2020 Assessment of the ISO New England Electricity Markets

Prepared By:

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External Market Monitor for ISO-NE

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PREFACE

Potomac Economics serves as the External Market Monitor for ISO-NE. In this role, we are responsible for evaluating the competitive performance, design, and operation of the wholesale electricity markets operated by ISO-NE.[1] In this assessment, we provide our annual evaluation of the ISO's markets for 2020 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 2020.

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]

- Energy prices fell 25 percent in 2020 to the lowest level since the inception of the nodal market in 2003, averaging $23.30 per MWh at the New England Hub. The primary driver was very low natural gas prices, which decreased by 36 percent from 2019 to 2020. 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 fell 2 percent from 2019 to record low levels as well. Load levels have been on a downward trend in recent years because of the continued growth in energy efficiency and behind-the-meter solar generation. In addition, mild winter weather and the effects of the COVID-19 pandemic contributed to lower electricity demand in 2020.
- The market was never short of operating reserves in 2020 because of low load levels and the availability of surplus capacity, so no Pay-for-Performance (PFP) events occurred.
- The capacity compensation rate was $7.03 per kW-month in the 2019/20 Capacity Commitment Period (CCP) and $5.30 per kW-month in the 2020/21 CCP.
  - These relatively high levels reflect that the peak load forecasts for the FCAs held in 2016 and 2017 were significantly higher than the actual peak loads in 2019 and 2020.
  - Capacity prices will fall through the 2023/24 CCP to $2 per kW-month because of declining load forecasts and the retention of the Mystic CCs, before rising to $2.61 per kW-month in the 2024/25 CCP as the Mystic cost-of-service agreement ends.

The IMM report provides detailed discussion of these trends and other market results and issues that arose in the ISO-NE markets in 2020. 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 and integration of state initiatives to promote renewable resources, reliability commitments, energy efficiency participation in the capacity market, and capacity accreditation.

2 See ISO New England's Internal Market Monitor 2020 Annual Markets Report, available at https://www.iso-ne.com/markets-operations/market-monitoring-mitigation/internal-monitor.

Cross-Market Comparison of Key Market Outcomes

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

Energy Prices ISO-NE exhibited the highest average energy prices of the RTO markets over the last three years because of its higher natural gas prices. ERCOT is the lone exception, which operates an "energy-only" market with shortage pricing as high as $9,000 per MWh that experienced shortages in 2019.

Congestion ISO-NE experiences far less congestion than other RTOs. As per MWh of load, the average congestion cost in New England has been less than $0.35 in the last five years – 10 to 20 percent of the congestion levels in other RTO markets. This reflects that large transmission investments have been made over the past decade, resulting in transmission service cost of more than $19 per MWh in 2020 – far higher than the 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 system-level and local 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.

Virtual Trading The virtual trading levels in ISO-NE have been one-third or less 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. In light of the recent extreme winter weather in ERCOT in February 2021, we compare the financial risks market participants face in ERCOT's energy-only market that relies heavily on shortage pricing to the financial risks in ISO-NE's PFP framework.

We find that PFP reduces the potential 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 the issue. (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 2020. Our pivotal supplier analysis suggests that structural market power concerns diminished noticeably in Boston and New England in 2019 and 2020 because of:

- The recent entry of more than 2.5 GW of generation;
- Transmission upgrades in Boston; and
- Falling load levels due to combined effects of mild weather conditions, 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 2020. 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 2020, 41 percent of capacity committed for local reliability was on units that were committed in a multi-turbine combined cycle configuration when a single-turbine configuration would likely have been adequate to satisfy the reliability need. Hence, we recommend the ISO consider tariff changes as needed to expand its authority to address this concern. (See Recommendation #2014-5)

Reliability Commitment and NCPC Uplift

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

- 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.
- 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.

In addition, since the day-ahead market schedules resources to satisfy load bids rather than forecast load, the ISO sometimes needs to commit additional generators with high commitment costs after the day-ahead market to satisfy forecast load and reserve requirements. Such commitments generate expenses that are uplifted to the market and increase the amount of supply available in real time, which depresses real-time market prices and leads to additional uplift. This undermines the market incentives for investment in resources that contribute to satisfying reliability requirements efficiently, since low-cost reserve providers receive little or no compensation, while high-cost providers receive higher out-of-market compensation.

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 2020 showed that:

- Commitment for local second contingency protection occurred on 101 days (roughly 1,200 hours), leading to $3.9 million (or 41 percent) of day-ahead NCPC.
- Additional commitment to satisfy the system-level 10-minute spinning reserve requirement occurred in roughly 4,050 hours, leading to $3.8 million (or 40 percent) of day-ahead NCPC.

Both of these requirements are satisfied by scheduling operating reserves, but resources that provide these services are often undervalued as the cost of scheduling operating reserves is not reflected efficiently in energy prices. We estimate that pricing these requirements in the day-ahead market would result in an additional revenue of:

- Up to $3 to $11 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.

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; (b) the ISO does not allow firm imports to satisfy local reserve requirements; and (c) resources committed for reliability are able to inflate their revenues and the ISO's NCPC costs by burning a more expensive fuel.

Lastly, a large share of the operating reserves needed to satisfy NERC and NPCC criteria are supplied by resources receiving no day-ahead schedules or compensation – latent reserves. Hence, their availability is less certain than resources that are procured in the day-ahead market.

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 those proposed under its Energy Security Improvements (ESI) Project (See Recommendation #2012-8)
- Procure local reserve products in the day-ahead and real-time markets to satisfy local second contingency protection requirements. (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 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)

We strongly support the ISO's efforts to eliminate the Forward Reserve Market because it has several major deficiencies, including:

- Forward reserve providers are required to offer energy at inflated prices, leading to inefficient dispatch and distorting clearing prices for both energy and operating reserves.
- Forward reserve providers must satisfy their obligations 16 hours per day without coordinated scheduling through the centralized day-ahead market. This raises the cost of participation by non-peaking generators and reduces the liquidity of the market.
- The forward reserve market does little to ensure sufficient reserves or reduce the need for the ISO to commitment out-of-market to satisfy its reliability requirements.

Investment Incentives and Policy-Driven Investment

The New England states have ambitious clean energy targets which will require large amounts of new intermittent renewable generation, coupled with flexible resources to balance the large variations in intermittent output. Hence, markets should reward flexibility and other attributes that are valuable for maintaining reliability. This will encourage new and existing resources to make cost-effective investments that help satisfy system needs.

In 2020, we found that lower capacity prices and load contributed to lower net revenues for most types of the resources. (See Section IV.A) These net revenues would not have been sufficient to support profitable investment in dual-fueled CTs, except for projects with specific competitive advantages. Net revenues from the wholesale market, federal incentives, and tradable REC prices were adequate to support investment in land-based wind generation, although capacity prices are falling and REC prices have been volatile in recent years. These results are expected given the prevailing capacity surplus in New England. Nonetheless, improving the markets' effectiveness in facilitating efficient investment remains important.

Impact of Recommended Enhancements on Investment Incentives

In Section IV.B, we analyze how our recommended enhancements would affect long-term investment incentives for several new and existing resource technologies. This includes recommendations to: (a) improve capacity accreditation rules (#2020-2), (b) procure operating reserves in the day-ahead market (#2012-8), and (c) modify the PPR so that compensation during a shortage starts at a reduced level but rises with the severity of the shortage (#2018-7).

These recommendations would generally increase the net revenues to resources that are most available and flexible (and thus more likely to be available during tight conditions), while reducing the returns to resources that are not. Specifically, under long-term equilibrium conditions, our recommendations would:

- Improve the incentives to install new longer-duration energy storage (or augment existing 2-hour resources);
- Reduce revenues to less valuable fossil-fuel steam turbines, which would receive lower capacity credit because of their long startup notification times; and
- Over time, they will improve the compensation of the region's most flexible resources (i.e., CCs and CTs).

Importantly, however, these recommended enhancements are likely to further increase investment incentives as the penetration of intermittent renewable resources increases.

Market Incentives and Investment Risks for Developers of Renewable Resources

Although state and federal incentives account for most net revenue to renewables in New England, wholesale markets are highly effective at providing granular price signals that differentiate projects based on their value to the power system. Such differentiation helps the most economic projects to win competitive solicitations for RECs and other clean energy attributes. However, to the extent that decisions to invest in specific projects are not guided by competitive market signals, it makes achieving clean energy targets more difficult and expensive.

To illustrate the value of wholesale markets in guiding investment, we analyze market outcomes in two high (8 GW and 12 GW) offshore wind penetration scenarios. (See Section IV.C) We find that while overall average LMP levels would be expected to fall in these scenarios, the average prices that offshore and land-based wind would fall much more sharply (to *negative* levels in one scenario). These results highlight how technology-specific solicitations can saturate the market with a particular technology, reducing the investment returns to that technology and increasing returns to complementary technologies.

We also find that certain solicitations can raise substantial risks for earlier developers and existing resources. (See Section IV.D) These include solicitations: (a) where competition is limited by technology or location-specific criteria, and (b) that utilize a long-term contract structure that insulates the developer from market risk by providing a single bundled payment for RECs and energy. In the high offshore wind scenarios described above, we found that revenues of early developers could be reduced as prices fall in high wind output hours and curtailments increase. At the same time, market risk to other types of renewable technologies would increase, requiring higher REC prices to motivate them to invest.

States will need a balanced portfolio of renewable technologies to achieve their decarbonization goals. A technology-neutral approach that compensates the resources based on their contribution to the ultimate policy goal (e.g., decarbonization) will encourage investors to develop the most efficient projects and enable the states achieve policy objectives at a lower overall cost.

Capacity Accreditation in the FCM

Capacity accreditation determines the number of megawatts a resource may offer and be compensated for in the capacity market. An efficient capacity market should provide the same level of compensation to all resources that provide comparable reliability benefits.

Current capacity accreditation methods over-value several resource types, including generators with long lead times, large units, units with shared fuel supplies, intermittent resources, and energy-limited resources. (See Section VI) We discuss below the categories of resources whose capacity is currently over-valued.

Conventional Resources

Several types of conventional generators have features that reduce their expected availability in critical hours, beyond the random forced outage rates modeled by the ISO. This includes resources with the following attributes:

- Low Flexibility – Some resources that require lengthy startup notification times, such as older steam turbines, are less likely to be able to support reliability during critical periods that arise unexpectedly.
- Large Resources or Resources with Correlated Outages – Large individual units provide less reliability value than multiple smaller units. This is because all capacity of a large unit can be lost in a single contingency, while several small units are less likely to

experience outages simultaneously. Likewise, multiple units that can be lost by a single contingency provide less reliability value than ones whose outages are uncorrelated.

- Pipeline Gas-Dependence – 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. A shared fuel source can limit the output of a group of units or serve as a single point of failure.

Based on our review of historical reserve shortage events from 2014 to 2020, we found that:

- Fossil steam units (all of which have long lead times) were committed and able to provide energy or reserves in only 13 percent of shortage hours.
- Large units that form a contingency over 1 GW were providing energy or reserves in only 48 percent of shortage hours.
- By contrast, gas turbines and combined cycles with short lead times were providing energy or reserves in 96 and 91 percent of shortage hours, respectively.

While these historical averages may understate the reliability value of large and long-lead time units, and are not intended as proposed accreditation values, they demonstrate that the value of these units is lower than that of smaller and more flexible resources.

Intermittent Resources

As the penetration of intermittent resources grows, supply shortages are more likely to occur in hours when intermittent output is low. The qualified capacity for these resources is currently determined based on median output in certain hours of the day, which overstates intermittent resources' reliability value during critical hours.

We estimate the capacity factor of wind and solar units during the five highest net load hours (load minus intermittent output) under multiple levels of renewable penetration. We find that:

- As the penetration of an intermittent resource type rises, its average output during the top net load hours declines precipitously; and that
- A diverse mix of intermittent resources results in higher capacity value of both wind and solar, compared to a dominant focus on one technology. The current accreditation approach does not capture these diminishing returns and diversity benefits.

Energy Storage Resources

Energy limited resources, such as battery storage, can produce output for a limited duration, so the reliability value of such resources is lower than for conventional resources. Under the current rules, a storage unit that can discharge for at least two hours may offer Qualified Capacity up to 100 percent of its installed capacity in the FCM. In past reports, however, we found that a 2-hour battery resource would have an average value of 66 percent of the value of a typical conventional resource for avoiding load shedding. This allows low-duration batteries (i.e., 2-hour resources) to be substantially overcompensated relative to their reliability value.

Importance of Marginal Capacity Accreditation

The use of inefficient capacity accreditation approaches for some resource types increases the cost of satisfying reliability criteria over time. Capacity accreditation based on each resource's incremental effect on reliability is known as marginal capacity accreditation. In general, the marginal value of a particular type of resource will tend to fall as its penetration increases.

Marginal capacity credit is key to providing efficient incentives for numerous beneficial investment outcomes in the coming years. These include:

- Investing in a diverse mix of renewables and avoiding oversaturated technologies;
- Adding storage to renewable generating facilities;
- Augmenting the duration of storage projects over time;
- Retiring inflexible generators and replacing them with flexible ones;
- Adding back-up fuel storage to a gas-fired generator; and
- Encouraging investment in innovative dispatchable zero-emissions technologies.

Current accreditation methods do not provide efficient incentives for these investments. Hence, we recommend that the ISO develop capacity accreditation rules based on each resource's marginal reliability value (See Recommendation #2020-2a).

This value can be determined by the planning model that the ISO uses to determine its Installed Capacity Requirement (ICR), the GE-MARs model. Using this model has the advantage of aligning capacity accreditation with the impact that resources are assumed to have when determining the ICR. However, improvements are needed to model each resource type in MARS as accurately as possible. In particular, the availability of several resource types is currently overestimated in MARS:

- Intermittent resources are assumed to provide their Qualified Capacity with 100 percent availability in MARS. This approach fails to consider that the output of these resources varies significantly.
- Units with long lead times are considered to always be available in MARS unless they are experiencing a random forced outage. MARS does not consider that these units might be unavailable because they were not committed sufficiently far in advance.
- MARS does not consider gas pipeline outages or shortages of shared fuel supplies could affect the availability of multiple units simultaneously.

An accurate resource adequacy model is important for determining the amount of capacity needed to ensure reliability and evaluating resources' marginal reliability value. Hence, we recommend that the ISO modify how various resource types are modeled in MARS (See Recommendation #2020-2b).

Energy Efficiency in the FCM

Energy efficiency (EE) investments can provide capacity benefits by decreasing the quantity of generation capacity needed to ensure reliability. In most wholesale markets, customers benefit from making EE investments as they reduce their energy consumption and associated capacity charges. However, ISO-NE allows entities that implement EE measures to participate as suppliers in the FCM as Passive Demand Resources. As we discuss in Section V, treating EE as supply rather than demand reductions creates at least three inefficiencies.

First, treatment of EE as supply has led the ISO to set inflated capacity requirements over the last decade, thereby increasing consumer costs. To avoid double-counting the impact of EE that are treated as supply, ISO-NE adds an estimate of EE resources to the load forecast before each FCA (called "reconstituted load"). However, since the amount of EE is not known when the load forecast is prepared, the reconstituted load will cause the capacity requirement to be artificially inflated or suppressed. Although the ISO has made improvements, we estimate that the FCA 15 requirements would have been artificially inflated by 378 MW. These errors are a consequence of accounting for EE as supply, not the normal uncertainty of forecasting EE's impact on load.

Second, treatment of EE as supply leads to cost-shifting among consumers without providing more efficient incentives to invest in EE. This is because when the amount of EE participating as supply is added to total demand before each FCA, the demand added back is not targeted to the obligations of LSEs that realize the load reductions. In addition, customers for whom it is already cost-effective to invest in EE (because it reduces their capacity purchases or retail bill) are effectively double compensated by FCA payments that duplicate these savings. The double payments are paid for by other customers who do not share in the benefits of the EE measure.

Third, treating EE investments as supply requires a burdensome qualification and verification process that, while rigorously designed, adds administrative complexity and cost. It can also act as a barrier to investment in some cases and does not ensure that EE suppliers provide the full benefits for which they are compensated. More importantly, quantifying EE is inherently inaccurate because it relies on a wide array of assumptions regarding highly uncertain factor, not the least of which is the assumption that the EE incentive caused a change in the purchases of the consumer. The ability to take credit for actions a consumer may have otherwise taken raises potential fraud and manipulation concern.

We recommend that the ISO account for EE as a reduction in load instead of as supply. (See Recommendation #2020-3) This would eliminate the need for an reconstitution mechanism that distorts the load forecast, the ICR, and cost allocation in the FCM. Importantly, this recommendation would not prevent loads from realizing the benefits of investing in EE. Instead, it would cause these benefits to be classified as savings on capacity purchases instead of as capacity payments to suppliers.

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 ensuring 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.

Addressing Issues in the Minimum Offer Price Rules

In recent assessments of the ISO-NE markets, we have recommended several improvements to the minimum offer price rule (MOPR). (See Recommendation #9 in the 2019 report) The ISO has stated it intends to eliminate the MOPR to ensure that state policy resources are not hindered by the MOPR. Thus, we have withdrawn the MOPR improvements from the recommendations in this report and will reassess them after the outcome of this process is known. In addition, we plan to provide comments to NEPOOL this summer identifying market rule changes needed to ensure that the markets will attract necessary investment and maintain needed existing units after the MOPR is eliminated. Such changes will include improving the ISO's accreditation of capacity resources and reflecting the increased financial risk in the ISO's capacity demand curves that investors will face in New England without the MOPR.

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)

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

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 assessments discussed in this report.

Recommendation Number and Description		High Benefit[4]	Feasible in ST[5]
Reliability Commitments and NCPC Allocation			
2010-4	Modify allocation of "Economic" NCPC charges to make it consistent with a "cost causation" principle.		✓
2020-1	Consider allowing firm imports from neighboring areas to satisfy local second contingency requirements.		✓
2014-5	Utilize the lowest-cost fuel and/or configuration for multi-unit generators when committed for local reliability.		✓
Reserve Markets			
2012-8	Introduce co-optimized operating reserves in the day-ahead market reflecting all system needs, such as the proposed ESI products.	✓	
2019-3	Incorporate a comprehensive set of local operating reserve requirements into the day-ahead and real-time markets.	✓	
2014-7	Eliminate the forward reserve market.		✓
External Transactions			
2016-5	Pursue improvements to the price forecasting that is the basis for Coordinated Transaction Scheduling with NYISO.		
Capacity Market			
2015-7	Replace the descending clock auction with a sealed-bid auction to improve competition in the FCA.		
2018-7	Modify the PPR to rise with the reserve shortage level, and not implement the remaining planned increase in the payment rate.	✓	✓
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.	✓	
2020-3	Account for energy efficiency as a reduction in load instead of as a supply resource in the FCM.		✓

4 Recommendation will likely produce considerable efficiency benefits.

5 Complexity and required software modifications are likely limited.

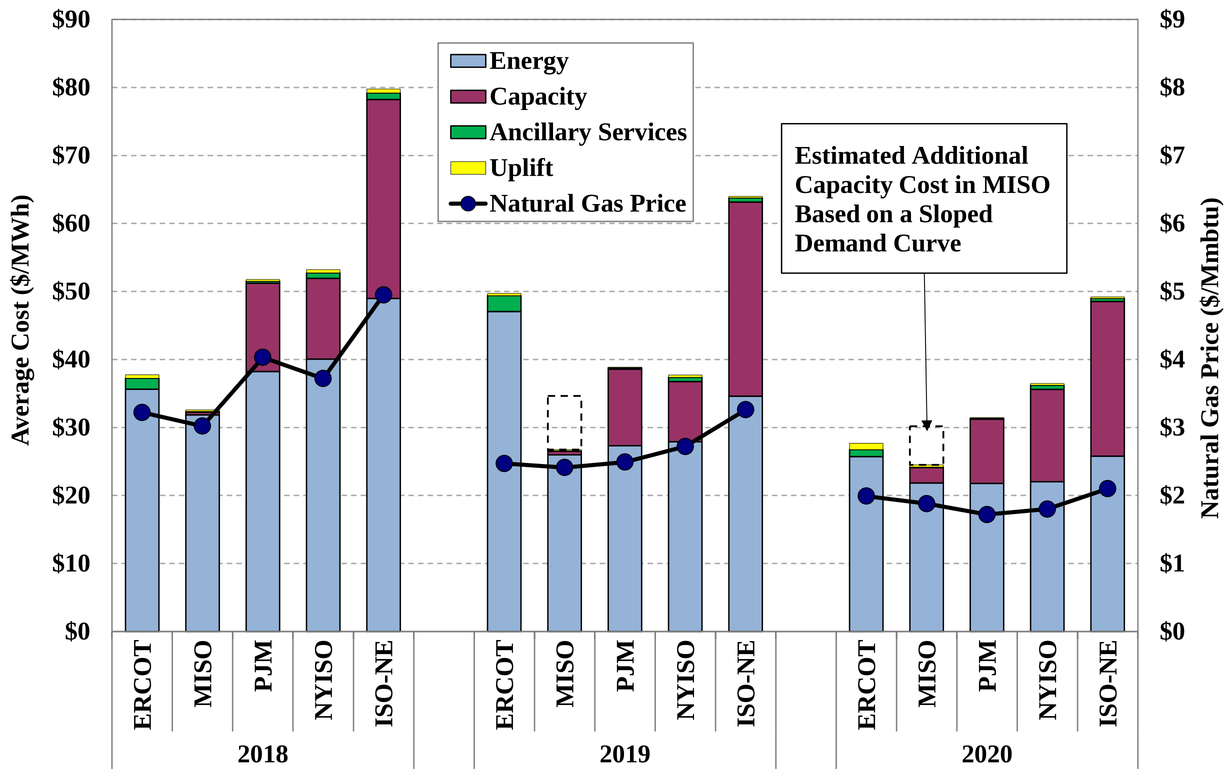
I. Comparing Key ISO-NE Market Metrics to Other RTOs

The 2020 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 2020. 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*
2018 – 2020



* Includes only wholesale market costs and not, for example, costs recovered through regulated retail rates. Such costs may be large in vertically integrated areas, such as MISO.

The all-in price metric is a measure of the total cost of serving load. The all-in price is equal to the load-weighted average real-time energy price plus capacity, ancillary services, and bid production 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 a 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. On the other hand, lower natural gas prices in the Midwest and PJM regions have contributed to lower energy costs in those markets. In 2020, gas prices in New England fell to levels consistent with most other areas of the country.

Carbon 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 2020, compliance added an average of approximately $6.60 per MWh to the marginal production costs of a gas-fired combined cycle generator in Massachusetts and $2.90 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 or MISO, while RGGI compliance costs are included in a small number of PJM states in 2020.

Transmission Congestion. Although we do not show the most congested locations in neighboring markets, such as Long Island, these import-constrained locations exhibit all-in 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 primarily because the capacity surplus in its "prompt market" design was larger than the surplus 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 energy efficient, behind-the-meter solar installations, and changing consumption patterns;
- ISO-NE's load forecast for the summer of 2020 fell from 26.8 GW in the forecast performed in 2016 that was used to develop inputs for FCA 11 to 25.1 GW in the 2020

CELT Report, a reduction of 6 percent. The NYISO's load forecast for the summer of 2020 fell by 4 percent over the same period.[6]

- Hence, both markets have made large downward revisions in their load forecasts. However, while such revisions are recognized immediately in the NYISO's prompt capacity market design, they are recognized on a four-year delay in New England's forward market. This load forecast change has been a key contributor to the 51 percent decline in the capacity compensation rate from the 2020/21 Capability Year to the 2024/25 Capability Year.

Lower capacity costs for PJM are attributable to capacity surpluses caused by a combination of factors, including a larger amount of available of capacity imports and lower generation development costs. The low capacity costs in MISO is attributable to its market design. 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. Although not optimal, MISO has been content with this market design because additional revenues are provided through retail rates to regulated entities that play a key role in maintaining resource adequacy in MISO. 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 operates an "energy-only" market (i.e., no capacity market) with a $9000 shortage price, which has a substantial impact on energy prices when ERCOT experiences reserve shortages. In the Summer 2019 for example, energy prices in ERCOT hit $9000 per MWh in several hours, leading to a substantial increase in its annual average energy costs. 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.

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. We discuss uplift in more detail in Subsection C.

B. Transmission Congestion

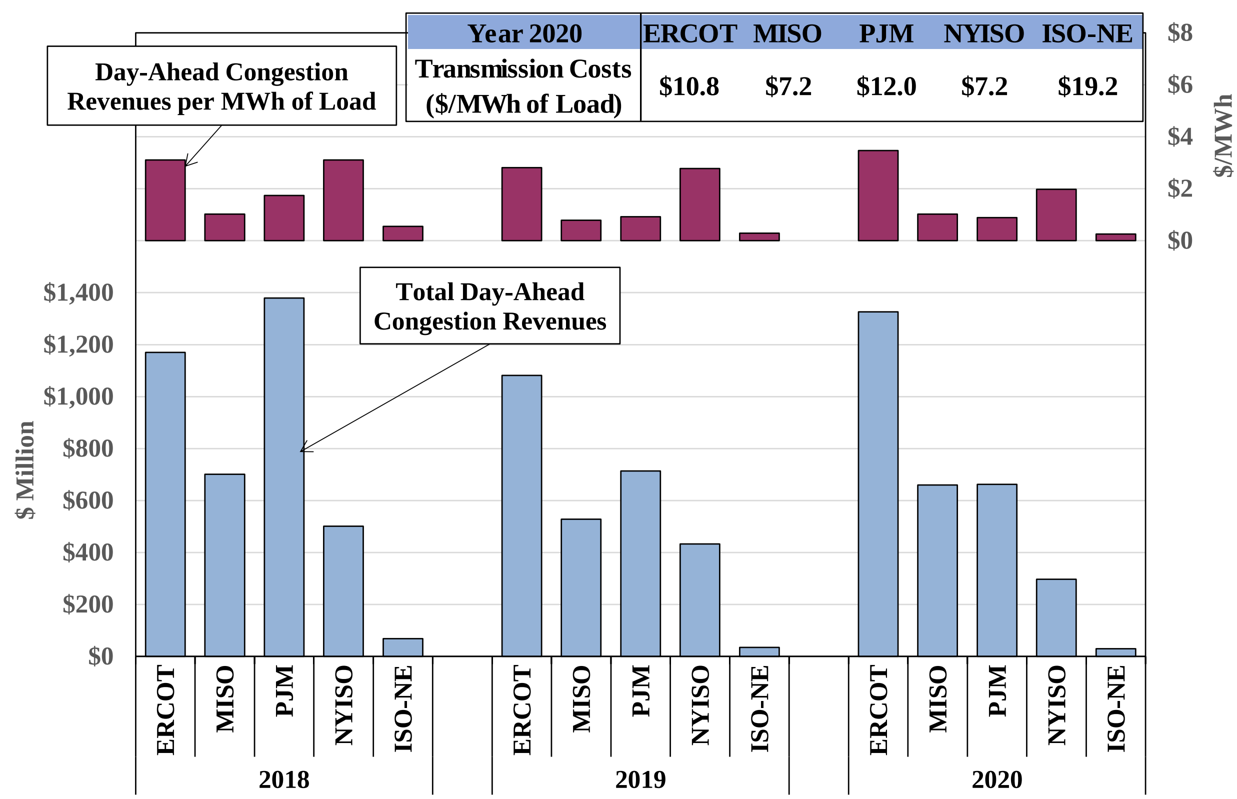
One of the principal objectives of the day-ahead and real-time markets is to commit and dispatch resources to control flows on the transmission system and efficiently manage transmission congestion. Figure 2 shows the amount of congestion revenue collected through the day-ahead

6 See NYCA Summer Peak Demand Baseline forecast in the 2016 and 2020 *Load & Capacity Data "Gold Book"* reports.

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. On a per MWh basis, congestion levels in the other RTOs are three to eight times larger than the congestion levels 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 over $19 per MWh in 2020, which are far above the average rates in the other RTO areas shown in the figure.

Figure 2: Day-Ahead Transmission Revenues



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 that are anticipated to exceed $15 billion to integrate renewable resources throughout MISO. Although the NYISO did not expand transmission significantly from 2018 to 2020, the NYISO has approved nearly $2 billion in transmission projects principally focused on delivering renewable energy from upstate New York to load centers in New York City and Long Island.

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. Eighteen transmission reliability projects, with a total estimated investment cost of $500 million, have been completed and placed in service in 2020. The estimated investment in New England to maintain reliability has been $11.7 billion from 2002 to March 2021, and another $1.1 billion is planned by 2029. 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 $0.36 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 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 system's reliability needs or 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 2020 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
		2018	2019	2020	2020	2020
Real-Time Uplift						
Total	**Local Reliability ($M)**	$4	$2	$1	$15	$3
	Market-Wide ($M)	$40	$16	$15	$8	$38
Per MWh of Load	**Local Reliability ($/MWh)**	$0.04	$0.01	$0.01	$0.10	$0.01
	Market-Wide ($/MWh)	$0.32	$0.14	$0.13	$0.05	$0.06
Day-Ahead Uplift						
Total	**Local Reliability ($M)**	$14	$7	$4	$17	$46
	Market-Wide ($M)	$12	$6	$5	$1	$15
Per MWh of Load	**Local Reliability ($/MWh)**	$0.11	$0.06	$0.04	$0.11	$0.07
	Market-Wide ($/MWh)	$0.10	$0.05	$0.05	$0.01	$0.02
Total Uplift						
Total	**Local Reliability ($M)**	$18	$9	$5	$32	$49
	Market-Wide ($M)	$52	$22	$21	$10	$54
Per MWh of Load	**Local Reliability ($/MWh)**	**$0.15**	**$0.07**	**$0.05**	**$0.21**	**$0.08**
	Market-Wide ($/MWh)	**$0.42**	**$0.19**	**$0.18**	**$0.06**	**$0.08**
	All Uplift ($/MWh)	**$0.57**	**$0.26**	**$0.22**	**$0.27**	**$0.16**

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 2020, ISO-NE's market-wide NCPC uplift was more than double the cost per MWh of load incurred by NYISO or MISO for at least two reasons:

- The lower market-wide costs for MISO and NYISO are partly attributable to their day-ahead ancillary services markets, which reduce the uplift charges for generation capacity committed to maintain adequate operating reserves at the system level. 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 fallen in the past three years. The significant reduction from 2018 to 2019 was driven primarily by reduced supplemental commitments in the Boston area after: (a) the completion of transmission upgrades in mid-2019;[7] and (b) the entry of the 700 MW Footprint combined-cycle plant in mid-2018. These developments have greatly reduced the ISO's reliance on the Mystic generating units, which were previously committed frequently out-of-market to maintain reliability in the Boston area. The local reliability NCPC continued to fall in 2020 because: (a) lower load levels during the COVID-19 pandemic further reduced supplemental commitments; and (b) lower natural gas prices reduced commitment costs of gas-fired resources.

[7] This was associated with the Greater Boston Reliability Project, which increased the import capability into the Boston load pocket by more than 400 MW.

Uplift for local reliability was much smaller in ISO-NE than in the NYISO in 2020. In the NYISO, a large amount of generation is committed in the day-ahead market for local second contingency protection in the load pockets of 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. Since these local transmission security and reliability requirements are not adequately reflected in the NYISO energy and reserve markets, it leads to large uplift charges and poor incentives for investment in resources that help maintain local security and reliability. On the other hand, local reliability uplift in ISO-NE was generally in line with the MISO market over the past two years.

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	2017	2.2%	$1.98	3.6%	$2.71	$0.81
	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
NYISO	2020	8.0%	$0.40	13.7%	-$0.06	< $0.1
MISO	2020	12.1%	$0.10	12.3%	$0.99	$0.20

Table 2 shows that virtual trading was generally profitable, indicating that it has generally improved price convergence between the day-ahead and real-time markets. The virtual trading levels in the ISO-NE market were substantially lower than the levels observed in both the NYISO and MISO markets. In 2020, the gross volume of cleared virtuals (including both virtual load and virtual supply) averaged less than 8 percent of load in the ISO-NE market, compared to 22 and 24 percent in the NYISO and MISO markets, respectively. We believe this substantial difference is primarily due to the costs that are allocated to virtual transactions in New England.

ISO-NE's NCPC allocation methodology 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 much 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.

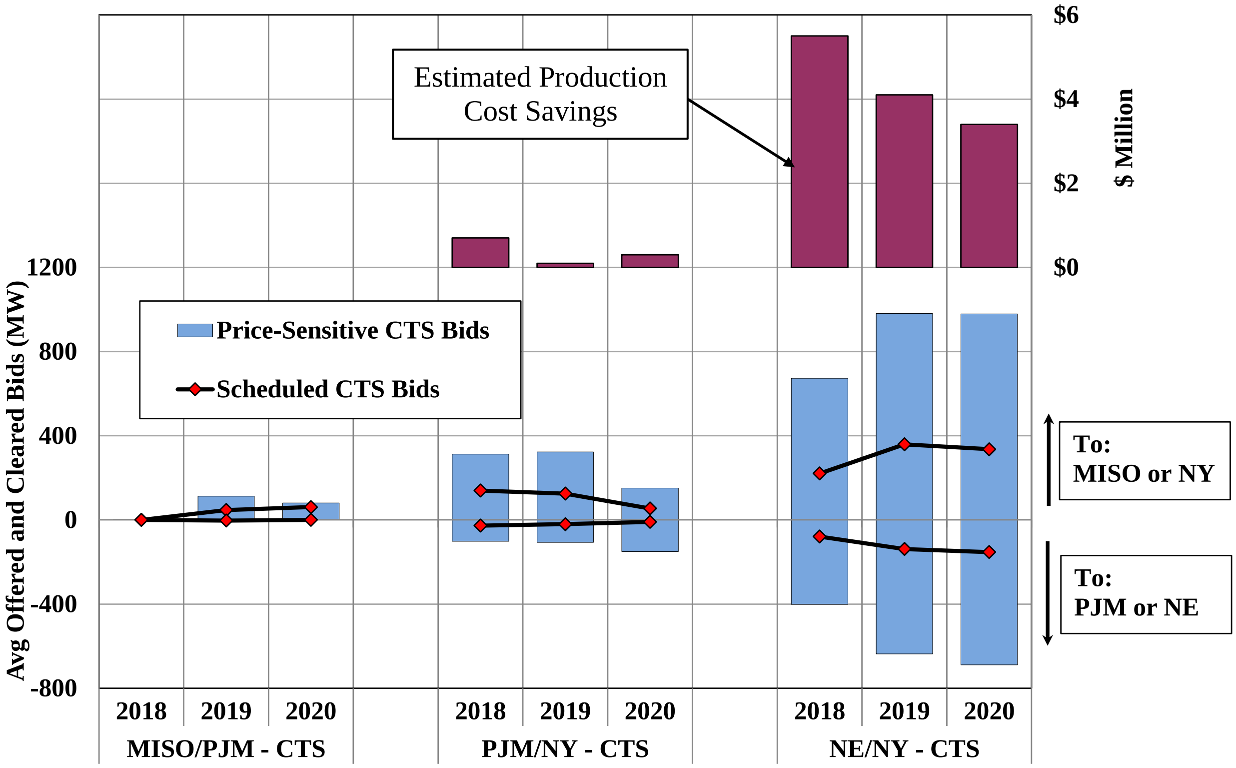
D. Coordinated Transaction Scheduling

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 2020.[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.

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

Figure 3: CTS Scheduling and Efficiency
2018 – 2020



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.

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 averaged over $4 million each year in the past three years, while the estimated savings have been minimal at the PJM/NY interface.[9] In addition to higher price-sensitive bidding volumes, 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 7 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 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 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 larger than the savings that have been achieved by any of the current CTS processes. Therefore, we will be evaluating the benefits of such a process in the future for New England and New York.

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*.

II. Competitive Assessment of the Energy Market

This section evaluates the competitive performance of the ISO-NE energy market in 2020. 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.[11] 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 economically or physically withholding generating resources. 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 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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[11] 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;[12] 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.

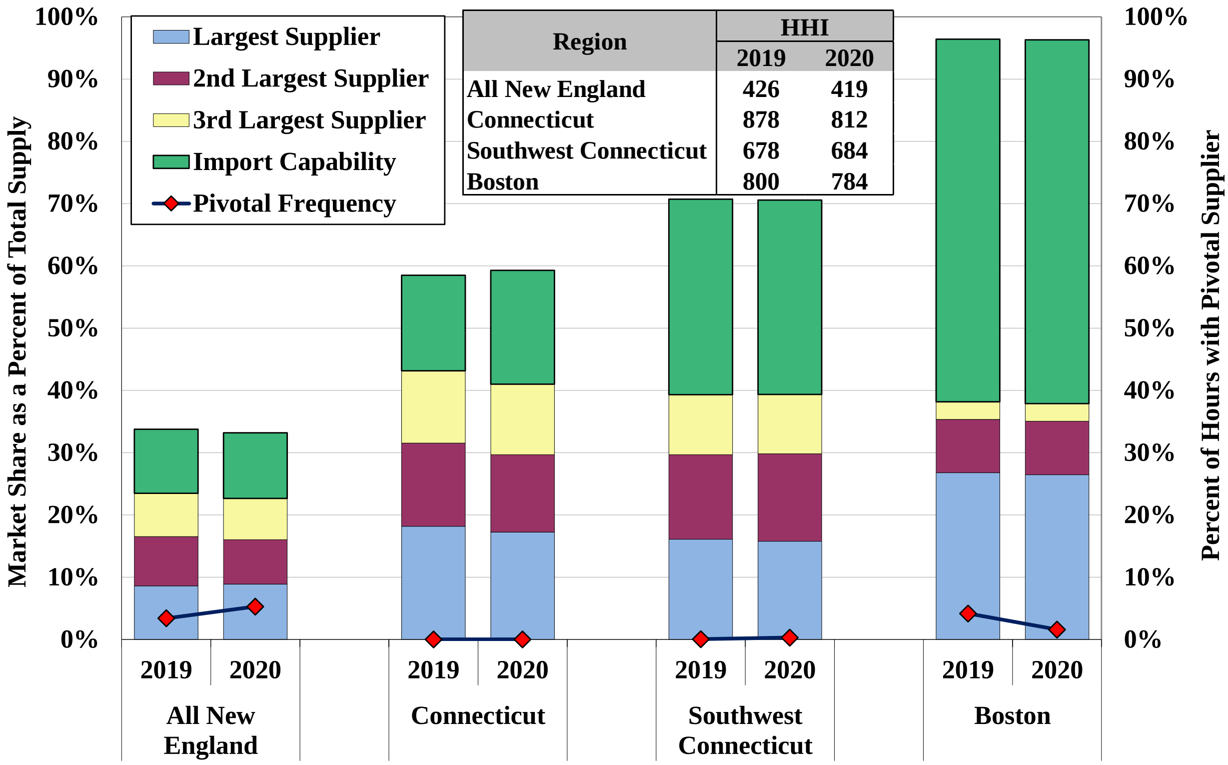
The Pivotal Supplier Test is a more reliable means to evaluate the competitiveness of energy markets because it recognizes the importance of both supply and demand. Whether a supplier is pivotal depends on the size of the supplier as well as the amount of excess supply (above the demand) held by other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

12 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 raise clearing prices. For the supplier to have the incentive to raise prices, it must have other supply that would benefit from higher prices.

Figure 4 shows the three structural market power indicators for four regions in 2019 and 2020. First, the figure shows the market shares of the largest three suppliers and the import capability in each region in the stacked bars.[13,14] 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 4: Structural Market Power Indicators
2019 – 2020



Region	HHI 2019	HHI 2020
All New England	426	419
Connecticut	878	812
Southwest Connecticut	678	684
Boston	800	784

13 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.

14 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 Base Interface Limit (or Capacity Import Capability) is used for external interfaces, and the N-1-1 Import Limits are used for reserve zones.

Figure 4 indicates that market concentration of internal generation did not change significantly in most regions from 2019 to 2020. The portfolio sizes of the three largest suppliers remained similar from 2019 to 2020 in each of the four regions. However, the import capability into Connecticut rose by 450 MW as a result of Greater Hartford/Central Connecticut upgrades in 2020, which lowered the HHI in that area. The figure also shows variations in the number of suppliers with large market shares across the four areas. In 2020, Boston had one supplier with a large market share of 26 percent (including import capability as a portion of the total supply into the area), while all New England has three suppliers with market shares of less than 10 percent each.

Import capability accounts for a significant share of total supply in each region (ranging from 10 percent in all New England to 58 percent in Boston), so 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 2020, which indicates that:

- In Southwest Connecticut and Connecticut, there were very few hours (< 0.05 percent) when a supplier was pivotal in 2020.
- In Boston, one supplier owned 64 percent of the internal capacity, but was pivotal in just 2 percent of hours in 2020. 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 5 percent of hours in 2020.[15]

The pivotal frequency has been falling in recent years partly because of new market entry, 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. Nonetheless, the pivotal frequency rose modestly in all New England from 2019 to 2020 as higher load levels in the summer of 2020 when warmer weather led to a 2 percent increase in average load and a 3 percent increase in peak load. Higher air-conditioning load in residential areas offset the effects of reduced load from commercial and industrial customers during the COVID-19 pandemic, resulting in higher overall load levels.

The pivotal frequency in Boston fell from 28 percent in 2017 to less than 5 percent in both 2019 and 2020. The entry of the Footprint power plant in 2018 contributed to this decrease and led to less frequent commitments of the Mystic facilities in the portfolio of the largest supplier in

15 The pivotal supplier results are conservative for "All New England" compared to those evaluated by the IMM (see their 2018 SOM report, Section 3.7.3) 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.

Boston. The increase in the import capability because of the Greater Boston Reliability Project upgrades reduced the reliance on the internal generation, contributing to the reduction in pivotal frequency in recent years as well.

In spite of the reduction in pivotal frequency, 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.[16] 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.
- Physical withholding: we analyze 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 physical deratings relative to load and participant characteristics. The objective is to determine whether the output gap and/or 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 physical deratings vary in a manner consistent with attempts to exercise market power.

Because the pivotal supplier analysis raises competitive concerns in Boston and all New England, Figure 5 shows the output gap and 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.

16 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.

Our physical withholding analyses focus on:

- 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. The "Other Derates" can be the result of ambient temperature changes or other legitimate factors.

Finally, the results in Figure 5 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 2020. In all New England, we compare the three largest suppliers, who collectively owned 25 percent of internal generating capacity in 2020, to all other suppliers.

Figure 5: Average Output Gap and Deratings by Load Level and Type of Supplier

Boston and All New England, 2020

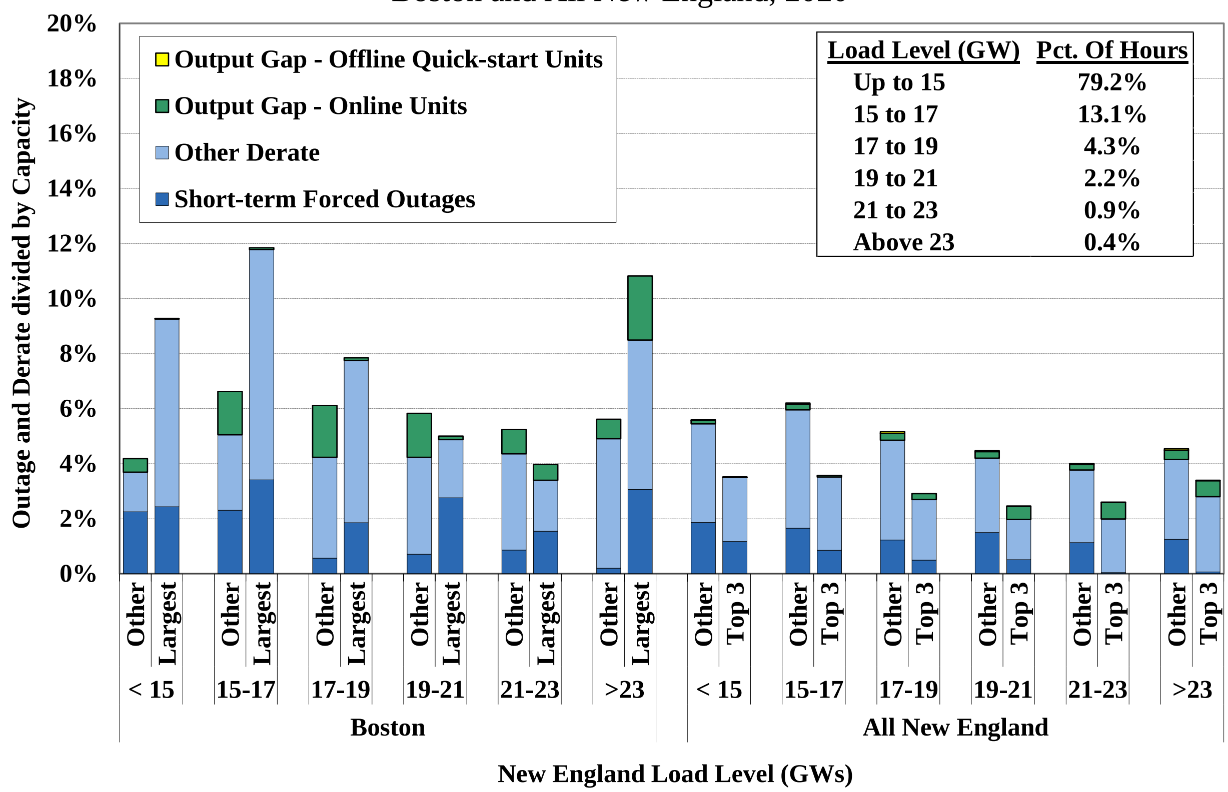


Figure 5 shows that the amount of "Other Derate" was usually higher than other categories. This was primarily because some combined-cycle capacity was often offered and operated in a configuration that reduced its available capacity during off-peak hours. This is generally efficient and does not raise 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 hot temperatures tend to reduce the ratings of thermal generators.

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 2020. 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 largest supplier exhibited an increased output gap and short-term forced outages during the highest load conditions, but it did not raise competitive concerns because it did not result in congestion and higher prices in the area. 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 2020 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: [17]

- 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.

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

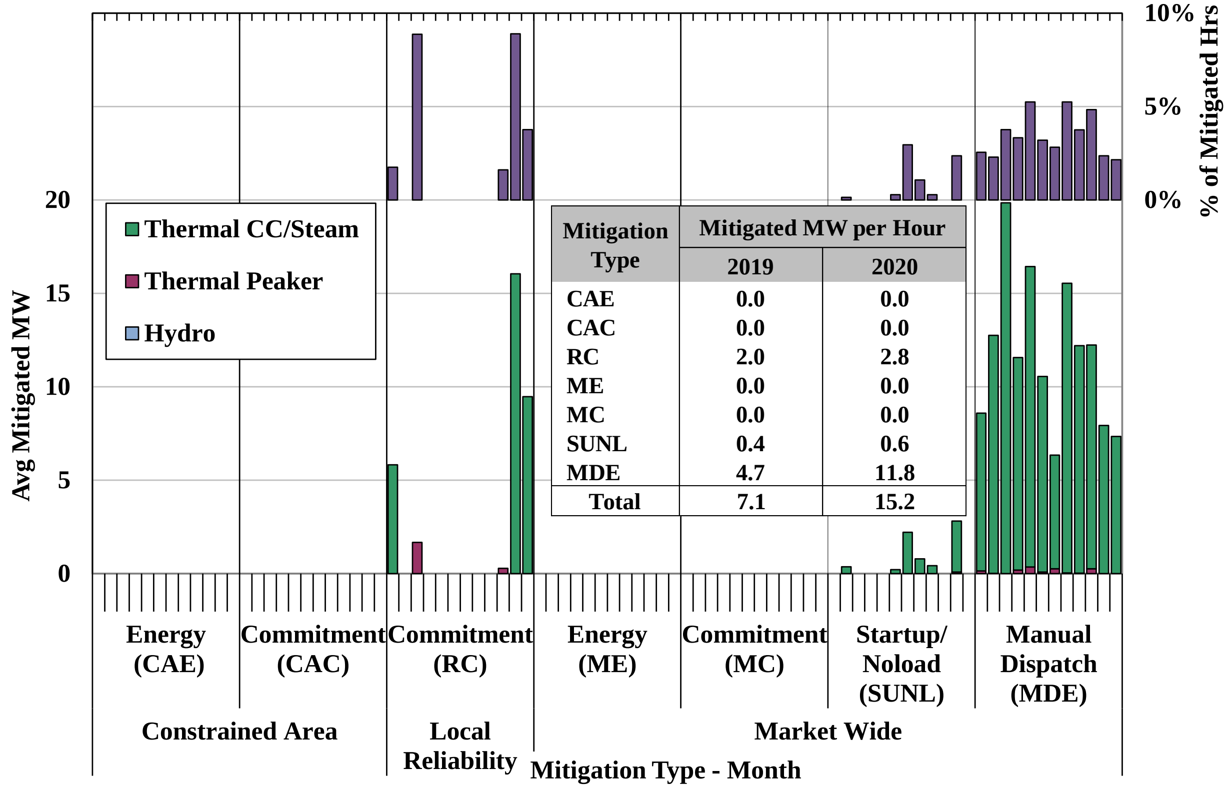
- Constrained Area Commitment Mitigation (CAC) – CAC mitigation is applied to a resource that is committed to manage congestion into a constrained area.
- Local Reliability Commitment Mitigation (RC) – RC mitigation is applied to a resource that is committed or kept online for local reliability.
- Start-up 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 is only applied to 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.

Figure 6 examines the frequency and quantity of mitigation in the real-time energy market during each month of 2020. 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 2019 and 2020.

Despite a modest increase, mitigation was still relatively infrequent in 2020, occurring in less than 6 percent of all hours. Similar to 2019, 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 rose modestly from 2019 to 2020, much of which was on combined-cycle units that were instructed to provide regulation service or to address transient issues on the transmission grid. Nonetheless, the quantities remain very low and the occurrences infrequent.

Figure 6: Frequency of Real-Time Mitigation by Mitigation Type and Unit Type
By Month, 2020



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. Likewise, generators are sometimes not required to burn the lowest-cost fuel. In previous years, substantial amounts of NCPC uplift were paid to dual-fuel units burning oil when natural gas was much less expensive. However, this was not a significant issue in the past two years. We discuss these two issues in more detail in Section III and continue to recommend that the ISO consider tariff changes that would expand its authority to address these issues.

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 generator, 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 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 has recognized this issue and developed 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, as well as the opportunity cost adder, referred to as Energy Market Opportunity Costs (EMOCs), that would be required to limit its generation accordingly.

This EMOC estimation model has been used since December 2018, but the past three winters (i.e., 2018/19 winter, 2019/20 winter, and 2020/21 winter) were generally mild. Although there were some cold days, episodes of very cold weather did not last long enough to put sufficient strain on the natural gas supply and oil inventories. As a result, the use of oil was limited and oil inventories sufficient during these three winter periods. Consequently, the EMOC adder rarely increased above zero for assets that utilized the functionality. The first non-zero EMOCs did not appear until February 2021, which were produced for two small generators during a seven-day period with sustained cold temperatures.[18] Therefore, the effectiveness of the EMOC calculation has not yet been challenged by tight market conditions. Nonetheless, this reference calculation enhancement should help address fuel security issues that ISO-NE faces by allowing generators to conserve fuel more effectively with their offers in the future.

E. Competitive Performance Conclusions

The pivotal supplier analysis suggests that structural market power concerns diminished noticeably in Boston and in all New England in 2019 and 2020, driven largely by:

- the new entry of more than 2.5 GW of generating capacity over the past three years;

[18] One small generator (5 MW) had non-zero EMOCs for seven days (February 6 to 12), and the other small generator (2 MW) had a non-zero EMOC for one day (February 8).

- transmission upgrades in Boston; and
- falling load levels related to combined effects of mild weather conditions, continued growth of energy efficiency programs and behind-the-meter solar generation, and the effects of the COVID-19 pandemic.

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 2020.

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.

The ISO has implemented a procedure to calculate EMOCs for oil-fired and dual-fuel generators with limited fuel inventories to be incorporated in their reference prices. This enhancement should lead to more efficient scheduling of energy-limited resources during tight fuel supply conditions in the future. However, its effectiveness has not been truly tested since its implementation because winter conditions have not been severe enough to put strain on gas supply and oil inventories. We will continue monitor this and evaluate how the EMOC estimator performs particularly under prolonged severe winter weather conditions.

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

III. Commitments for Reliability Needs and NCPC Charges

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. It commits:

- Local second contingency protection resources 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;
- Resources to satisfy system-level operating reserve requirements in the day-ahead market.

However, these local and system-level reserve requirements are currently not embodied in the day-ahead market products. Consequently, generators are frequently committed in the day-ahead market to satisfy local and systemwide reserve requirements, but the clearing prices of energy (and reserves) are understated because they do not reflect the costs of satisfying these requirements.

In addition, since the day-ahead market schedules resources to satisfy load bids rather than forecast load, the ISO must sometimes commit additional generators with high commitment costs after the day-ahead market to satisfy forecast load and reserve requirements. Such commitments generate costs that are uplifted to the market and depress real-time market prices, which undermines incentives satisfy the reserve 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 the overall size of NCPC payments is small relative to the overall New England wholesale market, NCPC payments are important because they usually occur when the market requirements are not fully aligned with the system's reliability needs or prices are otherwise not fully efficient. Consequently, the wholesale market does not provide incentives for investment in resources that enable the ISO to satisfy operating reserve requirements efficiently. Efficient incentives for flexible low-cost providers of operating reserves will be increasingly important as the penetration of intermittent renewable generations increases.

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:

- System-level operating reserve requirements;
- Forecasted system-level energy and reserve requirements; and
- Local second contingency protection requirements.

The final subsection provides a summary 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 energy schedules. However, these reserve requirements are not enforced 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 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 two 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 over 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 - 2020

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

The table shows that additional generating capacity was committed to satisfy the system-level 10-minute spinning reserve requirement in roughly 45 percent of all hours over the past two years. This was the second largest contributor to the NCPC uplift charges in the day-ahead market each year. Procuring and pricing this day-ahead reserve product would improve the pricing of both 10-minute spinning reserves and energy since the opportunity cost of not providing reserves is reflected in the price of energy. We estimate that the absence of a day-ahead product that can be priced in the market reduced energy prices across the system by an average of $2.21 per MWh in 2019 and $1.68 per MWh in 2020.[19] We 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 (see Section IV.B).

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

B. Commitment for Forecasted System-level Energy and Reserve Requirement

The day-ahead market clears physical and virtual load bids and supply offers and produces a coordinated commitment of resources. When the day-ahead market does not satisfy all forecasted reliability requirements (i.e., forecasted needs for energy plus operating reserves) for the operating day, the ISO performs the Reserve Adequacy Assessment (RAA) to ensure sufficient resources will be available. However, such commitments typically generate expenses that are uplifted to the market and increase the amount of supply available in real time. This depresses real-time market prices, leads to additional uplift, and undermines market incentives for suppliers to satisfy the system's requirements. Therefore, it is important to minimize such commitments after the day-ahead market because satisfying reliability requirements in the day-ahead market is much more efficient as discussed above.

In addition, the rising demand for natural gas in recent years has reduced the availability of gas to electricity generators during severe winter weather conditions, creating new challenges for the design of wholesale electric markets. The primary challenge is for the market to coordinate scheduling of electric resources that satisfies the system's reliability needs and allows timely procurement and scheduling of natural gas and other fuels, both for electric generation and other uses. The day-ahead market is intended to provide such incentives for market participants to ensure their resources are available for the next operating day.

Under its Energy Security Improvements Project (ESI), the ISO proposed three types of day-ahead reserves intended to more fully reflect the system's needs in the market and improve suppliers' incentives. These proposed products were rejected without prejudice by the Commission because it was not convinced they were needed for the narrow fuel security objectives at issue in the docket. Nonetheless, it would be valuable for addressing the broader market performance issues discussed in this Section. These products together would satisfy the

[19] 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.

NERC/NPCC reliability requirements and greatly reduce the ISO's need to resort to out-of-market operator actions:

- Generation Contingency Reserves (GCR) – reserve capability deployable within 10 minutes and 30 minutes to be able to respond to system contingencies. Currently, these reserves are procured only in the real-time market.
- Replacement Energy Reserves (RER) –reserve capability deployable within 90 minutes and 240 minutes to be able to restore operating reserves consistent with NERC/NPCC restoration time standards during the post-contingency recovery period.
- Energy Imbalance Reserves (EIR) – additional capability to cover the forecasted load. The forecast load frequently exceeds the total physical energy supply cleared in the day-ahead energy market. Currently, this requirement is satisfied in the RAA process.

We evaluated how these reserve requirements might affect the day-ahead market by analyzing the availability of reserves on each day during 2020. Figure 7 assesses how often the forecasted energy and total 240-minute reserve requirement could have been satisfied by available capacity on each day of 2020. The figure summarizes the available capacity available within 4 hours in the following categories that was not scheduled for energy in the day-ahead market:

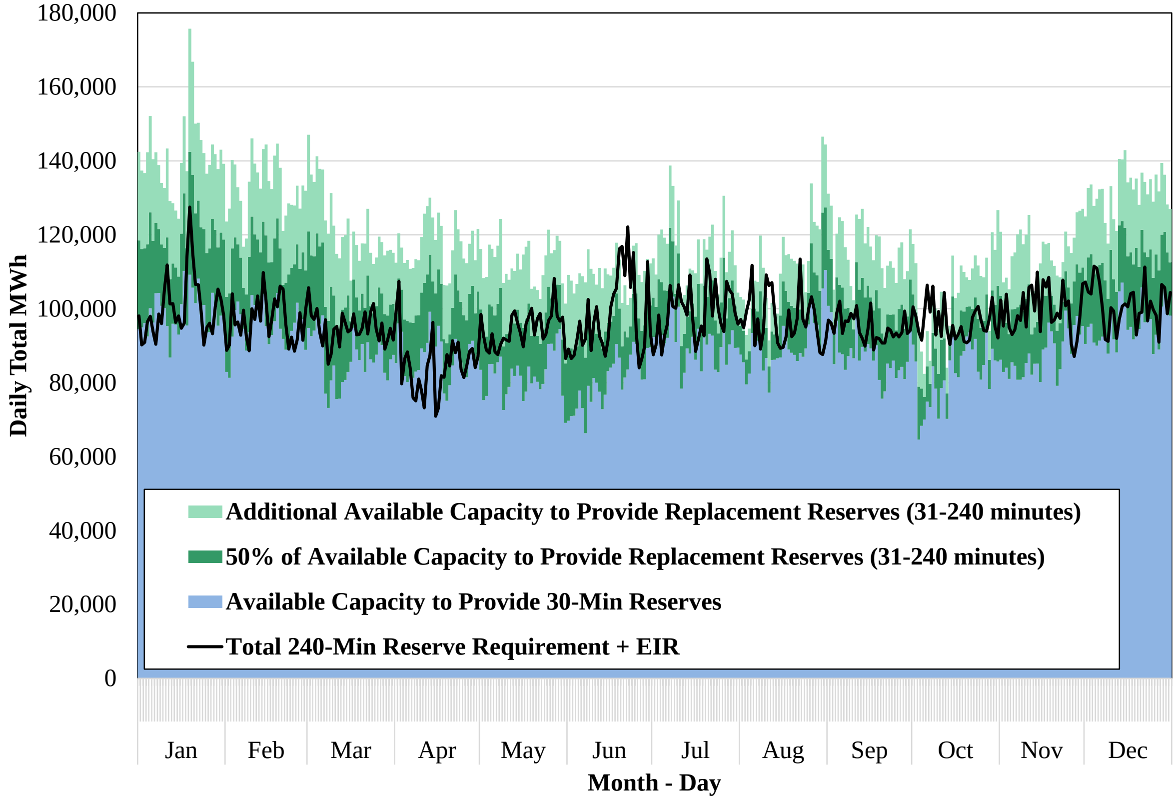
- Available 30-Minute Reserves (blue area) – includes the headroom of online capacity that is rampable in 30 minutes and offline capacity from available fast-start resources. This is the only class of resource that are actually scheduled and compensated in the market.
- Available 30+ Minute Reserves (green areas) – includes the headroom of online capacity that is rampable beyond 30 minutes and offline capacity from available non-fast-start resources capable of providing energy in 4 hours (i.e., Start Up Time + Notification Time < 4 hours). We show this capacity in two equal halves (the light and dark green).
- 240-Minute Reserve Requirement Plus Additional Energy Imbalance Reserve Requirement (black line) – This represents the required total amount of reserve capability to meet the forecasted energy and reserve needs for each operating day.

Even though it procures no reserve products in its day-ahead market, the ISO employs a capacity constraint in its day-ahead market to commit sufficient resources to satisfy its 10 and 30-minute reserve requirements (i.e., the blue area). However, there is not reserve scheduling or obligations associated with these commitments. This figure provides the following key findings:

- Available 30-minute reserve capability would have not been sufficient to satisfy the forecasted energy and reserve requirement on the vast majority of days in 2020, which is significant because this is the only capability that is scheduled and compensated. The remaining reserves shown in the figure are latent reserves not scheduled or compensated;
- The additional reserves available in up to 4 hours were sufficient to meet the ISO's needs in all but 25 days, all of which occur outside of the winter season. Roughly half of these are in shoulder months and caused by high levels of maintenance outages.
- The availability of these resources is uncertain because they had no obligations to pre-arrange fuel so they may have difficulty obtaining fuel when called. If only half of these resources were actually available, the ISO would have been deficient in 84 days.

- Procuring these reserves in the day-ahead market would increase their availability and allow prices the efficiently reflect the available supply of these reserves.

Figure 7: Available Capacity for Daily Forecasted Reliability Requirement in 2020



The estimated capacity margin could be smaller in future years because:

- Our estimates do not reflect energy limitations on certain gas-fired resources that face pipeline gas limitations;
- The winter in 2020 was relatively mild, reducing the severity of energy limitations on fossil-fired units;
- The resource mix may change in the coming years with retirements of fossil-fired units and new entry of renewable resources; and
- Higher penetration of renewable resources will also increase operational uncertainty, likely resulting in higher reserve requirements.

Therefore, it is very important to have a market mechanism that will provide transparent and efficient price signals that reflect the system's reliability needs and provide greater incentives for market participants to ensure their capacity available on the operating day with greater certainty. Since the real-time reserve deficiencies occur throughout the year, it is important that the day-ahead market commit resources to satisfy the forecasted energy and reserve requirements in each and every operating day. Therefore, we recommend that ISO-NE procure operating reserve products to fully satisfy and price its reliability needs, reducing the need for out-of-market commitments. The previously proposed ESI products would address these needs.

C. 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 during 2019 and 2020 by showing:

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

The table 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.[20]

Table 4: Day-Ahead Commitment for Local Second Contingency and NCPC Charges
2019 – 2020

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

20 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 $11.27/kW-year in 2020 ($8.24 of NH-to-Maine plus $3.03 of NE West-to-East).

Maine. Day-ahead commitments for local second contingency protection in Maine were most frequent in the past two years, occurring on 96 days (over 1,400 hours in total) and accounting for 45 percent of NCPC uplift in this category. Although Maine generally exports to other areas, operating reserves are still required to ensure local reliability in case two large contingencies were to occur. Reliability commitments in this area often occur in the shoulder months when transmission maintenance outages reduce import capability from New Hampshire.

Southeast New England. The combined area of Lower SEMA and Eastern Rhode Island constitute another import-constrained area that exhibited relatively frequent reliability commitments in 2019 and 2020, including 75 days (or 941 hours) across the two years.

Eastern New England. Although the frequency of day-ahead LSCP commitments fell from 2019 to 2020 in most areas because of lower load levels and delays in transmission maintenance due to the Covid-19 pandemic, they became more frequent for the broader region that is east of the New England West-to-East interface. This was partly because fewer units were committed for the smaller subareas within eastern NE.

In 2020, the uplift cost per MWh of committed capacity ranged from roughly $4/MWh in the broader region east of the New England West-to-East interface to $22/MWh in the small Seacoast load pocket in New Hampshire. The analysis highlights that market clearing prices are not fully efficient for at least two reasons:

- First, the units receiving NCPC payments systematically receive more revenues than lower-cost resources.
- 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 because, all else equal, they receive more total revenue (including NCPC) than lower-cost more flexible 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 by:

- At least $3 per kW-year in the area that is east of the West-to-East interface,
- Nearly $5 per kW-year in the Lower SEMA and Eastern Rhode Island area, and
- Over $11 per kW-year in Maine.

The frequent use of out-of-market NCPC payments highlights the need for market reforms to improve the efficiency of prices for energy and operating reserves in local areas. Satisfying local requirements through a day-ahead operating reserve market would substantially reduce the need to commit resources out-of-market in the local areas that currently receive sizable NCPC payments. These concerns are exacerbated by three 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 2020, multi-turbine combined-cycle commitments accounted for: (a) roughly 41 percent of the capacity committed for local reliability in the day-ahead market; and (b) roughly 49 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 imports from neighboring areas are currently not counted towards satisfying local second contingency protection—even if the import is associated with a CSO.

- In 2020, an average of 305 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 20 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.

Fuel Procurement. Satisfying local reliability needs with out-of-market commitments and NCPC payments provides adverse fuel procurement incentives. Under the market power mitigation rules, a generator committed for reliability can make more money by operating on a more expensive fuel because the relevant offer cap is calculated as a percentage over the generator's estimated cost.[21] Although this was not a significant issue in 2020, enforcing a requirement that generators committed for reliability burn the most economic fuel will reduce the frequency of commitments that require substantial NCPC payments. Ultimately, this will improve price signals for energy and reserves, and lower costs for the ISO's customers.

[21] See Section III.A.5.5.6.2. of the ISO Tariff.

D. Conclusions and Recommendations

In our assessment of day-ahead reliability commitment, we found that in 2020:

- Supplemental commitment to satisfy the system-level 10-minute spinning reserve requirement occurred in roughly 4,050 hours, leading to $3.8 million (or 40 percent) of day-ahead NCPC.
- Commitment for local second contingency protection occurred on 101 days (roughly 1,200 hours), leading to $3.9 million (or 41 percent) of day-ahead NCPC.

Both of these requirements are satisfied by committing generation to provide operating reserves, but operating reserves are not procured in the day-ahead market and the cost of scheduling operating reserves is not reflected efficiently in energy prices. Instead, the resources committed to ensure the ISO has sufficient reserves cause:

- The day-ahead prices to fall; and
- Result in NCPC payments to ensure the of all commitments and schedules are fully covered.

As a result, resources that provide these services 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 reserve needed to satisfy NERC and NPCC criteria are supplied by resources receiving no day-ahead schedules or 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 away from fossil-fuel generation toward battery storage.

Therefore, we recommend that the ISO implement a comprehensive set of 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. Procuring and pricing these requirements in the day-ahead market would result in substantial additional net revenue—especially for flexible resources such as fast-starting peaking units and battery storage units that will be helpful for integrating intermittent renewable generation.

This recommendation would have been fully addressed by the suite of reserve products that the ISO proposed under its ESI project. Although there are other ways to define and structure such products, we supported the ISO's proposal and believe it would have produced substantial benefits for the region. Unfortunately, the Commission rejected the proposal without prejudice for reasons that were specific to docket under which the proposal was submitted. We encourage ISO-NE to continue to work with its stakeholders to re-file the ESI products or an equivalent suite of operating reserve products.

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; (b) the ISO does not allow firm imports to satisfy local reserve requirements; and (c) resources committed for reliability are able to inflate their revenues and the ISO's NCPC costs by burning a more expensive fuel. 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;
- Consider allowing firm imports from neighboring areas to contribute towards satisfying local second contingency requirements;
- Administer market power mitigation of units committed for local reliability based on the costs of the lowest-cost fuel available.

IV. LONG-TERM INVESTMENT SIGNALS

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. As the EMM, we analyze the long-run investment signals for various resource types, highlight key trends in the development and retirement of resources, and recommend market design enhancements.

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. Hence, we evaluate the role of wholesale markets in supporting the states' goals to promote renewable resources.

In this section, we evaluate and discuss the following issues:

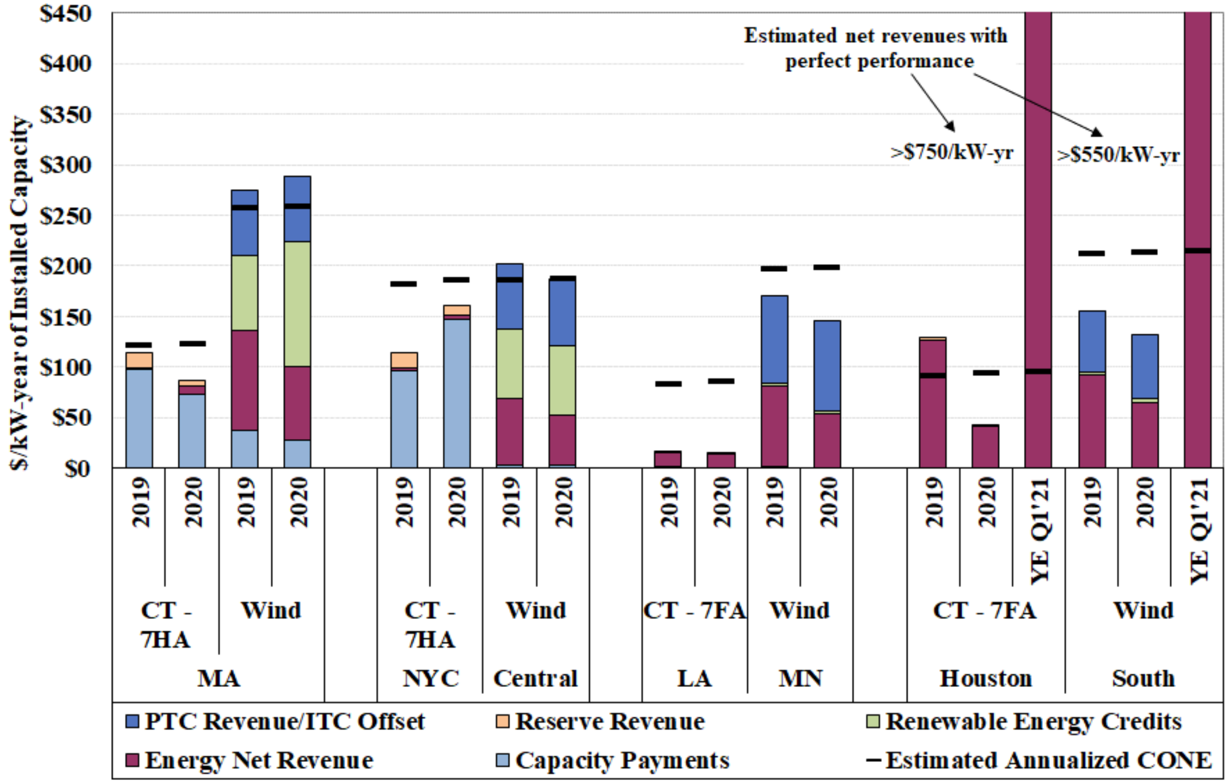
- Incentives for new generation investment in ISO-NE compared to other markets (subsection A),
- Impact of our recommended enhancements to reserve markets and capacity markets on investment incentives for new and existing resources (subsection B),
- Role of wholesale market incentives in guiding investment in renewable resources (subsection C), and
- Investment risks for renewable project developers in New England (subsection D).

The final subsection (subsection E) provides a summary of our conclusions and recommendations.

A. Cross-Market Comparison of Net Revenues

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 8 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. 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 2019 and 2020. It also includes these data for the year-ending March 31, 2021 ("YE Q1 2021") for the ERCOT market.

Figure 8: Net Revenues Produced in ISO-NE and Other RTO Markets
2019 – 2020, and Quarter 1 2021 for ERCOT[22]



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 appropriate 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 2024/25.

Net revenues for a CT from the energy and reserve markets declined in 2020 in all markets because of lower gas prices and demand during the COVID-19 pandemic.

- *New York City*. The only location where total net revenues increased in 2020 was New York City, where the capacity prices increased because of an increase in the local capacity requirement for Summer 2020.
- *ERCOT*. Although the net revenues of a CT in ERCOT declined substantially from 2019 because significant reserve shortages were not repeated in 2020, ERCOT remained the most profitable market for a CT to enter through the entire timeframe shown. Shortage

22 See Appendix (section VII) for the assumptions underlying our analysis. The combustion turbines chosen for each market reflect those that are most economic and likely to be built: a F Class Frame CT in MISO and ERCOT and a H Class Frame CT in New England and New York because of siting regulations.

pricing at $9000/MWh for several days in February 2021 caused net revenues to rise to over seven times the estimated net CONE. Capturing these net revenues, however, requires that resources be online or sell reserves and that they have not sold their energy forward at fixed prices. We also note that the shortage pricing in February did not cause a commensurate shift in the forward market prices for next four years.[23] This is likely because market participants are discounting the probability of a similar event and/or expecting better performance during extreme winter weather in the future.

- *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 leads to inefficiently low capacity prices. As discussed in Section I.A, adopting a sloped demand curve would have reduced the shortfall in the annual revenue requirement of the CT by 52 percent.

Shortage pricing is a very important component of the expected revenues in both ISO-NE and in ERCOT, although 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. Under the PFP framework, the performance payments are a transfer from underperforming to overperforming resources. Hence, there is no direct increase in consumer payments, which reduces the retail counterparty default risk.[24]

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.[25] 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 weaken the incentives that PFP provides.

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

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

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23 The average annual power futures in April 2021 for the years 2022-2025 rose by less than $3.50/MWh (after adjusting for increases in gas futures prices) relative to January 2021.

24 Although the PFP framework does not result in direct increase in consumer costs from higher prices during shortage events, it could increase capacity prices as capacity suppliers with poor performance could raise their offers in the FCM.

25 "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.

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 were comparable to its CONE in 2019 and 2020 primarily because of state and federal incentives. The share from these incentives rose significantly in 2020 because of: (a) decreased energy and capacity prices, and (b) increased Class 1 REC prices in New England. Nonetheless, ISO-NE market revenues are still important, since 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. We discuss the value of wholesale markets in facilitating investment in renewables in New England in subsection C.

The market for Class I RECs in New England continued to be tight in 2020. High prices in 2020 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).[26] Although prices in the past two years have been high, REC prices have historically been very volatile. Prices of Class 1 REC prices in New England are forecasted to fall in the medium term because of the additional supply from state solicitations of offshore wind and solar.[27] This will reduce investment incentives that are determined by expected revenues in the future, despite the fact that the current price for Class 1 RECs are high.

Figure 8 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.[28] However, renewable resources in most of MISO and ERCOT do not receive significant REC revenues. This contributes to the resources not receiving sufficient net revenue to be economic, despite that fact that the resource potential in MISO and ERCOT is better than in New England and New York. Additionally, increasing levels of congestion from wind resource locations to load centers have lowered prices and net revenues for resources in these areas in MISO and ERCOT in 2019 and 2020.[29]

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[26] See April 13, 2021 market update and November 12, 2019 market update from Power Advisory LLC.

[27] For instance, see (a) April 2021 market update from Power Advisory LLC, and (b) Table 61 of March, 2021 report on *Avoided Energy Supply Components in New England*.

[28] Figure 8 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.

[29] In 2019, wind turbines in ERCOT did not see the sharp increase in net revenue that the CT did because the high penetration of wind causes shortage events to increasingly occur when wind output is relatively low.

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 financial hedges.[30]

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.[31] 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.[32] If units under PPAs underperform, it is the ratepayers and not the wind unit owner that would generally bear the costs of the poor performance.[33] Even though financing new wind resources with financial hedges is effective and efficient, the availability of attractive

30 In recent years, the prevalence of a wind project entering into a Virtual PPAs with a corporate off taker has also grown considerably, with the cumulative capacity in 2020 being comparable to the amount of capacity with traditional PPAs. See articles from S&P Global.

31 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.

32 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”.

33 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/ MWh, while the RCPF for TMOR is $1000/ MWh.

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.

B. Impact of Recommended Enhancements on Long Term Incentives

Sections VI.D and III.D of the report discuss our recommendations to enhance the efficiency of pricing and performance incentives in the capacity and ancillary services markets. By rewarding valuable attributes efficiently, the market motivates suppliers to make cost-effective investments in new and existing resources that are needed most by the system. These recommended market reforms would generally increase the financial returns to resources with attributes that will become more valuable as renewable penetration increases. They would also increase the economic pressure on inefficient and inflexible resources to exit the market.

In this subsection, we estimate the impacts of the following three recommendations on investment incentives for several new and existing technologies:

- Develop capacity accreditation rules that provide capacity market compensation to each resource based on its marginal reliability value.[34] (See #2020-2)
- Implement a 10-minute spinning and other operating reserve requirements in the day-ahead market that will be co-optimized with the clearing of energy.[35] (See #2012-8)
- Modify the Performance Payment Rate (PPR) so that the prices during a reserve shortage rise gradually with the severity of the shortage.[36] (See #2018-7)

We evaluated the impact of these recommendations on incentives for several types of new and existing resources described below.

<u>Energy Storage Resources</u> – The value of storage resources increases as renewable penetration rises, but it also depends on their duration and penetration. Hence, we analyze the effects of our recommendations on battery resources with two, four, six hours of duration at two different levels of penetration.

<u>Combined Cycles and Gas Turbines</u> – Combined Cycles (CCs) and CTs constitute a significant portion of the existing flexible capacity, which will be increasingly necessary to complement the regions intermittent resources. Therefore, we analyze the impact of our recommendations on the incentives to continue operations for a CC or CT installed before 2000.

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34 See Section VI.D.

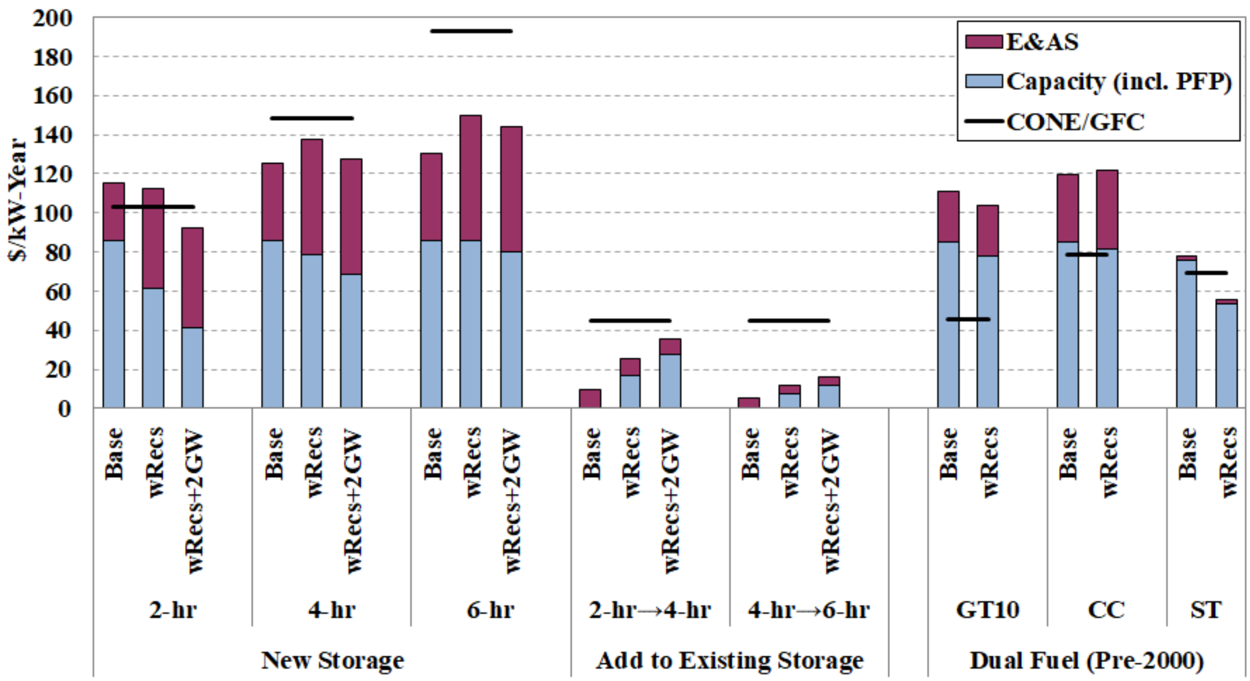
35 See Section III.D.

36 See Section V of the 2019 Report.

Steam Turbines – Steam turbines (STs) tend to have low capacity factors and long lead times for startup. Hence, these resources are less likely to be available during shortages and less useful for balancing the intermittency of renewables. As the resource mix shifts, it is important to provide market incentives that lead to the retirement of the least valuable units.

Figure 9 summarizes the estimated impact of recommended enhancements on energy and ancillary services (EAS) and capacity revenues compared to the corresponding CONE and going forward costs (GFC) for various resources. The "Base" category shows the estimated net revenues that would be received by each type of unit under the current market rules if the system was at "Level of Excess" (LOE).[37] The "wRecs" category shows our estimates if the above recommendations were adopted. The figure also shows the net revenues for battery storage units at a higher level of storage penetration, if our recommendations are adopted ("wRecs+2GW").

Figure 9: Net Revenue Impact of Recommendations at Level of Excess[38]



Our recommended enhancements generally increase the net revenues to resources that are flexible, reliable, and more likely to be available during tight conditions, while reducing the returns to resources that are not.

37 We estimated the net revenues for all resources based on 2019 energy and reserve prices at the Hub. We adjusted the observed prices using the applicable LOE adjustment factor, similar to the methodology followed in the *2021 ISO-NE Net CONE and ORTP Analysis*, available here.

38 See Appendix (section VII) for the assumptions underlying our analysis.

Energy Storage Resources. The impacts of our recommended enhancements depend on their duration and penetration. As discussed in VI, longer duration storage resources have more capacity value than 2-hour resources, which are overvalued currently. The recommendations help address this concern and align these units' net revenues with their true value. In the longer-term, as the penetration of storage rises, the recommended enhancements will cause the net revenues of 2-hour resources to fall more quickly than those of longer duration storage resources, thereby shifting incentives toward longer duration battery storage investments.

Combined Cycles and Gas Turbines. The net revenues to these units will generally be sufficient for them to continue operating, although the current capacity surplus is larger than in the figure. Existing CCs can benefit from spinning reserve enhancements. They have also performed well in shortage conditions because they can startup relatively quickly so their capacity accreditation should fall less than average. Consequently, the recommendations should increase their total net revenues. However, improvements in capacity accreditation could reduce the accreditation of CCs in New England that are gas-only, which do not provide the same level of reliability as dual-fuel resources under all circumstances. CTs do not provide spinning reserves, and hence, may not benefit significantly from the reserve market enhancements in the short-term.

Steam Turbines. The economics of existing steam generators that are less flexible and reliable are likely to worsen under our recommended enhancements. For average-performing steam turbines in ISO-NE, the recommended enhancements would lead to an estimated 30 percent drop in overall net revenues, primarily because of the reduced capacity value. These resources will receive a lower capacity credit because of their long startup lead times and low ramp rates, which limit their ability to perform during unexpected reserve shortages and load shedding events. In addition, their high operating costs and lack of flexibility result in no incremental energy revenues from the enhancements. Consequently, our recommendations are likely to result in lower total net revenues and increased economic pressure on these units to retire.[39]

In the future, higher renewable penetration is expected to reduce average energy prices while increasing price volatility, ancillary services requirements, and the frequency of reserve shortages. Therefore, our recommended enhancements are likely to have larger effects on the incentives for flexible units as additional renewables enter the market.

C. Role of Market Incentives in Guiding Investment in Renewable Resources

The New England states have established ambitious clean energy targets that will require vast amounts of new intermittent renewable generation and flexible resources. The states promote these resources through a number of incentive programs. However, this section demonstrates

39 Retirement decisions depend on a number of unit-specific factors. Nonetheless, structural changes that push revenues below expenses would worsen the outlook for owners and shorten the period over which they may be willing to incur losses or defer expenses, thereby increasing the likelihood of retirements.

that wholesale markets also provide important incentives for investment in new renewable generation that can lower the costs of achieving the states' policy targets.

Although state and federal incentives account for the majority of renewable resource revenues in New England, price signals from wholesale markets still have considerable impact on the returns to these resources. For instance:

- All New England states have RPS/ RES goals.[40] Eligible renewable resources that can help meet these goals can receive REC payments. To the extent that resources sell these credits on the spot REC markets or through fixed REC price contracts, they have substantial exposure to wholesale market energy and FCM prices.[41]
- Connecticut, Massachusetts and Rhode Island have all procured energy and RECs from 3 GW of OSW resources through 20-year contracts. These contracts mitigate the price risk for energy and RECs. However, the resources are still exposed to risks related to (a) curtailment, (b) FCM prices, and (c) negative energy prices.[42]
- Massachusetts utilities have entered into 20-year contracts to import over 9.5 TWh/year of hydropower at a fixed price over a new transmission line. The project depends on wholesale markets for its capacity revenues and for its energy revenues beyond year 20.
- Under the Massachusetts' Clean Peak Standard, storage resources generate clean peak energy credits if they charge during hours of high renewable generation and discharge during hours of peak demand. Storage resources are likely to consider the prices of these credits, as well as wholesale market prices when formulating their bids.
- Connecticut utilities have entered into a 10-year contract that provides a fixed rate per MWh for roughly 50 percent of the Millstone nuclear plant's output. Hence, the project is still exposed to market prices for half of its output and all of its output after 2029.
- Under Massachusetts' SMART program, small solar and solar+storage resources receive a fixed incentive for every kWh they generate.[43] Returns of projects in this program are influenced by the FCM prices, reserve prices, and energy prices during withdrawal hours.

Overall, state incentives work in conjunction with market price signals to determine the returns for investors in a broad range of renewable resources. The value of a renewable resource to the power system depends on its generation profile (over the day and across seasons), the penetration level of similar resources, the location of the resource, and the variability of its generation.

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40 RPS requirements in New England states include 44 percent by 2030 (CT), 38.5 percent by 2035 (RI), 42 percent by 2030 and increasing at 1 percent every year thereafter (MA), 75 percent by 2032 (VT), 25.2 percent by 2025 (NH), and 84 percent by 2030 (ME).

41 For resources that enter into long-term contracts for RECs, the contract prices are influenced by expectations of wholesale market prices.

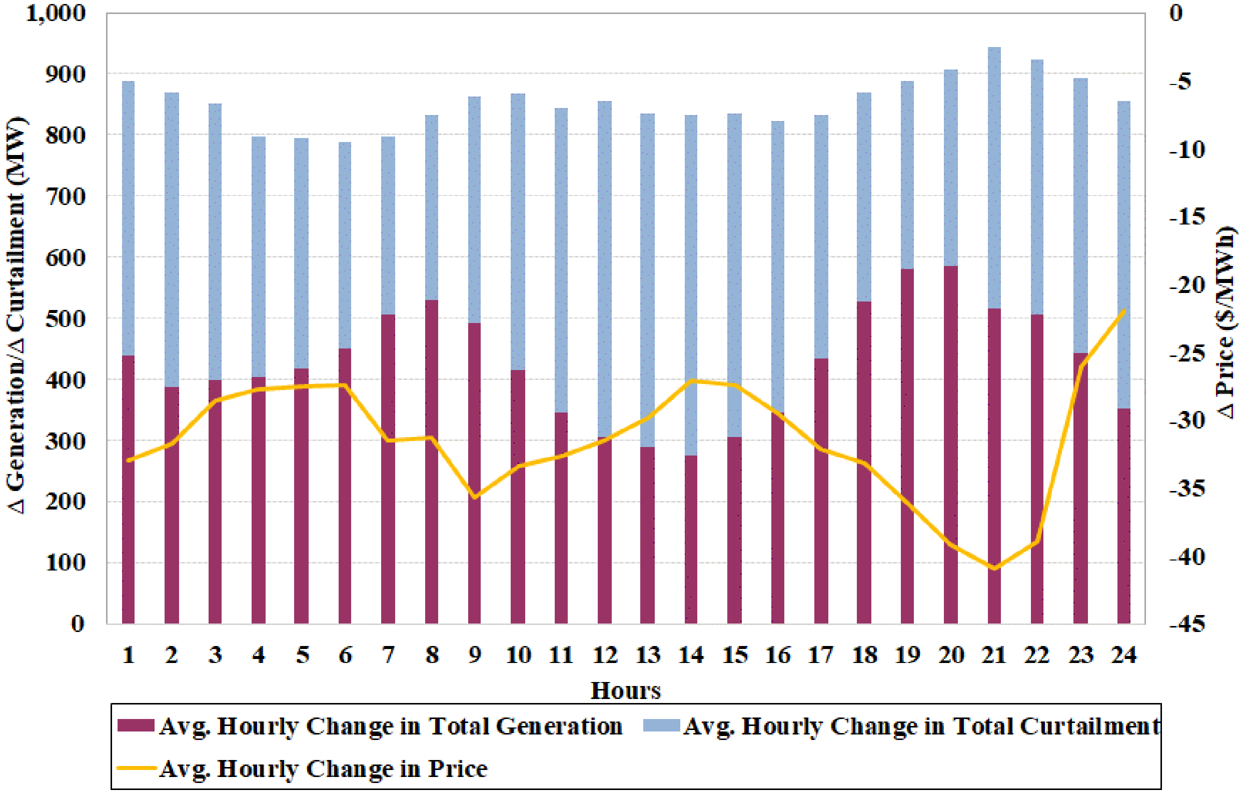
42 The contracts for Vineyard Wind and Mayflower Wind specify the following settlement for negative LMP hours: If the LMP is negative in an hour, the payment "shall be reduced by the difference between the absolute value of such hourly LMP at the Delivery Point and $0.00 per MWh".

43 See report for summary of program elements.

Wholesale markets provide highly granular price signals that differentiate resources based on all of these criteria. Figure 10 illustrates how wholesale markets guide policy-driven investment towards the most cost-effective mix of technologies.

This figure is based on results of Economic Studies performed by the ISO analyzing the impacts of addition large amounts of offshore wind (OSW) by 2030.[44] It shows the effects on prices (the yellow line), and wind output (maroon bars) and curtailments (blue bars) of adding an additional 4 GW to a base amount of 8 GW. These effects depend on the assumed offer prices of renewable units, which are in large part determined by the structure of the state incentives.[45]

Figure 10: Impact of Adding 4 GW of Offshore Wind to a Base Scenario of 8 GW
Rhode Island, Shoulder Months – 2030



44 See Anbaric request here for full list of assumptions.

45 For the purpose of this analysis, we projected prices by adjusting the assumed offer prices (i.e., the "Threshold Prices") the ISO used in its 2019 Economic Studies. Threshold prices are used in the studies to determine the order of curtailment of zero-marginal cost resources. For land-based wind and utility-scale solar PV, we used the "REC-inspired" values in the 2020 Economic Studies. Low wholesale market prices should cause their REC prices to increase. For OSW resources, we use a threshold price of -$85/MWh, based on the price range from bundled contracts for energy and RECs these resources receive.

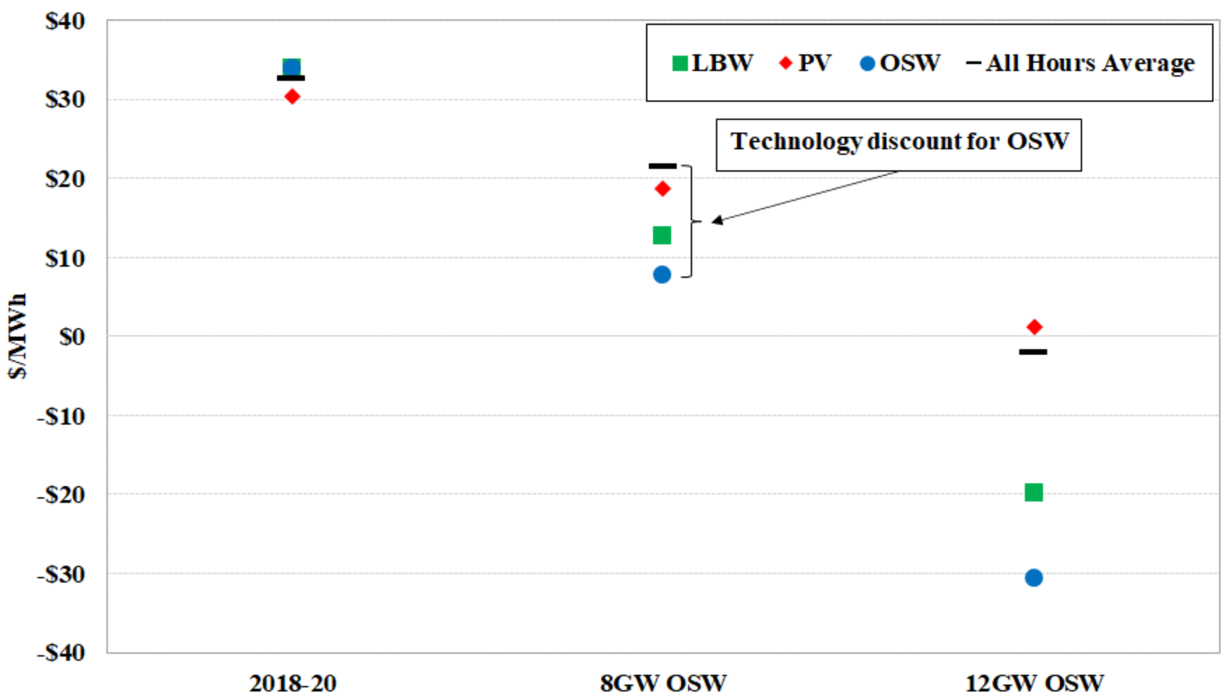
The figure shows that the additional 4 GW of offshore wind cannot be fully absorbed by the system when load is not high, causing:

- Prices to decline significantly in all hours in the shoulder months, declining the most when wind output is the highest.
- Curtailments of roughly half of the potential wind output. These are conservative estimates because we assume that all other renewable resources (land-based wind, solar PV, and Canadian hydro) would be reduced to make room for additional wind output.

This highlights how the markets can facilitate an efficient level of investment in a technology by signaling through prices and curtailments that its value is falling as its penetration increases. It will also signal the value of investment in complementary technologies, such as storage.

The relative market value of a technology can be estimated by a "technology discount" – the difference between the average price in a zone and the output-weighted average price received by a particular technology in the zone. The correlated output of intermittent resources, such as solar, can cause prices to be lower than average when their production peaks. This discount will tend to rise as penetration of a technology increases. Figure 11 shows the technology discounts for solar PV, OSW and land-based wind (LBW) with different levels of OSW.

Figure 11: Average Prices for Renewable Technologies in Different OSW Scenarios[46]



46 Technology discounts for current conditions (2018-20) are estimated based on the prices for ISO-NE Hub from 2018 through 2020. For the 8 GW OSW and 12 GW OSW scenarios, the All-Hours Average price, and the technology discounts for PV and OSW are estimated using the prices at the CT Hub, while the technology discount for LBW is estimated relative to the prices at NH Hub. The difference between NH and CT Hubs average LMPs is less than $0.1/MWh.

Figure 11 reveals some key results:

- The generation-weighted average prices paid to all three renewable technologies are within $2 per MWh of the hourly average zonal price under current conditions. Hence, the technology discounts/premiums are small at low levels of penetration.
- The entry of substantial OSW capacity leads to large reductions in average LMPs – falling by more than one third in the 8GW OSW scenario and to zero on average in the 12GW OSW scenario.
- Large quantities of OSW increase the technology discounts for both OSW and onshore wind because their output is correlated, although the discount for OSW is much higher. The very high discounts in the 12 GW case suggests that this level of penetration is highly inefficient without substantial investment in complementary technologies.
- Increasing penetration of OSW reduces the discount for solar PV because it is not correlated with the wind output. However, increasing penetration of solar would likely increase the technology discounts for solar resources.

Additionally, we note that just as high penetration of a specific technology results in a larger technology discount, high penetration of renewables in a specific location could also result in a 'locational discount' – causing additional investment in that location to be less valuable.

As discussed above, these results illustrate how markets naturally limit the returns to investments in resources with overlapping generation profiles as their penetration increases. Hence, markets can be leveraged to provide price signals that guide investment towards the most cost-effective mix of technologies. Ultimately, this would reduce the size of incentives that these resources require from the states.

These cases also show that high penetration of one technology would likely incent development of other technologies, such as storage resources that would profit from the frequent negative prices shown in these cases. However, such investment may involve a high level of risk if unexpected changes to policy-driven procurements make it more difficult to forecast future revenues. We discuss the risks faced by developers of renewable projects in the next subsection.

D. Investment Risks for Renewable Project Developers in New England

Entry of public policy resources that is not guided by competitive market signals could make achieving clean energy targets more difficult and expensive by increasing the risk to other renewable and flexible resource developers. This subsection discusses the risks faced by renewable resources due to uncertainty regarding future policy-driven investment.

As discussed above, many resources that are supported by state incentives in New England are exposed to wholesale market or REC market risks to varying degrees. Certain approaches for providing incentives to public policy resources can increase two types of investment risks that suppliers of renewable and other resources face, including future price/revenue risks and curtailment risks. The approaches that increase these risks include:

- Adding resources in a manner not sensitive to competitive market signals, including using bundled REC and energy contracts (as have been used for OSW resources).
- Offering incentives that are discriminatory based on technology or whether the resource is new raise the risk to other resources that entered previously.

Alternatively, if the entry and exit of resources is driven to a greater extent by competitive market outcomes, the risks developers face will be reduced and they will be able to better modulate their investment choices (e.g., time of entry, location, technology) or develop appropriate strategies for mitigating the risk (e.g., adding storage to an existing intermittent generator). The rest of this subsection discusses the risks to near-term investment in OSW, utility-scale solar, and land-based wind resources in New England.

Investment Risks for Offshore Wind Resources

Several states in New England have set ambitious targets for procurement of offshore wind. Distribution utilities in these states have already entered into long-term contracts with over 3 GW of OSW, with a comparable amount of capacity to be procured through 2035. These contracts provide a fixed price for every MWh of OSW generation (for energy and the associated RECs). Although this procurement mechanism mitigates the energy price risk to the OSW developer, it could still face considerable risk to its revenues if entry of additional resources results in substantial curtailment of its output in the future as shown in Figure 10.

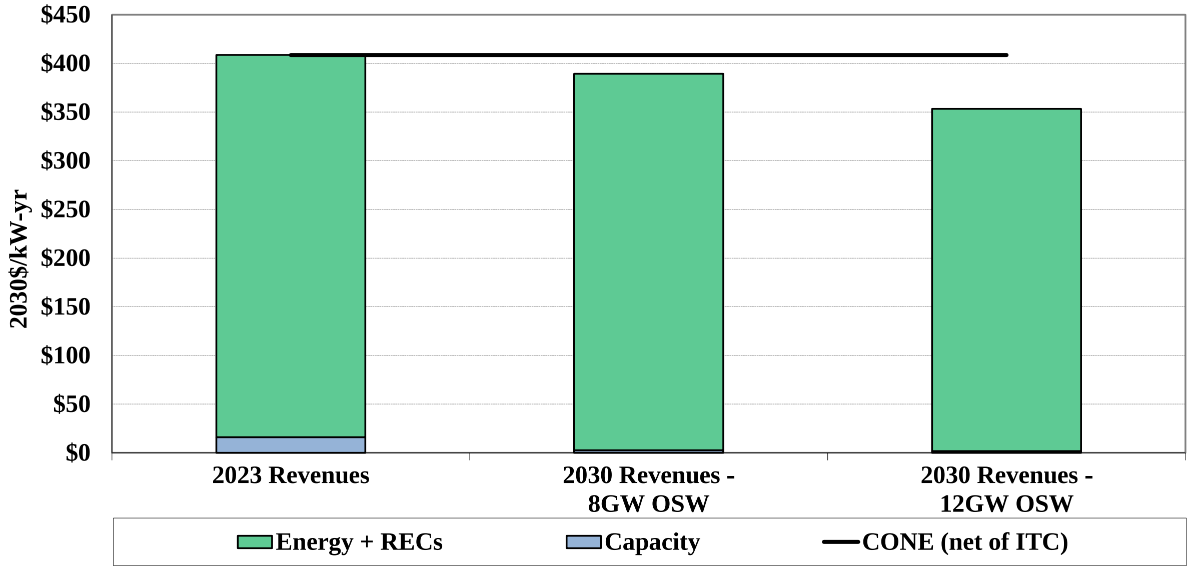
Curtailment adversely affects returns even if the resource has secured a long-term PPA because it reduces the volume of energy that would generate revenue for the project. If future investors are induced to enter (in spite of market signals) by higher incentive levels, but the near-term investor does not receive increased incentives in the future, the near-term investor will be harmed by the resulting curtailment of output.

Figure 12 illustrates how the revenues could change over time for an OSW project that enters service in 2023 and continues to operate in 2030 in the 8 GW OSW and 12 GW OSW scenarios. The analysis assumes that the 2023 entrant would utilize energy futures and FCA prices for 2023 when constructing its offer and that the offered bundled price for energy and RECs would produce a merchant rate of return on investment.[47]

Figure 12 shows that the revenues to the near-term entrant would fall well short of its CONE in 2030 because of subsequent OSW entry, with the shortfall increasing at higher penetration levels of OSW. This is primarily due to increasing curtailment levels as OSW penetration rises.

[47] Energy revenues in 2023 are based on the forward prices as of Apr. 30, 2021. Capacity revenues are based on prices from FCA-13 and 14. The assumed 2023 OSW capacity value is 46%, based on the 2021 CONE-ORTP study, falling to 7.5 and 5 percent in the 8 and 12 GW cases based on a study by the Brattle Group.

Figure 12: Impact of Policy Risk on a Myopic Near-Term (2023) OSW Entrant
Rhode Island Installation



This illustrates how policy initiatives that are not aligned with the market and allow for higher payments to future developers impose significant risks on near-term renewable developers. As a result, firms considering whether to invest in the near-term may require a substantial premium to enter. This may make it more costly or difficult to achieve public policy goals. Policy initiatives that work through transparent uniform market signals (i.e., that compensate resources at the same rate regardless of entry date) reduce the risks to early entrants.

Investment Risk for Other Renewable Resources due to Offshore Wind Mandates

Just as non-uniform prices for different vintages of a technology can be detrimental, non-uniform pricing between different technologies also raises the costs of satisfying clean energy targets. Focusing on promoting one specific technology tends to increase the financial risk to other types of renewable technologies. In this subsection, we evaluate two types of investment risks to solar PV and land-based wind resources related to OSW mandates:

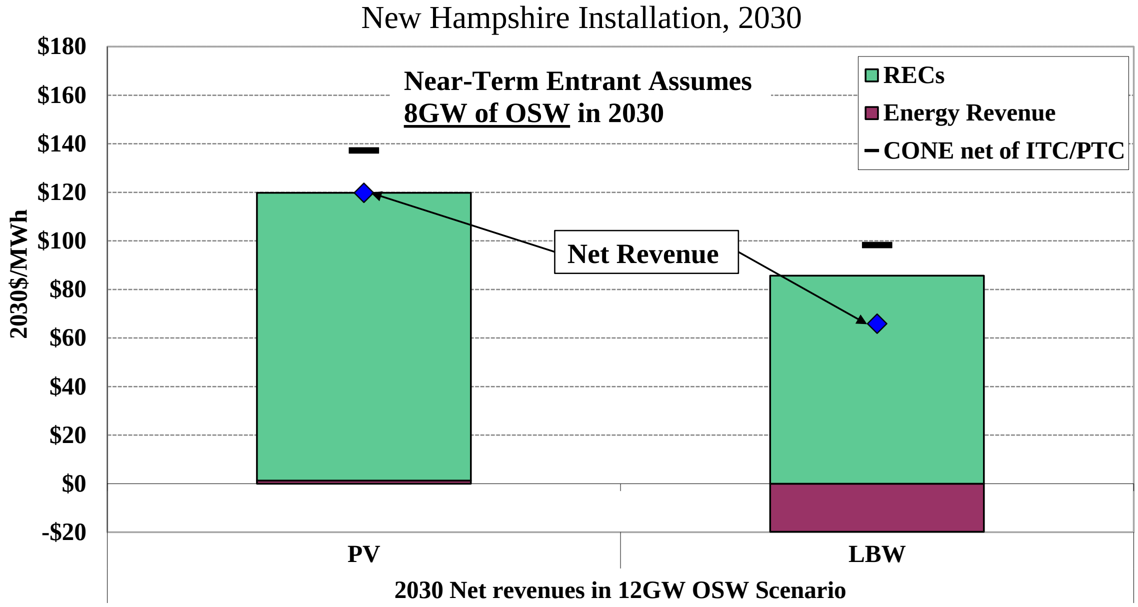
- *REC market price volatility*. Uncertainty about the entry date of OSW projects result in near to medium term uncertainty on the total supply of RECs.[48] Large swings in REC prices will lead investors to discount this revenue stream more heavily, thus blunting the ability of REC markets to incent new renewable entry.
- *Energy price volatility*. Higher penetration of OSW will reduce energy prices in a wide range of hours, as shown in Figure 10. Hence, the prices received by other renewables, such as solar and land-based wind, would also be reduced. Further, uncertainty about the magnitude of the OSW target would also make it difficult to forecast these price changes.

48 For instance, multiple forecasts suggest that REC prices will decline from current levels in the medium term when the OSW projects come online. See (a) April 2021 market update from Power Advisory LLC, and (b) Table 61 of the March 2021 report on *Avoided Energy Supply Components in New England*.

Figure 13 evaluates how policy uncertainty affects the incentives of land-based wind and solar developers participating in solicitations for long-term REC contracts. They would offer to sell RECs at a price that would, at a minimum, be sufficient to cover the difference between its expected wholesale market revenues and its CONE over the project life. Hence, if a developer forecasts lower future wholesale prices, its REC offer price will be higher.

To illustrate how uncertainty affects renewable developers, Figure 13 estimates the revenues in 2030 for near-term land-based wind and solar PV entrants that: a) expected 8 GW of OSW by 2030, but where b) 12 GW of OSW actually enters. The figure compares the net revenues in 2030 with the project CONE (net of federal subsidies).

Figure 13: Net Revenues of Onshore Wind and Solar PV Resources with 12 GW OSW



The energy prices in the 12 GW OSW scenario are much lower than those in the 8 GW OSW scenario so developers of solar PV and land-based wind resources would require much higher REC prices to recover their entry costs. Accordingly, if a near-term solar PV or land-based wind developer enters into a REC contract assuming a lower level of OSW penetration (than 12 GW), the total net revenues of the unit will fall short of its CONE in 2030. This illustrates how uncertainty in OSW targets makes it difficult to forecast the revenues from wholesale markets for developers of other renewable and flexible resources and increases their risk.

This analysis also illustrates the value of promoting investment in renewable resources through incentives and market signals that do not favor any specific technology. The states will likely need to rely on a variety of renewable resources to achieve their deep decarbonization goals. Providing large incentives to specific technologies can increase risks faced by other renewable resources. A technology-neutral approach that compensates the resources based on their contribution to the ultimate policy goal (e.g., decarbonization) can facilitate investment in the most economic technologies and help the states achieve their policy goals at a lower overall cost.

E. Key Findings and Conclusions

The ISO-NE markets provide price signals that motivate firms to invest efficiently in new resources and maintain or retire existing generating units. In this section, we evaluate the current and future investment incentives for various technologies in ISO-NE and find:

i. Lower capacity prices and load in 2020 contributed to lower net revenues for most types of the resources in 2020. These net revenues:
   - Would not have been sufficient to support profitable investment in dual-fueled CTs, except for projects with specific competitive advantages.
   - Would support profitable investment in land-based wind generation, but only when supplemented by state and federal incentives.

ii. New England has relied primarily on PPAs to drive investment in renewable resources while most wind resources in ERCOT have been financed by hedges with private counterparties.
   - The experience in ERCOT demonstrates that renewable resources can be developed even when there are no opportunities for PPAs with state agencies or regulated utilities.
   - When attractive PPAs are offered by utilities and/or state agencies, developers will not pursue hedges with private counterparties.

iii. Our key recommendations would generally increase the net revenues to resources that are most available and flexible (and thus more likely to be available during tight conditions), while reducing the returns to resources that are not.
   - Our recommendations are likely to have larger effects on investment incentives as the penetration of intermittent renewable resources increases.

iv. Despite the reliance on state and state and federal incentives to facilitate investment in public policy resources, the wholesale market remains critical.
   - It provides granular price signals that compensates projects based on their value to the power system and encouraging the most economic projects to be developed.
   - As the penetration of one renewable technology increases, the compensation it will receive from the market falls because it becomes less valuable to the system.
   - This helps guide investment towards the most cost-effective mix of technologies and reduces the overall cost of meeting policy targets.

v. Investments in public policy resources that are not guided by competitive market signals could make achieving clean energy targets more difficult and expensive by increasing the risk to renewable developers.

vi. We encourage states to pursue policy goals by compensating resources based on their contribution to the policy goal, regardless of entry date or technology, which will:
   - Reduce the risks to early entrants;
   - Facilitate investment in the most economic technologies; and
   - Help the states achieve their policy objectives at a lower cost.

V. Assessment of Energy Efficiency Participation in the FCM

Investments in energy efficiency (EE) reduce the system's peak load, decreasing the quantity of generation capacity needed to ensure reliability. Hence, investment in EE can provide substantial resource adequacy benefits. The economic signals provided by the energy and capacity market should provide efficient incentives for loads to invest in EE that reduces the overall cost of satisfying planning reliability needs.

Entities that invest in EE can currently participate as suppliers in the Forward Capacity Market (FCM) as Passive Demand Resources. For example, New England has several utility-run EE programs that provide financial incentives for installation of efficient equipment by end-use customers. Administrators of EE programs may obtain a Capacity Supply Obligation based on the expected impact of these measures on reducing peak load. Approximately 3 GW of new and existing EE resources have participated as supply in recent FCAs. When consumers implement EE measures but do not offer them as supply in the FCM, the benefits are simply captured through load reductions that are reflected in future load forecasts.

EE investments differ from generation and demand response because (1) they 'passively' affect load and cannot be activated on demand, and (2) their impact on peak demand is generally estimated as a counterfactual (e.g., how much higher load would have been), and so cannot be directly measured and verified. Treatment of EE as supply causes compensation of EE related to resource adequacy to be made through capacity payments instead of lower capacity obligations.

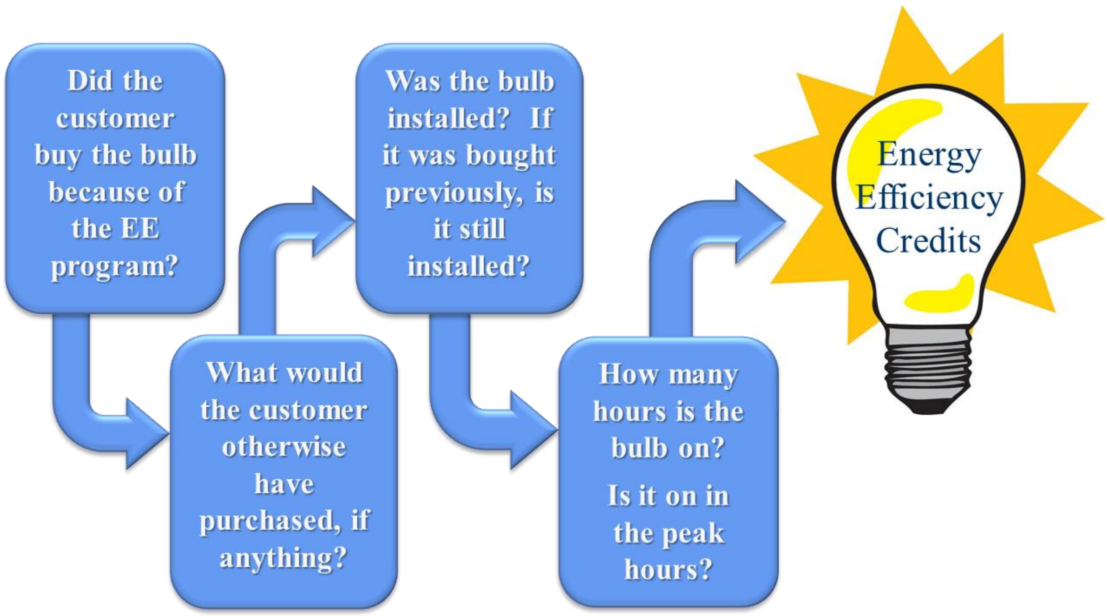
A variety of administrative procedures and rules have been utilized to treat EE as supply. In Subsection A, we discuss how these procedures have negatively affected the ISO-NE market and may undermine the intended purpose of EE. In Subsection B, we evaluate incentives for EE under the current framework compared to the more natural approach of treating EE as a reduction in demand.

A. Treating Energy Efficiency as Supply Raises a Number of Concerns

Treatment of EE as supply requires ISO-NE to synthetically shift EE from the demand side to the supply side of the market, and to adjust the demand to account for this shift as described below. The ISO also oversees an intricate process to qualify, monitor, and verify the impacts of EE resources. These mechanisms add administrative complexity to the FCM. In recent years, the process of accounting for EE has increased capacity requirements, thereby raising the costs of satisfying the ISO's resource adequacy needs. It also results in substantial cost shifting and raising potential gaming concerns. We describe each of these concerns in this subsection.

Inherent Inaccuracy in Estimating the Effects of EE

One clear difference between EE and all other resources is the accuracy of quantification of the capacity value of the resource. The performance of most other resources can be directly tested and measured. This is not the case for EE resources. ISO-NE must make an array of assumptions to estimate expected load reductions in peak hours, as illustrated below for an energy efficient lighting program.



The first question in the illustration above may be the most difficult. In monitoring EE resources in other markets, we have discovered offers that were based entirely on the procurement of sales data of relatively efficient light bulbs and other products from Home Depot, Costco, Lowes and other retailers. This is an example of an EE resource where virtually all of the claimed savings were related to customers' purchases of products for which the EE supplier had *no* effect in precipitating the purchases. We know this because this participant provided no meaningful incentives to customers to increase the sales of EE products, despite receiving substantial capacity revenues. In other words, the product purchases would have occurred with or without the EE resource and, therefore, would already have been accounted for in the RTO's load forecast. Although this is an extreme case, the ISO-NE's rules do not explicitly require that the EE supplier demonstrate that the purchase of the EE products were caused by the supplier.

More broadly, although ISO-NE has devoted significant resources to make the most reasonable assumptions it can, the resulting capacity credits are unlikely to be accurate. Because of this inherent inaccuracy relative to other resources, EE resources are not comparable to the other resources that are procured through the FCM. This inaccuracy in no way limits EE from benefiting on the demand side since the actual savings will translate to lower consumer costs and capacity requirements. The issue only arises because of the treatment of EE as supply.

Reconstitution of EE in the FCM and its Effects on the ICR in Past FCAs

Although EE measures actually reduce load, they are treated as supply resources in the FCM. To avoid double-counting the effects of EE, it is necessary for ISO-NE to add back the estimated load reduction of EE measures to the demand side of the FCM. Hence, ISO-NE calculates the Installed Capacity Requirement (ICR) based on a forecast of 'gross load', which is intended to reflect what load would be if EE measures that participate in the FCM did not exist.

The load forecast used for the ICR is developed based on historical data. Actual historical loads have already been reduced by EE measures – for example, if consumers installed more efficient light bulbs in a previous year, historical data would simply show lower load after that point. Therefore, gross load is 'reconstituted' by adding back an estimate of how much load was estimated to have been reduced by EE. This reconstitution serves no market or reliability function other than to avoid double-counting EE that is treated as supply.[49]

The need to reconstitute gross load has caused the ICR to be overestimated in recent FCAs. ISO-NE has observed that EE program administrators have routinely offered less EE as supply in the FCM than they actually installed.[50] The amount that was added back to the gross load forecast (based on actual installed EE) therefore routinely exceeded the amount of EE offered as supply. Hence, the load forecast was inflated and effectively did not account for a portion of the EE load reduction, causing the ICR to potentially be biased upward.

The 2020 CELT gross load forecast for the summer of 2024 was used for FCA 15, which was conducted in February 2021. The forecast was 947 MW higher than an improved reconstitution approach recently adopted by ISO-NE.[51] Installed EE measures began to significantly exceed FCA CSOs of EE resources in 2014. As a result, an artificially high ICR has been used in every FCA for at least the past five years. These errors have resulted from the reconstitution mechanism (which is specifically intended to offset the amount of EE that participates as supply in the FCM), not the ordinary uncertainty that is inherent in forecasting net load.

The treatment of EE as supply has caused the FCM to procure more generation than needed for reliability and put upward pressure on capacity prices. These effects undermine the objectives of programs to promote EE, which are to reduce the need for conventional generation and provide savings to consumers.

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[49] See ISO-NE, *Long-Term Load Forecast Methodology*, presented to Load Forecast Committee on September 25, 2020.

[50] See ISO-NE filing letter in FERC Docket ER20-2869. EE program administrators may conservatively offer EE in the FCA due to risk of incurring penalties if they are unable to deliver the amount of load reduction for which they receive a CSO.

[51] See testimony of Jonathan Black in FERC Docket ER20-2869, filed on September 11, 2020, at p. 16.

Continued Risk of Error in ICR Caused by the Reconstitution of EE

In 2020, ISO-NE presented improvements to its method to reconstitute gross load in the FCA and ARAs, which were accepted by FERC.[52] The new approach extrapolates based on EE that cleared in the last FCA when estimating the gross load for the next FCA. This approach is an improvement and will help to avoid the systematic upward bias of gross load that occurred in previous auctions. However, it still does not guarantee that the amount of EE added back to gross load is equal to the amount of EE that participates as supply in the FCA:[53]

- If there is an increasing trend of EE programs or participation over several years, the reconstitution will be underestimated and the ICR will be biased downward.
- If there is a decreasing trend of EE programs or participation over several years, the reconstitution will be overestimated and the ICR will be biased upward.

For example, summer EE capacity fell from 3.0 GW in FCA 14 (2020) to 2.8 GW in FCA15 (2021). If ISO-NE's updated methodology had been used for the 2020 CELT gross load forecast (used to develop the FCA15 ICR), it would have added back approximately 3.2 GW of EE, based on the results of FCA14. This would have overestimated EE supply offers and caused the load forecast used for FCA15 to be artificially inflated by approximately 378 MW.[54]

Errors in the ICR related to reconstitution of EE are distinct from uncertainty in the net load forecast. There is uncertainty around the future impact of EE regardless of whether it is treated as a supply resource or demand modifier, and such uncertainty is a normal part of any load forecasting process. However, the need to reconstitute gross load when EE is treated as supply introduces a separate and unnecessary source of uncertainty. Because the load forecast must be prepared before the amount of EE that participates in the corresponding FCA is known, the gross load forecast will inevitably over- or under-estimate EE participation.

As a result, treatment of EE as supply instead of as a demand modifier inherently results in unintended errors in the ICR. These may take the form of either random variation in the ICR or an upward or downward bias over multiple years, depending on the trend of EE participation. If the impact of EE measures continues to grow over time, these errors could become larger and result in larger unintended consequences that are contrary to the purpose of EE.

52 See FERC Docket ER20-2869.

53 ISO-NE's revised approach also does not ensure that the EE added back to load in the ARAs is correct. The EE is added back in the ARA is based on recent historical differences between the ARA and FCA. If EE suppliers offer different quantities in the ARA from year to year, then this approach will produce an error in the gross load forecast.

54 This estimate is based on extrapolating a linear trend through 0 MW in 2006 and 3,014.7 MW in 2023 to 2024. The updated reconstitution methodology adopted by ISO-NE performs a linear interpolation between 0 MW in 2006 and the quantity of EE that obtained a CSO in the most recently completed FCA.

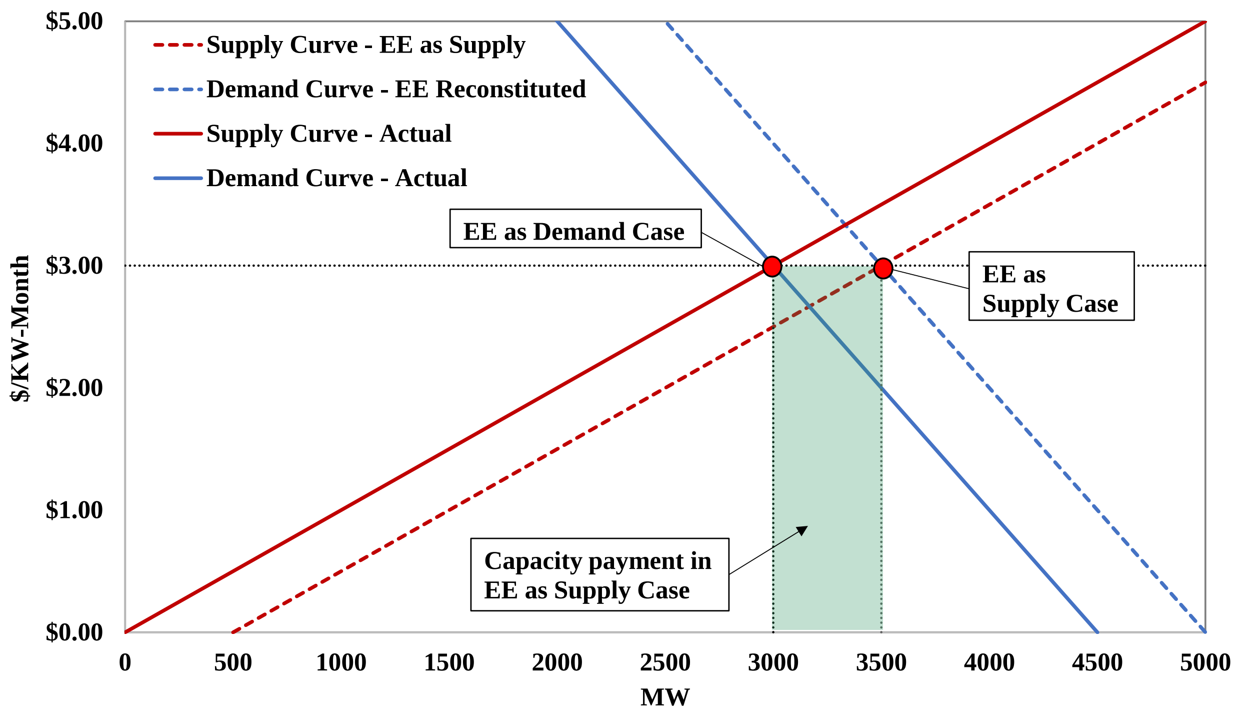
Wide-spread Cost Shifting Caused by Treating EE as Supply

Treating EE as supply instead of demand should not change the clearing price for capacity since the increase in supply should equal the increase in demand. On the supply side, however, it results in a capacity payment that must be allocated to the loads. On the demand side, it would result in a reduced capacity charge of the same amount for the LSE whose load has been reduced. This equivalence is illustrated in the following stylized example.

Figure 14 shows a stylized example of a capacity market under the two approaches to participation of EE:

- In the 'EE as Demand' case, the supply and demand curves reflect actual supply and demand. Most EE is recognized in the ISO's demand forecasts.
- In the 'EE as Supply' case, the supply curve increases to include the EE resources, while the demand curve must be shifted to include the reconstituted load. The gross load shown in this curve assumes that the reconstitution is accurate.

Figure 14: Stylized Example of EE Impact on FCA



In this example, we assume that the reconstituted load exactly equals the EE cleared in the FCA so the supply and demand shift by the same quantity. In this case, the price is unchanged, but the quantity procured increases along with the capacity payments. The increased payments in this example total $18 Million (500 MW * $3/KW-Month * 12 months). Importantly, this payment is not necessary to compensate an LSE that is an EE provider. Since the ISO's load forecast and capacity obligations for each LSE generally reflect the load reductions resulting from EE, the

LSE will already receive the capacity benefits of its EE investments through reduced capacity costs. The effect of this payment is almost entirely to shift the EE costs to other participants in the ISO-NE market.

When the ISO reconstitutes the load, it does not reconstitute the capacity allocations of the LSEs. Therefore, the increased ICR will result in higher capacity obligations for all LSEs, even though the LSE that experienced the load reduction is the only direct beneficiary. Hence, the cost of the payment to the LSE that is an EE provider is spread to all of the other LSEs. To understand this cost-shifting, consider the costs and settlements shown in Table 5 based on the example above. This table assumes that the 500 MW of EE is the result of a program by one LSE. We further assume that the LSE serves 10 percent of the load in the market and, therefore, is obligated to pay for 10 percent of the reconstituted load.

Table 5: LSE-Level Economic Outcomes and Settlements for EE on the Demand Side

Economic Outcomes of EE Program on Demand Side		
(a)	Payments to Retail Customers*	($10 Million)
(b)	Peak Load Reduction	500 MW
(c)	Capacity price	$3 per KW-Month
(d) = (b)*(c)*12	Capacity Cost Savings$_{LSE}$	$18 Million
(e) = (d) + (a)	**LSE Profit**	**$8 Million**

* Assumed incentive provided to retail customers agreeing to install the products. Some EE providers offer few or no incentives, which increases the profit margin earned by the provider.

This example shows that the capacity market can incent investment in EE by LSEs even before the ISO program to treat EE as supply. In this case, the LSE would realize $8 million in profits from its EE program. This profit depends on the size of the EE incentive offered to the retail customers. Some utility programs may offer incentives that in aggregate exceed the capacity payment (i.e., generating a negative profit), the net costs of which are recovered through retail rate charges. Reliance on such fixed retail charges is especially high for utilities that do not serve the load – where the load serving responsibility has been transferred to another entity.

Table 6 shows the additional effects of treating EE on the supply side. Like the prior results, these effects vary depending on whether the EE supplier is an LSE.

Table 6: Settlements Effects for EE on the Supply Side

Additional Economic Effects of Treating EE as Supply		**LSE**	**Non-LSE**
(f)	FCM Payment	$18 Million	
(g) = 10%*(b)*(c)*12	Additional Capacity Obligation for LSE from Reconsitituted ICR	($1.8 Million)	$0
(h) = (f) + (g)	Capacity Costs Shifted to other LSEs	$16.2 Million	$18 Million
(i) = (h) + (e)	**Profit after Cost-Shifting**	**$24.2 Million**	**$0 to $18 Mill**

Table 6 shows some important economic effects of treating the EE as supply. In either case, for LSEs and non-LSEs, almost all of the capacity costs paid to the EE supplier are shifted to loads other than those benefiting from the load reductions. This raises most of the concerns described below.

Effects on LSEs. Treating EE as supply entitles the LSE to capacity payments that duplicate the savings the LSE has already received on the demand side. Since these supplemental payments are borne by all load under the reconstitution process, the LSE's profits more than triple to $24.2 million. Unfortunately, this profit depends less on the value of the EE investments ($8 million) and more on the ability to receive a redundant payment for EE and shift the costs of the payment to others ($16.2 million). Ultimately, this inefficiently inflates LSEs' incentives to fund EE.

Effects on non-LSEs. The effect on non-LSEs, such as "merchant" EE developers, depends on the expenditures the entity makes in its EE program.

- In the extreme, an entity that spends very little and claiming all savings from the products targeted, the entity would extract nearly $18 million in profit. This is most likely to be a "merchant EE" supplier and does not generally benefit customers in New England. These suppliers account a very small share of the EE in New England currently.
- Utilities that spend large amounts on incentives and marketing of EE may use the entire payment to fund the program and the profits extracted could be zero. These utilities generally fund the EE programs through non-bypassable retail charges. The FCM payments in this case simply reduce retail charges for the utility and increase the costs incurred by other LSEs that must be recovered from their retail customers. Hence, treating EE as supply does not advance EE in this case, just shift who pays for it.

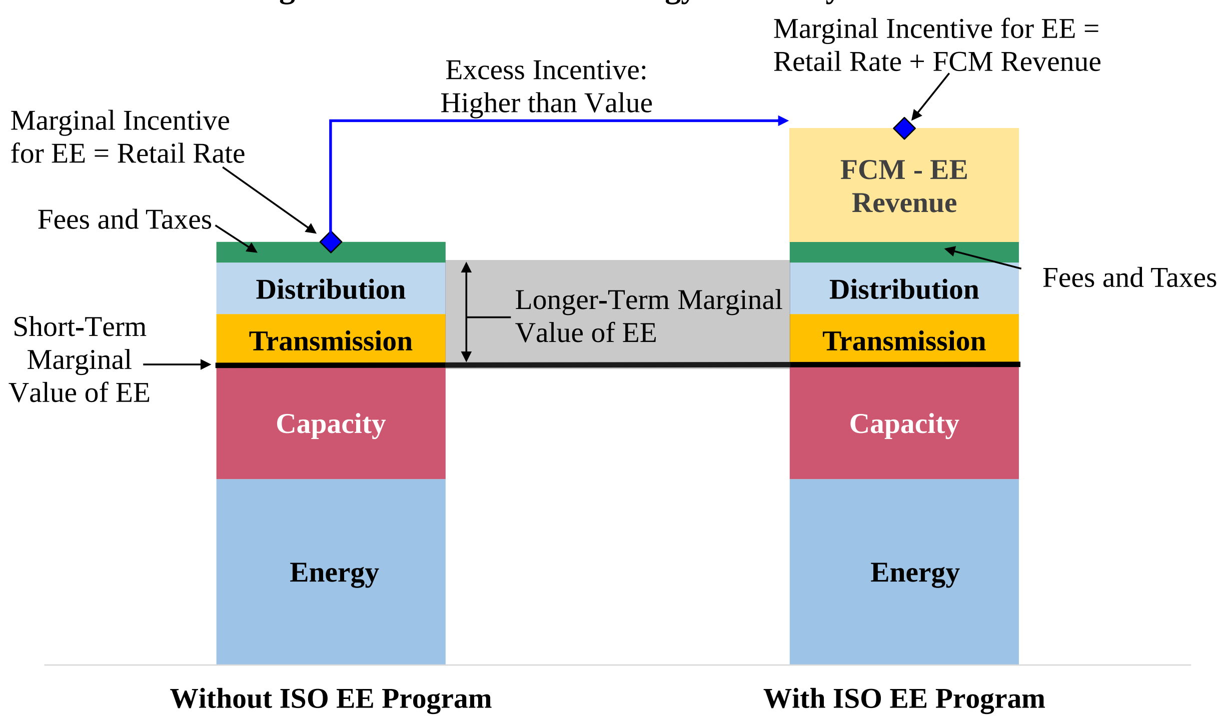
Therefore, treating EE as supply is not beneficial or necessary to facilitate EE in New England. In addition, there is little virtue in the cost-shifting that it produces.

B. Economic Justification for Payments to Retail Customers for EE

Making payments to customers directly or to intermediaries that facilitate EE investments can only be justified to the extent that such payments are efficient and lead to more economically efficient EE investments. Absent ISO-NE's EE program, customers that reduce energy consumption by purchasing energy efficient technologies will receive savings via lower electricity bills. Some states provide a further incentive for such savings via tax credits and rebates. Since electricity rates should include both the energy and capacity costs of serving retail customers, the savings customers receive when investing in EE should reflect the full value of the capacity savings. Therefore, making capacity payments for assumed load reductions essentially double-compensates such customers and is, therefore, not efficient.

This is illustrated in Figure 15 below. The two columns compare the incentives for consumers to purchase EE, both with and without EE participation in ISO-NE's capacity auction. This figure assumes that the FCA revenues are directly or indirectly paid to consumers to induce additional EE, although this is often not the case, as discussed below. Both columns show that the marginal value of EE to ISO-NE is based on the energy and capacity savings for peak load reduction. The incentive for consumers to invest in EE is represented by the blue diamonds, which are equal to the full retail rate. The left column shows that even without the FCA revenues, the incentive to invest in EE is higher than the value of the EE to ISO-NE. The right column shows that making FCA revenues available to customers through the EE product increases the divergence between consumers' incentives and the true value of EE to the system.

Figure 15: Illustration of Energy Efficiency Incentives



This illustration of the incentives retail customers have to invest in EE may vary significantly depending on the retail rate structure and design. For example,

- Some customers may be subject to retail rates that incent peak load reductions. For example, a large commercial office building may pay a demand-based retail rate linked to its peak period consumption. If this customer also receives FCA revenues directly or indirectly, it could be compensated twice for the same peak load reduction at the expense of other retail customers.
- Other customers are not subject to retail rates that reward them for reducing peak load. For example, a small residential customer may pay a simple volumetric rate that does not distinguish consumption during peak load hours. For these customers, the extent to which making FCA revenues available to the customers indirectly (i.e., through an EE supplier) results in duplicative savings/payments is less clear.

Although the extent to which supplemental payments to retail customers derived from the FCM are redundant to the savings such customers will receive naturally from reducing their consumption may vary, it is clear that the economic rationale for facilitating such payments through the FCM is dubious at best.

C. Conclusions and Recommendation

Investments in energy efficiency make valuable contributions to resource adequacy and should be facilitated by the ISO-NE markets to the extent that they are economic. ISO-NE's framework of treating EE as supply in the FCM is intended to recognize these benefits and reward EE investments consistently with supply-side resources. Although well-intentioned, our evaluation of the EE program in ISO-NE raises a variety of concerns related to its treatment of EE as supply, including the:

- Relative inaccuracy of the estimated savings that must be quantified to treat EE as a supply resource, particularly related to the extent to which the EE program caused a behavior change by the retail customer;
- Inaccuracy of the load reconstitution, which can cause the ISO to over- or under-procure supply side resources in the FCA;
- Double compensation of LSE's that offer EE savings on the supply side and benefit from capacity obligation reductions on the demand side at the same time;
- Wide-spread cost-shifting of the capacity payments to EE suppliers in specific LSE areas that are ultimately borne by all loads;
- Potential economic inefficiency of facilitating the indirect delivery of FCM revenues to retail customers whose savings under their retail rates already exceed the marginal value of the load reductions; and
- Costs and complexity of the ISO's administration of the EE provisions.

The current framework offers little advantage to offset the concerns raised above in this Section. We recommend accounting for EE as a reduction naturally on the demand side of the market rather than as a supply resource. (Recommendation #2020-3) Rewarding EE investments comparably to other resources does not require that they share the same participation model. Instead, each resource's participation in the market should reflect its unique characteristics. The defining characteristic of EE is that it is a passive reduction in load.

With no special rules or processes administered by the ISO, such reductions will result in savings by LSEs and their retail customers that reflect the marginal value of the reductions. These savings are realized as the LSE's capacity obligation falls and energy costs decline. This approach eliminates the need for a complicated process to qualify, measure, verify, and settle EE as supply resources, and to reconstitute the load in the FCM.

ISO-NE already prepares a net load forecast each year, which accounts for historical EE deployment trends and forward-looking program budgets.[55] Using this forecast to determine the ICR and the LSE's capacity obligation would provide efficient incentives to invest in EE. This approach would align the benefits and savings customers achieve by investing in EE with the true value of the EE load reductions to the system and its reliability. In addition to providing more efficient incentives to invest in EE, this approach will lower costs to consumers and substantially reduce the unnecessary administrative burdens on ISO-NE. Finally, this would not preclude IOUs or others from funding EE, but it would eliminate the cost-shifting associated with these expenditures. In other words, the retail customers that have access to the EE program of an IOU would bear the cost of the program rather than allowing some or all of the costs to be shifted to other retail customers.

55 See ISO-NE, *Long-Term Load Forecast Methodology*, presented to Load Forecast Committee on September 25, 2020, at p. 52 and ISO-NE, *Final 2020 Energy Efficiency Forecast*.

VI. Assessment of Capacity Accreditation in the FCM

The Forward Capacity Market is designed to procure enough capacity to ensure reliability by providing efficient price signals for resources to enter the market or retire. To this end, ISO-NE must accurately assess the system's resource adequacy needs and how reliability is affected by the addition or loss of various types of resources. An efficient capacity market should provide the same level of compensation to all resources that provide comparable reliability benefits. Specifically, all resources should be compensated according to their marginal reliability value – the improvement in system reliability that a small increment of that resource provides.

Current rules compensate many capacity resources in a way that is inconsistent with their marginal impact on system reliability. These resources include conventional generators that have lower flexibility due to operational restrictions, large units whose outages lead to larger and more impactful reductions in available supply than small units, gas-only units that lack backup fuel, intermittent renewables, and energy storage.

In each of these cases, the resource is allowed to offer levels of Qualified Capacity in the FCM that it cannot reliably provide during hours of critical system need. This is because: (a) current rules do not adequately consider the potential loss of large amounts of output from resources that are correlated, such as the output of intermittent wind resources, and (b) some units are less likely to provide output during critical hours than assumed in the ISO's reliability models because of their long start-up time or other inflexible parameters.

Failing to accredit suppliers' Qualified Capacity based on their marginal reliability value could have major consequences because overestimating resources' expected contributions in their accredited capacity values and the ICR will:

- Prevent the market from securing enough needed to maintain reliability; and
- Cause the market to provide inefficient economic signals that govern investment in and maintenance of capacity resources. Ultimately, this will cause the system to rely more heavily on less-reliable resources and less on more reliable and flexible resources.

As the effects of state policies to decarbonize the electric grid and to electrify other sectors grow, ISO-NE will rely on a wider array of capacity resources and face a more dynamic net load profile than in the past. The most cost-effective means to achieve policy goals while ensuring reliability is to attract investment in resources that complement each other. Hence, it is increasingly important to ensure that the capacity market accurately assesses the reliability value of every resource type under changing circumstances.

In Subsection A, we discuss classes of resources whose capacity accreditation is misaligned with their reliability value under current rules, as well as the factors that are driving the urgent need to improve the capacity accreditation rules. In Subsection B, we discuss how alternative approaches to capacity accreditation impact efficient incentives governing the long-term decisions to invest in and retire capacity resources. Subsection C highlights shortcomings in ISO-NE's resource adequacy model that affect the determinations of resources' reliability value that underly capacity accreditation. Subsection D provides a summary of our conclusions and our recommendation regarding capacity accreditation.

A. The Need to Improve the Existing Capacity Accreditation Framework

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 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).[56] The remainder of this section highlights how these approaches lead to inappropriately high ratings for three resource types:

- Conventional resources that are less valuable because they exhibit limited flexibility, are relatively large in size, or can only run on natural gas;
- Intermittent resources whose output is highly correlated; and
- Energy storage resources.

To compensate resources according to their reliability value, it will be necessary to estimate their value using a resource adequacy model that captures the correlated nature of resources' ability to provide output. This will become more important as the penetration of intermittent generation and energy storage resources increases.

Conventional Resources

Several types of conventional generators have features that increase the risk that they will be unable to support the system during critical hours, beyond what is reflected in their random forced outage rates (EFORd). Current capacity accreditation methods do not account for the resulting effect on resource adequacy.

For existing dispatchable capacity suppliers, Qualified Capacity is determined based on the Seasonal Claimed Capability that the resource can demonstrate during a test of its maximum output each season. Suppliers may obtain and be compensated for a Capacity Supply Obligation up to this Qualified Capacity level. This approach does not account for several factors that affect resources' reliability value:

- *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

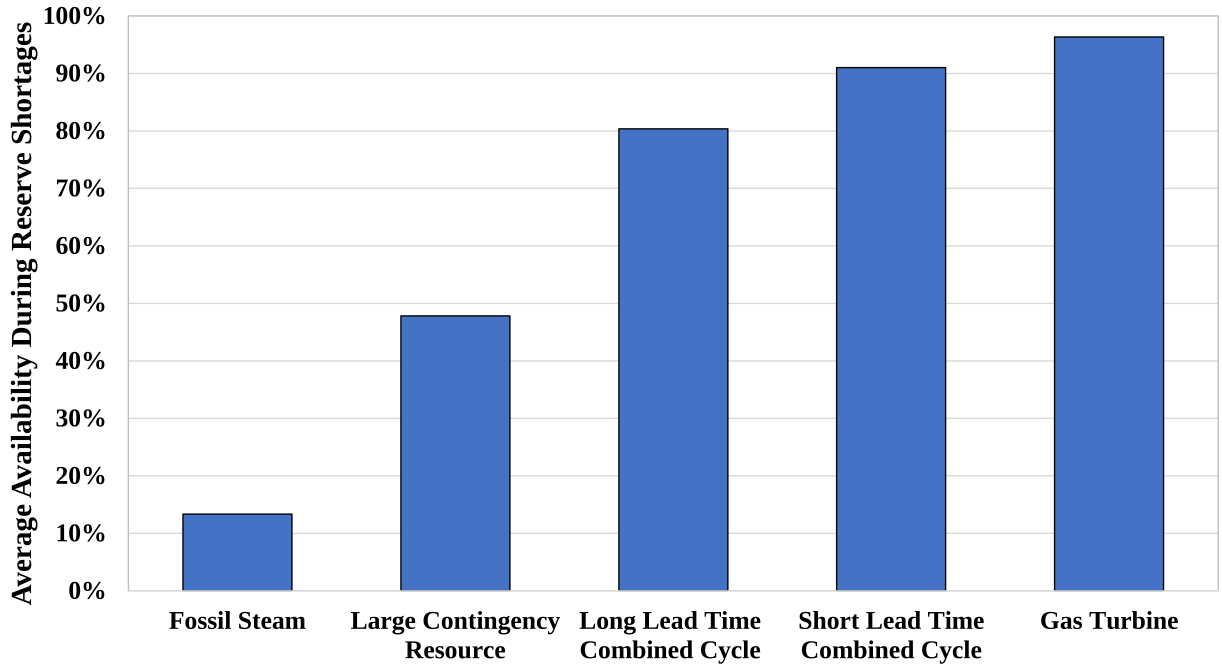
56 For most resource types, maximum Qualified Capacity is based on Seasonal Claimed Capability (SCC). See ISO-NE, *Having a Capacity Supply Obligation Lesson 2C: Introduction to Capacity Resources*.

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.[57] Currently, this is not accounted for in the Qualified Capacity a unit may sell.

- *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.[58] Currently, this is not accounted for in the Qualified Capacity of individual resources.
- *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 Qualified Capacity.

Figure 16 examines the impact of lead times and unit size on availability in critical hours.

Figure 16: Average Availability of Fossil Units During Reserve Shortage Events
2014 – 2020



57 Units that are inflexible but have very high capacity factors (such as nuclear plants) have a high reliability value. This is because they are likely to be already committed when a reserve shortage occurs.

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

It shows the average availability of fossil resources in ISO-NE during historical reserve shortages over the six-year period from December 2014 through 2020. Reserve shortages occurred in 20 hours during this period. A unit is considered available up to its seasonal claimed capability (SCC) if it provided energy or reserves during the reserve shortage hour.[59]

The results of this analysis are illustrative and are not intended as proposed capacity accreditation values. They show that units with long lead times and units that are part of a large contingency have historically been less capable of providing energy or reserves during reserve shortages than other dispatchable units.

- Steam turbine units were usually not online or committed during shortage events. When a reserve shortage occurs, offline steam turbines are generally not able to start in time to provide energy or reserves to relieve the shortage.
- Combined cycle units with long lead times were less likely to be online or committed during reserve shortages than ones with shorter lead times. However, long lead time combined cycle units were more likely to be online or committed than steam turbine units because they generally have higher capacity factors due to their lower production costs.

This analysis likely underestimates the capacity value of long lead time units when, unlike today, the system has little or no surplus reserve margin. For example, long lead time units are more likely to provide output in events when a high day-ahead load forecast requires all resources to be committed. ISO-NE has enjoyed a large reserve margin in recent years, so reserve shortages have occurred more unexpectedly. Hence, the capacity value of long lead time steam units is likely to be higher than the value shown in Figure 16 but lower than more flexible resources.

The figure shows that large resources, which are likely to be primary system contingencies, were less likely to provide energy or reserves than other combined cycles during reserve shortages. This is because some reserve shortages occur partly as a result of a large supply contingency.

Intermittent Resources

Currently, the Qualified Capacity 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.[60] This simple heuristic approach reflects typical output in the timeframes when peak loads have historically occurred. However, it does not ensure that resources' Qualified Capacity reflects their actual expected output during critical hours when the risk of load shedding is highest.

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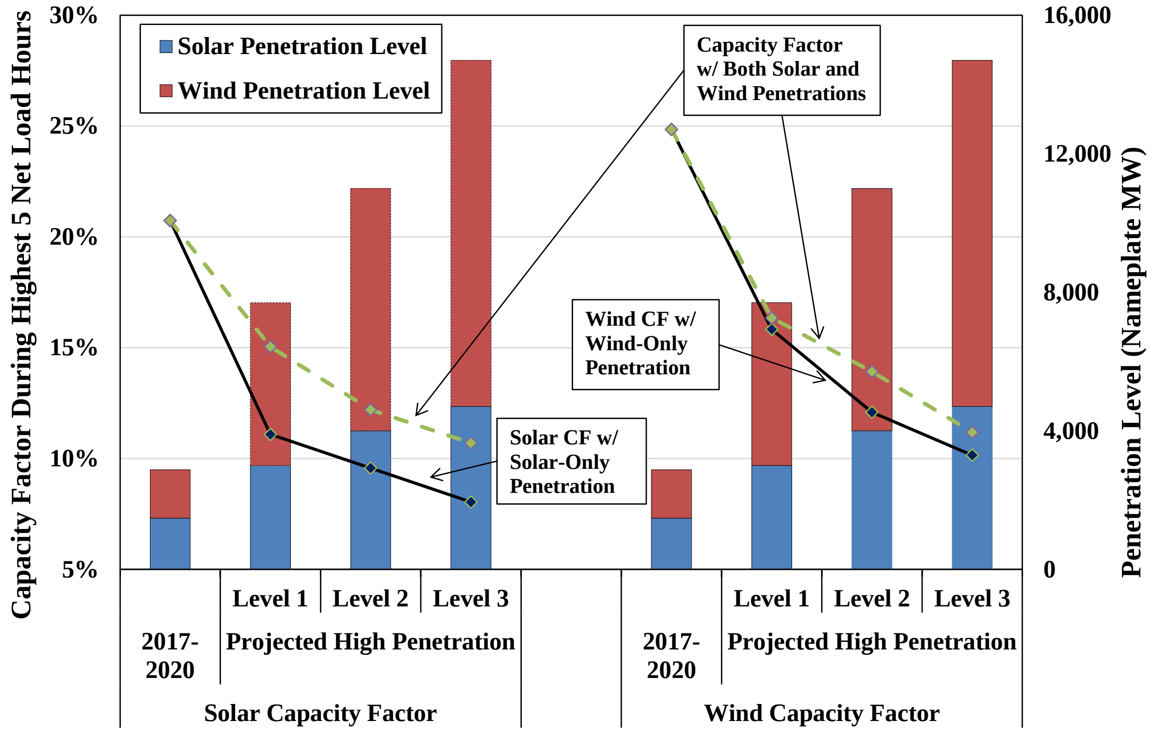
59 Units with lead times of 6 hours or more are considered 'long lead time' for this analysis. This includes all steam turbine units and some combined cycles. A unit is considered to be a large contingency resource if it is part of a single contingency of over 1 GW. The categories shown are mutually exclusive – hence, combined cycles classified as large contingencies are not included in either the long lead time or short lead time categories.

60 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.

Output of intermittent resources of the same type and geographic area is correlated. As these resources grow to a larger share of supply, the hours when output from all wind or solar capacity is low are more likely to be when additional capacity is needed. Hence, median output across a predetermined range of hours will not adequately capture the reliability value of an intermittent resource during critical hours.

Figure 17 shows the average capacity factor of wind and solar resources during the five highest net load hours each year over the last four-year period. Net load is calculated as load minus output from all intermittent resources (including behind-the-meter and front-of-meter). The chart shows average actual load patterns and the installed levels of wind and solar in the period from 2017 to 2020. The 'Projected High Penetration' scenarios reflect increased levels of wind and/or solar output, in amounts roughly consistent with state RPS targets by 2023 ("Level 1"), 2026 ("Level 2"), and 2030 ("Level 3").[61] Hourly renewable output in each scenario is scaled up while hourly load is held constant, causing the highest net load hours to shift. For each technology and penetration level, the analysis includes two scenarios: one assuming a combined addition of wind and solar and one assuming the addition of only the resource type being examined.

Figure 17: Average Output During Top Five Annual Net Load Hours
2017 – 2020



61 Solar penetrations at Level 1, Level 2 and Level 3 are based on forecasted PV participating in the ISO-NE markets in the 2021 CELT Forecast. Wind penetration levels are estimated based on projects in the ISO-NE interconnection queue.

The results of this analysis are not intended as proposed capacity accreditation values, but they demonstrate how the capacity value of intermittent resources could evolve as larger quantities of these resources enter the market:

- Output of solar and wind in top net load hours as a percentage of their capacity falls as penetration increases. Higher penetration of intermittent resources causes net peak hours to shift towards times when output of intermittent resources is low.
- The capacity factor of solar generation in top net load hours is increased by the penetration of wind generation, and vice versa. For example, in some hours the capacity factor of wind is very low, resulting in high net load, but the capacity factor of solar is higher. Specifically, the capacity factor of solar averages 8 percent under the highest ("Level 3") penetration of solar capacity, but its average capacity factor rises to 11 percent when the penetration of wind capacity is reflected in the scenario.

ISO-NE's current method to accredit capacity of intermittent resources fails to capture these effects because it does not account for the shifting of hours that will be critical to reliability as intermittent resources enter the system. When a correlated set of resources comprise much of the resource mix, capacity is needed specifically in the hours when output from those resources is low. The urgency of the need to improve the accreditation of intermittent resources is rising as state energy policies will likely lead the ISO-NE's supply portfolio and demand to change at an unprecedented rate in the coming years:

- The New England states aim to achieve economy-wide decarbonization targets of at least 80 percent by 2050. Achieving state goals could require large portions of the transport and building heat sectors to convert to using electricity, which would lead to rapid load growth and different seasonal and hourly consumption patterns. For instance, these changes could lead ISO-NE to transition from being a summer-peaking system to being a winter-peaking system by the early 2030s.[62]
- All of the New England states except New Hampshire also have renewable portfolio standards or similar programs with an objective of serving at least 48 percent of the load with clean resources by 2030.[63] These programs are expected to require over 12 GW of new renewable capacity by 2030.[64] Large-scale investments in storage resources may be driven by their synergies with intermittent renewables and state programs such as Massachusetts' Clean Peak Standard.

The current heuristic approaches for determining Qualified Capacity will lead intermittent resources to be compensated far in excess of their true reliability value. As the penetration of intermittent resources expand, critical hours when reliability is threatened will increasingly occur

[62] See *Net-Zero New England: Ensuring Electric Reliability in a Low-Carbon Future*, joint report by Energy & Environmental Economics and Energy Futures Initiative, November 2020.

[63] See *Avoided Energy Supply Components in New England: 2021 Report*, prepared by Synapse Energy Economics, Inc, March 2021, at p. 141-147.

[64] See S&P Global Market Intelligence, "New England Renewable Policies To Drive 12,500 MW Of Renewable Capacity By 2030", June 15, 2020.

when the correlated output of intermittent resources is low. These are hours when the net load that must be served by other types of resources is very high even though the gross load may not be particularly high. Hence, higher penetration levels of any one intermittent technology will cause the marginal reliability value of that type of resources to fall, which must be recognized by in the ISO's future accreditation of intermittent resources.

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 may increase the marginal reliability value of storage).

Under current rules, storage that can discharge for at least two hours may offer Qualified Capacity 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. In past reports, we performed simulations of GE-MARS to quantify the value of battery storage resources. 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; and.
- The capacity value of a 4-hour battery storage resource was 95 to 96 percent at 500 MW of penetration, declining to 76 to 78 percent at 2,000 MW of penetration.[65]

Over 600 MW of mostly 2-hour battery storage systems received CSOs in the most recent forward capacity auction.

Although a storage resource is limited in the duration over which it can provide energy, it can provide reserves for extended periods of time. Unless required to discharge and produce energy during load shedding events, its reserve capability will not be diminished during reserve shortages. Since load shedding is expected to occur in only a small percentage of reserve shortage hours, the risk of PFP penalties may not be significant for storage resources relative to the potential upside in the form of higher capacity revenue.[66] As a result, the current framework overestimates the reliability that is provided by storage resources and does not adequately encourage them to adjust their own capacity sales to a more realistic level.

65 This study was originally performed for the NYISO system. See Alternative ELR Capacity Value Study: Methodology and Updated Results, NYISO Installed Capacity Working Group on February 25, 2019 at https://www.nyiso.com/icapwg?meetingDate=2019-02-25.

66 This concern also applies to other resources with energy limitations, such as fossil generators with limited on-site fuel supply.

B. Impact of Capacity Accreditation on Incentives for Investment

The use of inefficient capacity accreditation approaches for some resource types increases the cost of satisfying reliability criteria over time. This is because investors are not encouraged to pursue the projects that best combine reliability benefits with other sources of project value.

Poor Accreditation Causes Investment to be Misaligned with Reliability

If investment in one type of project is over-compensated in the capacity market relative to its reliability benefits (i.e., the expected reduction in load shedding it provides), investors may over-invest in that technology on the basis of this phantom benefit. This will discourage investment in other projects that would provide higher reliability value. Ultimately, this increases the cost of maintaining reliability because investment in resources with diminishing reliability value will compel the ISO in increase its total capacity requirements.

A particularly important reality related to capacity accreditation is that that marginal reliability value of many resource types falls as their penetration increases. This is the case for gas-only resources, most intermittent resources, energy storage resources, and others. For accreditation purposes, the fact that any of these resources may provide high incremental reliability value at low penetration levels is irrelevant – only the incremental value of another unit of the resource matters. Any capacity accreditation method that does not reflect the reliability impact of an incremental addition or retirement in the context of the broader resource mix provides incoherent signals for investment in capacity resources. Simple heuristic approaches and 'average' capacity value approaches are, therefore, likely to lead to inefficient investment and retirement decisions and inflated consumer costs over time.[67]

Accrediting capacity resources based on their marginal contribution to reliability properly recognizes the diminishing value of correlated resources and the diversity benefits of other resource types. It is key to providing efficient incentives for investors to:

- Avoid technologies that have over-saturated the market;
- Add storage to intermittent renewable generation facilities;
- Efficiently choose between storage projects with different durations or augment storage durations by efficiently trading off cost and value to the system;
- Repower renewable projects when they approach the end of their useful lives;
- Pursue innovative technologies such as zero-emissions dispatchable resources or long-duration storage when they become viable, and their reliability value increases. Such investments may be needed to complement high penetrations of intermittent resources and short-duration storage while complying with state policies; and

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67 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 Appendix Section VIII.

- Retire units with common fuel supply contingencies or add backup fuel sources that increase the ability of generation to provide output when needed.

This list of benefits of aligning resources' accreditation with their marginal reliability value is not exhaustive but illustrates the fundamental value of making these improvements.

PFP Rules Do Not Fully Offset the Effects of Poor Capacity Accreditation

ISO-NE's Pay-for-Performance (PFP) rules may offset to some extent the effects of the accreditation concerns described above because PFP penalizes capacity suppliers that underperform during reserve shortage hours. The PFP penalty rate is $3,500/MWh and is set to increase to $5,455/MWh in 2024 and above $8,000/MWh in 2025. The risk of incurring PFP penalties provides an incentive for resource owners to avoid obtaining a capacity supply obligation that they will be unable to deliver when a reserve shortage occurs. Hence, when the maximum Qualified Capacity of a resource overstates its marginal reliability value, PFP rules may encourage resource owners to reduce their capacity sales to more realistic levels.

PFP rules alone are insufficient to ensure that incentives to invest in capacity resources are aligned with their marginal reliability value. Capacity payments are certain, while PFP events are uncertain and have been exceedingly rare, which will likely continue to be the case for the next few years or until the capacity surplus dissipates. Hence, capacity suppliers are likely to heavily discount the uncertain PFP costs relative to the certain capacity payments. Therefore, improving capacity accreditation to reflect resources' marginal reliability values will be an essential improvement for ISO-NE.

C. Shortcomings of ISO-NE's Resource Adequacy Model

In addition to the capacity accreditation issues discussed above, it is very important that the resource adequacy framework accurately models and determines the marginal reliability value of different types of resources. ISO-NE uses the resource adequacy model GE-MARS to determine its Installed Capacity Requirement (ICR). Using this model to assess the marginal reliability value of various resource types will align ISO-NE's capacity accreditation with the impact that resources are assumed to have when determining the ICR. However, improvements are needed to model each type of resource in MARS accurately.

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:

Intermittent resources. These resources are assumed to provide their Qualified Capacity with 100 percent availability in MARS, currently equivalent to median output during seasonal peak hours. This approach fails to consider that output of these resources varies significantly during individual hours in a manner that is highly correlated with other resources of the same type. As penetrations of intermittent resources grow, this will cause their marginal reliability value to be increasingly overestimated since reliability issues are most likely to occur in hours when output of intermittent resources is low and net peak load is high. Modeling intermittent resources in MARS based on realistic hourly output profiles would produce better estimates of the system's reliability and resources' marginal capacity value.

Inflexible Generation. Operational restrictions that limit units' short-notice availability, including startup lead times, ramp rates, and minimum runtimes and downtimes, are not considered in MARS. Instead, units with these restrictions are assumed to always be available up to their Qualified Capacity unless experiencing a random outage. As a result, MARS will not produce reliable estimates of these units' capacity value. It may not be possible to model operating restrictions in MARS, which is not designed to consider unit commitment separately from dispatch. In this case, separate heuristics may be necessary to determine the marginal capacity value of such resources.

Gas-only units with common fuel supplies. These resources are assumed to always be available up to their Qualified Capacity unless experiencing an independent random forced outage. MARS does not consider that the total amount of pipeline gas available to electric generation may reduce the availability of generation. It also does not consider that a single event affecting availability of fuel or pipeline operations could cause correlated loss of a large amount of capacity. It therefore overestimates system reliability and the capacity value of gas-only units when there is overdependence on resources with shared fuel supplies. An assumption that fuel supply limitations or outages affecting multiple units occur with nonzero probability would tend to decrease the reliability value of these units calculated using MARS.

To provide additional information regarding the consistency of the ISO's accreditation embodied in resources' Qualified Capacity and the modeling of the resources in MARS, we examine how these two processes address different key factors that determine resources' marginal reliability value. Table 7 summarizes whether the accreditation process and the MARS model accurately accounts for each of these key factors or resource characteristics.

Table 7: Evaluation of Resource Types in Capacity Market and MARS

Resource	QC Reflects Marginal Reliability Value?	Modeled Accurately in MARS?
Generator with long startup lead time	No	No
Large generator	No	Yes
Gas-only unit without backup fuel	No	No
Intermittent resources	No	No
Energy limited resources	No	No
Flexible capacity with backup fuel	Yes	Yes

D. Conclusions and Recommendations

Current capacity accreditation methods over-value several resource types, including generators with long lead times, large units, units with shared fuel supplies, intermittent resources, and energy-limited resources. Historical data shows that long-lead time and large units have underperformed during shortages. In addition, our analysis suggests that the reliability value of intermittent resources and storage is already lower than assumed in setting their accreditation levels and that it will fall as penetrations increase. Current methods to accredit resources do not account for these factors.

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. (See Recommendation #2020-2) Improving accreditation in this manner will:

- Provide efficient incentives to investors deciding whether to retire a resource by aligning its capacity payment with the resource's impact on the reliability of the system.
- Account for the diminishing value of resources whose ability to provide output 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 default expected capacity value of a resource should be determined 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. This is the Marginal Reliability Impact (MRI) method. MRI can be calculated for various factors that affect resources' expected contribution to reliability.

Due to the substantial and correlated fluctuations in output of intermittent resources, the estimated contribution of these resources should be determined using probabilistic methods such as the marginal Expected Load Carrying Capability (ELCC) methodology. A marginal ELCC can be calculated for each resource type indicating the reliability value of an incremental quantity of that resource, which is approximately equivalent to its MRI.[68]

Marginal ELCC and MRI approaches account for both the output uncertainty and the correlated nature of the intermittent output. Such approaches tend to provide lower accreditation levels as penetration increases. In addition to being more accurate and improving investment incentives in such resources, this change will be extremely valuable in maintaining the integrity of the ISO's forward capacity market regardless of whether the Minimum Offer Price Rules (MOPR) are retained:

- If the MOPR rules that protect market outcomes from the adverse effects of out-of-market entry are retained, improving the accreditation of these resources will allow many more to enter unmitigated because they will each have a smaller effect on the market.[69]
- If the MOPR rules are eliminated, improving the accreditation of these resources will reduce the adverse and exaggerated effect of the state-sponsored resources on the complementary generating resources that must be maintained to ensure reliability.

To improve its accreditation, ISO-NE will need to modify its resource adequacy model to more accurately assess impact on reliability of various resource types. This will also provide a better assessment of capacity needed to satisfy reliability criteria when determining the ICR. In particular, ISO-NE's GE-MARS model should be modified to consider:

- The output profile of intermittent resources in each hour of the year, instead of assuming that they are always available in the amount of their Qualified Capacity.
- Operational restrictions, such as startup lead times that affect the ability of dispatchable generators to contribute during critical hours. If this is not possible in MARS, it may be necessary to assess these resources' expected availability using a separate heuristic.
- The loss of multiple units as a combined contingency when they share a common failure point. For example, two units that share a single fuel line could be grouped together. Likewise, multiple units connecting to a single pipeline and lacking backup fuel supplies could be considered as a joint contingency and/or as energy-limited resources.[70]
- The effects of the energy limitations of battery storage, pumped storage, and pond storage resources' availability over a lengthy period of tight operating conditions (based on the duration of needs that could occur given the system's resource mix).

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68 We compare alternative methodologies including MRI and ELCC in Appendix VIII.

69 This is for two reasons. First, reduced accreditation would reduce the supply of sponsored resources in the CASPR substitution auction. Second, it would encourage some older inflexible conventional resources to retire, which would create additional room for entry of sponsored resources.

70 It may be necessary to estimate the likelihood of contingencies affecting common failure points which may be rare or nonexistent in recent historical data.

VII. Appendix: Assumptions Used in Analysis of LONG-TERM Incentives

In this section, we list various assumptions underlying the net revenue estimates for various technologies discussed in section IV.

Net Revenues of Dual-Fuel Units

Our net revenue estimates of dual-fuel resources are based on the following assumptions:

- Fuel costs for all units are based on the Algonquin City Gates gas price index.
- Units are scheduled before each day based on day-ahead prices, considering commitment costs, minimum run times, minimum generation levels, and other physical limitations.
- CC and ST units may sell energy, 10-minute spinning reserves, and 30-minute reserves; while the modeled combustion turbines (including older gas turbines) may sell energy and 10-minute non-spinning reserves. Each unit is assumed to offer reserves, limited only by its ramp rate, minimum down time and commitment status.
- CTs settle according to real-time prices and the deviation from their day-ahead schedule. Combustion turbines are committed in real-time based on hourly real-time prices.
- Online units are dispatched in real-time consistent with the hourly integrated real-time LBMP and settle with the ISO on the deviation from their day-ahead schedule. However, to account for the effect of the slower ramp rate of the ST unit in this hourly analysis, the unit is assumed to operate within a certain margin of the day-ahead energy schedule. The margin is assumed to be 25 percent of the maximum capability.
- CTs are assumed to sell forward reserves in a capability period when it will be more profitable than selling real-time reserves.[71]
- Fuel costs assume transportation and other charges of 27 cents/MMbtu for gas and $2/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.
- The minimum generation level is 152 MW for CCs and 90 MW for ST units. The heat rate is 8,000 btu/kWh at the minimum output level for CCs, and 13,000 btu/kWh for ST units. 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 all dual-fuel units are shown in Table 8:

71 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 8: Unit Parameters for Net Revenue Estimates of Dual-Fuel Units

Characteristics	CT - 7HA	CC 1x1	ST	GT-10
Summer Capacity (MW)	364	283	360	32
Winter Capacity (MW)	394	297	360	40
Heat Rate (Btu/kWh)	9,132	7,750	9,500	15,000
Min Run Time (hrs)	1	4	16	1
Variable O&M ($/MWh)	$1.8	$5.0	$9.9	$4.9
Startup Cost ($)	$11,000	$1,000	$6,507	$1,301
Startup Cost (MMBTU)	510	1,800	3,500	50

Impact of Recommended Enhancements on Long Term Incentives

In subsection IV.B, we illustrate the impacts of implementing our recommendations on net revenues of various units. Our estimates are based on the following assumptions:

- *Co-optimize scheduling and pricing of energy and operating reserves in the DA market* – We estimated the impact of this recommendation by increasing the DA energy and reserve prices by an amount equal to the shadow price on the 10-minute spinning reserve constraint in the resource commitment pass of the day-ahead market.[72] In the commitment pass, resources are committed and dispatched to meet both the energy and reserve requirements; while in the scheduling and pricing pass, resources are scheduled to satisfy the energy needs only. The shadow prices on the reserve constraints in the commitment pass would be a good proxy for potential price impact in the scheduling and pricing pass had the energy and reserves been co-optimized in the day-ahead market.
- *Improve Capacity Accreditation* – The following table shows the representative accreditation values that we assumed for various technology types in our analysis:

Table 9: Capacity Accreditation Assumptions[73]

Technology	With Recommendations	With Recommendations + 2GW of Storage
Energy Storage 2-hr	67%	40%
Energy Storage 4-hr	90%	77%
Energy Storage 6-hr	100%	93%
CC	95%	95%
GT-10	90%	90%
ST	70%	70%

72 Shadow prices on the 10-minute and 30-minute operating reserves constraints were rarely binding.

73 The slight decline in capacity revenues of a CC is due to the assumed startup time (4 hours) for a pre-2000 vintage unit. The capacity values of battery storage resources are based on results of GE-MARS simulations of the New York system. See footnote 65.

- *Modify the PPR to rise with the shortage level* – In our 2019 Annual Report, we estimated that the expected value of lost load (EVOLL) during the September 3, 2018 PFP event to be far lower than the marginal compensation based on the prevailing PPR. For illustrating the impact of this enhancement, we assumed that the average PPR will be similar to the higher end of the EVOLL ($1000/MWh) during the 2018 event.[74]

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.[75] For estimating net revenues in 2030, 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.[76] OSW capacity value in 2023 is assumed to be 46 percent and then decline to 7.5 and 5 percent in the 8GW and 12GW cases.
- We estimated the REC revenues for land-based wind using a 4-year average of the MA Class I REC Index for 2019 and 2020 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.[77]
- The CONE for renewable units was calculated using the financing parameters and tax rates specified in the ISO-NE Net CONE and ORTP study.[78]
- Table 10: summarizes the various cost and performance parameters that we assumed for solar PV, onshore wind and offshore wind units that commence operations in 2025. For

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74 Consistent with the ISO-NE CONE study, we assumed 11.3 hours for H. We also included scarcity revenues for each resource using values from the ISO-NE CONE and ORTP study. We assumed Average Actual Performance ("A") of 90 percent, 92 percent, and 12 percent for CC, GT-10, and ST, respectively.

75 For NREL data, see link.

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

77 For solar PV, our analysis assumes 30 percent ITC for 2023 entrant. For offshore wind, we assume 30 percent ITC for 2023 entrant. For land-based wind units, our analysis assumes full PTC for the 2019 and 2020 entrants. The PTC is available only for the first 10 years of the project life. The value of PTC shown is levelized on a 20-year basis using the after-tax WACC.

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

estimating the cost for entry in other years, we utilized the cost trajectory from inputs to the NREL's ReEDS model.[79]

Table 10: Cost and Performance Parameters of Renewable Units

Parameter	Utility-Scale Solar PV	Land-based Wind	Offshore Wind
Capital Cost (2025$/kW AC basis)	$1,627	$2,282	$3,530
Fixed O&M ($/kW-yr)	$31	$51	$113
Federal Incentives	ITC	PTC	ITC
Project Life	20 years		
Depreciation Schedule	5-years MACRS		
Average Annual Capacity Factor	14%	36%	46%

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.[80] 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 2020 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 2019 and 2020 vintages from S&P Global Market Intelligence. For MISO, we utilized publicly available information on the REC prices in Minnesota.[81]
- Consistent with the assumption for other markets, we assumed full PTC revenues for the land-based wind plants in ERCOT and MISO regions.

79 The capital costs for utility-scale solar PV and land-based wind units are based on the ISO-NE Net CONE and ORTP Analysis, and data from NREL for OSW. We assumed 'Class 7-low' projections for adjusting the land-based wind costs, 'Class 1-moderate' projections for OSW, and 'low' projections for utility-scale solar PV. Fixed O&M costs for all renewable 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.

80 See figure A-124 in the *2020 State of The Market Report for The New York ISO Markets*.

81 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.

Table 11: Land-based Wind Parameters for Net Revenue Estimates[82]

Parameter	ERCOT (South)	MISO
Investment Cost (2020$/kW)	$1,842	$1,670
Fixed O&M ($/kW-yr)	$44	$44
Federal Incentives	PTC	
Project Life	20 years	
Depreciation Schedule	5-years MACRS	
Average Annual Capacity Factor	35%	46%

Net Revenues of Battery Storage Resources

Our net revenue estimates for battery storage resources based on the following assumptions:

- The unit's injections and withdrawals are determined by co-optimizing the unit's energy and reserve revenues using the day-ahead market prices. We limit the injections and withdrawals to one cycle per day.
- The hourly net revenues are determined using the day-ahead energy and ten-minute spin prices, and the resource's output as determined by its charge and discharge schedules.
- The resource can earn additional revenues in the form of real-time reserve revenues in hours when the resource has a positive state of charge (SOC) and is not discharging.
- The following table summarizes our assumptions for cost and operating parameters.[83]

Table 12: Energy Storage Parameters for Net Revenue Estimates

Parameter	2-Hour	4-Hour
Capital Cost (2025$/kW)	$693	$1,176
Fixed O&M Cost (2025$/kW-yr)	$39	
Round-Trip Efficiency (%)	86%	
Project Life	20 years	
Property Tax	1.00%	
Depreciation Schedule	7-year MACRS	

82 The Fixed O&M and Investment costs are sourced from NREL ATB 2020, 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.

83 Our assumed battery costs are derived from NREL's 2020 Annual Technology Baseline. See link. We incorporated cost multipliers to estimate the costs of developing a 2-hour and 4-hour resources in New England. See EIA data. We estimated the CONE of a 6-hour resource by adding the difference in the CONE of a 4-hour and a 2-hour resource to the CONE of a 4-hour resource.

VIII. 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 Qualified Capacity (QC) 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.[84] 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).

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.

84 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.[85]

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.[86] An example of an ELCC calculation, based on a recent proposal in PJM,[87] 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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85 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.

86 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.

87 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 VI.C 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. In this case, separate heuristics may be necessary to determine the marginal capacity value of such resources. Any such heuristic should be designed based on the fundamental principle that a resource's capacity accreditation is based on its relative effectiveness at reducing the likelihood of load shedding. In the long run, it may be necessary to consider whether an alternative or improved resource adequacy model that can model resource commitments would better estimate the reliability value of all resource types.