results. Both approaches fundamentally consider how LOLE is affected by an incremental quantity of Resource X compared to an incremental quantity of perfect capacity. MRI is likely to be easier to implement because it requires a fixed number of MARS runs from a common base case (i.e., step 2 and step 3 make independently determined adjustments to the base case in step 1), while for ELCC MARS must be run iteratively (i.e., step 3 depends on the results of step 2, and determining the inputs to step 3 require some interpretation of the results of step 2). Thus, MRI methods can be automated, while ELCC methods would be difficult to fully automate.

Marginal approaches are preferable to average ELCC or heuristic approaches. ISO-NE's capacity market is designed based on a fundamental principle of economics—that prices reflect the marginal cost of serving demand so that suppliers have incentives to sell when their marginal cost is less than or equal to the marginal value to the system. Average ELCC methods divorce the payment an individual resource receives from its actual impact on reliability when choosing to enter the market, retire or repower. Hence, average ELCC methods can provide very inefficient investment incentives.

A marginal accreditation approach, therefore, offers several advantages:

(a) Investment signals – MRI and Marginal ELCC provide efficient signals for investment and retirement. As the resource mix evolves, these signals will be vital for guiding investment in clean resources. Marginal accreditation provides suppliers incentives to:

- Avoid technologies that have over-saturated the market by recognizing the diminishing reliability value of the technology. If an average or fixed credit is used, investors generally ignore this concern;
- Add resources that complement other types of resources on the system, such as adding storage onsite or separately to complement intermittent renewables. If an average or fixed credit is used, the incentive to do this is greatly diminished;
- Choose between storage projects with different durations by efficiently trading off cost and value to the system;
- Augment the duration of storage over time (for example, by adding more batteries to an existing project). If an average or fixed credit is used, the incentive to do this is greatly diminished;
- Efficiently repower renewable projects at the end of their useful lives;
- Efficiently retire or repower conventional units that are currently overvalued and maintain flexible dispatchable capacity that provides high reliability value.

(b) Avoids overpayment – marginal accreditation secures reliability at the lowest cost by paying each resource based on its marginal value to the system. Capacity prices, therefore, efficiently reflect the price needed to attract or retain capacity.

- This is analogous to the capacity market demand curve, which pays all resources a uniform clearing price based on the *marginal* value of the next MW of capacity.
- Average or portfolio ELCC approaches requires the procurement of more capacity (because some is overvalued), causing consumers to pay more in total for capacity.

Additional Features Required to Support Accreditation Methods

The MRI and Marginal ELCC methods can be used to determine accurate and efficient capacity accreditation values. This is because they align each resource type's accreditation with its impact on reliability in the ISO's resource adequacy model (MARS). This approach provides capacity accreditation values that (a) are consistent with the impact that each resource type has on the ICR, and (b) are the outcome of a modeling process that considers resources' availability and correlations at a detailed, hourly level. As a result, MARS can be used to effectively derive MRI or Marginal ELCC values for: intermittent resources, energy limited resources, hybrid resources, large units, and pipeline-only gas generators.

To support capacity accreditation based on MRI or ELCC approaches, additional efforts are needed to (1) ensure that the resource adequacy model produces accurate estimates of reliability value and (2) further adjust capacity credit values to account for features of some resources that affect reliability value but are not captured in MARS:

- The use of MARS to determine MRI or Marginal ELCC values requires that each resource type be modeled accurately in MARS. ISO-NE currently overestimates the reliability value of several resource types in MARS, including intermittent resources and gas-only resources. Issues with the modeling of these resources are described in Section IV of the report. These issues are largely related to the need to better model correlation of similar resources' availability and can be addressed through methodological changes within the existing MARS framework. Hence, we recommend that ISO-NE modify the resource adequacy model to enable accurate estimation of the marginal reliability value of different types of resources.
- Reliability value calculated using MARS may not sufficiently distinguish between expected availability of individual resources of the same type. Hence, in addition to MRI or Marginal ELCC values for each resource class and location, a separate adjustment to each individual resource's capacity accreditation may be needed reflecting its individual performance relative to other resources of the same type.
- MARS is not designed to consider unit commitment separately from dispatch. Therefore, it does not accurately estimate the reliability value of inflexible units, such as generators with long startup and notification times. It may not be possible to do so without fundamental changes to MARS. We encourage ISO-NE to explore whether this is possible but note that inflexible generators are especially vulnerable to pay-for-performance (PFP) penalties when flexibility-driven reserve shortages occur.