Capacity Market Alternatives for a Decarbonized Grid: Prompt and Seasonal Markets

DRAFT

Authors:
Todd Schatzki, Ph.D.
Joseph Cavicchi
Phillip Ross, Ph.D.

December 2023

Table of Contents

Glossary of Terms

Abbreviation	Definition
ARA	Annual Reconfiguration Auction
CSO	Capacity Supply Obligation
CCP	Capacity Commitment Period
CELT	Capacity, Energy, Loads, and Transmission
CM	Capacity Market
CONE	Cost of New Entry
CVC	Common Value Component
DCR	Demand Capacity Resources
EFORd	Equivalent Forced Outage Rate demand
EIA	U.S. Energy Information Administration
ELCC	Effective Load Carrying Capability
EMS	Energy Market Simulation
ES	Energy Storage
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
GADS	Generating Availability Data System
GFC	Going Forward Cost
GT	Gas Turbine
ICAP	NYISO installed capacity
ICR	Installed Capacity Requirement
IRM	Installed Reserve Margin
ISO-NE	ISO New England Inc.
IT	Information Technology

LMP	Locational Marginal Price
LNG	Liquid Natural Gas
LOE	Level of Excess
LOLE	Loss of Load Expectation
LSE	Load Serving Entity
MaxGen Event	Maximum Generation Emergency
MISO	Midcontinent ISO
MRI	Marginal Reliability Impact
NEAS	Net Energy and Ancillary Service
NEPOOL	New England Power Pool
NYCA	New York Control Area
NYISO	New York ISO
NIMBY	Not In My Backyard
NERC	North American Electric Reliability Corporation
ORTP	Offer Review Trigger Price
ONW	Onshore Wind
OFW	Offshore Wind
O&M	Operations and Maintenance
PFP	Pay-for-Performance
PJM	PJM Interconnection
PPR	Capacity Performance Payment Rate
PRA	MISO's Planning Resource Auction
PV	Photovoltaic
QC	Qualified Capacity
QMRIC	Qualified Marginal Reliability Impact Capacity
RA	Resource Adequacy

RCA	Resource Capacity Accreditation
RMR	Reliability Must Run
rMRI	Resource Accreditation Factor
RPM	PJM Reliability Pricing Model
RTO	Regional Transmission Organization
SAC	Seasonal Accredited Capacity
SNL	SNL Energy
STAR	NYISO Short-Term Assessment of Reliability
SSR	System Support Resources
WSR	Winter-to-Summer Ratio

Capacity Market Alternatives for a Decarbonized Grid: Prompt and Seasonal Markets[1]

I. Executive Summary

To maintain reliable system operations and resource adequacy, ISO New England Inc. ("ISO-NE") operates a Forward Capacity Market ("FCM") to ensure the region has sufficient resources to reliably meet load throughout the year. The current design of the FCM reflects market and system conditions at the time when the market was being developed, including concentration of peak loads and reliability risks in the summer months, and the expectation that new capacity would primarily use gas-fired technologies with predictable development timelines of three years or less.

However, today's electricity grid is evolving in a different direction due to a combination of state policies pursuing goals of decarbonizing the system and advances in performance and cost of technologies that can achieve these decarbonization objectives. While the "grid of the future" will continue evolve over the coming decades, three important changes have meaningful consequences for suitability of the region's current capacity market design to achieve resource adequacy:

- *First*, the mix of resources in and entering the system is broader and more diverse than the heavy reliance on gas-fired generation resource technology that dominated development when the FCM was designed. These new resources' contributions to resource adequacy vary and depend on the mix of resources on the grid, and their development timelines are both shorter and longer than gas-fired resources.
- *Second*, development risks associated with contracting, supply chains, environmental permitting, and local opposition are greater than they were historically, creating greater uncertainty about whether projects get constructed, and the timing of resource activation.
- *Third*, the profile of resource adequacy risks is broadening across the year, with growing risks in the winter months due to shifting seasonal peak loads and persistent concerns about longer-duration winter energy constraints.

To adapt its capacity market to these changes, ISO-NE is already undertaking enhancements to its resource capacity accreditation ("RCA") to better account for contributions to resource adequacy given the performance properties of resources in the system and changes in seasonal risks.

This report evaluates two additional potential changes being contemplated by ISO-NE to better adapt its capacity market to these changes in its evolving grid: the adoption of a prompt market and the adoption of a seasonal market. To assist in ISO-NE's on-going evaluation of alternative capacity market designs, this report aims to inform ISO-NE, stakeholders, and the New England states about these options to assist the region in evaluating whether it should pursue these options for the capacity market. To this end, we describe the general features of prompt and seasonal markets and evaluate the tradeoffs between prompt and forward markets, and annual market and seasonal markets.

---

[1] The full project team includes: Todd Schatzki, Ph.D., Joseph Cavicchi, Phillip Ross, Ph.D., Grace Howland, Redina Tahaj, Ph.D., Sam Wascher, Ph.D., Andrew Fixler, Yash Lalwani, Akincan Basar, Sam Churchill, and Mitch Patton.

This evaluation of tradeoffs is informed by quantitative modeling to both illustrate how prompt and seasonal markets would work and provide indicative quantification of potential impacts. Critically, our evaluation focusses on whether prompt and/or seasonal market approaches would provide a long-term platform for effectively achieving resource adequacy given the on-going and expected changes to the region's grid, including those arising from state environmental policies.

Based on our review of the evidence, we reach a preliminary recommendation that the region pursue a prompt-seasonal market for Capacity Commitment Period ("CCP") 19 (i.e., 2028-29). This recommendation reflects many considerations that we describe in the report. Both a prompt market and a seasonal market offer many advantages to the current forward-annual capacity market that will make the capacity better suited to a system where resource adequacy is achieved by the wide and changing mix of technologies and the reliability risks arise throughout the year in evolving patterns. However, adoption of a prompt-seasonal market would not be without some drawbacks and risks. In particular, none of the regions with such a heavy reliance on its capacity market to achieve resource adequacy have a prompt-seasonal capacity market. However, other regions have, or are in the process of assessing or implementing, prompt and seasonal market designs, and the technical risks of developing a prompt-seasonal market appear manageable.

Forward and Prompt Market Tradeoffs

Adoption of a prompt market would provide a number of important benefits:

- ***Market clearing based on more accurate information about demand.*** With the current forward market, demand curves reflect forecasts of capacity requirements to meet the reliability criterion (i.e., Installed Capacity Requirement ("ICR")). Because forecasts are uncertain, a forward market may either procure too much or too little capacity compared to the requirements needed at the commitment period, which has adverse economic and potential reliability consequences. For example, a prompt market would lower costs if the forward market over-procures capacity when forecasts are too high.
- ***Market clearing based on offers that reflect better estimates of resource supply.*** With a prompt market, capacity supply would reflect resources' contributions to reliability measured immediately prior to the commitment period, while with a forward auction, these contributions are measured three years prior to the commitment period. While year-to-year changes in accreditation were minimal in the past, with the shift to enhanced capacity accreditation, this will likely not be the case going forward. Given this, the forward market may result in lower effective reliability if resource contributions at the commitment period are lower than assumed (three years prior) in the forward capacity auction ("FCA"). This assumption is reasonable given expanded reliance on technologies whose contributions decline as system reliance on them increases (e.g., intermittent renewables, battery storage). In addition, changes in accreditation between the FCA and the commitment period may result in awarding of Capacity Supply Obligations ("CSO"s) to less cost-effective resources, if, for example, the reliability contributions of resources awarded CSOs decline materially relative to other resources that were not awarded CSOs.
- ***Reduced delivery risk and market uncertainty.*** With a prompt market, resources will face less risk that they will be unable to fulfill their capacity obligations due to a failure to develop new resources in a timely way or due to unexpected plant failures. In addition, resources face less uncertainty when estimating offer prices in a forward market compared to a prompt market.
- ***Retirement notification requirements that allow more efficient capital decisions.*** Under the FCM, decisions to retire assets are made four plus years from the date of deactivation. This timing likely does not reflect the preferred time-frame for requiring notification, given various tradeoffs, but primarily reflects only one criteria: the need for timely information about retirements prior to the CCP. In principle, the

preferred time-frame for retirement notification should reflect many considerations, with some benefiting from longer time frames and others benefiting from shorter time frames. A shorter time frame would support more efficient capital decisions given more accurate information and estimates of expected future net income, and supply offers that more accurately reflect deliverable capacity (given the risk that resources experience major maintenance events that lead to plant shut-down after the FCA). A longer time frame would reduce the risk that resources needed to be retained for transmission security needs, although these risks may be modest given robustness of the region's transmission grid.

- ***Better alignment with time-frame for operational decisions that affect resource capability, particularly winter fuel arrangements.*** A prompt market aligns with the timing in which gas-fired resources (dual fuel and gas-only) make winter fuel arrangements. By comparison, committing to these arrangements prior to the forward market would result in avoidable financial risks, which would raise costs and decrease the likelihood these arrangements are made. Thus, a prompt market would be expected to improve reliability through increased winter firm gas arrangements by lowering the cost of responding to incentives created by the enhanced resource capacity accreditation, which will award higher qualified capacity to gas-fired resources with firm fuel supplies.
- ***More neutral competitive platform for new investment across technologies.*** The current forward market allows resources to enter prior to investing capital, which benefits technologies with longer development timelines. For resources with development timelines of less than three years, opportunities to earn revenues from the FCM may be limited in the first 1-2 years of operation, given the reliance on Annual Reconfiguration Auctions ("ARA"s), which often do not clear new supply and historically clear at lower prices than the corresponding FCA (for the same commitment period). Under a prompt market, these resources would likely earn higher capacity market revenues. Such resources potentially include solar photovoltaic ("PV") and storage. By providing comparable competitive conditions across technologies (and by lowering costs for technologies with short development timelines), a prompt market may result in a more cost-effective mix of resources. Alternatively, if some entry is supported, in part, through state subsidies, including multi-year contracts or other incentives, then the cost of operating such programs would decrease under a prompt market.
- ***Simpler and less costly capacity market procedures.*** With a prompt market, the process of administering and participating in the capacity market could be simplified which would lower costs. Changes (some of which would reflect future design decisions) include elimination of certain elements of the current FCM (e.g., annual reconfiguration auctions), potential elimination or simplification of other elements (new resource pre-qualification and progress monitoring) and simplification and shortening of certain procedures (e.g., existing resource accreditation).

While the prompt market offers many benefits, the move to a prompt market has certain potential consequences. However, in comparison to the benefits offered, these potential consequences are likely to either be less consequential or can be reasonably managed through appropriate market design and operation:

- ***Primary capacity auction would not provide a price hedge.*** The current FCM provides a price hedge that can mitigate financial risks for some market participants. While the forward commitment required to achieve this hedge creates costs for many market participants, for some market participants the value of the forward market in hedging price risks may outweigh these costs. For new capacity, the FCM allows resources to lock in prices prior to development. However, this hedge is limited to one year and thus does relatively little to mitigate risk over the project's financial lifetime. As a result, new capacity often relies on financial instruments to mitigate price risks and support project financing. Thus, the forward nature of the FCM is not critical to new resource financing.

  For retail electricity suppliers, the FCM plays a more important role because it fixes capacity prices for all or much of the contract periods for which they provide supply. Thus, a prompt market would expose these suppliers to greater risk, which would likely affect rates charged to consumers. However, retail suppliers have options to mitigate these risks, including bilateral contracts with generators or other market participants and futures/forward instruments. Moreover, these risks have been managed in both Illinois and New York, states with retail competition and prompt capacity markets.

- ***Long-run price formation.*** One concern raised by stakeholders about a prompt market is that it limits suppliers' ability to include certain costs in their offer prices and thus would lead to lower long-run prices. For example, with a prompt auction, new capacity could not include the (amortized value of) plant capital investment in offers but would need to offer at its net avoidable costs when online (which would likely be lower). However, for a combination of reasons, this concern seems unlikely to lead to a change in long-run prices. In particular, this change does not affect long-run market fundamentals including demand for capacity and the long-run costs of supplying capacity that would be expected to drive entry and exit decisions. In addition, market prices are frequently set at the value of demand rather than supply offer prices, such that the specific value of offer prices does not affect the market-clearing prices. These considerations suggest that it will be important to carefully develop market mitigation processes for existing resources consistent with a prompt market to avoid making these processes too stringent and inadvertently leading to lower (short-run) prices.
- ***More volatile prices.*** In principle, a prompt market may be more volatile than a forward market because of unexpected shocks to capacity supply. Thus, the tradeoff to having the market clear using more accurate information about supply is that this information may cause more variation in prices. In practice, however, any difference in volatility appears modest. The empirical data suggests that the prompt market of New York ISO ("NYISO") has comparable volatility to the forward markets in ISO-NE and PJM Interconnection ("PJM").

Annual and Seasonal Market Tradeoffs

As with any commodity market, as differences in product definition or temporal variation in prices emerge, redefining the product more granularly can improve quality, produce more accurate pricing and result in more efficient economic outcomes. However, the tradeoff to these benefits is the cost of developing and maintaining more highly-differentiated ("granular") markets and potential complications associated with making products more granular.

Given increased importance of seasonal variation in resource adequacy and capacity accreditation, adoption of a seasonal market would provide a number of important benefits.

- ***Accounting for differences in the value of capacity in reducing resource adequacy risks across seasons.*** A seasonal market can account for differences in the value of capacity in reducing reliability risks across seasons. By accounting for these differences when procuring capacity in each season, so that more capacity is procured in seasons with greater reliability risks, it can lower the costs and improve resource adequacy. A seasonal market also creates price signals that incentivize investments to benefit reliability in the seasons when it is most needed.
- ***Accounting for differences in resource accreditation across seasons.*** A seasonal market can better account for differences in the contributions made by different types of resources to resource adequacy across seasons. As a result, it can ensure that the market is clearing an accurate measure of aggregated supply in each season to support reliable price formation. It also ensures that compensation to individual resources reflects the value of the services offered, and thus provides appropriate incentives for resources to develop and supply capacity in each season given its relative market value.
- ***Accounting for differences in costs across seasons.*** A seasonal market allows resources to account for differences in their net going forward costs of supplying capacity in each season, accounting for differences in avoidable costs, net energy market revenues, expected pay-for-performance costs and

qualified capacity. As a result, it can lower costs by awarding CSOs to resources able to support resource adequacy in each season at the lowest cost.

A complication with a seasonal market arises because of “non-divisible” costs – that is, fixed costs to operate the unit regardless of the whether the unit operates for the entire year or only a portion of the year. This issue has implications for whether resources will earn sufficient revenues to cover their annual costs, whether resources will have flexibility to make offers reflecting both annual and seasonal components (and the rules for market mitigation), and the design of the seasonal auction. In particular, a seasonal auction can be run sequentially, with each auction procuring capacity for the immediate seasonal period but no others. If run simultaneously, capacity for each season in the year would be cleared in one auction that is designed to procure capacity across all seasons in the year at the lowest cost. The simultaneous approach can accommodate both annual and seasonal offer components and can lower costs by better accounting for these annual costs when procuring capacity. However, a simultaneous auction with these properties would be substantially more complex to design and operate each year.

The development of a seasonal market would involve substantial ISO-NE staff and stakeholder attention to address many design decisions (e.g., number of seasons, seasonal demand curves). The development of auction software would also be a substantial effort if a simultaneous auction is pursued.

Quantitative Analysis

We quantitatively analyze market outcomes under the current FCM and the prompt and seasonal market approaches. The results of this analysis generally confirm our economic and analytic findings, but also provide indications of the order of magnitude of potential changes in prices, quantities, and payments, and highlight certain findings through quantitative comparisons.

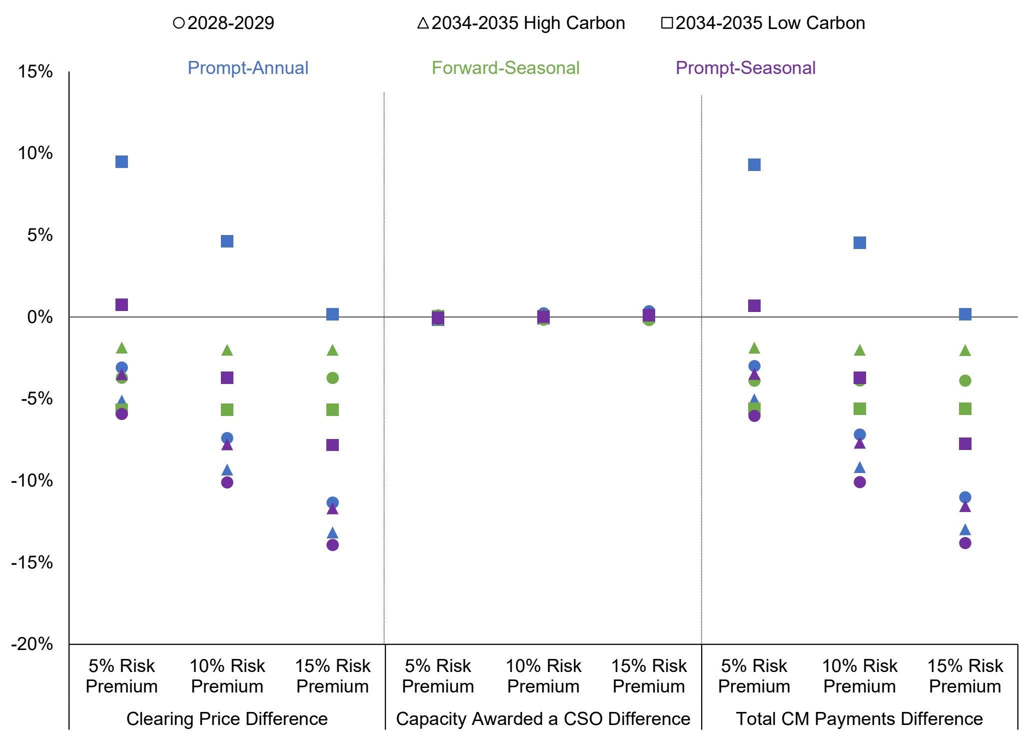
Key findings include:

- Prompt and seasonal market alternatives to the current FCM tend to lower prices and total payments, while producing comparatively small changes in the quantity of CSOs awarded. The figure below shows scenarios for each market alternative to the FCM (prompt-annual, forward-seasonal, and prompt-seasons) for different year/resource mixes (2028-29, 2034-35 High Carbon, 2034-35 Low Carbon) and different assumptions about forward offer forward premiums (5%, 10%, 15%).
- A prompt-annual market reduces prices and total payments by 3.9% and 3.8%, on average, respectively. In 6 of 9 scenarios, payment reductions range from 3% to 13%. In 3 of 9 scenarios, payments increase, with increases ranging from 0.2% to 9.3%. A forward-seasonal market lowers prices and total payments in all scenarios, with reductions ranging from 1.9% to 5.7%, and 3.8% on average.
- The prompt-seasonal market results in the lowest prices and total payments, on average – prices are lower by $0.33 per kW-month (7%) and payments are lower by $116 million annually (7%). Prices and payments are lower in 8 of 9 scenarios; in these scenarios, cost reductions range from 3.5% to 13.8% compared to the current FCM. In one scenario, prompt-seasonal market payments increase by 0.7% relative to the forward-annual market. Similarly, prices are 3.5% to 13.9% lower with the prompt-seasonal market compared to the current FCM in 8 of 9 scenarios, and 0.8% higher in one scenario.
- Uncertainty in demand under the forward market has meaningful impacts on prices, quantities, and payments. Across the range of demand uncertainty considered (± 1,000 MW), costs ranged by approximately 10%, relative to no demand uncertainty. When forecast demand is lower than final demand (at the commitment period), procured quantities were below ICR which could lead to reliability concerns.

Such a deficit is potentially mitigated through procurement of additional supplies through reconfiguration auctions.

- Results are sensitive to a range of assumptions tested (years, resource mixes, forward premiums), but these tests encompass only a subset of relevant uncertainties. Our analysis makes certain conservative assumptions, such as those regarding forward demand forecasting uncertainty and winter gas firming. Our analysis does not account for all differences between market alternatives and do not account for certain market dynamics (e.g., entry/exit in response to changes in prices), and thus does not account for the full range of potential outcomes. Further, it also does not reflect a particular market design or represent a full impact analysis of a design proposal.

Impact of Alternative Market Concepts on Price, Quantity and Payments (Relative to FCM)



II. Background

A. Context and Proposed Market Enhancements

1. Resource Adequacy in New England

System operators establish resource adequacy targets to ensure that there are sufficient system resources available to meet established reliability criteria.[2] Within ISO-NE resource adequacy criteria reflect the common standard of a "1-in-10" loss of load expectation ("LOLE") – that is, the system should be designed so that, in expectation, there is no more than one loss of load event every ten years. Because revenues from ISO-NE energy and ancillary services markets appear insufficient to support the development and maintenance of sufficient resources to meet this reliability standard, the regulatory structure in the ISO-NE system includes additional mechanisms to ensure that resource adequacy standards are met.[3] In particular, the New England markets include a capacity market that procures sufficient capacity on a forward basis to satisfy the 1-in-10 reliability standard.

The ISO-NE Forward Capacity Market ("FCM") is designed to provide additional revenues – the "missing money" – to ensure there are sufficient system resources to maintain resource adequacy. Without the FCM, the ISO-NE energy and ancillary services markets would incent resources to enter the market, but the equilibrium quantity of resources would be insufficient in expectation to achieve the 1-in-10 reliability standard. The FCM provides additional revenues intended to ensure that new capacity has sufficient revenues to fully recover their costs when the equilibrium quantity of resources in the market equals the quantity needed to meet the 1-in-10 reliability standard.[4]

The ISO-NE FCM has been in operation since 2008.[5] The FCM procures capacity supply obligations ("CSOs") through an annual Forward Capacity Auction ("FCA") run three-plus years in advance of the 12-month commitment period.[6] The FCA clears offers to supply capacity against a sloped, administratively-determined demand curve.[7] This demand curve is designed to ensure revenues sufficient to cover the net cost of new entry ("Net CONE") when

---

[2] 18 CFR Part 40, FERC, Order, Planning Resource Adequacy Assessment Reliability Standard, March 17, 2011.

[3] Other mechanisms that ensure system reliability include long-term planning procedures that identify reliability risks and develop solutions to mitigate these risks.

[4] "Missing money" is the term often used to describe the revenue needed above and beyond energy and ancillary services market revenues to attract new – or retain existing – economic resources sufficient to meet resource adequacy targets. *See*, e.g., Cramton, Peter and Steven Stoft, "The Convergence of Market Designs for Adequate Generating Capacity with Special Attention to the CAISO's Resource Adequacy Problem," MIT Center for Energy and Environmental Policy Research, 07-007, April 2006.

[5] For general information on the FCM, *see* ISO-NE, "Forward Capacity Market," 2023, available at https://www.iso-ne.com/markets-operations/markets/forward-capacity-market.

[6] This summary of ISO-NE's FCA design reflects the design as defined in the ISO-NE Tariff. ISO-NE recently filed a proposal to delay FCA 19 by one year, which will shorten the time between the forward auction and commitment period, reduce the number of reconfiguration auctions, and impact other auction timelines. *See*, ISO New England Inc., "Market Rule Changes to Delay Nineteenth Forward Capacity Auction and Related Capacity Market Activities," Docket No. ER24-339-000, November 3, 2023, available at https://www.iso-ne.com/static-assets/documents/100005/changes_to_delay_19th_fca_and_related_capacity_mtk_activities.pdf.

[7] Throughout the report, we use the term "clears" to mean that a resource's offer to supply capacity in the FCA, a capacity auction, or an ARA is selected, and it is awarded a CSO.

market-clearing capacity equals the quantity needed to meet the 1-in-10 reliability standard (referred to as the Installed Capacity Requirement ("ICR")).

Following the FCA and before the commitment period, three Annual Reconfiguration Auctions ("ARAs") are run to allow for a rebalancing of capacity supply and demand. Rebalancing occurs for many reasons, including: (1) allowing new capacity resources that enter the market after the FCA an opportunity to supply capacity, (2) enabling resources that clear the FCA that are unable to fulfill their CSO to find alternative suppliers, and (3) accommodating changes in demand (i.e., changes in the ICR, which anchors the administrative demand curve).

The design of the FCM reflected market and system conditions at the time when the market was being developed. In the mid-2000s, resource adequacy concerns primarily reflected the risk that there would be inadequate resources to meet peak summer loads. Thus, the market was designed to procure resources on an annual basis reflecting their ability to contribute to meeting summer loads. At the time, most resources being developed were gas-fired resources relying on either combustion turbine or combined-cycle technology, which had key permit issuance and construction timelines that could be completed within approximately three years. The region had also just undergone a period of substantial build of merchant generation, following restructuring of the region's industry, which created a demand for a market design that would limit further build while also supporting investment when needed given the apparent financial risks. Given these circumstances, the market was designed to procure an annual capacity product three years forward of the commitment period to help coordinate the development of new resources.

Since the FCM first started, the market has undergone several important changes over time. These changes reflect important innovations designed to improve the market's operation and performance. In 2014, the Federal Energy Regulatory Commission ("FERC") approved the Pay-for-Performance market design, which creates incentives for resources awarded CSOs to perform when the system is facing stressed system conditions.[8] These design principles were subsequently adopted by PJM Interconnection ("PJM") in its pay-for-performance market rules.[9] In 2016, the FERC approved FCA demand curves based on estimates of marginal reliability impact ("MRI") of capacity resources on the risk of loss of load.[10] This MRI approach now serves as an important foundation for the Resource Capacity Accreditation ("RCA") project, and, as we discuss below, would support the development of seasonal market demand curves. At present, in the RCA project, ISO-NE and stakeholders are in the process of enhancing the approach to determining the capacity credit resources receive in the FCM to better reflect the actual contribution their resources provide to achieving resource adequacy.[11]

These market changes illustrate that ISO-NE and the region has a history of adjusting its capacity market to account for actual market outcomes (e.g., the performance of resources under the market) and opportunities to improve market design.

---

[8] Initial Order: ISO-NE, 147 FERC ¶ 61,172, Order on Tariff Filing and Instituting Section 206 Proceedings, May 30, 2014, Docket Nos. ER14-1050 et al., denying reh'g 153 FERC ¶ 61,223, Order Denying Rehearing, November 19, 2015, Docket Nos. ER14-1050-002 et al.; Order on Compliance: ISO-NE, 149 FERC ¶ 61,009, Order on Compliance Filing, October 2, 2014, Docket Nos. ER14-2419-000 et al., denying reh'g, 153 FERC ¶ 61,224, Order Denying Rehearing, November 19, 2015, Docket Nos. ER14-2419-003 et al.; ISO-NE & NEPOOL Participants Comm., 147 FERC ¶ 61,172 (2014), r'hg denied 153 FERC ¶ 61,223 (2015).

[9] PJM, 151 FERC ¶ 61,208, r'hg granted in part, denied in part,151 FERC ¶ 61,208 (2016) (denying rehearing on all but one issue relating to force majeure, and accepting compliance filings).

[10] ISO-NE, 155 FERC ¶ 61,319, Order Accepting Filing, June 28, 2016, Docket No. ER16-1434-000.

[11] *See*, generally, ISO-NE, "Resource Capacity Accreditation in the Forward Capacity Market Key Project," available at https://www.iso-ne.com/committees/key-projects/resource-capacity-accreditation-in-the-fcm/.

2. Changes in Market and System Conditions

Like many regions of the U.S., New England is undergoing several changes affecting energy use throughout the region's economy and the region's electricity system and markets. These changes are arising from a combination of factors including state policies aimed at decarbonizing the region's economy and grid, and technological innovation that increases performance and decreases costs of new technologies. These changes include:

- Federal and state policies aimed at reducing emissions throughout the economy, and particularly the electricity sector through the substitution of existing fossil-fired resources (coal, fuel oil and natural gas) for non-emitting resources (e.g., hydropower, solar photovoltaic ("PV"), and onshore and offshore wind power) and complementary technologies (e.g., battery storage resources).[12]
- Technological innovation that has substantially decreased investment costs and increased performance for a range of technologies, including solar PV, onshore and offshore wind, and battery storage.[13] With these innovations, certain technologies can be cost-competitive with fossil generation (given federal subsidies) for new entry.
- State policies aimed at electrifying heating, transportation and other activities currently relying on liquid fossil fuels. These changes increase electricity demand while the region is simultaneously trying to shift generation toward non-emitting generating resources.

Together, these trends have had several important consequences for resource adequacy and the performance of the region's current capacity market design:

- ***Changes in the mix of resources in and entering the system.*** Given state policies and technology changes, the region's grid is experiencing increases in intermittent resources (e.g., solar PV and wind), increases in storage resources (i.e., battery storage) and reductions in dispatchable fossil resources. These trends are expected to continue for the coming decades assuming state policies achieve their objective of decarbonizing the electricity system.
- ***Changes in the process by which new resources enter the system.*** In recent years, the process by which new resources enter the system has become increasingly complicated and uncertain, including longer and more uncertain development timelines given challenges in supply chains (reflecting increased demand for new technologies and hold-over effects of COVID-related supply chain disruptions), project cancellations due to financing limitations or contracting constraints, uncertainties in regulatory permitting, and uncertainties in local opposition to any new infrastructure (not in my backyard, "NIMBYism") including both non-emitting and emitting resources, transmission and other energy infrastructure.

[12] Connecticut: An Act Concerning Climate Change Planning and Resiliency (2018), Global Warming Solutions Act (2008); Maine: 38 MRSA §576-A (2019); Massachusetts: Global Warming Solutions Act (2008); Rhode Island: Resilient Rhode Island Act of 2014, 2021 Act on Climate; Vermont: Global Warming Solutions Act (2020). For further discussion of state-level programs and requirements from New England states as they affect New England grid, *see* Schatzki, Todd, et al., Pathways Study, Evaluation of Pathways to a Future Grid, April 2022, available at https://www.iso-ne.com/static-assets/documents/2022/04/schatzki-et-al-pathways-final.pdf.

[13] LBNL, "Utility-Scale Solar, 2023 Edition," October 2023, pp. 19-27, available at https://emp.lbl.gov/sites/default/files/utility_scale_solar_2023_edition_slides.pdf; LBNL, "Land-Based Wind Market Report: 2023 Edition," August 2023, pp. 36-38, 43-48, available at https://emp.lbl.gov/wind-technologies-market-report; NREL, "2021 Cost of Wind Energy Review," December 2022, p. 22, available at https://www.nrel.gov/docs/fy23osti/84774.pdf.

- ***Changes in the profile of resource adequacy risks over the year.*** Historically, resource adequacy risks were primarily concentrated in summer months when the system experience peak annual loads. However, resource adequacy risks are shifting toward winter months given persistent concerns about longer-duration energy constraints during winter months (given constraints to energy storage at fossil-fired resources)[14] and increasing winter peaks relative to summer peaks, particularly as building heating demands, at their peak in winter months, shift toward the electricity sector.[15]

These changes to market and system conditions are expected to have important consequences for the region's markets and systems, including the processes through which ISO-NE maintains resource adequacy. An important on-going response to these changes is the RCA project initiated by ISO-NE. The RCA project aims to improve system reliability and the FCM's cost-effectiveness by more accurately capturing resource's contributions to supporting resource adequacy.[16] If adopted, the project will change the process for measuring the quantity of capacity that resources receive credit for in the FCM so that the market compensates resources for their reliability contributions and the market in aggregate procures sufficient resources to achieve the 1-in-10 reliability criteria.

With the likely adoption of the RCA enhancements and the on-going changes to the region's resource mix, the process by which resources enter the system, and the growing shift in risk from summer to winter, ISO-NE has begun to evaluate whether other FCM changes might improve market performance. In particular, ISO-NE is considering whether to develop proposals for two potential changes to its capacity market:

- ***Prompt Market.*** Under this concept, the timing of the primary capacity auction would occur shortly before the commitment period rather than three-plus years in advance of the commitment period.
- ***Seasonal Market.*** Under this concept, the capacity market would include multiple markets and products in each year, as compared to the current annual market and product.

ISO-NE initiated discussions of these approaches in July 2023 and these discussions are on-going.[17] If ISO-NE develops proposals for prompt and/or seasonal market elements, if feasible, it expects to propose that such changes would go into effect alongside the RCA enhancements for Capacity Commitment Period ("CCP") 19 for the year 2028-29.

[14] For example, ISO-NE has been working with the Electric Power Research Institute to conduct a probabilistic energy-security study for the New England region under extreme weather events, given that weather, particularly changing extremes and range of variability, is a key factor affecting resource (i.e., energy) availability, demand patterns, and related reliability concerns. *See*, ISO-NE, "Operational Impacts of Extreme Weather Events Key Project," available at https://www.iso-ne.com/committees/key-projects/operational-impacts-of-extreme-weather-events.

[15] ISO-NE, "2023 Regional System Plan," Draft November 1, 2023, available at https://www.iso-ne.com/static-assets/documents/100004/10-2023-draft-rsp23-public-meeting.pdf; ISO-NE, "2023-2032 Forecast Report of Capacity, Energy, Loads, and Transmission," May 1, 2023, (hereafter "2023 CELT Report") available at https://www.iso-ne.com/static-assets/documents/2023/05/2023_celt_report.xlsx.

[16] ISO-NE, "Resource Capacity Accreditation in the Forward Capacity Market Key Project," available at https://www.iso-ne.com/committees/key-projects/resource-capacity-accreditation-in-the-fcm/.

[17] Geissler, Chris, and Andrew Gillespie, "Tradeoffs with Alternative FCM Commitment Horizons," ISO-NE NEPOOL Markets Committee, July 11, 2023, available at https://www.iso-ne.com/static-assets/documents/2023/07/a09a_mc_2023_07_11_prompt_seasonal_tradeoffs_presentation.pdf.

B. Assignment

To assist in ISO-NE's on-going evaluation of alternative capacity market designs, Analysis Group was asked to evaluate the prompt and seasonal market concepts for ISO-NE's capacity market. This report aims to inform ISO-NE, stakeholders, and the New England states about these options to assist in region in evaluating whether it should pursue these options for the capacity market. To achieve these ends, this report is designed to achieve multiple objectives:

- Describe in general terms the features of prompt and seasonal markets, but not develop detailed designs for either alternative (which would be required in subsequent stages if ISO-NE opts to pursue either option);
- Provide information on the tradeoffs involved in switching to a prompt and/or seasonal market;
- Identify issues that would need to be addressed in a subsequent design process if the region pursues these alternatives; and
- Provide recommendations.

A key element of the study is the evaluation of tradeoffs from pursuing a prompt and/or seasonal market. To evaluate the tradeoffs involved in exercising these design options, we use a variety of analytic, quantitative, and non-quantitative approaches and many sources of information:

- Economic principles, including the factors affecting: supply costs, risks and offers; demand for capacity (and associated demand curves); market-clearing in auction-based markets; and alignment with and support for State policy goals;
- Experience from and on-going developments in ISO-NE and other regional transmission organizations ("RTOs"), including Midcontinent ISO ("MISO"), New York ISO ("NYISO"), and PJM;
- Quantitative metrics and information related to new resource entry, resource development timelines, retirements, existing resource participation, price volatility, price formation, resource accreditation, and ICR values; and
- Quantitative analysis of the impact of change in market on various market metrics, including prices, quantities of capacity awarded CSOs, and costs.

The evaluation reflects multiple criteria, including economic efficiency, costs, reliability, and alignment with and support for the States' policy goals.

Prompt and seasonal market alternative are complementary as they relate to different dimensions of the current capacity market. Thus, the study will consider potential combinations of prompt and seasonal markets, given opportunity to adopt one but not the other:

- Forward-annual market (*i.e.*, status quo)
- Prompt-annual market
- Forward-seasonal market
- Prompt-seasonal market

Along with evaluating these various combinations, the study will also consider transition issues given the practical realities of designing new market rules within a stakeholder process and developing software and procedures to operationalize the market design. In particular, we consider how the region might proceed with a prompt-seasonal market design (if pursued), and whether to develop this market in a single phase (i.e., transitioning immediately to a prompt-seasonal market) or in two phases (in particular, first adopting a prompt market and later adopting a seasonal market).

Throughout the assessment, we assume the region adopts some form of RCA market enhancements.[18] The RCA project is an important initiative to improve the system reliability by more accurately capturing resource's contributions to supporting resource adequacy. Enhanced RCA methodologies would more accurately estimate capacity accreditation through MRI analyses that better account for the correlation of expected high demand hours with expected capacity resource availability/output.[19] Future capacity accreditation values capture the expected impact of ISO-NE's shift to MRI.

While the specific details of the RCA market enhancements are still being developed within the New England Power Pool ("NEPOOL") stakeholder process, the basic RCA design principles have been developed and, as described above, are an important factor affecting the tradeoffs of the prompt and seasonal markets. While our assessment reflects these general design principles, the specific accreditation values ("rMRIs") we show and use in our quantitative analysis *do not* reflect the on-going work in the RCA project. Instead, we assume proxy values for accreditation factors consistent with the RCA design principles and reflecting various publicly available analyses, including those from other RTOs. Thus, the values we report and use are reasonable proxies but do not reflect all factors specific to the New England markets and system, and thus these values do not provide useful benchmarks for the ongoing deliberations in the RCA project.

While our report provides a thorough assessment of the tradeoffs between the current FCM and the prompt and seasonal market options, our study is not intended to be an impact assessment of these options. In particular, the region has not yet decided to pursue either option, and our assessment does not reflect a particular market design reflecting many important design details.

C. Overview of Prompt and Seasonal Capacity Market Designs

This report evaluates alternative market designs for the FCM, with two key design features in question. First, we consider the timing of the "primary" capacity auction, with the choice between the current three-year forward auction and a "prompt" auction that occurs immediately prior to the delivery period. We define the primary capacity auction as the first auction for a future commitment period under each approach, which in practice clears most capacity and awards most CSOs. Second, we consider the number of market periods within the year, with the choice between the current annual market and a seasonal (winter/summer) market.

Our evaluation considers each of these markets under the assumption that the region adopts enhanced resource accreditation rules through the RCA project. Because these enhanced rules are currently under development, the

[18] *See*, generally, ISO-NE, "Resource Capacity Accreditation in the Forward Capacity Market Key Project," available at https://www.iso-ne.com/committees/key-projects/resource-capacity-accreditation-in-the-fcm/.

[19] Notably, ISO-NE, NYISO, and PJM are all moving toward estimation of capacity accreditation using MRI analysis. NYISO completed and published informational capacity accreditation based on the results of MRI analyses (*see* NYISO, "Capacity Accreditation," available at https://www.nyiso.com/accreditation). PJM recently filed proposed capacity market modification with FERC that seek approval of an MRI analysis to estimate capacity accreditation (Affidavit of Dr. Patricio Rocha-Garrido on Behalf of PJM, Interconnection, L.L.C., October 13, 2023, available at https://www.pjm.com/-/media/documents/ferc/filings/2023/20231013-er24-98-000.ashx).

details of these rules are not known. However, many of the broad contours of these rules are known to some degree and thus we evaluate the prompt and seasonal alternatives in light of these basic RCA design principles.

1. Prompt Capacity Market

Under ISO-NE's current capacity market, the FCM, capacity is initially procured through an auction that occurs approximately 3.5 years prior to the commitment period. This auction is designed to satisfy resource adequacy obligations, with existing resources subject to "must offer" obligations and demand based on forecasts of future capacity needed to meet the reliability criterion (the Net ICR). To account for changes in supply between the FCA and the commitment period (e.g., new supplies, unexpected curtailments in operational capability or changes in ICR), subsequent "reconfiguration" auctions allow the market to rebalance demand and supply.

With a prompt market, capacity would be procured through a single auction held shortly before the commitment period. Thus, in effect, the primary auction would be shifted forward in time to occur shortly before the commitment period. While the exact timing of the prompt capacity auction would be determined through a thorough market design process, the timing would likely occur at roughly the same time as the last reconfiguration under the current FCM.

With the prompt market, there would be a single auction prior to the commitment period. As a result, there would be no need for the annual reconfiguration auctions that allow rebalancing of supply and demand in the FCM.[20]

An important change with a prompt auction is the way in which new resources participate. Under the current FCM, new resources can offer supply into the FCA before being online and activated. However, with a prompt market, all resources participating in the market would need to be activated in order to participate in the primary auction, including all "new" resources participating in the prompt auction for the first time.[21] Thus, under the prompt market, new resources are developed and financed without clearing in the FCA.

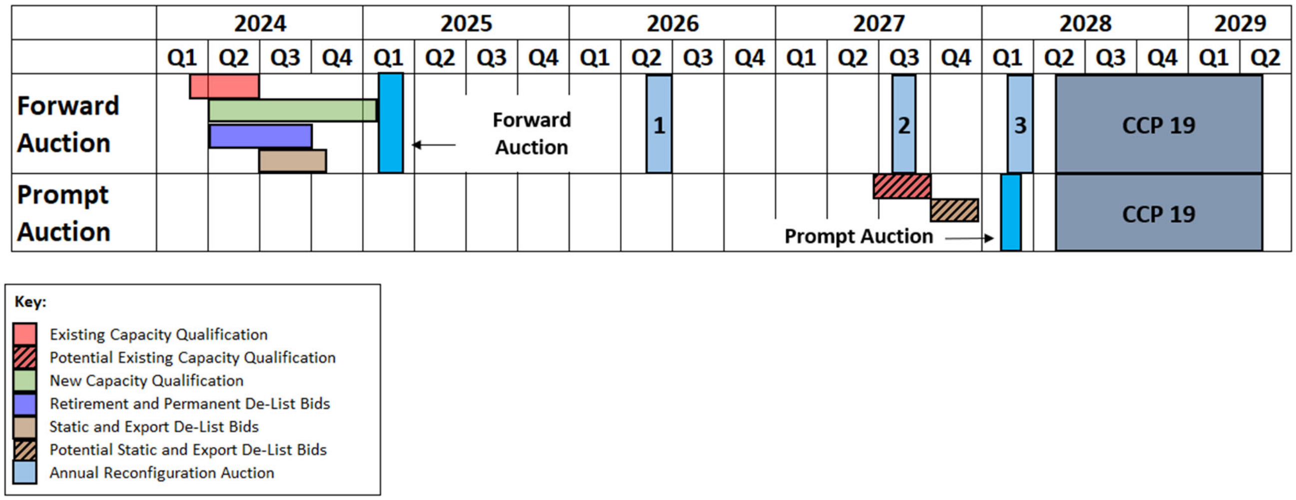
Figure 1 illustrates the timing of key events prior to each commitment period under the current FCM and under the prompt market approach. Under the FCM, the process of securing capacity for a future commitment period starts more than four years prior to the commitment period with the initial phases of resource qualification and submission of offers to supply capacity (generally referred to as "de-list" offers for existing resources). Under the current FCM, this includes many procedures, including: qualification of new and existing resources (which includes evaluation of each resource's performance to determine its contribution to resource adequacy and certain requirements for new resources, including posting of credit), and the submission and review of de-list offers when resources seek to retire from operation ("deactivation") or seek to submit offers above a predetermined threshold ("dynamic de-list threshold"), at which concern over the exercise of market power arises.[22]

[20] The market would still require mechanism for resources to substitute capacity supply on a month-to-month basis given unexpected, intra-year changes in resource's ability to fulfill CSOs.

[21] The specific criteria for participation in a prompt capacity auction would need to be determined as part of the market design process. Precisely how the design would define a unit as "activated," "operational," or "in service" is an important design element that is outside of the scope of this report.

[22] *See*, ISO-NE, "Forward Capacity Auction 18 Schedule," January 4, 2023, available at https://www.iso-ne.com/static-assets/documents/2021/02/fca-18-market-timeline-02-10-2021.pdf.

Figure 1. Current FCM Timeline and Illustrative Prompt Market Timeline



Under a prompt market, these steps involved in procuring capacity for each commitment period would change. *First*, the primary capacity auction would occur shortly before the commitment period and reconfiguration auctions would be eliminated.

Second, certain processes currently occurring within the FCM could potentially be eliminated or moved outside the FCM. For example, the process for retiring and deactivating resources currently occurs within the FCM because these decisions have implications for the supply offers into the FCA, particularly from new resources that can respond to resource retirements. With a prompt market, the process by which resources seek to retire and deactivate could be moved outside the FCM because retirement notification for an upcoming commitment period would presumably need to occur with more advance warning than the timing of the prompt auction. Similarly, with a prompt auction, "new" resource qualification could be eliminated or substantially simplified, as all resources would be operational and activated before participating in the prompt auction.

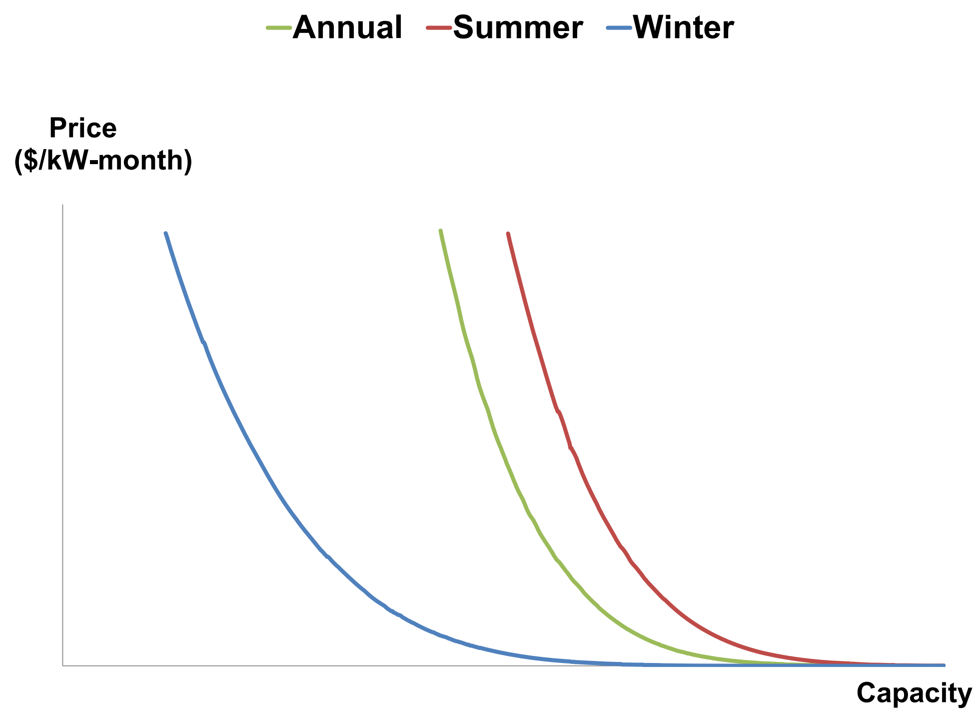
Third, a prompt auction may allow certain qualification processes to be shortened, although whether shorter timeframes are feasible is uncertain and would depend on factors such as the extent to which a prompt market reduces administrative burdens on ISO-NE and stakeholders and whether the timing of any current qualifications processes are contingent on steps that may be eliminated.

2. Seasonal Capacity Market

At present, the FCM achieves resource adequacy through an annual capacity product procured through a single, annual auction. Seasonality can be introduced into different features of a capacity market, including the auction frequency, capacity product, the auction demand curve, and the supply offer terms (both the quantity that can be supplied and at-cost offers). In particular, a fully seasonal market could include season-specific capacity products and auctions that clear seasonal supply offers against a seasonal demand curve, where both the demand curve and offers to supply capacity reflect season-specific considerations.

Demand. With seasonal demand curves, the demand for capacity in each season – as reflected in administrative demand curves – can be designed to reflect season-specific factors and thus may differ across seasons. For example, **Figure 2** shows illustrative annual and seasonal demand curves that reflect different demand for capacity in summer and winter. If pursued, the design of seasonal demand curves would be among the more important issues in the design process.

Figure 2. Illustrative Annual, Summer, and Winter Demand Curves



In principle, seasonal demand curves could reflect the same considerations used in designing annual demand curves – that is, demand curves need to ensure adequate revenues for new resources to enter the market at the annual 1-in-10 reliability criterion while also appropriately pricing additional capacity beyond (and short of) this reliability criterion. This would have several consequences for seasonal demand curves:

- *First*, seasonal demand curves can reflect resource adequacy risks specific to that season. In principle, there are multiple approaches to account for seasonal resource adequacy risks. One approach is to extend the current capacity market construct, with demand curves reflecting annual MRIs, to develop seasonal demand curves based on marginal reliability impacts specific to each season. This approach has sound economic foundations that translate to a seasonal framework. Thus, if marginal reliability impacts differ across seasons, these differences appropriately translate into seasonal demand curves with different shapes, as illustrated in **Figure 2**.
- *Second,* resource adequacy outcomes reflect expected risks (i.e., unserved energy) across seasons, rather than reflecting the outcome of a single annual market. A consequence of this is that MRI curves in each season should be scaled equally since impacts in either season contribute to meeting the 1-in-10 resource adequacy criterion. Further, the reliability outcomes under the seasonal demand curves can reflect different quantities of capacity in each season and, in turn, different quantities of expected unserved energy in each season.
- *Third,* revenue adequacy would reflect the total revenues earned from capacity market prices across all seasons. Thus, in constructing the demand curves, the curves would need to be calibrated so the new entry reference unit earns sufficient revenues to cover its costs of entry when the quantity of capacity aligns with the annual 1-in-10 resource adequacy requirement. Determining this criterion would potentially be

more complex than with the current FCM, because the calibration would reflect market revenues and reliability outcomes over all seasons, rather than over only a single annual auction.

We discuss the implications of these decisions further in **Section IV**.

Supply offers. With a seasonal capacity market, supply offers can reflect seasonal costs and seasonal contributions to resource adequacy (*i.e.*, seasonal rMRI values). In principle, seasonal capacity offer prices reflect the avoidable going forward costs if the unit were not to operate in a given season. As we discuss in **Section IV**, seasonal costs can vary due to many factors: some costs are incurred in some seasons but not others (e.g., winter weatherization costs); energy and ancillary service revenues can vary by season; and resource accreditation can vary across seasons, thus affecting the estimated cost per unit of capacity. Differences in capacity accreditation also affect the quantity of qualified capacity that resources can offer across seasons.

The design of a seasonal capacity market would require many questions to be addressed. We list these below and discuss these in further detail in **Section IV**.

- ***Simultaneous vs. sequential auctions.*** A seasonal market can be designed to procure capacity through a single joint auction that clears all seasons simultaneously or through sequential auctions in which each auction is cleared independent of other auctions. A simultaneous auction would likely be more complex to design and administer than a sequential auction.
- ***Number of seasons, and the duration of each season.*** In principle, a seasonal capacity market could be designed for any number of seasons with each season having equal or varying duration. For example, a seasonal market could include two seasons (winter, summer), four seasons (winter, spring, summer, fall) or even more seasons. Similarly, for example, a market with two (summer and winter) seasons could have equal six-month seasons or durations that differ across seasons (e.g., eight months for summer and four months for winter). As we discuss below, a number of considerations affect that choice, particularly the distribution of reliability risks across the calendar year and the cost of complexity introduced by additional seasons.
- ***Demand Curves***. In estimating the demand curve, multiple factors will need to be considered, including: how seasonal ICR will be determined, whether (and how) MRI values will be determined in each season, and the basis and criteria for price caps.

3. Experience with Prompt and Seasonal Markets in Other RTOs

Several RTOs have features of prompt and/or seasonal capacity markets. Below, we provide an overview of these markets to provide context for the options facing New England and identify experience that could inform the decision to pursue a prompt or seasonal market approach.

a. NYISO

The NYISO installed capacity ("ICAP") market is a mechanism to achieve resource adequacy in the state by meeting the annual installed reserve margin ("IRM") requirement set to ensure the probability of loss of load events occur no more than 1-in-10 years on average.[23] Due to transmission constraints to move power throughout the state, NYISO

[23] Johnson, Owain, and Adila McHich, "Introducing the NYISO Electricity Capacity Market," CME Group, June 25, 2018, available at https://www.cmegroup.com/education/articles-and-reports/introducing-the-nyiso-eletricity-capacity-market.html.

has established four nested locational reserve requirements in the following areas: New York City (Load Zone J), Long Island (Load Zone K), Lower Hudson Valley (Load Zones G-J), and New York Control Area ("NYCA")-wide.[24]

NYISO's ICAP market includes prompt capacity auctions with a seasonal component. Capacity is procured through several different auctions that occur shortly before the commitment period. The market is anchored by a spot auction held two days prior to the start of each month, but also includes a voluntary capability period auction (the "strip auction") clearing a six-month strip of capacity, and a monthly voluntary auction that facilitates transactions for obligations in any month in the six-month capability period after the strip auction takes place.[25]

Like the ISO-NE FCM, the ICAP market has an administrative demand curve. The ICAP demand curve is a critical component of the NYISO ICAP market, determining capacity prices, and thus revenues to generators with capacity supply obligations.[26] Under the current structure, each geographic locality has its own ICAP demand curve. These demand curves include a seasonal adjustment to account for seasonal differences in capacity available from resources in the system and their impact on the prices that would prevail, all else equal, between seasons. Specifically, there is one annual reference point that anchors each locational demand curve, and seasonality considerations are introduced through the winter-to-summer ratio ("WSR") to reflect the different volumes of capacity available in the summer versus winter capability periods.[27]

NYISO is currently proposing an update to the demand curve for capability period 2025-2026 to calculate separate seasonal reference points, resulting in separate demand curves by locality for the summer and winter capability periods.[28] Specifically, the proposed tariff revision would update reference point calculations to reflect seasonal differences in reliability risk (a different winter and summer LOLE), and seasonal differences in the level of excess

[24] Johnson, Owain, and Adila McHich, "Introducing the NYISO Electricity Capacity Market," CME Group, June 25, 2018, available at https://www.cmegroup.com/education/articles-and-reports/introducing-the-nyiso-eletricity-capacity-market.html.

[25] Stegmann, Kelly, "Installed Capacity (ICAP) Market," NYISO, October 17-20, 2023, pp. 73-75, available at https://www.nyiso.com/documents/20142/3037451/8-ICAP.pdf/da39103d-df67-e44c-ecee-8535eaec2a3c.

[26] NYISO ICAP demand curves are similar in many respects to FCM demand curves, with a price cap, a price floor, and a demand curve slope that intersects the zero-crossing point (with a price equal to zero) and the reference price, reflecting the IRM (or local minimum capacity requirements) and Net CONE. Specifically, "[t]he ICAP Demand Curves are designed with three basic elements: a cap on the maximum allowable prices, a floor on prices (at zero), and a sloped demand curve that determines prices for varying levels of capacity between this cap and floor. In principle, the ICAP Demand Curve slope reflects the declining marginal value of additional capacity in terms of incremental improvements in reliability – that is, as the quantity of capacity increases. Incremental capacity provides diminishing value in terms of reductions in loss of load expectation (LOLE)." Hibbard, Paul, et. al., "Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2021/2022 through 2024/2025 Capability Years Final Report," Analysis Group, Inc. and Burns & McDonnell, September 9, 2020, p. 108, available at https://www.nyiso.com/documents/20142/14526320/Analysis-Group-2019-2020-DCR-Final-Report.pdf.

[27] The ICAP demand curves are anchored by the reference point, which accounts for seasonal differences in capacity available through the WSR. Specifically, "The WSR captures differences in the quantity of capacity available between winter and summer seasons given differences in seasonal operational capability. The ICAP Demand Curves account for differences in the prices that would prevail, all else equal, between seasons due to these seasonal differences in capacity. The WSR is calculated as the ratio of total winter ICAP to total summer ICAP in each year." Hibbard, Paul, et. al., "Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2021/2022 through 2024/2025 Capability Years Final Report," Analysis Group, Inc. and Burns & McDonnell, September 9, 2020, available at https://www.nyiso.com/documents/20142/14526320/Analysis-Group-2019-2020-DCR-Final-Report.pdf.

[28] Mohrman, Maddy, "2025 - 2029 ICAP Demand Curve Reset: Seasonal Reference Point Price Proposal," ICAPWG/MIWG, August 24, 2023, p. 17, available at https://www.nyiso.com/documents/20142/39593642/3%202025-2029%20DCR%20Reference%20Point%20Price%20Proposal%20-%20ICAPWG%2008242023.pdf/a20a1914-69bf-f1d8-f39c-068c0cf40857.

("LOE").[29] This proposal to calculate seasonal reference points also results in calculating seasonal maximum allowable prices for the seasonal demand curves.[30] This seasonal demand curve proposal is at the stage where draft tariff language has been proposed.[31]

New York's resource adequacy construct differs from ISO-NE in important ways. In particular, load serving entities in New York procure power supply for non-shopping retail customers using a managed portfolio approach that provides some flexibility to procure capacity outside the NYISO ICAP through bi-lateral arrangements with resource owners and/or other market sellers. Thus, while NYISO relies on the ICAP market for price discovery and meeting some portion of resource adequacy needs, resource adequacy needs in New York are addressed in part through other arrangements, which differs from resource adequacy in ISO-NE.[32] In addition, New York's planning process offers greater opportunity for transmission owners to pursue non-transmission backstop opportunities than is available in ISO-NE, although, in practice, NYISO has found the regulated non-transmission backstops unnecessary.[33]

b. MISO

MISO's Planning Resource Auction ("PRA") is the mechanism used to ensure resource adequacy in the region, where the planning reserve margin that must be met is set through a LOLE study.[34] On August 31, 2022, FERC approved MISO's seasonal capacity market construct.[35] The shift to a seasonal market structure is motivated by a number of factors. Specifically, "MISO explains that reliability risks associated with resource adequacy have shifted from 'Summer only' to a year-round concern, noting that, since 2016, MISO has declared 40 Maximum Generation Emergencies ('MaxGen Events'), with more than 60% occurring outside of the summer months. MISO states that the significant increase in MaxGen Events is being driven by the confluence of: the retirement of traditional, baseload generation resources; planned and forced generator outages in non-summer months; an increased reliance on intermittent generation such as wind and solar; and extreme weather events resulting in numerous forced generator

---

[29] Mohrman, Maddy, "2025 - 2029 ICAP Demand Curve Reset: Seasonal Reference Point Price Proposal," ICAPWG/MIWG, August 24, 2023, pp. 18-20, available at https://www.nyiso.com/documents/20142/39593642/3%202025-2029%20DCR%20Reference%20Point%20Price%20Proposal%20-%20ICAPWG%2008242023.pdf/a20a1914-69bf-f1d8-f39c-068c0cf40857.

[30] Mohrman, Maddy, "2025 - 2029 ICAP Demand Curve Reset: Seasonal Reference Point Price Proposal," ICAPWG/MIWG, August 24, 2023, p. 23, available at https://www.nyiso.com/documents/20142/39593642/3%202025-2029%20DCR%20Reference%20Point%20Price%20Proposal%20-%20ICAPWG%2008242023.pdf/a20a1914-69bf-f1d8-f39c-068c0cf40857.

[31] NYISO, "MST 5.14, Seasonal Reference Point Price Revisions, Draft Tariff Revisions," available at https://www.nyiso.com/documents/20142/39102681/MST%205.14%20-%20Seasonal%20Reference%20Point%20Price%20Revisions.pdf/34efe711-8465-1685-be3b-95a0f57b9d2a

[32] Hibbard, Paul, et al., "NYISO Capacity Market, Evaluation of Options," May 2015, pp. 25-26, available at https://www.analysisgroup.com/uploadedfiles/content/insights/publishing/nyiso_capacity_market_evaluation_of_options.pdf.

[33] Hibbard, Paul, et al., "NYISO Capacity Market, Evaluation of Options," May 2015, available at https://www.analysisgroup.com/uploadedfiles/content/insights/publishing/nyiso_capacity_market_evaluation_of_options.pdf; NYISO, "2020 RNA Report," November 2020, p. 12, available at https://www.nyiso.com/documents/20142/2248793/2020-RNAReport-Nov2020.pdf.

[34] MISO, "Resource Adequacy," available at https://www.misoenergy.org/planning/resource-adequacy/#t=10&p=0&s=FileName&sd=desc.

[35] MISO, 180 FERC ¶ 61,141, Order Accepting Proposed Tariff Revisions Subject to Condition, August 31, 2022, Docket Nos. ER22-495-000, ER22-495-001.

outages, including multiple polar vortex and Arctic storms."[36] The main reforms to the PRA include: (1) a seasonal resource adequacy construct, and (2) capacity accreditation based on availability in periods with expected capacity tightness, and thus potential for loss of load.[37] Functionally, MISO will operate one prompt market per year, where capacity is procured separately for each of the four seasons in that given year.[38]

As the first main reform, MISO's seasonal resource adequacy requirements mean implementing seasonal loss-of-load expectation studies, seasonal reserve margins, seasonal local reliability requirements, and seasonal capacity import/export limits.[39] The four seasonal periods are defined as follows: winter is December to February, spring March to May, summer June to August, and fall September to November.[40] One motivation behind including four distinct seasons is to ensure that excess capacity never needs to be procured, for example in the spring and fall shoulder periods. Specifically, the FERC order accepting the seasonal capacity market construct states that, "by providing a more granular assessment of seasonal resource adequacy needs, MISO's proposal will ensure that LSEs [load serving entities] are not required to procure capacity beyond what is necessary to ensure resource adequacy in a given Season."[41] The independent market monitor, Potomac Economics, discusses two further benefits to the four season structure in its comments submitted to FERC in the process of evaluating MISO's seasonal capacity market proposal: (1) coordinating outages, and (2) retirement/suspension flexibility.[42] In terms of coordinating outages, Potomac states that, "[r]esources whose availability or capability varies significantly by season would receive revenues that reflect these seasonal differences. This could include resources that are not equipped for the freezing temperatures associated with winter operations or hydro resources with very different seasonal water conditions. In addition, relatively high-cost resources would have an opportunity to achieve savings by taking seasonal outages during shoulder seasons."[43] Potomac further comments on the four season structure's impact on efficient resource retirement decisions, where, "[r]esources retiring mid-year would have more flexibility to select a

---

[36] MISO, 180 FERC ¶ 61,141, Order Accepting Proposed Tariff Revisions Subject to Condition, August 31, 2022, Docket Nos. ER22-495-000, ER22-495-001, pp. 3-4.

[37]MISO, 180 FERC ¶ 61,141, Order Accepting Proposed Tariff Revisions Subject to Condition, August 31, 2022, Docket Nos. ER22-495-000, ER22-495-001, p. 4.

[38] MISO, "MISO Planning Resource Auction (PRA) Timeline for Planning Year 2023-2024," p. 3, available at https://cdn.misoenergy.org/2023-2024%20PRA%20Timeline626264.pdf.

[39] MISO, "Resource Adequacy Reforms Conceptual Design DRAFT," December 10, 2021, pp. 2-4, available at https://cdn.misoenergy.org/20211201%20RASC%20Updated%20Seasonal%20RA%20Conceptual%20Design%20Document619550.pdf.

[40] MISO, "Resource Adequacy Reforms Conceptual Design DRAFT," December 10, 2021 , p. 4, available at: https://cdn.misoenergy.org/20211201%20RASC%20Updated%20Seasonal%20RA%20Conceptual%20Design%20Document619550.pdf.

[41] MISO, 180 FERC ¶ 61,141, Order Accepting Proposed Tariff Revisions Subject to Condition, August 31, 2022, Docket Nos. ER22-495-000, ER22-495-001, p. 29.

[42] Potomac Economics, Ltd., "Motion to Intervene Out of Time and Comments of the MISO Independent Market Monitor," January 16, 2022, Docket No, ER22-495-000, available at https://elibrary.ferc.gov/eLibrary/filedownload?fileid=E156AB83-7DF8-C489-90E6-7E6CA6900000.

[43] Potomac Economics, Ltd., "Motion to Intervene Out of Time and Comments of the MISO Independent Market Monitor," January 16, 2022, Docket No, ER22-495-000, p. 3, available at https://elibrary.ferc.gov/eLibrary/filedownload?fileid=E156AB83-7DF8-C489-90E6-7E6CA6900000.

retirement or suspension date without having to procure significant replacement capacity to satisfy post-retirement capacity obligations."[44]

Second, MISO has implemented a seasonal accredited capacity ("SAC") proposal, whereby specific resources are accredited based on availability in RA ("resource adequacy") hours in each season.[45] Resource accreditation is adjusted annually based on quantitative analysis similar to that being developed in ISO-NE's RCA project. MISO's adoption of seasonal capacity accreditation has occurred in parallel to its adoption of a seasonal capacity market construct. Altogether, MISO has fully implemented both prompt and seasonal constructs into their capacity market structure.

c. PJM

PJM's capacity market, the Reliability Pricing Model ("RPM"), consists of a forward auction, roughly three years prior to the commitment period, of an annual capacity obligation. On February 24, 2023, PJM established a Critical Issue Fast Path – Resource Adequacy stakeholder process to address "resource adequacy challenges in the PJM Reliability Pricing Model or capacity market," with a proposal due for submission to FERC in October 2023.[46] This process was undertaken to address multiple issues, including enhanced risk modeling, particularly in accounting for winter risk, potential modifications to the Capacity Performance construct, improved resource capacity accreditation, and coordination of any RPM changes with other options for securing resource adequacy (i.e., Fixed Resource Requirements).[47]

As PJM undertook this process, one consideration evaluated was the transition to a seasonal market structure. PJM prepared proposals for both an annual capacity market including limited seasonal components and a more-extensive seasonal market proposal.[48] Pursuit of a seasonal capacity market design was in part motivated by the increased impact of extreme winter weather events on the PJM system and generator outages, such as the 2014 Polar Vortex and the 2022 Winter Storm Elliott.[49] Under the potential seasonal proposal, PJM would have to meet its annual resource adequacy requirement through procurement of summer and winter products. Capacity resources would

[44] Potomac Economics, Ltd., "Motion to Intervene Out of Time and Comments of the MISO Independent Market Monitor," January 16, 2022, Docket No, ER22-495-000, pp. 3-4, available at https://elibrary.ferc.gov/eLibrary/filedownload?fileid=E156AB83-7DF8-C489-90E6-7E6CA6900000.

[45] RA hours are seasonal, and defined as, "a 65-hour target that include all hours with declared MaxGen Events and the remaining hours with the tightest operating margin, subject to a maximum operating margin threshold of 25%." MISO, 180 FERC ¶ 61,141, Order Accepting Proposed Tariff Revisions Subject to Condition, August 31, 2022, Docket Nos. ER22-495-000, ER22-495-001, p. 35.

[46] PJM, "Critical Issue Fast Path – Resource Adequacy," available at https://www.pjm.com/committees-and-groups/cifp-ra.

[47] PJM, "Critical Issue Fast Path – Resource Adequacy, Issue Charge," available at https://www.pjm.com/-/media/committees-groups/cifp-ra/postings/cifp-ra-issue-charge.ashx.

[48] PJM, "Critical Issue Fast Path – Resource Adequacy, Executive Summary: PJM Seasonal and Annual Proposals," available at https://www.pjm.com/-/media/committees-groups/cifp-ra/2023/20230823/20230823-item-01a---20230823-cifp-stage-4---pjm-exec-summary.ashx.

[49] PJM, Capacity Market Reforms to Accommodate the Energy Transition While Maintaining Resource Adequacy, FERC Docket No. ER24-99-000, October 13, 2023, PDF p. 619, available at https://www.pjm.com/-/media/documents/ferc/filings/2023/20231013-er24-99-000.ashx.

then submit offers reflecting seasonal costs and seasonal resource accreditation, with offers clearing against seasonal demand curves.[50]

At this stage, in its proposal to FERC filed October 13, 2023, PJM retained an annual capacity market design proposal, included certain seasonal enhancements outside the auction structure, and indicated that it would "allow for further stakeholder discussion on transition to a more granular capacity market design."[51]

Despite proposing to retain a forward, annual capacity market structure, PJM's proposal includes certain enhancements reflecting seasonal considerations. Key components of the seasonal reforms introduced capacity performance testing requirements, including (1) Seasonal Capacity Performance Testing, requiring physical demonstrations of generator capability in each season, and (2) Seasonal Operational Performance Testing, which, "[a]llows PJM-initiated testing of generators' availability status to better ensure they are capable of operating if and when needed for reliability, up to twice in each season (summer and winter), excluding re-tests following a failed test."[52]

PJM indicates that it is continuing to evaluate future changes to the capacity market, including the possibility that it will adopt a seasonal capacity market in the future.[53] Specifically, "[…] there are a number of elements that PJM anticipates will continue to evolve in the pursuit of 'more perfect' markets, including, at least: seasonal or other more granular capacity market design; evolution in understanding of distribution of potential delivery-year weather patterns and related enhancements to risk assessments; and accreditation enhancements to more accurately value the expected contribution to reliability of different resources."[54]

III. Evaluation of the Key Tradeoffs Between a Forward and Prompt Market

Forward and prompt markets both create price signals that incentivize the entry of new resources and the exit (retirement) of existing resources. Assuming the demand for and supply of capacity is the same and assuming a

[50] PJM, "Critical Issue Fast Path – Resource Adequacy, Executive Summary: PJM Seasonal and Annual Proposals," pp. 5-6, available at https://www.pjm.com/-/media/committees-groups/cifp-ra/2023/20230823/20230823-item-01a---20230823-cifp-stage-4---pjm-exec-summary.ashx.

[51] "The Board also expressed support for continued evolution of the capacity market, 'including a more granular approach to the market' such as a seasonal market construct, as it continues to 'focus on evolving our markets to meet the energy transition.' PJM and stakeholders discussed sub annual market design approaches but ultimately the Board, pursuant to stakeholder feedback, elected to allow more time for discussion on the design and implementation of such an approach." PJM, "Capacity Market Reforms to Accommodate the Energy Transition While Maintaining Resource Adequacy," FERC Docket No. ER24-99-000, October 13, 2023, p. 22, available at https://www.pjm.com/-/media/documents/ferc/filings/2023/20231013-er24-99-000.ashx. PJM, "Critical Issue Fast Path – Resource Adequacy, Executive Summary: PJM Seasonal and Annual Proposals," p. 2, available at https://www.pjm.com/-/media/committees-groups/cifp-ra/2023/20230823/20230823-item-01a---20230823-cifp-stage-4---pjm-exec-summary.ashx.

[52] PJM, "Capacity Market Reforms to Accommodate the Energy Transition While Maintaining Resource Adequacy," FERC Docket No. ER24-99-000, October 13, 2023, Attachment D p.10, available at: https://www.pjm.com/-/media/documents/ferc/filings/2023/20231013-er24-99-000.ashx.

[53] PJM, "Capacity Market Reforms to Accommodate the Energy Transition While Maintaining Resource Adequacy," FERC Docket No. ER24-99-000, October 13, 2023, PDF pp. 635-680, available at https://www.pjm.com/-/media/documents/ferc/filings/2023/20231013-er24-99-000.ashx.

[54] PJM, "Capacity Market Reforms to Accommodate the Energy Transition While Maintaining Resource Adequacy," FERC Docket No. ER24-99-000, October 13, 2023, Attachment D p.44, available at https://www.pjm.com/-/media/documents/ferc/filings/2023/20231013-er24-99-000.ashx.

competitive market, both markets should result in (more or less) the same prices, quantities and entry and exit decisions in the long run. That is, given the same underlying supply and demand fundamentals, the price signals from a prompt and forward market lead to similarly efficient market outcomes.

In practice, these stylized conditions do not reflect reality in several respects. In particular, uncertainties in supply and demand at the time of the FCA may lead to differences in forward and prompt market outcomes and auction timing can affect which resources can compete to supply capacity (and the terms of their offers). These differences presented a basic choice. On the one hand, the market could operate like a prompt market, determining the price for capacity based on supply and demand at the time of delivery. In this regard, the prompt market would operate much like spot markets do for most commodities, providing a price signal reflecting resources' ability to supply, and cost of supplying, capacity when needed. On the other hand, the market could operate on a forward basis given the unique features of capacity as a product, particularly the large investment costs, financial risks, and multi-year investment horizons, as well as the potential benefits of competition between offers to supply new capacity.

Given the potential benefits of forward procurement, in the mid-2000s, the region opted to develop a capacity market based on forward procurement of capacity through a centralized, must-offer auction. However, these potential benefits were premised on plant development relying on particular technologies – gas-fired combined cycle and combustion turbine plants – with relatively predictable development timelines. We start our evaluation of forward and prompt markets by examining whether current market conditions align with this premise. We provide background on the evolving mix of resources in the ISO-NE system and the development timelines and processes for new resources to assess whether new plant development continues to rely heavily on gas-fired technologies and whether these and other plants can predictably be developed within a three-year period following the FCA.

Following this background, we evaluate the forward and prompt markets along several important dimensions: uncertainty in supply and demand; financial risk; market competition and price discovery; and administrative and operational considerations. We end by identifying certain key issues the region would need to address if pursuing a prompt market.

On balance, we find that a switch to a prompt market would provide the region with benefits that outweigh expected costs. These benefits include but are not limited to: reduced supply and demand uncertainty when clearing the primary auction; opportunities to relax constraints on resource retirements; better alignment of auction timing with the window for making winter fuel arrangements; simplified and lower cost auction process; and uniform alignment of capacity market timing with the development timelines of all resources.

A. Background on Evolving Mix of New System Resources

When the FCM was developed in the mid-2000's, a key rationale for procuring resources three years in advance of the commitment period was to align with the typical timelines for new power generation projects. At this time, the typical new entry unit was a gas-fired generator with typical development timelines on the order of three years. Given this development timeline, the auction was set to occur three years in advance of the commitment period to provide new resources with the opportunity to clear in the capacity market before beginning plant development (i.e., making certain significant financial commitments). By making development conditional on clearing the capacity market, the view was that the project would be easier to finance because there would be greater revenue certainty and the auction could coordinate entry and use capital more efficiently by clearing the least costly projects, avoiding over- or under-build of new plants and promote competition through head-to-head competition for new entry. The validity of this reasoning was predicated on three years being an accurate timeline for new entry development.

Since the FCM was developed, several important changes have occurred to the types of new capacity resources entering the system and the development process. First, the mix of resources that has recently entered (and is anticipated to enter) the ISO-NE grid is not comprised primarily of gas-fired resources, but instead includes a broad mix of resources with development timelines that are both longer and shorter than three years.

The changing mix of new resources reflects a combination of factors. One factor is state (and federal) policies aimed at decarbonizing the electric grid, which have affected the mix of resources entering the system in recent years and will require a wide mix of non-emitting resources if New England state decarbonization goals are to be achieved. A second key factor is technological innovation that has led to reductions in cost and increases in performance of onshore and offshore wind power, solar PV, and storage technologies.

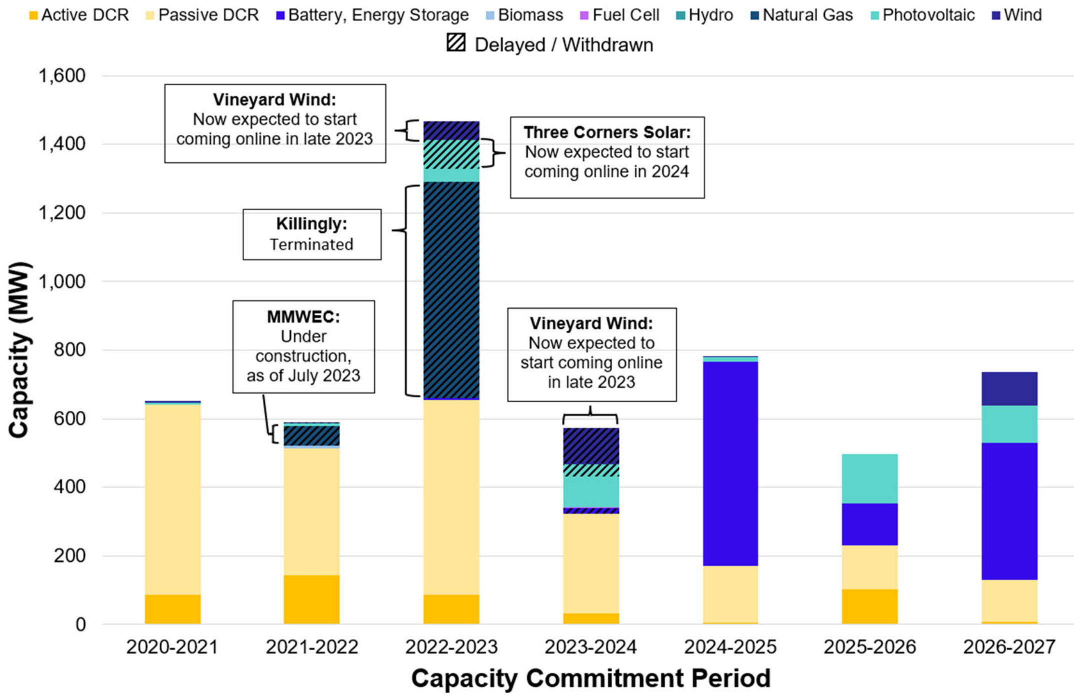
This change in system resources can be seen from the mix of resources that has cleared the FCA, illustrated in **Figure 3**. Over the past seven auctions, 5,293 MW of new capacity (excluding imports) has obtained a CSO through the ISO-NE FCA.[55] Much of this capacity was non-gas-fired resources, including demand capacity resources ("DCR"), battery storage, and solar PV. The largest category of cleared new entry is passive DCR which accounts for 2,201 MW which is over 40% of new cleared capacity (excluding imports) in the last seven auctions. Following passive DCR are battery storage, natural gas-fired generation and solar PV, with 1,139 MW, 690 MW and 527 MW, respectively. The remaining 736 MW capacity consists of active DCR, as well as wind, biomass, fuel cell, and hydro generators.

Recent trends suggest a reduced reliance on new natural gas capacity. No new natural gas resources have cleared the four most recent FCAs, while battery storage has been the largest category of new entry (excluding imports) for the most recent three FCAs with 1,118 MW. Looking forward, other technologies may have growing roles. For example, offshore wind resources may increase given Massachusetts, Connecticut, and Rhode Island have collectively committed to procure more than 8 GW of nameplate offshore wind capacity through the early 2030s, and with Maine committed to procure contracts for an additional 2.8 GW by 2035.[56]

[55] Throughout our discussion, we refer to summer qualified capacity unless otherwise specified.

[56] The Commonwealth of Massachusetts, Department of Public Utilities, "Notice of Filing and Request for Comments", D.P.U. 23-42, May 10, 2023. RI.gov, "Raimondo calls for up to 600 MW of new offshore wind energy for Rhode Island," October 27, 2020, available at https://www.ri.gov/press/view/39674; Faulkner, Tim and ecoRI News staff, "Massive Solar Facility Would Displace Farmland, Forest," November 25, 2020, available at https://www.ecori.org/renewableenergy/2020/11/23/conn-solar-farm-criticized-for-displacing-farmland-and-woodlands. State of Connecticut, Substitute House Bill No. 7156, Public Act No. 19-71, "An Act Concerning the Procurement of Energy Derived from Offshore Wind", available at https://www.cga.ct.gov/2019/act/pa/pdf/2019PA-00071-R00HB-07156-PA.pdf. 131st Maine Legislature, "An Act Regarding the Procurement of Energy from Offshore Wind Resources," Legislative Document No. 1895, S.P. 766, May 4, 2023, available at https://www.mainelegislature.org/legis/bills/getPDF.asp?paper=SP0766&item=1&snum=131.

Figure 3. Summer Qualified Capacity of Cleared New Entry Generation and Demand Capacity Resources for FCA 11 through FCA 17



Notes:
[1] Excludes import resources.
[2] Resources included here are those that (a) have "New" status in sheet "4.3 Qualified & Cleared Capacity" of the CELT report, and (b) do not have an in-service date that pre-dates the start of their CCP by five or more years, according to sheet "2.1 Generator List" of the same CELT report.
[3] For CCPs 2020-2021 through 2023-2024, generators are considered delayed/withdrawn if they are not listed as generators in sheet "2.1 Generator List" of the CELT report for that CCP, or if the in-service date for that unit occurred after the start of the commitment period for which they had a CSO.
Sources:
[A] ISO-NE, 2017-2023 CELT Reports, sheets "2.1 Generator List" and "4.3 Qualified & Cleared Capacity," available at https://www.iso-ne.com/system-planning/system-plans-studies/celt/.
[B] McCarron, Heather, "Nation's first offshore wind farm will begin producing power in Cape Cod waters this year," Cape Cod Times, October 19, 2023, available at https://www.capecodtimes.com/story/news/environment/2023/10/19/first-offshore-u-s-wind-power-cape-cod-ma-vineyard-wind/71234783007/.
[C] S&P Capital IQ, "Killingly Energy Center: Power Plant Profile," July 11, 2023, available at https://www.capitaliq.spglobal.com/web/client#powerplant/powerplantprofile?id=22148.
[D] S&P Capital IQ, "MMWEC Simple Cycle Gas Turbine Plant, Project Details," available at https://www.capitaliq.spglobal.com/web/client?auth=inherit#powerplant/PowerPlantProjectDetails?ID=57842.
[E] Jaynes, Cristen Hemingway, "Construction Begins on Maine's Largest Solar Project," EcoWatch, November 18, 2022, available at https://www.ecowatch.com/maine-largest-solar-project.html.

The development timelines for the mix of technologies being increasingly relied on in the region vary widely and are both shorter and longer than the original three-year benchmark for gas-fired resources. **Figure 4** provides estimates of the "engineering" timelines to develop various types of new generation resources.[57] These estimates appear to

[57] The estimates in **Figure 4** include initial engineering, permitting, and financing phases, as well as plant construction. The sources do not, however, provide details sufficient to confirm that they account for the same development steps.

assume no development delays, which are increasingly common, as we discuss below. Estimated development timelines range from 20 to 40 months for gas turbines and from 32 to 48 months for combined cycle generators. Non-gas technologies are both shorter and longer than these ranges. On the shorter end, development timelines range from 9 to 24 months for battery storage and from 18 to 24 months for solar PV. On the longer end, offshore development timelines can be up to 48 months. Overall, these estimates demonstrate a range of timelines that are both shorter and longer than the three-year time period between the FCA and the corresponding commitment period.

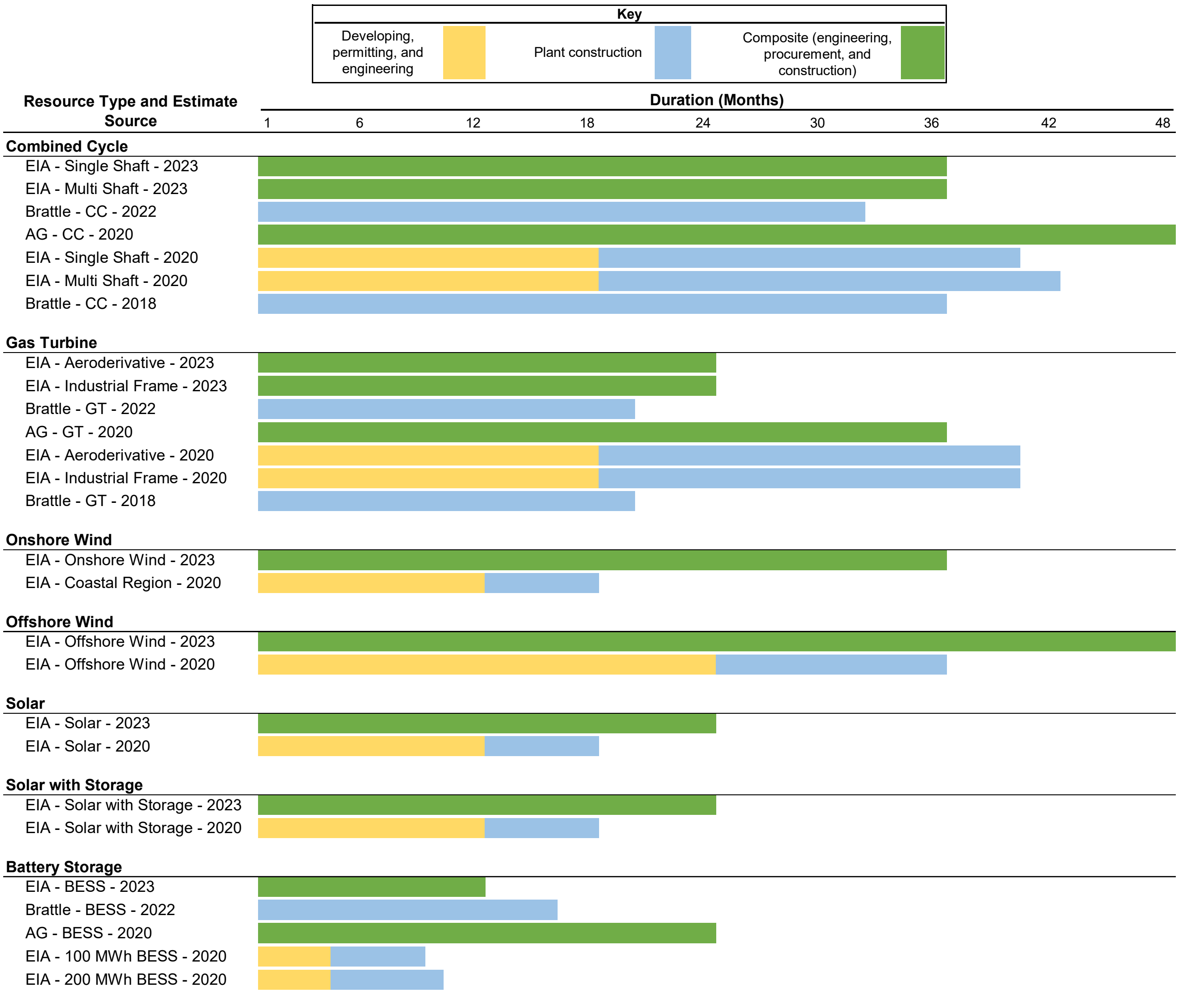
Along with the changing mix of new capacity resources, a variety of circumstances have led to increases in the risks associated with plant development. These risks include interruptions and delays that extend the time required to develop new infrastructure and termination of projects that have cleared the FCA. Multiple factors have contributed to these risks. One factor is delays and challenges to environmental and other regulatory permitting, and delays and legal challenges from local groups opposing development of the resources (i.e., "NIMBY-ism"). A second factor relates to supply chains and the ability of project developers to secure needed project equipment and personnel to develop the project. A third set of factors relates to plant financing and economics, with some projects failing to secure financing after clearing the FCA and other projects terminating contracts that were intended to support plant economics after subsequent changes in market conditions.

The various challenges and risks of energy infrastructure development are illustrated in **Figure 3** above. While the FCA cleared offers for substantial new resources over the past seven auctions, these resources are often not developed in time to supply capacity in the commitment period for which they initially cleared. In the three-year period covering the commitment periods for 2020-21 to 2022-23, over 90% of new cleared capacity from generators (i.e., excluding DCR) was unable to fulfill CSOs for their first commitment period. These projects included both gas-fired and renewable plants. Thus, even with 3-year forward clearing, project delays (or other factors) prevented these projects from fulfilling awarded CSOs, suggesting that the premise that resources could reliably be developed in the three years *after* clearing the FCA may be less valid now than when the FCA was first developed. Box 1 discusses these development challenges in greater detail with specific examples of the types of delays various types of projects face and the implications for potential development timelines.

Given these changes, the timing of new resource development and uncertainty faced in this process does not align with the expectations about development when the FCM was developed that new resources would clear the market and be online for the commitment period three years in the future.[58] New resources have development timelines both shorter and longer than three years and development uncertainties create a meaningful risk that any undeveloped resource clearing in the FCA will be unable to provide timely delivery of capacity for its first commitment period.

[58] ISO-NE and New England Power Pool, Testimony of Alan McBride on Behalf of ISO New England Inc., FERC Docket ER 24-339-000, November 2, 2023, pp. 25-26, available at https://www.iso-ne.com/static-assets/documents/100005/changes_to_delay_19th_fca_and_related_capacity_mtk_activities.pdf.

Figure 4. Estimated Engineering Timelines for Development of New Power Generation



Sources:

[A] U.S. Energy Information Administration, "Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2023," March 2023, available at https://www.eia.gov/outlooks/aeo/assumptions/pdf/elec_cost_perf.pdf.

[B] Newell, Samuel A., et. al., "PJM CONE 2026/2027 Report," April 21, 2022, available at https://www.brattle.com/wp-content/uploads/2022/05/PJM-CONE-2026-27-Report.pdf.

[C] Hibbard, Paul, "Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2021/2022 through 2024/2025 Capability Years – Final Report," Analysis Group and Burns & McDonnell, September 9, 2020, available at https://www.analysisgroup.com/globalassets/insights/publishing/2021-analysis-group-study-to-establish-new-york-icap-demand-curve-parameters.pdf.

[D] Sargent & Lundy, "Capital Cost Study: Cost and Performance Estimates for New Utility-Scale Electric Power Generating Technologies," December 2019, as presented in "Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies," US Energy Information Administration, February 2020, available at https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf.

[E] Newell, Samuel A., et. al., "PJM Cost of New Entry: Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date," April 19, 2018, available at https://www.pjm.com/~/media/committees-groups/committees/mic/20180425-special/20180425-pjm-2018-cost-of-new-entry-study.ashx.

In this regard, the prompt market aligns better with the realities of development in today's markets. The implications of this better alignment would vary for different types of technologies being developed to achieve the decarbonized grid. For technologies with shorter development timelines, such as battery storage and solar PV, a prompt auction would allow these resources to participate in the primary capacity market auction when they first become operational, which may increase revenues. For example, a resource developed in two years likely has not cleared its capacity in the FCA for the first and possibly second years of its operation. While it could sell capacity in the ARAs, as we show below, these auctions have historically cleared only a fraction of offered supply and prices are lower than initial FCA prices. Thus, for these resources, a prompt market could provide additional revenues that would further incentivize development.

For resources with longer development times or relying on technologies with larger development risks (e.g., offshore wind, gas-fired resources), clearing in the FCA before developing the project would provide reduced value (e.g., if development starts prior to the FCA) or uncertain value (e.g., if the project clears before starting development despite large development timing risks). We discuss these risks in the following section. Thus, the opportunity for developers to offer new capacity before committing capital is of less value in today's market given the types of technologies being developed and the development risks they face than it was when the FCM was initially designed.

Box 1. Recent Energy Developments in New England

Recent new generation in New England has exhibited a wide range of development timelines, many of which differ from the estimates displayed in **Figure 4.**Take, for example, the CPV Towantic Energy Center, a combined-cycle plant in Oxford, CT. It first secured a CSO in February 2015 for the 2018-2019 commitment period, began its air permitting process in September 2014, and was commissioned by May 2018 in time to fulfill its CSO. Permitting through construction and commissioning took about 4 years, somewhat longer than the combined-cycle development timeline estimates in **Figure** 4.

On the other hand, another recent combined-cycle project's timeline falls well outside **Figure 4**'s estimates. The Killingly Energy Center began its permitting process in August 2016 but faced multiple delays and opposition from environmental groups and even the Governor of Connecticut. The plant did not retain the CSO it secured in 2019, being unable to become operational by 2022. Between late February 2022 and July 2023, the plant's development was terminated.

The estimated timelines for wind projects may be similarly optimistic. The Vineyard Wind project, currently under construction off the coast of Massachusetts, has far exceeded the maximum, three-year development estimate for offshore wind shown in **Figure 4**. The offshore wind farm's permitting process alone, which it began in December 2017, took over three years to complete. It is now in its second year of construction and is not yet complete. Another offshore wind project, Park City Wind, has similarly had difficulties. It has been engaged in its permitting process for over three years and in October, citing unexpected construction costs contributed to by recent supply chain issues and inflation, Park City Wind canceled its power purchase agreements in hopes of obtaining more lucrative contracts. Now, over three years into development, it has no power offtake contract for its supplies.

Onshore wind has faced even stronger headwinds. Of three recent large prospective projects in New England, one is abandoned, and one took nearly six years between the start of its permitting process and its commissioning. The project that was successful, Weaver Wind, had a total development timeline of approximately 71 months, again well outside the estimates in **Figure 4**.

See **Table** 1 for a more comprehensive list of the development history of recent New England energy projects.

Table 1. Recent Construction Projects’ Timelines

Resource Type	Name	First ISO-NE Capacity Market Participation	Permitting Overview	Construction Overview	Other Issues	Status as of Dec. 2023	Approximate Total Lead Time
CC	Killingly Energy Center *Killingly, CT*	- Bid, unsuccessfully, for capacity obligation in Feb. 2017 and Feb. 2018 - Awarded CSO in Feb. 2019	- Permitting terminated before completion	- Construction has not begun	- Environmental group opposition - State executive branch opposition - Litigation - Canceled ISO-NE contract	- Terminated between late Feb. 2022 and July 2023	N/A
CC	Salem Harbor Power Station *Salem, MA*	- Awarded CSO in Feb. 2013	- Permitting granted after 13 months	- Construction delays	- Litigation - $17+ million in fines - Chapter 11 bankruptcy proceeding	- Active - In service May 2018	64 months (5+ years)
CC	CPV Towantic Energy Center *Oxford, CT*	- Awarded CSO in Feb. 2015	- Permitting granted after 14 months	N/A	N/A	- Active - In service May 2018	43 months (~3.5 years)
GT	Peabody Power Plant (MMWEC) *Peabody, MA*	- Unsuccessfully bid for capacity obligation in Feb. 2017 - Awarded CSO in Feb. 2018	- Permitting granted after 44 months	N/A	- Location change - Local opposition - Project redesigns	- Under construction - Expected to be in service by December 2023	83 months (~7 years), and counting
Battery Storage	Medway Grid Battery Storage *Medway, MA*	- Awarded CSO in Feb. 2021	- Majority of required permitting granted after 15 months	N/A	- Local opposition	- Under construction	21 months, and counting
PV	Three Corners Solar *Kennebec County, ME*	- Awarded CSO in Feb. 2019	- Permitting granted after 3 months	N/A	- Site rezoning	- Under construction - Expected to be in service by May 2024	22 months, and counting
PV	Farmington Solar Array *Farmington, ME*	- Unsuccessfully bid for capacity obligation in Feb. 2019 - Awarded CSO in Feb. 2020	- Permitting granted after 7 months	N/A	N/A	- Active - In service Oct. 2021	41 months (~3.5 years)
ONW	Number Nine Wind Farm *Aroostook County, ME*	- Never bid for capacity obligation - Power purchase with ISO-NE in Sept. 2013	- Permitting suspended before approval was granted	N/A	- Difficulties building new transmission lines	- Suspended	N/A
ONW	Bowers Wind Project *Penobscot County, ME*	- Never bid for capacity obligation	- Multiple applications, all rejected after 6 years	N/A	- Location change - Reduction in number of turbines - Local opposition	- Terminated	N/A
ONW	Weaver Wind *Hancock County, ME*	- Never bid for capacity obligation	- Permitting granted after ~4 years	N/A	- Environmental group opposition	- Active - In service Dec. 2020	71 months (~6 years)
OFW	Vineyard Wind 1 *Off the coast of MA*	- Awarded CSO in Feb. 2019	- Citing and permitting completed after ~3 years	N/A	- Local opposition	- Under construction - Expected to be in service by December 2023	72 months, and counting (~6 years)
OFW	Park City Wind *Off the coast of MA*	- Never bid for capacity obligation	- Permitting ongoing	- Unexpected construction costs	- Canceled power purchase agreements - Litigation	- Paused while negotiating new power purchase agreements	41 months, and counting (3+ years)
Import	New England Clean Energy Connect (NECEC) *Built through ME*	- Never bid for capacity obligation	- Permitting granted after ~3.5 years	- Construction delays of 21 months due to litigation	- Environmental group opposition - Litigation	- Under construction	76 months, and counting (6+ years)

Note: Lead time is calculated as the difference between the plant’s commissioning and the initiation of its permitting process. This represents an underestimate of total lead time, as the formulation of permit applications requires prior work that is not captured in this timeline.
Sources: Provided in **Appendix Section C**.

B. Uncertainty in Supply and Demand

A key difference between the forward and prompt markets is the uncertainty created by the need to forecast market conditions more than three years in advance of the commitment period, which affects both offers for supply and demand for capacity (as reflected in the administrative demand curve). In addition, with a forward market, capacity resources need to make commitments to deliver capacity more than three years in advance of the commitment period despite uncertainties in future market conditions. Given this uncertainty, the commitment imposes opportunity costs on resources as it limits resources' ability to respond to future changes in market conditions. This cost is particularly high for resources contemplating retirement because current rules require retirement notice about 3.5 years prior to the commitment period (at the outset of the FCA qualification period).

1. Uncertainties in Supply Under Forward and Prompt Markets

With a forward auction, there is greater risk that the supply of capacity offered in the forward auction changes over the three-plus year period between the forward auction and the commitment period. Uncertainties in supply reflect at least three factors: *first*, development risks, unexpected outage events, and other factors that prevent resources from delivering capacity with a CSO; *second*, new supply that enters the market after the forward auction; and *third*, changes to the value of capacity in supporting resource adequacy between the FCA and the commitment period.

By contrast, under a prompt auction, these uncertainties are largely mitigated by design. That is, a prompt auction requires that resources be activated at the time of the auction and measures qualified capacity based on the most-recent accreditation assessments. While capacity would still be subject to unexpected outages during the commitment period, uncertainty of supply is substantially reduced.

The greater uncertainty under a forward auction has several potential adverse consequences. *First,* financial risk is imposed on capacity owners, which they will be expected to include in their offer prices. *Second*, reliability may be compromised if the market is unable in the short run to supply capacity resources to replace those resources that withdraw. *Fourth*, the process of reviewing and assessing if new resources are meeting development milestones and determining whether action is needed in the event they are not can be contentious, time-consuming and prevent ISO-NE from working on other high value initiatives.

a. Uncertainties in Deliverability of Supply

With a forward auction three-plus years prior to the commitment period, both new and existing resources face uncertainty about their ability to deliver supply to fulfill CSOs awarded through the auction. **Section III.A** described the many uncertainties recently faced by new resources entering the market given challenges securing financing, uncertain permitting timetables, and local opposition. As a result, some resources that clear in the FCA never get built and other resources are delayed in delivering capacity to the system. Thus, in recent years, many new resources cannot fulfill CSOs cleared in the FCA.

Section III.A focused primarily on generation plants, but other types of resources face similar uncertainties in supply. For example, a forward market allows for demand-side resources, such as energy efficiency, to take on a CSO without having contracted for the quantities of reductions in energy use needed to fulfill the CSO. Because demand response resources, such as energy efficiency projects, are not typically aggregated until after the procurement, there is uncertainty in the quantity that entities with these CSOs can actually procure. Thus, demand-side providers can secure either too few or too many resources compared to their obligation. If, for example, too few resources are secured compared to the CSO, similar to generation resources that experience delays, additional capacity resources may need to be procured and/or the entity will incur deficiency penalties if they are unable to sell out of their CSO.[59]

Existing resources also face uncertainties in their ability to deliver capacity offered three plus years prior to the commitment period. Under a forward market, existing resources typically submit offers assuming their resources are able to operate at full capacity. However, in practice, resources may experience outages (e.g., equipment failures) or other operational constraints that limit their ability to fulfill capacity supply obligations.[60] These risks are particularly large for older units, which face a higher likelihood of experiencing major equipment failures.

By contrast, with the prompt market, these uncertainties in supply offered into the market are largely resolved prior to the auction. That is, new resources must be on-line and operational, existing resources must be operational and not encountering major outages, and demand-side resources must be procured and active.

b. Uncertainties in Resource Capacity Accreditation

If new resource capacity accreditation rules are approved, capacity accreditation would be updated annually based on system loads and the mix of resources in the system, as well as each individual resource's actual performance. Thus, a resource's capacity accreditation could change between the time of the FCA and the commitment period due to many factors.

Under the current RCA proposal, the qualified capacity each resource can offer would be estimated prior to the FCA, based on the resource's rMRI value (and its qualified capacity). Thus, FCA accreditation values calculated prior to the FCA and qualified capacity awarded in the FCA may not align with a resource's actual contribution during the commitment period.[61] Given on-going and expected changes in the resource mix in the ISO-NE system, including increasing quantities of intermittent and storage resources, resources could experience meaningful changes in qualified capacity between the FCA and the commitment period. This is a change compared to current rules for calculating qualified capacity.

ISO-NE has not determined how any change in rMRI values between the FCA and the commitment period would be accounted for under RCA enhancements. Regardless of the market rules selected, changes in capacity accreditation between the FCA and the commitment period would have consequences for and potentially add complexity to the capacity market. For example, if rMRI values were held fixed, the contributions provided by resources procured through FCA (individually and in aggregate) would be less than assumed when the FCA was conducted. On the other hand, if rMRI values used to determine qualified capacity change between the FCA and commitment period, rules for making those adjustments and any needed changes to procured quantities would need to be determined.

---

[59] By contrast, if demand response managers secure *a larger* quantity of capacity than were cleared in the FCA, then they may be able to offer these resources in subsequent ARAs. However, as we discuss below, the ability to sell this new supply of capacity and the price awarded for this supply is uncertain and historically has been lower than what was earned in the FCA.

[60] Within the ISO-NE market, these events are referred to as significant decreases in capacity and reflect particular criteria under which the resource supplier must either obtain replacement capacity or face de-rating of capacity. ISO-NE Tariff, Market Rule 1, Section III.13.1.2.2.4. Adjustment for Significant Decreases in Capacity Prior to the Existing Capacity Retirement Deadline, Docket # ER23-911-000, Effective Date: March 21, 2023.

[61] For some resources, accreditation depends on the resource mix and the resources' penetration. As time passes, FCA accreditation will be based on an assumed resource mix and particular resources' penetration that will likely differ closer to the commitment period. *See*, e.g., "2022 Assessment of the ISO New England Electricity Markets," Potomac Economics, June 2023, p. 68.

By contrast, under a prompt market design, capacity accreditation would be set prior to the primary auction, which would occur shortly before the commitment period when the resource is obligated to deliver its capacity. With this approach, capacity accreditation awards would align with the most-current estimates of each resource's contribution to resource adequacy.

The use of less current capacity accreditation with the forward market could have several potential implications. *First*, the actual contributions of the resources procured through the capacity market to support resource adequacy would differ from the contributions assumed when CSO awards are made. Thus, if accreditation values are meaningfully lower at the commitment period, reliability risks would be greater than the levels implied by the FCA outcomes if rMRI values are held fixed at values used in the FCA. In this case, it is possible that if the values used in the auction better reflected resources' final reliability contributions (at the commitment period), the auction would have procured additional capacity.[62] By contrast, with a prompt market, reliability procured through the auction would be consistent with the current assessment of risks. *Second*, changes in capacity accreditation could affect the cost-effectiveness of auctions if accreditation values affect the rank-ordering of offers in the offer supply curve.[63] Thus, using more accurate capacity accreditation in a prompt market would ensure that the lowest cost resources are procured to achieve resource adequacy.

The RCA enhancements may also lead to uncertainty in accreditation values when those values depend on actions taken by resources to improve their reliability. In particular, going forward, RCA accreditation will account for the risk that gas-fired resources without firm fuel supply may not be available during the periods of greatest system need. Thus, given this risk, capacity resources with a less-firm fuel supply will have a lower accreditation than resources with firm supply. Unlike many factors affecting capacity accreditation which are 'fixed' well in advance of the delivery period (i.e., the technology type), the firmness of gas-fired resource's fuel supply depends on on-going resource owner decisions, such as on-site fuel oil storage (for dual fuel resources) and agreements for firm gas supply (for gas-only resources). Thus, for gas-only resources, capacity accreditation is expected to depend on some form of attestation by the resource owner about actions it has or will take to secure fuel and their actual contribution will depend on whether they fulfill these actions.

With a longer time period between the auction and the commitment period under the forward market, there is a greater risk that the actual arrangements to secure fuel supplies made by resource owners are inconsistent with the attestations made in their offers. As we discuss further in **Section III.B.4.c**, with a prompt market, these arrangements can be made with lower risk because these commitments are made immediately prior to the commitment period when resource owners can rely on more liquid markets to make supply decisions. By contrast, with the forward market, these commitments would be made three to four years in advance, when there is substantial uncertainty about fuel markets in the commitment period. These resource accreditation decisions affect a large quantity of resources, as there is more than 9,100 MW of winter qualified capacity of existing natural gas-only fired resources in the ISO-NE system that bid into FCA 17, and thus have a consequential impact on resource adequacy.[64]

---

[62] In the opposite case in which capacity accreditation values are too low in the auction, the auction could lead to procurement of more capacity than would have been procured with accurate values for the commitment period.

[63] Accreditation values would affect resource offers when the offer reflects the resource's fixed avoidable costs relative to its qualified capacity.

[64] ISO-NE, 2023 CELT Report, sheet "2.1 Generator List" and sheet "4.3 Qualified, Cleared Capacity." Generators are assumed to burn only natural gas if their primary fuel is listed as "NG" and they have no secondary fuel listed.

With a prompt market, ISO-NE resource qualified capacity is set a few months prior to the auction, thus avoiding the misalignment between the values that clear in the auction and the most up-to-date values for the commitment period. Thus, establishing accreditation values immediately prior to a commitment period under the prompt auction ensures that the quantity of capacity resources procured reflects the most accurate and up-to-date reliability contribution the procured resources would be expected to make.

c. Potential Financial Consequences of Deficiency Risk

As described above, because more than three years pass between the FCA and the commitment period under the current forward market, new and existing resources face the risk that they will be unable to fulfill the CSO, leading to a "deficiency" risk. The nature of this risk differs for new and existing resources. Because new generation plants can take on a CSO without being built or operational, their deficiency risk reflects the likelihood that the new resource is not operational by the commitment period. As discussed above (e.g., **Box 1**), the recent development timelines in New England are uncertain and can stretch beyond three years, suggesting that these risks are meaningful. For non-traditional resources, such as demand-side resources, the risks would depend on the developer's experience reliably developing resources to fulfill awarded CSOs. For existing resources, risks may be lower, although for older resources with higher risk of experiencing major equipment failures, the risk could be meaningful.

The financial cost of deficiency risk reflects the costs incurred if the resource fails to deliver capacity under the CSO. If a resource with a CSO is not developed by the commitment period, the resource would incur deficiency penalties unless it can sell the CSO to other capacity suppliers in reconfiguration auctions or through other bi-lateral trades.[65] The financial consequences of deficiency penalties are complex to determine (e.g., given rules regarding forfeiture of financial assurance when failing to deliver capacity). Thus, while resources unable to fulfill their CSO have been able to cover the CSO with other capacity, determining the associated cost is complex, including when the CSO is covered at a price is below the clearing prices in the original FCA.

In contrast, under a prompt market, deficiency risk would be minimal. The prompt market would likely require that the new resources are operational prior to participation in the capacity market, which significantly reduces the risk that the unit is not developed and activated for the commitment period. The reduced deficiency risk for new entry in a prompt market relative to a forward market is expected to result in a lower offer price for new units, particularly when there is greater uncertainty about their development timeline.

d. Potential Market and Reliability Impacts From Failure to Deliver

From a reliability standpoint, a failure to deliver could diminish reliability if the undelivered resources were not replaced by other resources either because new supply resources were not available or ARA prices were too low to incentivize new capacity. Reconfiguration auctions and an elastic source of short-term new supply can potentially mitigate the likelihood of this outcome, particularly if the ARAs produce sufficiently high prices to incentivize

[65] A "failure to cover charge" is applied if a resource does not demonstrate the ability to deliver the full amount of its CSO. The failure to cover charge is calculated as the difference between the monthly CSO and the capacity the resource is able to deliver (its "Demonstrated Output"), multiplied by the Failure to Cover Charge Rate, set based on a reclearing of ARA3 and intended to produce a rate exceeding the ARA3 price to incentive resources to cover their CSO rather than pay the failure to cover charge. ISO-NE, "Market Rule 1 – Section 13, Forward Capacity Market," March 21, 2023, 13.3.4. Covering Capacity Supply Obligations, available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf. *See also,* ISO-NE and NEPOOL Participants Comm., 165 FERC ¶ 61,266 (2018), available at https://www.ferc.gov/sites/default/files/2020-05/E-15_14.pdf.

additional capacity supplies. The increasing availability of resources with shorter development timelines (e.g., storage) would mitigate these risks.

As we discuss below, in practice, this risk has not materialized in prior auctions, as the market has cleared sufficient quantities of resources (relative to Net ICR) in the FCAs to avoid shortages of supply. ARAs have mitigated individual resource's failure to deliver through new capacity resources entering the market and downward adjustments to demand. However, the quantity of supply offers in the ARAs has been modest (typically less than 250 MW), with ARAs the most recent CCP being a noted exception (with quantities of nearly 1 GW). And, reliance on downward adjustment to demand depends on original forward forecasts being higher than final demand (at the commitment period). By contrast, a prompt market mitigates these risks by reducing the likelihood that capacity resources are not delivered.

e. Administrative Costs of Monitoring New Resource Progress

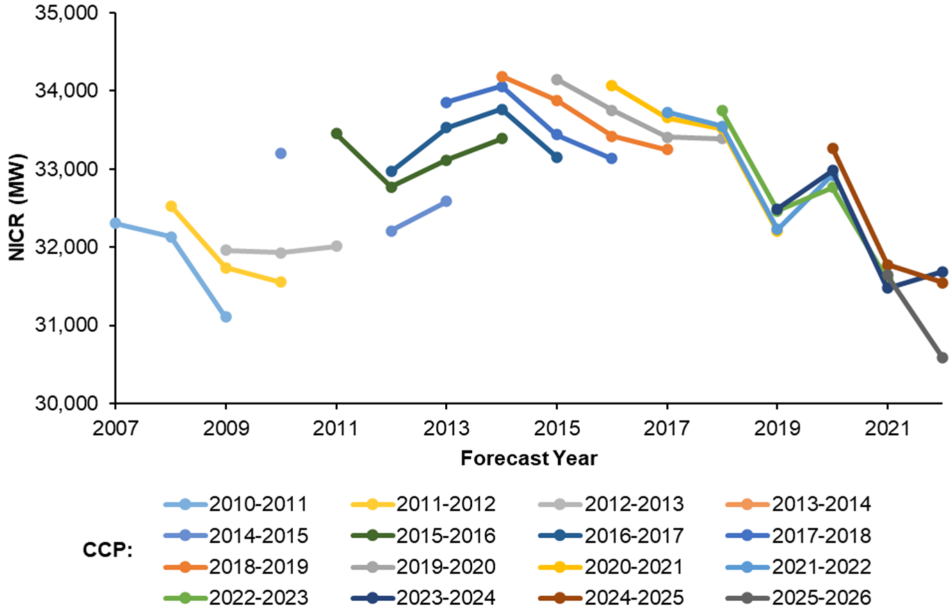
Under the current FCM, new resources can clear the FCA before being developed. Under current market rules, development progress is monitored to determine if the resource is making sufficient progress toward development to being on-line to fulfill the CSO. For ISO-NE, this process is time-consuming and may take attention away from other valuable projects. It can also be controversial because it requires the ISO to determine whether the resource is making the progress necessary to remain in the market, and the ISO's information and judgment could differ from that of the developer. With a prompt market, this process is likely avoided because resources would be expected to be operational (or nearly operational) before they participate in the capacity auction.

2. Uncertainties in Demand Under Forward and Prompt Markets

Under the current forward market structure, FCAs take place over three years prior to the commitment period, requiring that a forecast of ISO-NE's peak energy demands be developed to determine the quantity of capacity necessary to meet ISO-NE's resource adequacy requirements (i.e., Net ICR).[66] Like any forecast, forecasted Net ICR is uncertain and forecasted values may be higher or lower than final values (i.e., those calculated immediately prior to the commitment period). Given the three-plus year time lag between when FCA forecasts are developed and the commitment period, differences between forecast and final values are potentially large. **Figure 5** and **Figure 6** show that the forecast Net ICR—not surprisingly—has changed between the time of the FCA and the start of the commitment period. While the Net ICR has gone both up and down during the time-lag between the FCA and the commitment period, in recent years the Net ICR has typically declined compared to initial forecasts.

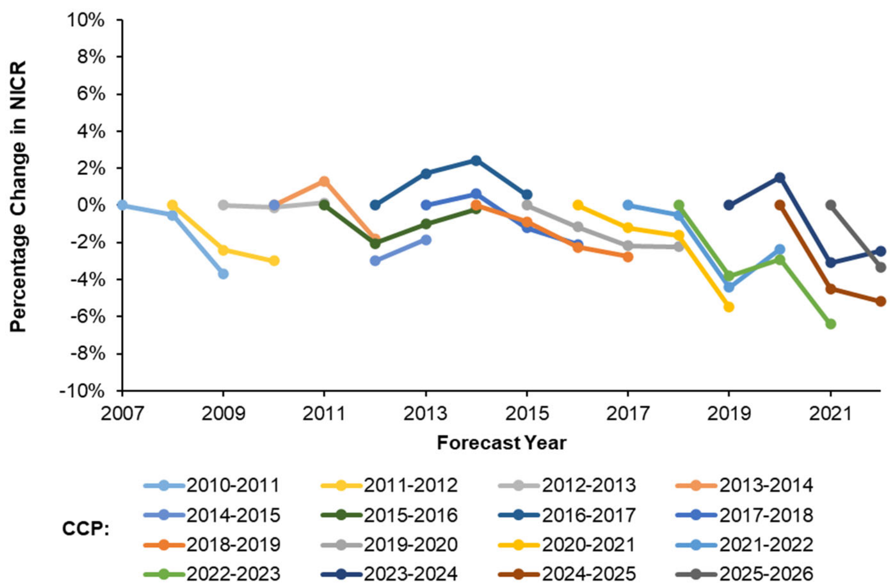
[66] The Net ICR—set in the fall prior to the annual FCA in February of the following year—is a key input into the setting of ISO-NE's administrative demand curve schedule used in the FCA auctions. *See* ISO-NE, "Installed Capacity Requirement," available at https://www.iso-ne.com/system-planning/system-plans-studies/installed-capacity-requirement.

Figure 5. Comparison of ISO-NE Net ICR by CELT Forecast and Commitment Period



Note: The values for CCP 2014-2015 are not plotted as a continuous line because the FCA was based on the 2010 CELT Forecast, while the ARAs were based on the 2012 and 2013 CELT Forecasts.
Source: ISO-NE, "Summary of Historical Installed Capacity Requirements and Related Values," available at https://www.iso-ne.com/static-assets/documents/2016/12/summary_of_historical_icr_values.xlsx.

Figure 6. Percentage Changes in ISO-NE Net ICR from FCA by CELT Forecast and CCP



Notes:
[1] Percentage changes for the FCAs are plotted at zero.
[2] The values for CCP 2014-2015 are not plotted as a continuous line because the FCA was based on the 2010 CELT Forecast, while the ARAs were based on the 2012 and 2013 CELT Forecasts.
Source: ISO-NE, "Summary of Historical Installed Capacity Requirements and Related Values," available at https://www.iso-ne.com/static-assets/documents/2016/12/summary_of_historical_icr_values.xlsx.

Changes in Net ICR between the FCA and the commitment period can reflect normal forecast uncertainty. In particular, unforeseen supply/demand shifts can lead to changes in Net ICR between the FCA and the commitment period.[67] For example, the economic forecasters relied on by ISO-NE didn't predict the magnitude and duration of the U.S. financial crisis that began in late 2008. Thus, ISO-NE's original Net ICR projections did not capture the financial crisis' economic impact on energy use and the Net ICR values fell for several future commitment periods to reflect the fact that the projected impact of the crisis on Net ICR was more severe than originally projected. More recently, ISO-NE demand forecasts didn't fully capture the impact of rapid growth of behind the meter solar resources and new equipment codes and standards that materially reduced Net ICR over time. As ISO-NE revised its demand forecasts to account for unforeseen demand reductions, Net ICRs declined between the FCAs and the commitment period.[68]

By its design, a forward market has greater demand forecast uncertainty than occurs under a prompt market. Under the prompt market, demand (as reflected in the demand curve) is determined based on "final" resource adequacy requirements estimated immediately prior to the commitment period.[69] As a result, there is no uncertainty in demand because there are no subsequent adjustments to Net ICR after the prompt market clears for the upcoming commitment period.

In contrast, under the forward market, supply offers clear against a demand curve based on forecast demand which likely differs from final demand given changes in market fundamentals over time. As result, final demand prior to the commitment period could be higher or lower than the original forecast. If the forecast turns out to be too high compared to the eventual demand, then price, quantity and cost are higher than they otherwise would have been if the "correct" forecast had been made, which may result in greater costs being incurred; by contrast, if the forecast turns out to be too low, then the price, quantity and cost is lower than it otherwise would be, and reliability may therefore be adversely impacted.[70]

In comparison to the current FCM, a prompt market would avoid such uncertainty, as well as the corresponding impacts on costs and reliability. Instead, the prompt auction relies on demand curves reflecting the most current capacity requirements (given current estimates of demand) and thus can achieve more efficient market outcomes.

---

[67] *See*, e.g., Scibelli, Maria, "Investigation of Bias in the Installed Capacity Requirement (ICR), FCA 1 through FCA 10," ISO-NE, Agenda Item 6.0 | PSPC Meeting No. 330, May 29, 2018, available at https://www.iso-ne.com/static-assets/documents/2018/05/a6_pspc_rev_icr_bias_invtgn_05292018.pdf.

[68] Net ICR forecasts also fell over time as ISO-NE enhanced its methodologies for determining Net ICR. These enhancements have generally caused Net ICR to decline over time. While reducing the quantity of capacity procured in FCAs incorporating these enhancements, they have also resulted in downward adjustments to Net ICR estimates for commitment periods relying on prior methodologies. In addition, changes to market parameters, such as operating reserve requirements, can change Net ICR.

[69] Here, "final" demand or Net ICR refers to the demand and underlying demand parameters (i.e., Net ICR) that would be estimated at or shortly before the start of the CCP. Under the current FCM structure, this "final" demand is analogous to estimated demand for the third annual reconfiguration auction.

[70] Reconfiguration auctions do not attempt to directly adjust for changes in demand. Instead, the reconfiguration auctions clear offers among suppliers to buy and sell CSOs against a demand curve reflecting an updated Net ICR given changes to demand.

3. Effectiveness of Annual Reconfiguration Auctions (ARAs) in Mitigating Impact of Uncertainty on Market Outcomes

In the intervening years between the FCA and the commitment period, ISO-NE runs three ARAs which allow capacity suppliers to change their capacity market positions. Capacity suppliers looking to shed CSOs can submit demand bids, while suppliers looking to take on additional CSOs can submit supply offers.[71]

The auctions fulfill several roles in the forward market. *First*, these auctions provide a means to indirectly readjust anticipated demand for capacity through a recalculated Net ICR based on an updated load forecast. However, these adjustments do not reflect the full participation of demand in a re-clearing of the market. *Second,* capacity resources can shed CSOs, which may be necessary for resources that are unable (or concerned about their ability) to fulfill their capacity obligations. ARAs can allow resources with qualified capacity that did not clear in the FCA to supply capacity for the corresponding commitment period. This supply can include recently qualified capacity that was not available for the FCA or capacity that was available but did not sell capacity in the FCA. Thus, ARAs provide a means for incremental resources to provide resource adequacy support, including replacement of CSOs shed by resources that cannot fulfill their CSOs.

Table 2 summarizes the results of the ARAs and FCAs for the last seven commitment periods for which all three ARAs were completed. Overall, the quantities cleared in the ARAs are both positive and negative and the total MW transacted only make up a small fraction of the FCA clearing quantities. **Table 2** also shows that historically capacity clearing prices generally decreased from the FCA to the third ARA.[72] However, there is variation within some of the time periods between the FCA and the Commitment period. For example, for the 2021-2022 and 2023-2024 commitment periods, the clearing price decreased relative to the FCA price for the first two ARAs, but then increased in the third ARA. Overall, ARA clearing prices are notably lower than the corresponding FCA clearing prices.

In principle, the ARAs can adjust for changes in Net ICR between the FCA and the commitment period, when the initial forecast is higher or lower than the final Net ICR values. Thus, the ARAs may to some degree mitigate the economic impacts from procurement of more or less capacity than needed relative to amounts that would be procured through a prompt auction based on final Net ICR values. The forward market outcomes to date generally illustrate the potential impacts when the Net ICR used in the FCA is higher than the final demand, resulting in procured quantities that are greater than may have occurred if the primary procurement reflected ARA demand.

[71] The ARA clearing mechanism accounts for both market participant offers and bids and a revised demand curve that accounts for changes in the forecast Net ICR. ISO-NE, "Overview and Timeline of Reconfiguration Auctions and CSO Bilateral Periods," available at https://www.iso-ne.com/markets-operations/markets/forward-capacity-market/fcm-participation-guide/overview-and-timeline.

[72] The ARA clearing prices are determined by the interaction of auction bids and offers and an updated demand curve based on the revised Net ICR. We did not separately assess the drivers of the historical ARA prices.

Table 2. Forward Capacity Auction (FCA) and Annual Reconfiguration Auction (ARA) Results by Capacity Commitment Period (CCP): 2017-2018 – 2023-2024

CCP	Auction	Total Supply Offers Submitted (MW)	Total Demand Bids Submitted (MW)	Total Supply Offers Cleared (MW)	Total Demand Bids Cleared (MW)	Net Capacity Cleared (MW)	Clearing Price
2023-24	FCA					33,956	$2.00
	ARA1	974	1,636	195	-235	-40	$1.93
	ARA2	231	1,134	42	-82	-40	$0.80
	ARA3	785	1,594	256	-131	125	$1.35
2022-23	FCA					34,839	$3.80
	ARA1	156	1,808	124	-781	-657	$1.11
	ARA2	100	1,508	88	-494	-406	$1.34
	ARA3	57	1,094	28	-527	-499	$0.40
2021-22	FCA					34,828	$4.63
	ARA1	203	820	184	-3	180	$2.90
	ARA2	138	1,048	40	-141	-101	$0.30
	ARA3	173	1,677	134	-150	-16	$1.57
2020-21	FCA					35,835	$5.30
	ARA1	155	584	102	-1	101	$3.67
	ARA2	188	535	149	-8	140	$2.00
	ARA3	71	862	60	-89	-29	$0.40
2019-20	FCA					35,567	$7.03
	ARA1	257	1,335	209	-75	133	$5.87
	ARA2	183	1,522	111	-129	-18	$3.50
	ARA3	148	851	144	-134	10	$2.99
2018-19	FCA					34,695	$9.55
	ARA1	N/A	N/A	N/A	N/A	N/A	N/A
	ARA2	132	1,125	118	-20	98	$5.32
	ARA3	89	1,522	86	-121	-36	$4.06
2017-18	FCA					33,712	$15.00 new $7.025 existing
	ARA1	N/A	N/A	N/A	N/A	N/A	N/A
	ARA2	168	929	134	-32	102	$7.13
	ARA3	164	962	137	-111	26	$3.50

Notes:
[1] Quantities reported in the table are Rest-of-Pool quantities and exclude imports and exports.
[2] In auctions with location-specific prices, System-wide or Rest-of-Pool prices are reported. All ARA clearing prices are Rest-of-Pool prices.
[3] A value of "N/A" indicates that results were not available for that reconfiguration auction.
Sources:
[A] ISO-NE, "FCM Reconfiguration Auction and CSO Bilateral Period Results," available at https://www.iso-ne.com/markets-operations/markets/forward-capacity-market/fcm-auction-bilateral-results.
[B] ISO-NE, "Results of the Annual Forward Capacity Auctions," available at https://www.iso-ne.com/about/key-stats/markets#fcaresults.

While the ARAs can in theory help to mitigate these impacts, in practice, adjustments to procured capacity in the ARAs have been relatively small compared to the changes in Net ICR between the FCA and the final ARA. In general, capacity suppliers are unwilling to sell back CSOs at prices that would clear demand in the ARAs. For the 2022-23 commitment period, the adjustment was relatively large – the ARAs led to a 1,562 MW reduction in capacity procured relative to the FCA, while Net ICR declined by 2,160 MW between the FCA and the ARA3.[73] By contrast, in the 2020-21 commitment period, procured capacity increased by 212 MW while Net ICR decreased by 1,870 MW between the FCA and the ARA3.[74] As a result, during the commitment period, there has frequently been more capacity committed than the amount that would have likely cleared in a corresponding prompt auction based on the final Net ICR values for the commitment period.

ARAs can also mitigate impacts when Net ICR in the FCA is lower than the final value prior to the commitment period. In this instance, procured capacity and auction prices would be lower than if demand in the FCA has reflected the higher realized final demand. In this case, in principle, the ARAs could procure additional capacity needed to account for the higher demand.

In contrast, with a prompt market, the inefficiencies associated with load forecast and ICR uncertainty are significantly reduced. Under the prompt market, Net ICR will be estimated within months of the commitment period and thus capacity market auction outcomes will more closely reflect the amount of capacity needed and the price will be set in alignment with the marginal supplier of capacity.

The ARAs have allowed suppliers to manage their CSO positions, allowing them to shed CSOs given changes in their ability to fulfill a CSO and allowing new resources (and existing resources that did not clear in earlier auctions) a means to take on a CSO. If a supplier needs to decrease a CSO because of a significant decrease in capacity or inability to develop the capacity resources, the ARAs provide an opportunity to buy out of a CSO rather than face a failure-to-cover charge for the deficiency.[75] If a supplier has new capacity to offer, the ARAs provide a means to take on a CSO. Experience to date shows that the flexibility offered by the ARA has led to some adjustments to supplier positions, with larger changes in some years than others (see **Table 2**). In general, it appears that suppliers with resources that experience significant decreases in capacity or fail to meet development timelines have been able to secure replacement capacity through the ARAs.

However, the low prices historically experienced in ARAs compared to the corresponding FCA may disadvantage new resources that take less than three years to develop relative to other new and existing resources. For example, utility scale solar PV and battery storage, which represent most of the recent new entry in New England (**Figure 3**), have engineering timelines of less than three years. If resources are awarded a CSO in the FCA and then begin to develop the resource, the resource may be operational and activated prior to the commitment period for which the resource cleared in the FCA. In this case, the resource would not have a CSO during the first year (or two) of operation unless one was obtained through an ARA. However, as shown in **Table 2**, only a fraction of offered supply has cleared in past ARAs and the prices are generally lower than in the FCA. Thus, resources with development timelines less than 3 years may reasonably expect that they will not have the same opportunity for capacity market revenues as under a prompt market. The result is that a forward market discourages the development of new resources with shorter development timelines relative to a prompt market, holding all else equal.

---

[73] ISO-NE, "Summary of Historical Installed Capacity Requirements and Related Values," available at https://www.iso-ne.com/static-assets/documents/2016/12/summary_of_historical_icr_values.xlsx.

[74] ISO-NE, "Summary of Historical Installed Capacity Requirements and Related Values," available at https://www.iso-ne.com/static-assets/documents/2016/12/summary_of_historical_icr_values.xlsx.

[75] Under certain circumstances ISO-NE may need to submit a buy bid into an ARA in instances where a supplier is not meeting developmental milestones. *See,* ISO-NE, "Market Rule 1, Section III.13.3.4," pp. 145-148, available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf.

4. *Opportunity Cost of Forward Commitments*

When a resource commits to a capacity supply obligation three years in advance, there is an opportunity cost from the reduced optionality for the resource to take certain actions in the future. For example, the reduced optionality can affect when the resource elects to retire and which capacity market to supply into. Under a prompt market, this opportunity cost is reduced because plant owners have better information about market conditions given the short time horizon from the time the commitment is made to the commitment period.

a. Retirements

Under the FCM, resources must give notice of an intent to retire ahead of the FCA – that is, more than three years in advance of the commitment period. To ensure transparency and provide information to the market about retirements and the outcome of reliability reviews, ISO-NE publishes data in the early phases of the FCA qualification process.[76] The current retirement and permanent de-list bid process begins about 10 months prior to the forward capacity auction (more than four years before the start of the CCP) when resources submit their de-list bids and ISO-NE publicly identifies the resources that have submitted bids to retire or permanently de-list.[77] Following a reliability review by ISO-NE, resources are notified two months later whether their request is accepted, providing the market at least eight months prior to the FCA to respond.[78] If the de-list bid triggers a local reliability need, the request is rejected and ISO-NE begins a process of identifying approaches to mitigate the local reliability need and potentially retain the resource past its retirement date.[79] As a result of this timing, resources seeking retirement through permanent or retirements bids must submit these bids roughly 4 years before the relevant capacity commitment period.[80]

Figure 7 shows recent resource retirements and announced retirements in New England, with resource retirements announced as far out as 2027. Major recent retirements include Mystic 7 in 2022 (575 MW summer qualified capacity ("QC") of oil generation),[81] Pilgrim Nuclear in 2019 (677 MW), and Bridgeport Harbor in 2021 (383 MW). Major announced future retirements include Mystic 8 & 9 in 2024 (1,413 MW of natural gas generation), West Springfield 3 in 2024 (94 MW), and Potter 2 in 2024 (72 MW). Recent retirements in 2018, 2019, and 2021 also include demand capacity resources.

---

[76] ISO-NE, "CCP Information Releases and FCM De-list Bids," available at https://www.iso-ne.com/isoexpress/web/reports/auctions/-/tree/fcm-delist-bids.

[77] This process refers to permanent and retirement de-list bids. ISO-NE, "Master Forward Capacity Market Schedule," January 4, 2023, available at https://www.iso-ne.com/static-assets/documents/2022/02/fcm-schedule-01-26-2022.pdf.

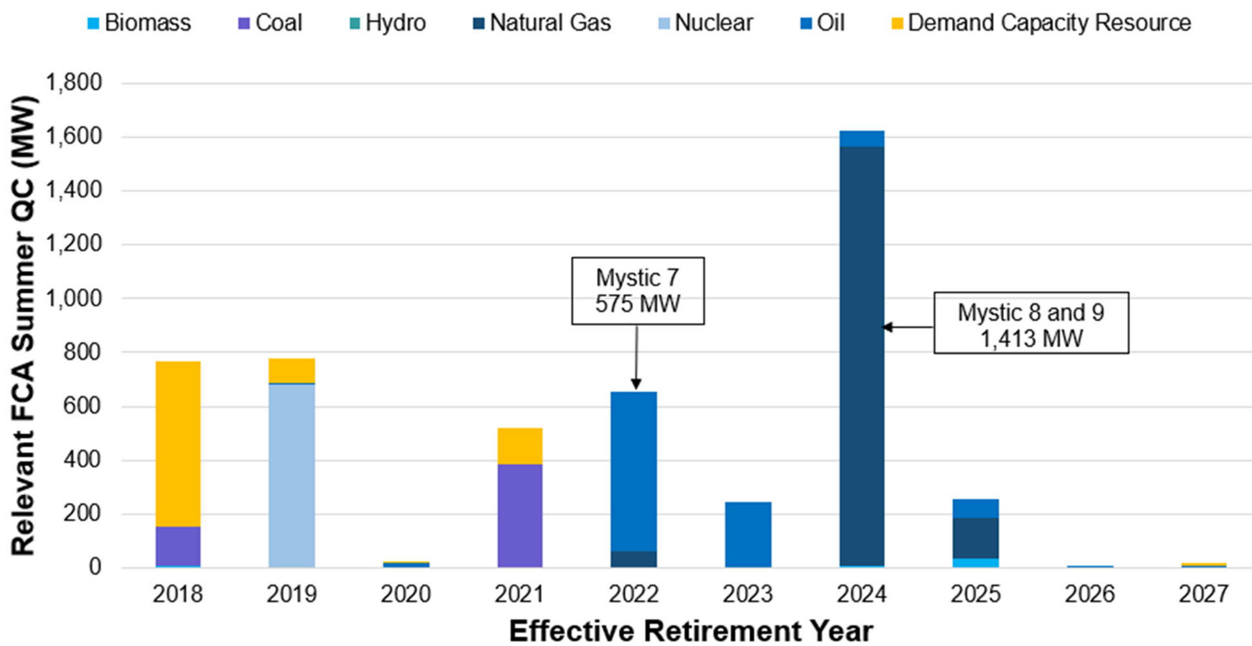
[78] *See*, e.g., ISO-NE, "2027-2028 CCP Resource 16750: Norden #2 Reliability Review Determination Letter for the FCA 18 Retirement De-List Bid," August 18, 2023, available at https://www.iso-ne.com/static-assets/documents/2023/08/norden-2_2027-28.pdf; ISO-NE, "Planning Procedure No. 10, Planning Procedure to Support the Forward Capacity Market," Section 7.0, June 2, 2023, available at https://www.iso-ne.com/static-assets/documents/2020/02/pp-10.pdf.

[79] ISO-NE, "Planning Procedure No. 10, Planning Procedure to Support the Forward Capacity Market (PP 10)," Section 7.5, June 2, 2023, pp. 32-33, available at https://www.iso-ne.com/static-assets/documents/2020/02/pp-10.pdf.

[80] Resources could also retire if they do not clear in the FCA (e.g., through a price de-list) and then subsequently seek retirement through a permanent de-list or retirement bid or a non-price retirement request. In this case, retirement could occur less than 3.5 years prior to the relevant capacity commitment period.

[81] Throughout this paragraph, MW quantities are in summer qualified capacity unless otherwise specified.

Figure 7. Retiring Resources by Resource Category and Retirement Year, Summer Qualified



Note: All resources are generators except for Demand Capacity Resources which are colored yellow. Imports are excluded.
Sources:
[A] ISO-NE, 2016-2023 CELT Reports, available at https://www.iso-ne.com/system-planning/system-plans-studies/celt/.
[B] ISO-NE, "ISO New England Status of Non-Price Retirement Requests, Retirement De-list Bids and Substitution Auction Demand Bids," last updated August 22, 2023, available at: https://www.iso-ne.com/static-assets/documents/2016/08/retirement_tracker_external.xlsx.

NYISO, MISO, and PJM all have shorter retirement notification requirements than the three to four years required in ISO-NE. Both MISO and NYISO, which operate prompt markets, have notification requirements of roughly one year. NYISO requires resources who wish to retire or mothball to give at least a 365-day notice, which starts on the date of the next quarterly Short-Term Assessment of Reliability ("STAR") after the resource submits its deactivation notice.[82] Similarly, MISO requires resources planning to suspend operations of all or any portion to submit their deactivation notices at least four full quarters prior to changing status. MISO also allows certain resources who suspend operations to be designated as System Support Resources ("SSRs") to maintain reliability.[83] In PJM, which has a forward capacity market, plant owners considering retirement or mothballing only need to notify PJM at least two quarters before the proposed deactivation date. However, resources considering retirement would either need to: (1) find replacement capacity if the resource cleared in a forward capacity auction and decides to retire before the commitment period; or, (2) seek an exemption from PJM's forward capacity auction must offer requirement.

Each RTO includes processes for evaluating whether retiring resources create reliability problems that it would seek to mitigate. For example, in PJM, after a resource submits a retirement notification, PJM completes a reliability analysis in the subsequent quarter to determine if the retirement causes reliability concerns that would require

---

82 New York Independent System Operator, Inc., Open Access Transmission Tariff, Attachment FF, available at https://nyisoviewer.etariff.biz/ViewerDocLibrary/MasterTariffs/9FullTariffNYISOOATT.pdf.

83 MISO, FERC Electric Tariff, Section 38.2.7, available at https://docs.misoenergy.org/legalcontent/TariffAsFiledVersion.pdf.

transmission upgrades. PJM may also request that resources continue operating until these upgrades are completed to maintain reliability with the plant operating under a reliability must run ("RMR") contract.[84]

The change to a prompt market would provide more flexibility to ISO-NE and stakeholders to modify retirement notification requirements to provide resource owners with more flexibility regarding retirement timing. At present, the retirement notification requirements primarily reflect one criterion: providing information about retirements prior to the primary capacity auction to ensure that the market has sufficient time to respond to retirements with new resources that can enter via the capacity market. Given this criterion, permanent de-list bids must be submitted approximately 3.5 years prior to the commitment period when the resource requests to deactivate.

However, the choice of retirement notification requirements involves many additional considerations, including: the optimization of asset value (given tradeoffs between fixed operating costs, revenue opportunities, option values given uncertain market futures, and the risk of major equipment failures); and the potential need to retain a resource seeking to retire to maintain local or system transmission security until transmission (or non-transmission) solutions can be implemented through out-of-market, RMR contracts. With a prompt market, this period could potentially be reduced, thus allowing the region to develop retirement notification periods unconstrained by a single consideration to account for the potential benefits of a shorter retirement notification period.

If the region pursued a prompt market, modifications to the retirement notification process (if any) would need to evaluate many important considerations and tradeoffs. We do not provide a full assessment of these tradeoffs but discuss several key issues in further detail below.

Shorter notification requirements provide suppliers with greater flexibility when making retirement decisions. By providing more flexibility regarding the timing of retirements, suppliers can make these decisions closer to the commitment period relying on better market information available to inform revenue and cost forecasts, which would increase asset value. The prompt market also improves these decisions by not forcing older units into forward commitments for capacity three years prior to the commitment period. Because older units face a greater risk of experiencing major equipment failures that may prompt a rational decision to retire the unit, a prompt market can allow these units to make more informed retirement decisions without taking on a capacity supply obligation.

While shorter notification requirements provide resource owners with greater flexibility, there are tradeoffs. First, if retirements occur with less notice and outside the normal auction qualification process, a question is whether there is sufficient information about market and system conditions to allow participants to respond efficiently to resource retirements (and system conditions that would affect market outcomes more generally). As it does currently, ISO-NE could continue to provide information to the market that would affect retirement and developer decisions, such as information releases related to each commitment period.[85] Further, ISO-NE could develop processes to disseminate additional information to facilitate efficient developer decisions related to entry of new resources to meet needs in a timely manner when they emerge. For example, NYISO provides information to the market regarding

[84] "Explaining Power Plant Retirements in PJM," PJM Learning Center, available at https://learn.pjm.com/three-priorities/planning-for-the-future/explaining-power-plant-retirements.aspx.

[85] ISO-NE, "CCP Information Releases and FCM De-list Bids," available at https://www.iso-ne.com/isoexpress/web/reports/auctions/-/tree/fcm-delist-bids.

projected future conditions, including their STAR five-year forward reliability assessments as well as other projections of future conditions.[86]

Second, a shorter retirement notification could also increase the likelihood that resources seeking to retire are retained to maintain local reliability until solutions can be developed to mitigate the reliability concern. Retention of resources seeking to retire has potential consequences, including the impact of entering into out-of-market RMR contracts that compensate the resource through a cost-of-service rather than through market revenues, and the potential for these contracts to cause distortions in the wholesale energy and capacity markets. Specifically, capacity market price suppression is typically the dominant wholesale market distortion that arises in connection with RMR contracts (energy and fuel markets can also be impacted, but retiring resource operation is often limited diminishing these other market impacts).

The risks that RMR contracts may distort market outcomes are present with either a forward or prompt market. For example, despite operating a forward market, PJM has utilized RMR contracts to retain resources beyond requested retirement dates.[87] Thus, the forward market does not mitigate the risk of RMR contracts. NYISO, like PJM and ISO-NE, has also had to rely occasionally on RMR contracts, but resource retirement and market responses in the NYISO region have largely been orderly as market participants had time to anticipate potential retirements. However, the likelihood and duration of RMR contracts, and potential distortionary market impacts, could increase with shorter retirement notification periods.

While shorter notification periods may increase the likelihood, duration and market impact of RMR contracts, several factors suggest that these increases may not be meaningful. *First*, in the vast majority of cases, retirement requests do not cause reliability risks. Over the past 15 commitment periods, of the 280 retirement requests evaluated in reliability review by ISO-NE, only six were rejected (Brayton Point 1-4 for 2014-15, and Salem Harbor 3 & 4 for 2017-18) solely for transmission system security risks. However, while these stations were large plants and could have sought RMR contracts, the stations were instead retired. Thus, in general, retirements have not led to the need to retain resources for transmission security.

Second, in recent years, the region has made substantial investments in transmission infrastructure that would mitigate the likelihood that retirement requests are rejected for reliability concerns.[88] These investments have proactively mitigated many transmission reliability issues in the region before they are triggered by resource

[86] NYISO issues quarterly short-term assessments of reliability ("STAR Reports") that evaluate system reliability over the next five years considering forecasts of peak power demand, planned upgrades to the transmission system, and changes to the generation mix. *See*, e.g., NY ISO, "Short-Term Assessment of Reliability: 2023 Quarter 2," July 14, 2023, available at https://www.nyiso.com/documents/20142/16004172/2023-Q2-STAR-Report-Final.pdf/5671e9f7-e996-653a-6a0e-9e12d2e41740. In addition to short-term reliability assessments, NYISO also conducts ten-year reliability planning analyses through their Comprehensive Reliability Plans. *See*, e.g., the latest draft, NYISO, "Draft 2023-2031 Comprehensive Reliability Plan," October 2, 2023, available at https://www.nyiso.com/documents/20142/40370875/09a_NYISO_2023-2032_CRP_Draft3_forOct2ESPWG-TPAS.pdf/dfd49d18-1398-cf6e-3dff-c65822910feb; NYISO, "2021-2030 Comprehensive Reliability Plan," December 2, 2021, available at https://www.nyiso.com/documents/20142/2248481/2021-2030-Comprehensive-Reliability-Plan.pdf.

[87] For example, PJM has an active RMR contract with Indian River 4 from June 2022 to December 2026. *See* Table 5-29 Part V reliability service summary for a history of PJM RMR contracts from 2005 to present: Monitoring Analytics, "2023 Quarterly State of the Market Report for PJM: January through September," November 9, 2023, Section 5 Capacity, p. 362, available at https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2023.shtml.

[88] ISO-NE and New England Power Pool, "Testimony of Alan McBride on Behalf of ISO New England Inc.," FERC, Docket ER24-339-000, November 2, 2023, pp. 26-29, available at https://www.iso-ne.com/static-assets/documents/100005/changes_to_delay_19th_fca_and_related_capacity_mtk_activities.pdf.

retirements that then require mitigation and potential retention of the resource.[89] Over the past two decades, over $12 billion in transmission system investments have been made through these planning efforts.[90] Past retentions were more likely when the system was less robust. Thus, the likelihood that new transmission security issues arise from new retirement requests has diminished over time.

Third, as noted above, RMR contracts risks arise in forward and prompt markets and market impacts (i.e., possible price suppression) could result regardless of the capacity market structure. The magnitude of the market impacts will largely be driven by differences in the timing of responses to potential retirement related reliability impacts that will depend on specific, complex circumstances. While in theory a forward market could provide for better alignment of response to resource retirements, in practice forward market resource retirement decisions can be more complicated (i.e., arising from non-price retirement requests as opposed to submission of permanent or retirement de-list bids). Resource retirement announcements may follow a multi-year period of revealed weak performance and/or challenges to meeting regulatory requirements may be observable by market participants and often highlighted by owner's themselves and system operators where appropriate.

b. Prompt Market Aligns with NYISO Capacity Market

The ISO-NE capacity market allows resources outside the ISO-NE control area to supply capacity (imports) and allows resources within the control area to supply their capacity to other markets (exports). Imports and exports can improve market efficiency by allowing resources to flow to where they are most needed (as reflected by price).

The primary market competing with New England for capacity is the NYISO ICAP market. This competition includes resources in each system, as well as resources from other systems, primarily Hydro-Quebec.[91] At present, the timing of delivery in these capacity markets is not aligned because ISO-NE operates a forward market while NYISO operates a prompt market. Thus, under the current forward market, resources in New England, New York and Quebec must decide three years in advance between committing resources through ISO-NE's market or holding resources to supply at a later period into NYISO's market. This arrangement may benefit ISO-NE if resources value the price security of locking in prices three years in advance while the arrangement may benefit NYISO if resources prefer the flexibility of supplying into either market (i.e., through the NYISO spot auctions or the ISO-NE ARAs).

Under a prompt market in ISO-NE, the timing of delivery of capacity in the two markets would be aligned. This alignment would reduce uncertainty about price signals between the two capacity markets and thus result in more efficient allocation of capacity resources between the two regions, with capacity flowing into the region where it is most valuable.

---

[89] ISO-NE and New England Power Pool, "Testimony of Alan McBride on Behalf of ISO New England Inc.," FERC, Docket ER24-339-000, November 2, 2023, p. 27, available at https://www.iso-ne.com/static-assets/documents/100005/changes_to_delay_19th_fca_and_related_capacity_mtk_activities.pdf.

[90] ISO-NE and New England Power Pool, "Testimony of Alan McBride on Behalf of ISO New England Inc.," FERC, Docket ER24-339-000, November 2, 2023, p. 28, available at https://www.iso-ne.com/static-assets/documents/100005/changes_to_delay_19th_fca_and_related_capacity_mtk_activities.pdf.

[91] ISO-NE and NYISO each have multiple neighboring system from which resources can supply, but the only system able to supply both ISO-NE and NYISO directly is Hydro-Quebec.

c. Prompt Market Facilitates Improved Resource Accreditation for Winter Fuel-Dependent Resources

New England has well documented winter fuel security concerns primarily tied to pipeline constraints for the supply of natural gas.[92] Given these pipeline constraints, gas-fired generators looking to secure a firm supply of fuel for the coldest days of the winter period need to make arrangements prior to the winter. The nature of these arrangements depends on the technology at the gas-fired plant. For example, gas-only generators can enter into forward contracts with natural gas suppliers for gas supplies (including firm transportation service or contracts for stored natural gas with liquid natural gas ("LNG") terminals).

Historically, decisions to make these arrangements reflect market economics, given the returns earned from producing electricity when fuel markets are tight, and ISO-NE programs to incentivize additional fuel storage. Because of uncertainties in electricity and fuel markets, these arrangements are typically made in the summer or fall prior to the upcoming winter period. Moreover, these gas-only generators have not needed to establish fuel availability to receive full capacity accreditation.

Under ISO-NE's revised RCA process, accreditation factors for natural gas-fired only capacity resources will reflect demonstrated fuel supply arrangements. Thus, natural gas-fired only resources (~9,100 MW[93] of winter qualified capacity in ISO-NE) that want capacity accreditation reflecting firm fuel supplies for the FCA may need to commit to enter into such fuel arrangements prior to submitting their FCA offers. Uncertainty in market conditions for a commitment period three years in the future will make it costly for a resource owner to commit to firm fuel supply that achieves a higher accreditation factor. The higher costs associated with entering into these arrangements, if included in the resource's offer, could also increase the risk that the resource's offer (reflecting the higher costs) does not clear and the fuel arrangement is not completed. A prompt market reduces the time lag between firming fuel supply and need by almost three years and thus better aligns gas-only generator fuel supply markets with the capacity markets, especially in winter. Prompt market capacity offers will reflect expected fuel market conditions close to the time of resource operation, reducing uncertainty, increasing the likelihood that accredited capacity associated with such arrangements is cleared, and lowering consumer costs relative to an FCA.

This uncertainty is illustrated by **Figure 8**. **Figure 8** shows Dutch TTF natural gas futures price curves (a proxy for the cost to secure LNG supply for delivery in New England)[94] as of each September from 2021 to 2023 for delivery in winter months December to January over two upcoming winter periods (2023-2024 and 2024-2025). The figure shows that TTF gas futures prices varied from ~$7/MMBTU to just over $50/MMBTU — reflecting expectations of winter delivery prices rising and falling significantly as of the first September trading date in 2021, 2022 and 2023. Under a forward market with a firm fuel contract requirement, gas-only generators would at a minimum need to purchase an option to receive gas in a winter three plus years in the future. The cost of arranging for future fuel supply will reflect LNG and natural gas futures prices at the time when the fuel supply obligations are agreed or reflect formulas based on fuel market indices at a future date (e.g., the delivery period). In addition, the liquidity of

---

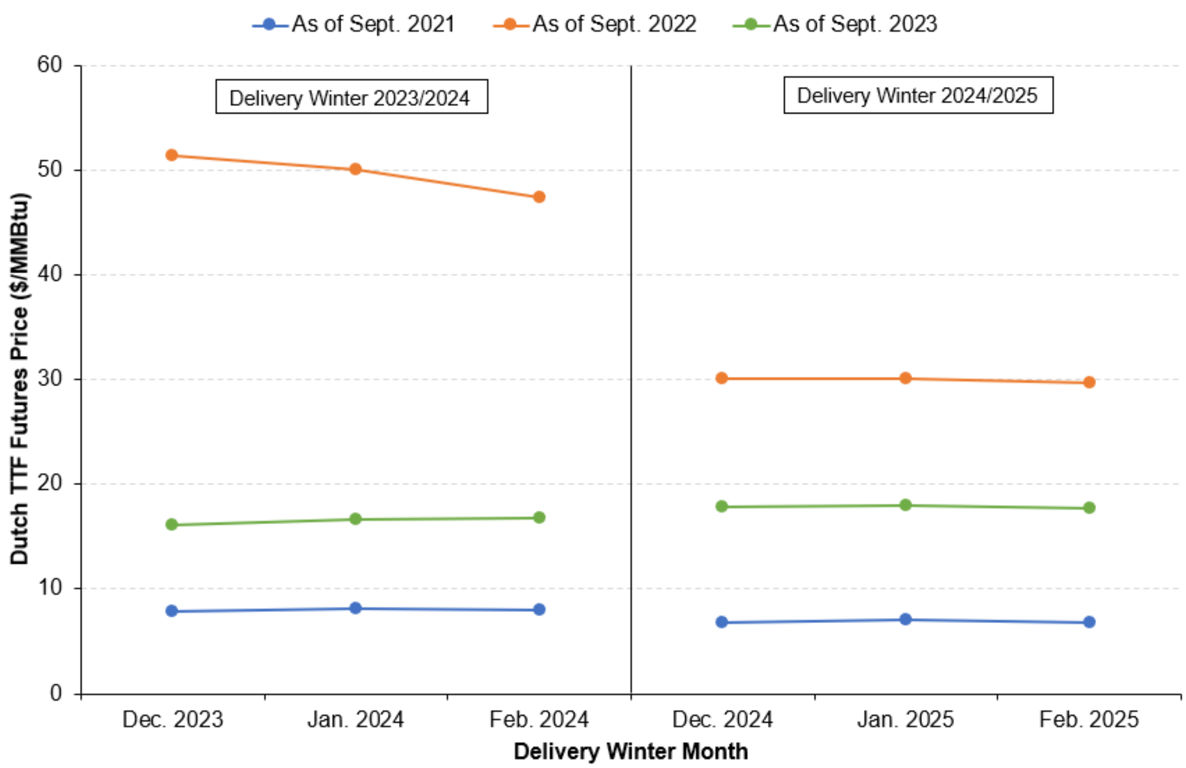
[92] ISO-NE, "Operational Fuel-Security Analysis," January 17, 2018, available at https://www.iso-ne.com/committees/key-projects/implemented/operational-fuel-security-analysis.

[93] Based on generators that bid into FCA 17. ISO-NE, 2023 CELT Report, sheet "2.1 Generator List" and sheet "4.3 Qualified, Cleared Capacity." Generators are assumed to burn only natural gas if their prime fuel is listed as "NG" and they have no secondary fuel listed.

[94] "In recent years, Dutch TTF prices have represented a good proxy for LNG prices in the Atlantic Basin." ISO-NE and New England Power Pool Participants Committee, Revisions to ISO New England Inc. Transmission, Markets and Services Tariff to Update the Inventoried Energy Program, Docket No. ER23-1588-000, Document Accession #: 20230407-5030, April 7, 2023, Attachment D, Testimony of Todd Schatzki on Behalf of ISO New England Inc., pp. 5-6.

natural gas futures contracts three plus years in advance of the FCA is limited, which would increase hedging costs and forward market capacity offer prices if some type of hedge were included in these offers.[95] Entering into such contracts three-years prior to the delivery on the contracts exposes the generator to additional costs (e.g., posting credit when the contract is entered into) and substantial risk because the value of its forward market contract at delivery may be markedly different than the value at the time the purchase is agreed.[96]

Figure 8. Monthly Dutch TTF Futures, As of First September Trading Date 2021 to 2023 for Delivery Winters 2023-2024 and 2024-2025



Note: Prices are converted from $/MWh to $/MMBtu using the following conversion factor: 1 MWh = 3.4121 MMBTU (ICIS, "European Spot Gas Markets Methodology," 2022, available at https://cjp-rbi-icis-compliance.s3.eu-west-1.amazonaws.com/wp-content/uploads/2022/08/02133719/European-Spot-Gas-Markets-Methodology-26-July-2022.pdf.)
Source: Decembers 2023-2024 Delivery Dutch TTF Futures Prices (Tickers "TZTZ3 Comdty" and "TZTZ4 Comdty"), Januarys 2024-2025 Delivery Dutch TTF Futures Prices (Tickers "TZTF4 Comdty" and "TZTF5 Comdty"), and Februarys 2024-2025 Delivery Dutch TTF Futures Prices (Tickers "TZTG4 Comdty" and "TZTG5 Comdty"), Bloomberg L.P.

[95] *See* Dutch TTF natural gas futures contract volumes comparing upcoming winter months to the same months 3 plus years into the future: ICE, "Dutch TTF Natural Gas Futures," available at https://www.ice.com/products/27996665/Dutch-TTF-Gas-Futures/data?marketId=5419234.

[96] The value of these contracts reflects many factors including the spread between global LNG prices and regional pipeline gas prices and the likelihood of tightness in regional pipeline supplies that cause spikes in these regional prices.

C. Risk and Financial Consequences of Uncertain Prices

The prior section discussed how differences in uncertainty in demand and supply under forward and prompt auctions affects the market outcomes and opportunity costs to market participants. In this section, we focus on how differences in these uncertainties affect differences in the financial risks faced by capacity suppliers.

1. Risk Mitigation from Forward Positions

A forward market provides a forward price signal that allows resources to hedge some financial risks. With a forward market, prices are locked in three plus years prior to the commitment period, which can mitigate financial risk from uncertain revenue to capacity resources and uncertain prices to customers. The nature of this hedge and thus the value it provides to market participants varies depending on the market participant's circumstances. By contrast, because a prompt market clears the market shortly before the commitment period, it acts like a commodity "spot" market and, in contrast to the forward market, exposes market participants to more financial risk.

In theory, a forward market can benefit new resources by providing some revenue certainty before the decision to build the plant is made. If this revenue certainty lowers the project's financial risk and lowers the cost of financing the plant, the resource's net cost of new entry will be lower. Previously, the FCM had allowed new resources to lock-in FCM prices at the clearing price in the new resource's first FCA for seven years, although this provision was eliminated starting with FCA 15 in 2021.[97] Thus, under the current FCM, new resources have some price certainty for only the first year of the plant's operation (through clearing at or above its minimum offer price) but in none of the subsequent years, when it earns the market price. By contrast, a plant's economic lifetime (amortization period) is typically around 20 years. As a result, the price certainty offered by the forward market is limited, although some further benefit may be gained if capacity market prices are serially correlated over time. Therefore, the benefits of a forward market relative to a prompt for certainty in capacity market payments three years in advance may be limited.

Experience with forward and prompt markets indicates that both can support the development of new resources and the forward commitment for new resources is not necessary to incentivize new investment. For example, between March 2018 and March 2023, 2.3 GW (in winter capacity) of new merchant entry has come into service under the NYISO prompt market.[98] By comparison, over the same period, 2.9 GW (in winter capacity) of new merchant entry came into service in ISO-NE.[99] In both regions, developers can rely on various bilateral financial arrangements (e.g., revenue puts) to hedge revenue risks and provide greater revenue certainty.

---

[97] While this provision increased incentives for new entry, it did so by preferentially treating new resources relative to existing resources, which would be expected to result in inefficient use of capital (i.e., economically premature resource retirement). *See* FERC Docket EL20-54.

[98] This total includes new storage and fossil resources. NYISO, 2023 Gold Book, April 27, 2023, p. 74, available at https://www.nyiso.com/documents/20142/2226333/2023-Gold-Book-Public.pdf/c079fc6b-514f-b28d-60e2-256546600214; NYISO, 2022 Gold Book, April 2022, p. 72, available at https://www.nyiso.com/documents/20142/2226333/2022-Gold-Book-Final-Public.pdf/cd2fb218-fd1e-8428-7f19-df3e0cf4df3e; NYISO, 2021 Gold Book, April 2021, p. 72, available at https://www.nyiso.com/documents/20142/2226333/2021-Gold-Book-Final-Public.pdf/b08606d7-db88-c04b-b260-ab35c300ed64; NYISO, 2020 Gold Book, April 2020, p. 63, available at https://www.nyiso.com/documents/20142/2226333/2020-Gold-Book-Final-Public.pdf/9ff426ab-e325-28bc-97cf-106d792593a1; NYISO, 2019 Gold Book, April 2019, p. 43, available at https://www.nyiso.com/documents/20142/2226333/2019-Gold-Book-Final-Public.pdf/a3e8d99f-7164-2b24-e81d-b2c245f67904?t=1556215322968.

[99] This total includes new storage, fuel cell and fossil resources. 2023 CELT Report, sheet "2.1 Generator List."

Under the forward market, many new resources may not make their entry into the market conditional on their clearing in the FCA. If development timelines are greater than three years, then resources must begin development prior to knowing if they will be awarded a CSO for the commitment period three years ahead. Even for gas-fired resources, uncertainties in the development timeline may cause developers to start the development process prior to the FCA to ensure that they are online by the commitment period. As is discussed above, many recent resources in New England made significant development investments more than three years prior to being in-service.

The forward market may also hedge financial risks for existing capacity resources and for competitive retail supplies. Some existing resources may benefit from locking-in capacity market revenues in advance, as it can allow them to make on-going investment and maintenance decisions with better information about impacts on plant finances. More importantly, under the FCM, competitive retail suppliers know capacity market prices when submitting offers to supply default retail service. This reduces their financial risk and thus lowers the rates charged to customers for default retail service. Under a prompt market, these competitive retail suppliers may not know capacity market prices prior to submitting offers to supply default service, which may raise risks and rates for default service.

Financial markets and transactions among market participants offer various means to mitigate these financial risks. Plant developers in all regions with centralized capacity markets rely on various financial contracts to mitigate revenue risks to support project financing, including revenue puts and heat rate call options.[100] Competitive retail suppliers can manage capacity market price risk through bilateral agreements with capacity suppliers and other market participants that want to hedge their price risk. In addition, if there is substantial demand for instruments to hedge capacity market price risks, futures/forward markets could emerge to replace the ISO-NE FCA forward prices. For example, futures market products exist for NYISO's prompt capacity market products allowing market buyers and sellers to lock-in capacity prices in advance of the prompt auctions.[101] If the region pursues a prompt market, there may be transition period in which market participants adjust to the changes in financial risk. However, these changes in financial risks appear manageable, particularly given options for bilateral transactions and potential financial instruments.

2. *Financial Risk from Forecasting Going Forward Costs*

In principle, offers into the capacity market reflect resources' estimate of their net going forward costs. These estimates reflect forecasts in operating costs and particularly net energy and ancillary service revenues and account for many uncertain factors, including temporary plant outages (e.g., equipment failures), current energy market conditions (e.g., wholesale energy prices), external market factors affecting resource participation (e.g., offers by distributed resources, including energy efficiency, that reflect actual projects not speculative forecasts), current capacity market conditions (e.g., opportunity costs from participation in other markets), and fuel costs. Under a forward market, these offers are made three years in advance, while offers under a prompt market are made shortly before the commitment period when offers can better reflect current asset and market conditions in their FCA offers.

---

[100] Budofsky, Daniel, Michael Reese, and Olivia Matsushita, "Financial Hedges for United States Gas-Fired Power Generation Facilities," Pillsbury, June 5, 2017, available at: https://www.pillsburylaw.com/en/news-and-insights/financial-hedges-for-us-gas-fired-power-generation-facilities.html.

[101] *See*, e.g.,, ICE, Futures Daily Market Report for Financial Power 03-Nov-2023, NYC-NYISO In-City Capacity Calendar-Month Future with open interests through 2025, available at https://www.cmegroup.com/markets/energy/electricity/nyiso-nyc-in-city-capacity-calendar-month-swap-futures.html#venue=globex.

Given the greater uncertainties faced in a forward market, resources may include a premium to account for this risk, which could affect market-clearing prices.

D. Competition, Price Formation and Price Volatility

1. Competition and Coordination of New Entry

When originally designed, an important rationale for the FCM's design was to improve the efficiency of capital investments in new plants through a centralized, forward procurement that created competition among generators to supply new capacity and produced appropriate levels of investment in new plants. By clearing new resources in a centralized auction, the FCM could secure the lowest-cost new generation and avoid the risk that too much or too little new capacity would be developed. One hope was to avoid the boom-and-bust cycles of plant development, as the New England region (and other restructured electricity markets) had recently experienced a period of substantial investment following the initial restructuring of electricity markets and appeared to be leading into a period of low investment given the excess supply.

While the FCM has been successful in promoting competition among capacity resources (including new capacity) and procured appropriate quantities of resources (given their costs), the fact that procurements are forward rather than prompt has not been critical to achieving these outcomes. There is little evidence that forward procurement has been important in weeding out low-cost suppliers from high-cost suppliers, particularly since the first year FCA offer price reflects a small portion of total plant revenue streams. Entry and exit of resources have been relatively orderly. Many factors have contributed to the limited effect of forward procurement on these outcomes, including slow growth in the need for new plants given flattening of capacity requirements and the growth in state policies as a key driver of much of the new capacity entering the region. Given these changes, we would not expect a switch to a prompt market to have much effect on competition among new entrants to the capacity market and the coordination of new capital investment to avoid over- or under-procurement.

While a prompt market reduces the ability of new resources to make entry conditional on FCM price levels and reduces the "coordination" of entry in the market (i.e., increases the risk of excess simultaneous entry into the market), as discussed above.

In fact, a prompt market may improve competition by providing a neutral platform on which alternative technologies can compete to supply capacity. Under the FCM, the impact of forward procurement on new resource economics can vary with the project's expected developing timing. In theory, a forward market can benefit new resources that can make entry contingent on clearing the FCA (although, as noted above, this option may be less beneficial to entry decisions under current market conditions than it was in the past). However, this timing may be detrimental or have limited benefit to other market participants. Under the FCA, resources with short development timelines are likely disadvantaged because capacity market participation in the first year or two of operations may be limited to the ARAs, which historically have cleared a fraction of all offered supplies at prices below the corresponding FCAs. In contrast, technologies with long development timelines may see little advantage in the option to make entry contingent on clearing if investment commitments must be made prior to the FCA in order to be online for the initial commitment period.

A switch to a prompt market should maintain effective competition so long as the market has access to good information about market and system conditions and sufficient time to respond competitively to these changes in market conditions. The current FCM creates some information about new entry and retirement that would be available to the market at a later time under the prompt market. For example, retirement notifications may occur with less notice than under the current market and the financial commitment (through awarding of CSOs) to new resources would only occur shortly before the commitment period.

However, the market has other means to obtain information about the timing of new entry that can inform when new resources are entering the market: new resources often clear in state-sponsored utility procurements for new resources (e.g., renewable resources), and interconnection queues, and applications for environmental permits provide information about new resource construction.[102]

In addition, ISO-NE can provide the market with information about current and future market conditions. Under the FCM, the market receives a rich set of information future market conditions, with many of these metrics being important parameters in the FCA. Currently, 3-4 years in advance of the commitment period, market participants have information used in the FCA (e.g., Net ICR and underlying calculations, information about retirement de-list bids and qualified capacity) and information from other ISO-NE planning processes and other third parties. This information supports the efficiency of long-term investment decisions regardless of whether the capacity auction is run on a forward or prompt basis. To the extent that certain information supporting the FCA is particularly valuable to undertaking such decisions, ISO-NE can develop processes to continue to provide such information on a forward basis outside of the capacity market if the region moves to a prompt market structure.

Finally, capacity resources incentivized by New England state clean energy market policies and programs would likely benefit under a prompt market. Resource developers would no longer face the prospect of clearing in FCAs, but then encountering delays that could lead to cost increases. And, as noted above, capacity resources with shorter development timelines can participate in auctions without delay. At the same time, as the next section explains, over the long-run capacity market prices should be expected to reflect similar market supply and demand fundamentals such that capacity market revenues should be comparable under either a forward or prompt market.

2. Price Formation in Forward and Prompt Markets

Forward and prompt markets both create price signals that incentivize the entry of new resources and the exit (retirement) of existing resources. Assuming demand for and supply of capacity is the same, and assuming a competitive market, both a forward and prompt market should result in (more or less) the same prices, quantities, and entry and exit decisions in the long-run. That is, within a competitive market with the same underlying supply and demand fundamentals, the price signals from a prompt and forward market should lead to efficient market outcomes that reflect these market fundamentals.

The prior sections identified many ways in which the use of a forward or prompt market could cause differences in supply and demand, particularly due to differences in uncertainty and risk. However, setting these differences aside, the question has been raised if differences in the way going forward costs and thus offers are determined in the forward and prompt market could cause persistent differences in market-clearing clearing prices.

One issue is if differences in net going forward costs for new resources between a forward and prompt auction may affect long-run capacity prices. With a forward auction, developers that have not sunk capital into the project have the option to include the one-time capital costs of building the plant when calculating offer prices because these costs can still be avoided. However, with a prompt auction, these costs are sunk, not avoidable and thus cannot be

[102] *See also*, **Section III.C.1**. These market data can inform market participants' expectations of future supply/demand balance and likely support the evolution of New England capacity futures/forward markets.

included in competitive offers. The question is whether this difference in offer prices from new resources between a forward and prompt auction would lead to differences in long-run capacity market prices.

A second potential difference in going forward costs between a forward and prompt auction could arise for existing resources that have differences in avoidable costs given their ability to reduce or "avoid" costs over different time frames. In some circumstances, costs that are avoidable three plus years prior to the commitment period may not be avoidable shortly before the commitment period. For example, major maintenance activities may need to be scheduled one year or more prior to the date of the maintenance. Scheduled activities may not be cancelled without incurring penalties, and thus may not be avoidable. Thus, if offer prices from existing resources differed because of differences in a resource owners' ability to avoid costs, the question is whether this would lead to differences in long-run capacity market prices.

For several reasons that we outline below, these differences will lead to meaningful differences in long-run capacity market prices.

First, as described above, the forward or prompt nature of the auction does not change the underlying demand or supply fundamentals. Thus, in the long-run, in a competitive market, one would expect (more or less) the entry and exit decisions to reflect these fundamentals and thus result in the same quantity and price outcomes. These entry decisions reflect forward-looking expectations of capacity market (and energy market) prices over the plant's economic lifetime, such that entry occurs when expected revenues cover expected costs. The prompt market may change the mechanics of the capacity market auction, but it does not change the revenue expectations required to incentivize new entry. The same logic and considerations hold for retirement decisions.[103] Given this logic, if prices were higher, this would incentivize new entry that would push prices down until the market reached the equilibrium price. Similarly, if prices were lower, this would incentivize retirements or reductions in new entry that would push prices up. These decisions do not reflect the clearing prices in particular auctions but expected discounted net income across new plants' economic lifetimes and existing plants' planning horizons given forecasts of future market revenues.

Second, forward auctions in both ISO-NE and PJM have cleared new capacity resources at relatively low prices, far lower than estimated Net CONE values. This outcome suggests that the perception that new resources offer supply at "high" prices is inconsistent with actual bidding behavior of many market participants. For example, in the PJM region numerous new capacity resources have cleared in capacity auctions at prices well below estimated Net CONE values.[104]

Third, capacity markets often clear at the value of capacity, as reflected in the administrative demand curve, rather than the cost of supply as reflected in supply offer prices. This is true when the marginal offer clearing the market is from both new and existing offers. **Figure 9** illustrates outcomes when the market clears at the demand curve. When all supply offer prices fall below their corresponding demand curve prices, the price is set at the price on the demand curve that corresponds with the quantity of offered supply (i.e., the vertical intercept from the quantity offered to the demand curve). When market outcomes are set at the demand curve, the market clearing price does not depend on the offer prices, but on the value the capacity provides as determined by the demand curve. Thus, under

[103] That is, an existing resource considering retirement will consider future costs and revenue streams, where revenue streams will reflect forward-looking expectations of capacity prices (among other things).

[104] PJM's capacity auctions cleared more than 27,000 MW of new gas fired capacity in its 2015-2021 forward capacity auctions with market prices approximately 60% below the net cost of new entry. *See*, The Brattle Group and Sargent and Lundy, PJM Cost of New Entry Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date, April 19, 2018, pp. 5-6.

these circumstances, any differences in offers prices between a forward and prompt auction would not affect market-clearing prices.

Figure 9. Illustration of Market Clearing at Demand Curve

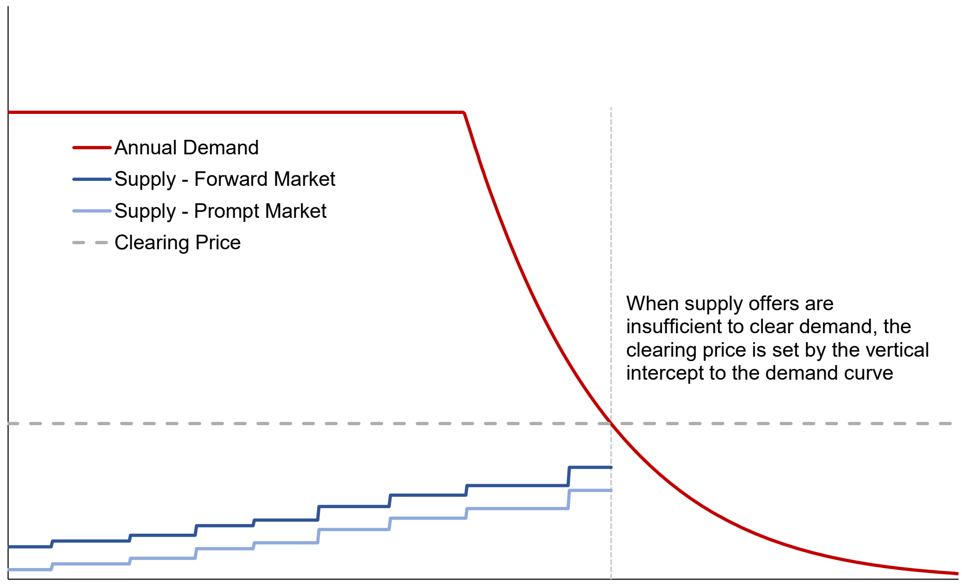
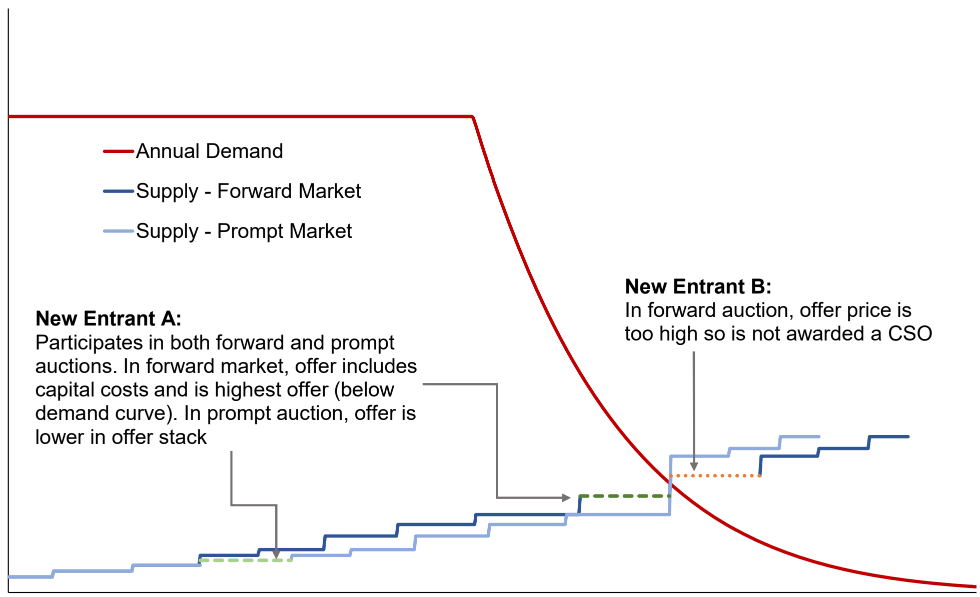


Figure 10 illustrates circumstances that can arise when the market clears at new entry. In the illustration, under the forward market, the offer from the new entry is highest offer in the bid stack, so the market clears at the demand curve, not at the new entrant offer price. The next-highest offer is above the demand curve, and thus does not clear. Under the prompt auction, the new capacity resource is developed prior to the auction, and thus its offer price is further down in the offer stack and shifts (to the right) all of the other offers in the offer stack. Under the assumptions in the example, the market still clears at the vertical intercept to the demand curve, which results in the same price as under the forward market.

Finally, given many resources' development timelines, some new capacity may be poorly positioned to take advantage of the option to include upfront capital costs in their offers. Resources with longer development timelines (including the gas-fired resources for which the FCM was originally designed) may need to commit to development, financing, and construction before the FCA. Having already decided to proceed with the project, owners may not want to risk submitting high offer prices that do not clear in the auction, causing them to lose capacity market revenues.

Together, these factors lead us to conclude that meaningful differences in long-run price formation between forward and prompt markets are unlikely to emerge.

Figure 10. Illustration of Market Clearing at Demand Curve with New Entry



3. Market Mitigation

Capacity markets include market mitigation procedures aimed at ensuring that bidders cannot exercise market power, including requirements that market participants submit offers for review and potential mitigation if their offer prices exceed certain thresholds ("dynamic de-list bid thresholds"); and procedures for determining mitigated offer prices if requested offer prices are deemed not to reflect going forward avoidable costs. Market mitigation is a common practice in capacity markets with many different designs, including prompt markets such as the NYISO's ICAP market, and is generally effective at deterring the exercise of market power in these markets.

Market efficiency can depend on the implementation of market mitigation, with excessive or lax mitigation affecting the competitiveness of market outcomes. Given the need to maintain this balance, these procedures should and do vary across markets given their region-specific considerations. In addition, these procedures have changed over time, in part reflecting experience gained from actual performance of the market. For example, ISO-NE recently modified the method for setting dynamic de-list bid thresholds so they are updated annually based on FCA prices.[105]

Given the balance required for effective market mitigation, with any change in market structure, some changes in market mitigation may be necessary. Thus, if the region pursues a prompt market, an important part of the process will be reviewing existing market mitigation procedures to determine whether they require modification. The prior section concluded that differences in long-run price formation between forward and prompt markets are unlikely to emerge in competitive markets. However, this conclusion depends on appropriate market mitigation for a prompt market and potential adjustments to existing procedures to the extent that unexpected impacts to competition and

[105] ISO-NE, "Market Rule 1 Change to Implement New Methodology for Calculating Forward Capacity Market Dynamic De-List Bid Threshold," December 31, 2020, available at https://www.iso-ne.com/static-assets/documents/2020/12/ddbt_filing.pdf.

price discovery emerge. Thus, maintaining this balance is important. However, while the details of review and mitigation procedures may require modification, the overall structure of capacity market mitigation (e.g., review and potential mitigation of offers meeting certain criteria) would not need to significantly change with a prompt market as compared to the current FCA.

Thus, if the region were to shift from a forward to prompt auction, it may be important to revisit market mitigation rules and procedures to ensure they are appropriate for the specific circumstances of the revised auction format. One set of issues will be the determination of avoidable costs. For example, as noted above, the short time horizon between the prompt auction and of the commitment period could have implications for determining which costs are avoidable and which costs are not given the many considerations relevant to such determinations.[106] A second set of issues could involve dynamic de-list bid thresholds, particularly if rules for determining avoidable costs constrain the portion of fixed costs that can be incorporated into offers. If the region were to pursue a prompt market, it might consider potential changes to this design and its requirements at the outset of the effort or at a later date to the extent that actual price dynamics under the prompt market differ meaningfully from the current FCAs. We do not explore either of these issues further but include assessment of market mitigation as an issue to be addressed if the prompt market is pursued.

A second set of issues could arise if opportunities to exercise market power in a prompt market differ from the current FCM due to the absence of some offers from new entry. Given this possibility, development of a prompt market should assess whether this possibility poses a meaningful incremental risk from the current FCM and, if so, how to develop mitigation procedures for these circumstances.[107]

4. Price volatility in forward and prompt markets

In principle, prompt and forward auction capacity price volatility could differ.[108] In commodity markets, spot market prices can quickly rise or fall in response short-term (transient) supply and demand shocks. Large spot market price increases or decreases lead to high price volatility. In contrast, forward market prices (i.e., prices for future dates) rise and fall based on longer-term changes in expected supply and demand fundamentals. Forward market buyers and sellers can evaluate the longer-term impact of spot market supply and demand shocks to determine whether they reflect changes in fundamentals or transient effects. As a result, forward market price movements and volatility are generally lower.

However, capacity markets differ in important respects from typical commodity markets. First, forward and prompt capacity markets differ in the timing of the primary auction for CSOs. They are not sequential auctions for the same delivery period with two-part settlement. Second, and more importantly, transient shocks to demand and supply are

[106] Important considerations include, for example, the extent to which expenditures can be foregone if the plant does not accept a CSO, but also medium-run considerations (e.g., allowances for inclusion of depreciated plant investment in years after the investment is made).

[107] In the NYISO ICAP, all offers in mitigated capacity zones (i.e., currently zones other than Rest of State and Long Island) are subject to market power mitigation given concerns that limited market size creates opportunities to exercise market power (NYISO, Market Administration and Control Services Area Tariff (MST), 23 MST Attachment H ISO Market Power Mitigation Measures, 23.4.5 MST Attachment Installed Capacity Market Mitigation Measures, Section 23.4.5.2, available at https://nyisoviewer.etariff.biz/ViewerDocLibrary/MasterTariffs/9FullTariffNYISOMST.pdf).

[108] Note that in this section we consider capacity price volatility (measured as the standard deviation of the price changes). While prompt and forward capacity price levels will also vary over the long-term, the expected prices under either market design must be high enough to incentivize entry. A market design anchored with demand curves should ensure that in expectation it can support new resource development when it is needed to satisfy the region's resource adequacy objectives.

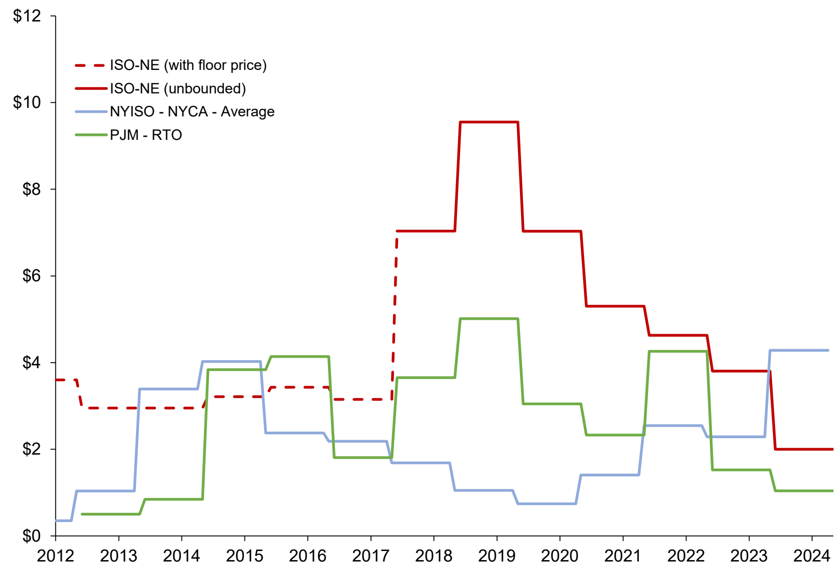
more limited within capacity markets in comparison to other commodity markets. For example, consider first capacity market supply. Capacity market supply resources are almost all existing at the time auctions are run, regardless of whether the auction is prompt or forward, and generally *must* offer their full capability, which generally changes little over time, except for events like unexpected or long-term outages. Some volatility could arise from entry and exit to the extent that prompt markets provide less time for the market to respond with new capacity (given retirement notification requirements). Similarly, while forecast capacity demand also varies during the time between when a forward auction is run and the commitment period, the capacity demand forecasting process is stable and year-to-year changes in Net ICR are likely to be similar with forward market three-year-ahead forecasts and prompt market one-year-ahead forecasts. Thus, since there are few significant supply and demand shocks that would affect prompt auctions rather than forward auctions, prompt market price volatility would not necessarily be expected to be substantially greater than forward market price volatility.[109]

To evaluate actual price volatility differences, we compare the results of PJM's and ISO-NE's forward capacity auctions against the results of NYISO's prompt capacity auctions. We compare the market clearing prices and price volatilities for the following capacity market auctions: 1) four zonal, prompt-seasonal NYISO auctions, each held just over six months prior to their delivery periods of either the coming summer or winter; 2) four zonal, forward-annual PJM auctions, held three years prior to their delivery years; and 3) ISO-NE's rest-of-pool annual forward auctions, a little over three years prior to their delivery years. Of course, prices in these markets differ due to many factors, including changes in administrative demand curves, regulatory changes that impact CSO obligation costs, and particular circumstances specific to each market. Our comparisons do not account for all of these differences but are intended to assess whether forward and prompt market structures are associated with obvious and large differences in volatility.

For delivery years 2012-2024, **Figure 11** shows the auction clearing prices of three unconstrained geographic regions: ISO-NE's rest-of-pool, NYISO's NYCA region, and PJM's RTO region. All three markets are comparable in their variations, independent of each market's status as either a forward-annual or prompt-seasonal market. **Figure 12** shows a similar result for constrained markets.

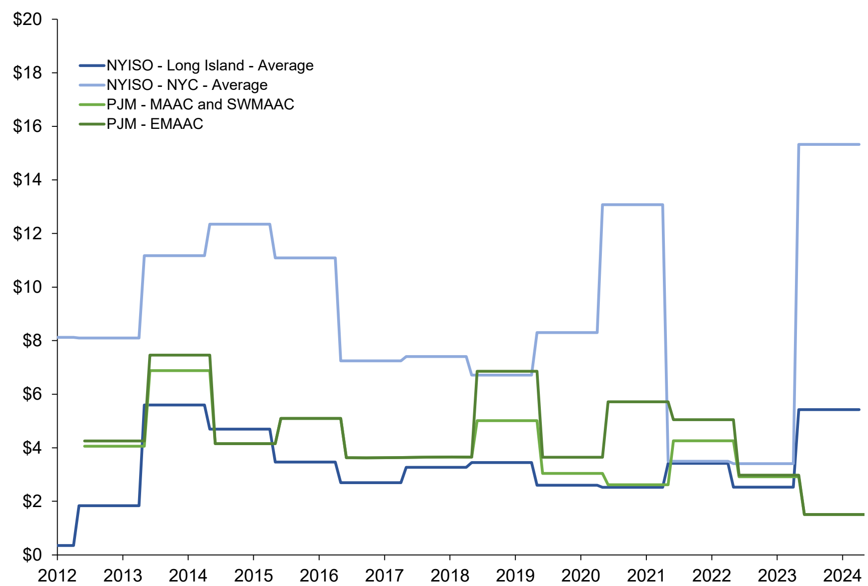
[109] **Section III.B** provides a more in-depth review of ISO-NE supply/demand changes during the time between when the forward auction occurs and the delivery period.

Figure 11. Capacity Prices for Unconstrained RTO Regions, Delivery Years 2012-2024



Sources:
[A] ISO-NE, "Markets," available at https://www.iso-ne.com/about/key-stats/markets#fcaresults.
[B] NYISO, "Installed Capacity: View Strip Auction Summary," available at http://icap.nyiso.com/ucap/public/auc_view_strip_detail.do.
[C] PJM, "Capacity Market (RPM)," available at https://www.pjm.com/markets-and-operations/rpm.aspx.

Figure 12. Clearing Prices of Constrained Zonal RTO Regions, Delivery Years 2012-2024



Sources:
[A] ISO-NE, "Markets," available at https://www.iso-ne.com/about/key-stats/markets#fcaresults.
[B] NYISO, "Installed Capacity: View Strip Auction Summary," available at http://icap.nyiso.com/ucap/public/auc_view_strip_detail.do.
[C] PJM, "Capacity Market (RPM)," available at https://www.pjm.com/markets-and-operations/rpm.aspx.

In **Table 3**, we formalize these comparisons with a statistical measure of each capacity market's clearing price volatility.[110] **Table 3** shows that prompt and forward capacity market prices have comparable volatility. When annualized, the volatility of NYISO's auctions is comparable to those of PJM's forward market auctions. While the volatility of ISO-NE's forward-annual rest-of-pool clearing price was the lowest of all markets, ISO-NE's volatility was calculated only for 2017 through 2024 delivery year auctions due to the application of a price floor for all prior delivery years (which kept prices artificially stable). Over this same time period, volatilities in areas outside of local zones in NYISO and PJM, which are most comparable to the ISO-NE prices, were lower than reported in **Table 3**: volatility in NYCA (NYISO) was 52.3% and in RTO (PJM) was 53.7%.[111]

Table 3. Capacity Market Price Volatility by ISO Region

ISO Market	Volatility
NYISO - Annualized	
Long Island	72.0%
NYCA	64.7%
NYC	57.0%
G-J Locality	44.3%
PJM *(Annual)*	
RTO	72.3%
EMAAC	47.8%
MAAC	40.4%
SWMAAC	40.4%
ISO-NE - ROP *(Annual)*	33.3%

Notes:
[1] Volatility was calculated as the standard deviation of the natural logs of the ratio of each year's price to the previous year's price.
[2] For each region, the maximum range of data was selected. From earliest to latest, the years are as follows: NYISO's Long Island, NYCA, and NYC markets from 2006-2023; ISO-NE's ROP market from 2017, the first year without a floor price, through 2024; PJM's markets from 2012-2024; and NYISO's G-J Locality market from 2014-2023.
[3] NYISO data are for 6-month strip auction prices, with summer and winter deliveries beginning May 1 and November 1, respectively, of each given year.
Sources:
[A] ISO-NE, "Markets," available at https://www.iso-ne.com/about/key-stats/markets#fcaresults.
[B] NYISO, "Installed Capacity: View Strip Auction Summary," available at http://icap.nyiso.com/ucap/public/auc_view_strip_detail.do.
[C] PJM, "Capacity Market (RPM)," available at https://www.pjm.com/markets-and-operations/rpm.aspx.

In summary, based on the available historical data, capacity auction price volatilities of ISO-NE's forward-annual auctions, PJM's forward-annual auctions, and NYISO's prompt-seasonal auctions appear comparable. Our comparisons do not account for all of the factors that differ across these markets, but assist with assessing whether

[110] These estimates reflect relatively small samples and thus the differences between estimates in **Table 3** may not be statistically significant.

[111] Volatilities in local load zones would be subject to locational constraints that would, all else equal, tend to increase volatility.

there are large differences in volatility between forward and prompt market structures. While prompt auctions may introduce greater price volatility in some cases, the historical capacity market price volatilities fall into similar ranges and pose comparable financial risks to market participants.

5. Price Discovery During Transition to a Prompt Market

If the region transitions to a prompt auction, consideration should be given to price discovery as the region makes this transition. Under the present schedule, the next primary capacity auction (reflecting capacity with must offer requirements) would occur in February 2024 for the 2027-28 commitment period.[112] If the region adopts a prompt auction, the next auction would not occur until late 2027 or early 2028.[113] Thus, three to four years could pass with no primary auction, which would create uncertainty for stakeholders about capacity market prices for the 2028-29 commitment period given on-going changes to demand and supply. At present, regular annual auctions provide information to the market about capacity prices that informs asset decisions, including retirement of existing resources and development of new resources. Thus, the gap in price discovery during the transition period to a prompt market would create uncertainty that could affect these decisions.

ISO-NE should consider options to provide information to the market to facilitate price discovery during the transition to a prompt market, if pursued. Continued information reporting about new resource capacity entering the market and retirement of existing resources will inform market participants about the supply resources in the market, which would inform assessments of future capacity prices. ISO-NE could also continue to produce demand curve parameters and indicative demand curves to allow market participants to assess how changes in demand could affect pricing. With sufficient information available market participants can form expectations and seek hedging options (which would be expected naturally to bring forth forward/futures market trading).

E. Administrative and Operational Considerations

Several administrative and operational considerations are relevant to the tradeoffs between a forward and prompt market.

First, with a prompt market, the process of administering and participating in the capacity market could be simplified in a number of respects:

- ***Certain elements of the FCM process could be eliminated.*** With a prompt auction, certain aspects of the current FCM process could be eliminated. For example, a prompt market would not require either (1) annual reconfiguration auctions or (2) procedures to pre-qualify new resource offers, ensure that these offers have provided sufficient assurances regarding their offers (e.g., credit requirements), and monitor the development progress of these new resources. Other elements might also be eliminated (e.g., elimination of price-based review of retirement notifications).
- ***Certain elements of the resource qualification could be simplified and/or performed on a shorter timeline.*** With a prompt auction, certain aspects of the capacity market process could be simplified or

[112] ISO-NE, “Forward Capacity Auction 18 Schedule,” available at https://www.iso-ne.com/static-assets/documents/2021/02/fca-18-market-timeline-02-10-2021.pdf. ISO-NE has filed a proposal with FERC to push back the FCA 19 auction to no earlier than February 2026. ISO-NE, “Market Rule Changes to Delay Nineteenth Forward Capacity Auction and Related Capacity Market Activities,” FERC DocketER24- [ ]-000, No. November 3, 2023, available at https://www.iso-ne.com/static-assets/documents/100005/changes_to_delay_19th_fca_and_related_capacity_mtk_activities.pdf.

[113] The exact timing of the prompt auction under these assumptions would depend on future market design decisions.

shortened compared to the current design. For example, qualification processes for existing resources and review of de-list offers might be performed on a shortened time frame, assuming that the elimination of other elements of the processes leading up to the primary auction either reduces the number of steps required before the auction or reduces burdens on ISO-NE staff.

- ***Shifts certain elements of the current capacity market to other processes.*** Under the current FCM, retirement notification occurs in the earliest phases of the FCA. With a prompt auction, this process could be moved outside the capacity market, which would not reduce administrative burdens but shift them within ISO-NE. In addition, to conform with FERC Order 2023, ISO-NE also plans to move key elements of the interconnection process outside the capacity market. These changes will happen independent of any decision to pursue a prompt or seasonal market.[114]

On the whole and in the long-term, the prompt market would lower administrative costs and burdens for ISO-NE and market participants by reducing the number of auctions and eliminating administrative steps currently required under the FCM given its forward nature (e.g., new entry financial and qualification requirements). However, we do not quantify the magnitude of these savings, particularly in relation to other changes in economic benefits and costs associated with a change to a prompt market.

Second, with a prompt market, development of enhancements to the capacity market for future commitment periods could occur in a more-timely manner. At present, under the FCM, the impact on market enhancements on outcomes during the commitment period occur four or more years after the market rule changes have been approved.[115] For example, the pay-for-performance rules were approved in 2014 to impact CSOs for the 2018/19 commitment period.[116] This lag between enactment of new market rules and the date when those rules affect commitment period outcomes potentially constrains ISO-NE's ability to best respond to circumstances that would benefit from rule changes to affect outcomes in upcoming commitment periods (without disrupting already cleared market outcomes). This lag also affects energy and ancillary services markets, as changes to these market rules affect capacity market outcomes through estimates of going forward costs and Net CONE. With a prompt auction, this lag could be eliminated or reduced such that market enhancements could be implemented affecting the upcoming commitment period.

F. Key Issues in the Design of a Prompt Market

If the New England region were to pursue the use of a prompt market, ISO-NE and stakeholders would need to undertake a process of developing a detailed design proposal and taking this proposal through a stakeholder process. This process would require addressing many detailed design issues; below, we identify several key issues to address:

[114] ISO-NE, "ISO-NE Responses to Capacity Related Questions Raised in the Context of Order No. 2023 Compliance Discussions," November 17, 2023, available at https://www.iso-ne.com/static-assets/documents/100005/2023_11_17_order_no_2023_capacity_question_and_answer.pdf.

[115] This assumes that new market rule changes are approved prior to the start of qualification for the upcoming FCA, which occurs more than four years prior to the commitment period being procured in that auction.

[116] ISO-NE, 147 FERC ¶ 61,172, Order on Tariff Filing and Instituting Section 206 Proceedings, May 30, 2014, Docket Nos. ER14-1050 et al.

1. Modification of the Resource Qualification Process

As noted in **Section III.B**, the switch to a prompt market would require modifications to pre-auction processes required to qualify resources, quantify their capabilities and eligible capacity, and submit and review any offers subject to review by the market monitor. Given changes to the manner in which new resources enter into the capacity market, this would require elimination and addition of certain procedures.

2. Modifications to the Retirement Notification Process

The switch to a prompt market would require changes to the process of "de-listing" resources from the capacity market. At present, de-listing and retirement notification occur in the same process prior to the FCA, with some de-listing decisions depending on whether the resource clears in the FCA. However, under a prompt market, the close tie between de-listing and deactivation would not be necessary. As a result, modifications to the retirement notification process can be made, which may provide resource owners with more flexibility regarding the timing of retirements.

3. Auction Structure

The FCA uses a descending clock auction to clear offers to supply capacity against the administrative demand curve. One factor in adopting the descending clock auction was the view that early rounds of bidding provide information to new entrants (that have not started development) about the value of new capacity that can be valuable in forming competitive offers.[117] However, there are many other considerations for the choice of auction design for capacity market, including potential for bidder collusion, incentives for offers to reflect true costs, other strategic bidding considerations and simplicity and cost.[118] As a result, auction design differs across capacity markets as regions face different market conditions, balance tradeoffs differently, and have different experience from other regions to draw on given when their market was developed.

A change to a prompt auction would provide the opportunity to revisit this decision to determine whether another auction structure (e.g., sealed bid auction) would be better suited and produce more efficient outcomes. In particular, because new resources are already committed prior to participation in a prompt auction, the original rationale of improving information for new resource offers would no longer be relevant. The reassessment could reflect the different circumstances of a prompt auction, account for evolving experience with auction design and consider other auction design elements.

[117] Bidders of new capacity face uncertainty about its value, which is "common" across bidders – i.e., they value it for the same purposes (i.e., deriving profits) and not for values outside of its market value. In these circumstances, auction theory suggests that bidders unknowingly overvalue the asset that wins the auction – referred to as the "winner's curse." In principle, when bidders hold private information about the common value, a descending clock auction reduces common value uncertainty by revealing this information and thus can lead to higher, more efficient prices. Bulow, Jeremy and Paul Klemperer, "Prices and the winner's curse," *RAND Journal of Economics* 33(1): 1-22, Spring 2002. Klemperer, Paul, "What Really Matters in Auction Design," *Journal of Economic Perspectives* 16(1): 169-189, Winter 2002.

[118] *See, e.g.,* Harbord, David and Marco Pagnozzi, "Britain's Electricity Capacity Auctions: Lessons from Colombia and New England," *Electricity Journal* 27(5), July 2014; Holmberg, Par and Thomas Tangeras, "A Survey of Capacity Mechanisms: Lessons for the Swedish Electricity Market," *The Energy Journal* 44(6), 2023.

4. Market Mitigation

As noted in **Section III.D.3**, prompt market design would require that market mitigation procedures be evaluated for potential changes. While we do not envision the need for significant changes to the basic framework, the details of the circumstances when mitigation is required and the procedures for determining mitigated offers may require some adjustment.

IV. Evaluation of the Key Tradeoffs Between an Annual and Seasonal Market

Resource adequacy has traditionally been maintained through annual procurement of capacity to address risks that largely occurred due to peak loads during summer months. This approach was reasonable as resource adequacy risks were concentrated almost exclusively in one season (summer) and differences in the contributions of different technologies to resource adequacy across seasons were modest and generally supported non-summer reliability.[119]

Market conditions, however, have changed in recent years in ways that spread resource adequacy risks across more than one season. *First*, winter resource adequacy risk has increased due to a shift in the seasonal load profile caused by a combination of factors, including electrification of heating and transportation, and the persistence of long-duration winter energy security risks.[120] Given these changes, it's expected that ISO-NE will shift from a summer peaking system to a winter peaking system in the foreseeable future. *Second*, for many of the technologies increasingly relied on in a decarbonized grid, the contribution to resource adequacy varies between summer and winter seasons, with these contributions dependent on the overall mix of resources in the fleet and relative demand across seasons.

Given the growing importance of these summer and winter seasonal factors, a seasonal market can more accurately account for differences in these factors across seasons. As with any commodity market, as differentiation in product definition or temporal variation in prices emerges, offering more products in the market can provide many benefits, including more reliable quality, more accurate pricing and thus more efficient economic outcomes. However, offsetting these benefits are the costs of developing and maintaining more highly-differentiated ("granular") markets.

For these reasons, in principle, a seasonal capacity market can achieve resource adequacy more cost-effectively and improve reliability outcomes compared to an annual capacity market. A seasonal market may also improve reliability by incenting a resource mix better-suited to evolving summer and winter reliability risks, particularly to the extent that it can automatically adjust for evolving patterns of seasonal risks over time without the need for *ad hoc* modifications to account for these changes. However, offsetting these potential benefits would be the costs to the region and system of making the transition and maintaining the more complex system (and the risk of other

[119] The ISO-NE capacity market has procured capacity on an installed capacity basis (i.e., ICAP) rather than an unforced capacity basis. Thus, seasonal differences in qualified capacity generally reflected only seasonal differences in plant capability due to thermal (weather) performance, with higher capability in winter than summer.

[120] ISO-NE has been working with the Electric Power Research Institute to conduct a probabilistic energy-security study for the New England region under extreme weather events, given that weather, particularly changing extremes and range of variability, is a key factor affecting resource (i.e., energy) availability, demand patterns, and related reliability concerns. *See*, ISO-NE, "Operational Impacts of Extreme Weather Events Key Project," available at https://www.iso-ne.com/committees/key-projects/operational-impacts-of-extreme-weather-events.

unintended consequences).[121] Thus, the decision to pursue a seasonal market should reflect whether the potential gains from the seasonal market over medium to long term offset these administrative costs and potential risks, which would likely be concentrated in the short term.

This section evaluates the tradeoffs between an annual and seasonal market. We describe three key benefits to switching to a seasonal market:

- A seasonal market can reduce the costs of procuring capacity needed to meet reliability risks through two separate seasonal markets, rather than one annual market that procures resources that better match the demand for resources in each season;
- A seasonal market can reduce costs (and improve the resource contributions to resource adequacy) by accounting for seasonal differences in resource accreditation values; and
- A seasonal market can lower costs by accounting for differences in resource (going forward) costs across seasons, thus procuring resources for resource adequacy when they can most cost-effectively supply resource adequacy.

In evaluating each of these potential benefits, the report will also consider whether (and if so, how) the choice between a forward and prompt market affects the tradeoffs posed between an annual and seasonal market. We also consider several other issues relevant to the choice between an annual and seasonal market (e.g., market mitigation, and administrative and operational burdens) and some key issues that would need to be addressed with a seasonal market (e.g., the choice between simultaneous and sequential clearing of seasonal markets, and the number and duration of seasons).

A. Accounting for Differences in the Value of Capacity in Reducing Resource Adequacy Risks Across Seasons

When resource adequacy risks occur in one season (e.g., summer), the capacity market need only procure capacity for that one season to adequately address year-round resource adequacy risks for the entire system. As resource adequacy risks outside the summer season increase, however, achieving resource adequacy outcomes will depend on capacity resource contributions in each season, not only the summer. Given the growing dependence of reliability on season-specific outcomes, a seasonal market can adjust the demand for capacity to reflect the value provided by capacity in improving reliability in each season. By adjusting the demand for capacity in each season, the market can procure a mix of seasonal resources that achieves more-cost effective quantities of capacity resources in each season. Conversely, a seasonal market can achieve a more reliable supply of resources for any given expenditure on resource adequacy in the capacity market.

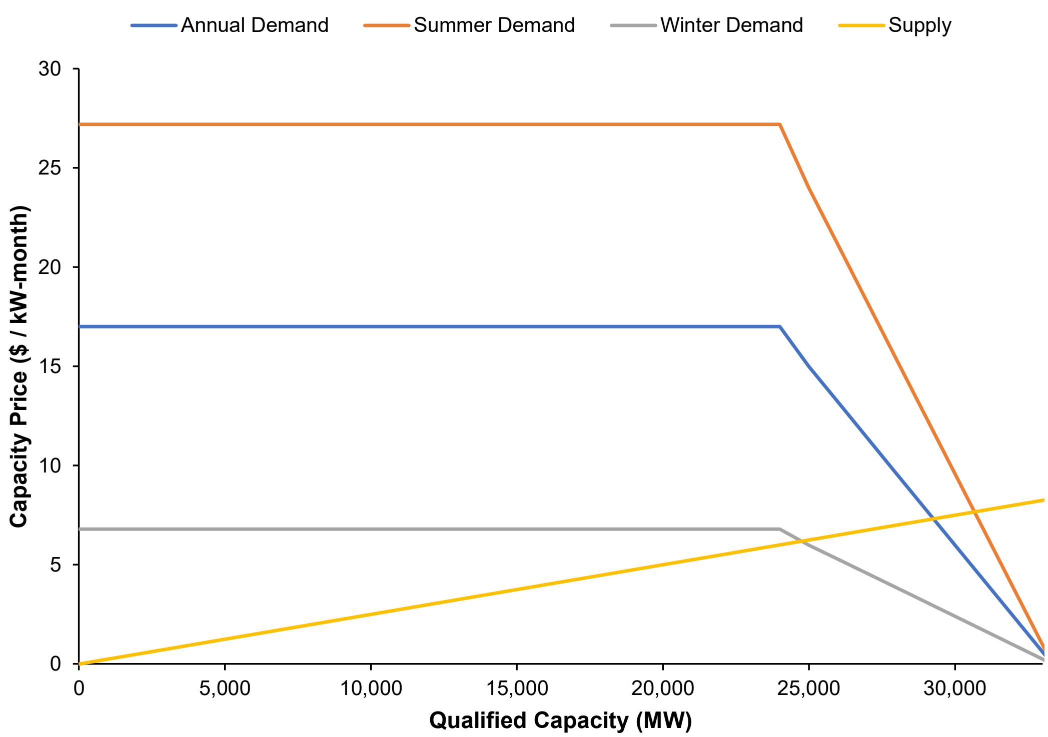
The potential gains from procurement of seasonal capacity are illustrated in **Figure 13**. This example abstracts from many specifics that would likely emerge under a seasonal market, such as differences in seasonal offers to supply capacity and differences in the shape of demand curves to account for seasonal reliability impacts. The illustration includes both an annual demand curve (blue line) and summer and winter demand curves (orange and grey lines,

[121] Another common tradeoff that does not appear to be relevant for a seasonal capacity market in ISO-NE would be sufficient market liquidity.

respectively), where these curves assume that annual marginal reliability impacts are decomposed into summer and winter components.[122]

The illustration shows that, with a seasonal market, prices and quantities vary by season given the differences in value of capacity and the cost to supply it in each season. In each season, capacity is procured until the cost of supply equals the value of capacity, as implied by the seasonal demand curve. In the summer, because the (marginal) value of capacity is greater than in the winter, the market procures a larger quantity of capacity and clears at a higher price. While the market pays more for capacity in the summer, because of the increasing cost of procuring larger quantities of capacity, it provides greater reliability value (per MW) than in the winter and it is therefore cost effective to procure this additional capacity at higher cost.

Figure 13. Illustrative Seasonal Capacity Market with Differentiated Seasonal Demand



By differentiating capacity procurement by season, the total cost of the FCA and the average cost of reliability benefits are reduced (by approximately 9% in the illustration).[123] Average costs are reduced by procuring more capacity in the summer, when the value of capacity is greater, as compared to the winter. Thus, a seasonal market

[122] For the purposes of this stylized exhibit, the annual demand curve is a weighted average of summer and winter impacts, where summer and winter demand impacts are assumed to account for 80% and 20% of annual impacts, respectively.

[123] Total cost reflects the price multiplied by the quantity, while the average cost of reliability benefits is measured as the total cost divided by the consumer surplus (i.e., the area under the demand curves). The 9% decrease is calculated as the percent change in this ratio of total cost to consumer surplus in the illustration of an annual versus seasonal capacity market procurement process. Seasonal market prices can lower costs and improve reliability by aligning price signals for capacity with the market's value of capacity each season given existing supplies (and their costs) and the value of capacity in mitigating risk in each season.

is able to improve market efficiency by procuring capacity consistent the reliability benefits provided by capacity in each season. The potential gains from differential procurement of seasonal capacity obligations will depend on regional market conditions, including seasonal capacity supply offers and seasonal demand curves.

Along with supporting short-run market efficiency, a seasonal market can improve long-run efficiency by creating price signals that reflect the market's value of capacity in each season given existing supplies (and their costs) and the value of capacity in mitigating risk in each season. These price signals provide incentives for investment in new capacity that provides contributions to resource adequacy in the seasons when it is most valued. For example, if summer capacity prices are higher than winter prices, new investment is incentivized to use technologies that offer larger summer accreditation than winter accreditation.

Seasonal demand curves that account for the season-specific value of capacity can be developed through the application of ISO-NE's current methodology for estimating demand curves to each season. Under the FCM, the demand curve is based on estimates of the (marginal) reliability impact of capacity (i.e., MRI values) corresponding to different levels of capacity resources, where the MRI values reflect the impacts across the entire calendar year.[124] Using these MRI curves, the demand curve is constructed by calculating the scaling factor needed to adjust the MRI curve so that the curve intersects the point where the price provides revenues sufficient to support new entry (i.e., price equals Net CONE) and the quantity equals the quantity of capacity needed to achieve the 1-in-10 reliability criterion (i.e., Net ICR).

With a seasonal market, this methodology can be used to derive demand curves for each season. Under this approach, MRI values would be developed in each season based on the reliability risks (i.e., loss of load events) for different quantities of capacity resources. As is the current practice, these curves can be scaled to develop seasonal demand curves that reflect underlying reliability risks while still achieving the reliability criterion (i.e., ensuring the market provides sufficient revenues to support new entry when expected reliability is at the 1-in-10 resource adequacy criterion).

The development of seasonal demand curves will require additional work, particularly in determining the appropriate steps to scale MRI curves to arrive at seasonal demand curves. If the region pursues a seasonal market, the development of seasonal demand curves will be an important part of the design process. We do not develop a complete methodology for such demand curves, although in **Section IV.F.4**, below, we note several design principles that can guide the development of these curves.

B. Accounting for Differences in Resource Accreditation Across Seasons

With a seasonal market, capacity market offers can reflect each resource's contributions to resource adequacy in that season, rather than an average of contributions across seasons. When contributions to resource adequacy differ meaningfully across seasons, failure to account for these differences can diminish capacity market cost-effectiveness – that is, more costly resources may be awarded CSOs in lieu of less costly resources. Historically, seasonal contributions to reliability were relatively similar and, to the extent they were not, setting accreditation at

[124] The MRI curve is calculated using a resource adequacy modeling tool, GE MARS, which uses Monte Carlo simulation to estimate the distribution of reliability outcomes subject to various resources and system contingencies. ISO-NE, "Installed Capacity Requirement (ICR) Reference Guide," September 15, 2021, p. 27, available at https://www.iso-ne.com/static-assets/documents/2021/06/icr-reference-guide.pdf.

summer values did not adversely affect market outcomes. However, the contributions of many resources now in the ISO-NE system differ meaningfully across seasons.

Table 4, which provides illustrative average winter and summer capacity accreditation values for New England for various technologies, illustrates these differences.[125] These values are proxies for potential accreditation values based on our research on accreditation values across RTOs (including ISO-NE) and do not reflect the on-going work in the RCA project.[126] Seasonal differences in resource accreditation arise due to many factors – for example:

- For gas-fired resources, contributions to resource adequacy in the winter may be diminished if a resource does not have access to firm fuel supply when needed and thus faces the risk of interruptions in fuel supplies during stressed market conditions. As discussed in **Section III.B.4.c**, given this risk, gas-fired resources without firm fuel supplies through dual fuel capability or firm-fuel contracting arrangements (e.g., with an LNG terminal) will receive lower capacity accreditation due their lower contribution to resource adequacy.[127]
- For intermittent renewable resources, including solar PV, wind power, and hydropower, resource adequacy contributions depend on many factors including the timing of energy supply (given dependence on weather conditions) and correlations with supply of energy from other resources on the system during periods when resource adequacy risks are greatest. Given differences in weather conditions across seasons and the timing of peak electricity demands, resource adequacy contributions from intermittent resources can differ widely across seasons.

  For solar PV, not only is supply highly dependent on weather conditions, but increasing quantities of solar generation can shift the periods of greatest reliability risk to later in the afternoon, when supply from solar PV is waning thus diminishing the solar PV's contribution to reliability. During the summer, when daylight hours are longer and the timing of peak loads still occurs in hours with daylight, solar PV provides some reliability benefit. By contrast, during the winter period, solar receives little credit in New England due to significantly shorter daylight hours and the timing of periods of greatest risk (peak loads) in late afternoon or early evening.

  Wind generation is generally more consistent throughout the year but there is still seasonal variation. Offshore and onshore wind output is dependent on weather conditions which are generally more favorable during the winter in New England. Thus, onshore and offshore wind receive higher accreditation in the winter than summer.

---

[125] Note that the accreditation factors in this table are based on nameplate capacity for intermittent resources and qualified capacity for all other resources. In practice, under the RCA procedures, actual values will reflect unit-specific factors and would not be uniform across technology classes.

[126] Assumed capacity accreditation values differ across summer and winter seasons for technologies whose performance is affected by external factors, including weather conditions and interactions with other resources on the system. For technologies not subject to such factors, capacity accreditation values are assumed to be the same in summer and winter, although in practice, seasonal differences in actual resource accreditation may arise due to asset-specific seasonal performance.

[127] During high-risk winter days, the availability of pipeline gas for the electricity system is considerably limited due to high demand from other natural gas customers. As a result, the region's electricity system relies on supply from LNG storage terminals during these periods. In addition, other neighboring regions may experience demand for natural gas during high-risk winter hours, further constraining pipeline gas supplies to the region. Thus, without firm fuel arrangements, the contribution of gas-only resources to winter reliability is potentially constrained. *See* ISO-NE, "Natural Gas Infrastructure Constraints," available at https://www.iso-ne.com/about/what-we-do/in-depth/natural-gas-infrastructure-constraints.

Table 4. Assumed Illustrative Accreditation Factors by Resource Class, CCP 19

	rMRI		
Resource Class	**Annual**	**Summer**	**Winter**
Coal ST	0.907	0.907	0.907
Nuclear ST	0.969	0.969	0.969
ST (other)	0.901	0.901	0.901
CC (firm fuel)	0.959	0.959	0.959
CC (non-firm gas)	0.810	0.959	0.660
CT (firm fuel)	0.899	0.899	0.899
CT (non-firm gas)	0.749	0.899	0.600
Passive DR	1.034	0.964	0.879
2 hour ES	0.644	0.690	0.504
4 hour ES	0.904	0.970	0.684
Import	0.980	0.980	0.980
Active DR	0.820	0.820	0.820
Offshore Wind	0.311	0.222	0.349
Onshore Wind	0.168	0.120	0.187
Solar	0.123	0.167	0.012
Dispatchable Hydro	0.955	0.955	0.955
Run of River Hydro	0.257	0.235	0.509

Notes:
[1] Acronyms: ST-steam turbine, CC-combined cycle, CT-combustion turbine, ES-energy storage, DR-demand response.
[2] For active demand, imports, dispatchable hydro, and all thermal resources, except those with non-firm winter gas, rMRI is approximated using historical average equivalent forced outage rate demands ("EFORd"s) by technology class.
[3] Energy storage rMRIs are based on ISO-NE's marginal reliability analysis.
[4] Onshore and offshore wind values are calculated using ISO-NE's blended wind results from the latest marginal reliability analysis and PJM's wind breakdown shape from their 2026-27 capacity market proposal. Offshore wind rMRI is reduced to account for the rest of Vineyard Wind coming online by 2025.
[5] Solar values are calculated using ISO-NE's results from the latest marginal reliability analysis and reduced to account for assumed utility solar PV additions coming online by 2028.
[6] For intermittent power resources (offshore wind, onshore wind, solar, and run of river hydro), rMRI is expressed in terms of nameplate capacity. For all other resources rMRI is expressed in terms of qualified capacity.
Sources:
[A] ISO-NE, "NERC GADS EFORd Class Averages as used by ISO New England," 2017-2021 averages, available at https://www.iso-ne.com/static-assets/documents/genrtion_resrcs/gads/class_ave_2010.pdf.
[B] ISO-NE, "Resource Capacity Accreditation in the Forward Capacity Market: FCA16 Baseline Case Accreditation," available at https://www.iso-ne.com/static-assets/documents/2023/04/a05f_mc_2023_04_11-13_rca_impact_analysis.pptx.
[C] PJM, "Capacity Market Reform: PJM Proposal," available at https://www.pjm.com/-/media/committees-groups/cifp-ra/2023/20230727/20230727-item-02a---cifp---pjm-proposal-update---july-27.ashx.
[D] Velocity Suite.
[E] PJM, "Interconnection Queue Data," available at https://www.pjm.com/planning/service-requests/services-request-status.

- For battery storage resources, resource adequacy contributions reflect many factors, some of which vary across seasons. One factor is the extent to which resource adequacy risk reflects long-duration (e.g., multi-day) or short-duration (e.g., multi-hour) events. Because current battery storage is typically limited to short durations (e.g., 2 to 4 hours), their contribution to addressing long-duration risks is limited. As a result, storage resources receive lower accreditation in the winter than summer due to, among other things, the greater prevalence of long-duration risks in the winter.

A seasonal market can account for these seasonal differences in resource accreditation. With a seasonal market, offers for supply can be based on season-specific capacity accreditation that more accurately reflects each resource's contribution to resource adequacy. Given the meaningful differences in capacity accreditation for many resources in the ISO-NE system, accurately measuring these contributions in each season would be valuable for at least two reasons. *First*, accounting for season-specific capacity accreditation will produce more accurate measures of the aggregate contributions to resource adequacy supplied across procured resources in each season. These more accurate measures can provide more accurate information about the level of reliability achieved in each season, particularly compared to an annual market that would rely on an average of contributions to resource adequacy across seasons but may provide less meaningful information about the balance of reliability across seasons. Accurate measures of aggregate qualified capacity in each season are also necessary for developing accurate seasonal market prices.

Second, accounting for seasonal differences in resource adequacy results in compensation for supplying capacity that reflects the relative value of the services provided in each season as determined by the market within the auction. Like seasonal price signals, compensation based on each resource's actual seasonal contributions creates incentives for investment in resources with winter-summer accreditation that best addresses the relative value of capacity in each season.

Seasonal price signals also send an accurate price signal for natural gas-only fired resources to take steps to firm-up their fuel supplies to receive the higher resource accreditation. With an annual market, the price signal to incent fuel-firming is muted by the averaging of winter and summer accreditation. However, with a separate winter market, the price signal will reflect winter reliability risks which may be either higher or lower than contemporaneous summer risks. Thus, a separate winter capacity market can send a comparatively high price signal for resources to firm-up fuel supplies when doing so represents a cost-effective way to improve system reliability, while also sending a comparatively low price signal when additional summer capacity provides a lower cost way to improve the region's reliability.

C. Accounting for Differences in (Going Forward) Costs Across Seasons

A seasonal market allows resources to submit offers that reflect their season-specific going forward costs. By accounting for season-specific costs, market-clearing reflects costs that more accurately reflect the true cost to resources of supporting resource adequacy. When season-specific costs vary across resources, the seasonal market can result in a more cost-effective fleet of resources supporting resource adequacy in each season, thus lowering costs.

1. Seasonal Fixed Costs

Going forward costs can vary across seasons for several reasons. One potential source of variation is that ***non-variable or fixed operations costs may vary across seasons***. In principle, there may be many sources of variation in fixed costs across seasons, although we focus on an important source of potential seasonal cost variation in the New England region: actions needed to ensure reliable operations during winter (“weatherization”) and actions needed to secure reliable winter fuel supplies.[128]

Table 5 illustrates two general types of generator fixed costs: (1) general fixed operations and maintenance (“O&M”), and (2) costs specific to the winter, including weatherization and procuring firm fuel for reliable winter operations. Focusing on the winter seasonal costs, winter fuel arrangements and commitments are particularly important considerations in New England, where the tightness of the natural gas pipeline supply on cold winter days can constrain fuel supplies to generators without a firm source of supply.[129] As discussed above, generators with firm fuel arrangements may have greater contributions to reliability in the winter and thus are awarded larger resource accreditation.

Along with firm fuel arrangements, resource owners can take various actions to mitigate performance risks associated with severe winter weather. **Table 5** lists multiple potential activities to improve winter operational reliability including various equipment investments, operational systems and annual winter plant and system preparations. Because weatherization costs in New England are primarily associated with winter operations, we expect that to the extent there are differences in season-specific costs for individual plants that they would be larger in the winter than summer. However, in practice, determination of seasonal costs will be plant-specific.

In principle, a seasonal market can allow resources to offer capacity at prices reflecting their season-specific going forward costs. However, determining seasonal going forward costs raises potential challenges. Thus, if the region pursues a seasonal market, an important part of the process will be establishing rules for seasonal capacity market offers. There are several important issues that need to be considered. *First*, in some cases, expenditures are clearly attributable to seasonal activities. However, many costs represent year-round activities that may or may not vary in intensity across the year. Thus, rules will need to determine how costs can be allocated to particular seasons. *Second*, many weatherization costs are capital investments. In principle, if undertaken for seasonal weatherization, then these costs could be allocated to that season based on allowed depreciation consistent with current market rules.[130] *Third,* many costs may be incurred annually regardless of whether the plant operates in one or all seasons. These “annual” costs are “non-divisible” in that they are not incurred in proportion to seasonal operations. Thus, determinations will need to be made about how these costs can be included in offers – for example, will seasonal offer prices be limited to a seasonal allocation of these costs or can seasonal offer prices include all annual costs in the event the resource is awarded a CSO in one season but not another? As we discuss below, some auction structures would address this concern by allowing both an annual component (compensating if the resource clears in at least one season) and a seasonal component (compensating for awards specific to that season).

[128] In principle, other components of fixed costs may vary across seasons depending on the particular resources involved. Potential costs subject to seasonal variation include: labor costs, and costs of ongoing maintenance, services and testing. Other costs are less likely to vary by season, such as major maintenance costs, insurance, and property taxes.

[129] ISO-NE, “Natural Gas Infrastructure Constraints,” available at https://www.iso-ne.com/about/what-we-do/in-depth/natural-gas-infrastructure-constraints.

[130] ISO-NE, “Market Rule 1,” Section III.13.1.2.3.2.5, Static De-List Bid Incremental Capital Expenditure Recovery Schedule, pp.48-49, available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf.

Table 5. Seasonal Weatherization Actions Required and Costs Incurred by Generation Resources

Cost Category	Annual Cost	Seasonal Cost
Fuel		
Winter Fuel Arrangements and Commitments		X
Plant Fixed O&M [1]		
Routine Maintenance	X	[May include seasonal components]
Materials and Contract Services	X	[May include seasonal components]
General and Administrative Expenses	X	
Actions for Winter Weather Readiness [A], [B]		
Work Management System	X	X
Critical instrumentation and equipment protection		X
Insulation, heat trace, and other protection options		X
Heat trace capability and electrical continuity/ground faults		X
Wind Breaks	X	X
Covers, enclosures, and buildings		X
Supplemental Equipment		X
Operation Supplies	X	X
Staffing	X	X
Communications	X	X
Special Operations Instruction (prior or during severe winter weather event)		X

Notes:
[1] Plant Fixed O&M cost categories are derived from the assumptions used by the U.S. Energy Information Administration ("EIA"), Velocity Suite, S&P Global, and Concentric.
[2] Winter readiness activities derived from various sources, including "Generating Unit Winter Weather Readiness," Reliability Guideline, and North American Electric Reliability Corporation ("NERC") EOP-012-2 Reliability Standard.
Sources:
[A] NERC, EOP-012-2, Technical Rationale and Justification, June 2023.
[B] NERC, Reliability Guideline, Generating Unit Winter Weather Readiness, Current Industry Practices, Version 4, June 2023.
[C] EIA Fixed O&M: EIA, Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies, February 2020, pp. XII-XIII, available at https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf.
[D] Velocity Suite Fixed O&M: ABB Ability Velocity Suite, Better Model Inputs: Estimating Fixed and Variable O&M Costs in ABB Ability Velocity Suite, 2019, available at http://vsservices.velocitysuiteonline.com/registrationservice/getdocument.aspx?key=E926AA2A9D4A8739C5C4761E82CF1D1F.
[E] S&P Global Fixed O&M: Generation Supply Curve on CIQ Pro help page.
[F] Concentric Fixed O&M: ISO-NE Net CONE and ORTP Analysis: An Evaluation of the Net Cost of New Entry and Offer Review Trigger Price Parameters to be Used in the Forward Capacity Auction, FCA-16 and Forward, Concentric Energy Advisors, Inc. and Mott MacDonald, p. 86.

These complications in calculating each resource's avoided costs may have implications for market mitigation. At present, offer review and potential mitigation by the internal market monitor reflects detailed determinations regarding allowable expenditures when calculating going forward costs. With a seasonal market, these determinations would potentially also need to assess allocation of costs to annual and seasonal components, and the allocation of costs across seasons.

2. *Other Factors Affecting Seasonal Going Forward Costs*

Along with seasonal variation in operating costs, seasonal capacity market offers may vary due to several other factors. *First*, ***expected energy market net revenues may vary across seasons***. Expected energy market net revenues will reflect many factors, including expected locational marginal prices ("LMPs"), fuel costs and the timing and quantity of energy supplied. For example, for intermittent resources, expected net revenues will depend on seasonal weather conditions, with solar PV resources earning higher expected net revenues in summer than winter and the opposite likely being true for wind resources. Storage resources will have higher expected revenues when arbitrage opportunities are greater, which will depend on other resources on the system. Natural gas-fired resources' expected net revenues in winter will depend on dual fuel capability and other factors affecting access to non-gas fuels.

Second, ***seasonal differences in resource accreditation cause going forward costs per unit of capacity to vary across seasons*** even if total costs in dollar terms are the same across seasons. For example, a 4-hour battery with annual going forward costs of $2.00 per kW-month (on an annual basis) will have costs of $2.15 and $1.51 per kW-month for summer and winter, respectively, given the assumed accreditation values of 0.97 and 0.68 for summer and winter seasons, respectively, from **Table 4**.[131] Because seasonal accreditation values differ across resources (i.e., some with higher values in the winter and others with higher values in the summer), the rank order of offers within the offer curve may differ across seasons, which in turn could affect which resources are awarded CSOs in capacity market auctions.

Third, ***expected pay-for-performance payments may differ between seasons and may vary across individual resources***.[132] Under current market rules, capacity offers can include an estimate of the expected pay-for-performance payments. With the current annual FCM, expected payments reflect each resource's expectations about annual performance and market-wide annual pay-for-performance ("PFP") parameters. Under a seasonal market, however, expected PFP payments would depend on expectations for resource performance and PFP parameters that would be specific to each season.

Expectations about expected PFP payments could vary by season due to many factors. First, expected reserve shortage hours and balancing ratios (the benchmark against which performance is measured) could vary by season. Second, a resource's ability to perform during reserve shortage events can vary by season due to resource-specific factors, such as fuel security, operational risks, and duration and predictability of reserve shortages.

Given all of these factors, the avoidable costs to resources of supplying capacity will vary by seasons, and procuring capacity at the seasonal level will allow those resources with the lowest costs to supply capacity.

[131] If costs were equal across seasons, seasonal GFC could be calculated by multiplying annual GFC by the ratio of seasonal to annual accreditation: Seasonal GFC = Annual GFC * Seasonal rMRI / Annual rMRI. For the summer season: GFC = 2 * (0.97/0.90) = 2.15. For the winter season: GFC = 2 * (0.68/0.90) = 1.51.

[132] Under current market rules, resources receiving a CSO accept the pay-for-performance financial obligation, which could require financial payments or receipts depending on the resource's performance during periods when the system experiences reserve shortages. To account for the expected financial consequences of the PFP obligation, resources can include an estimate of expected payments (or receipts) of accepting the PFP obligation in their FCA offers as part of going forward costs. A rational bidding strategy would not accept an offer below the expected PFP payments because the resource can earn these revenues in expectation by forgoing the CSO and earn PFP revenues in the spot market.

D. Issues Arising from the Choice Between a Forward- and Prompt-Seasonal Market

In **Section III**, we evaluated the choice between the current forward market and a prompt capacity market. This choice has important consequences for the choice between an annual or seasonal market structure and the extent to which the potential benefits of greater market segmentation can be realized.

One critical issue is the improved accuracy from greater market segmentation that can be better realized under a forward or prompt market structure. As discussed in **Section III**, an important difference between forward and prompt market structures is the greater uncertainty about supply and demand in a forward market relative to a prompt market. With three years between the auction and commitment period, there is substantially more uncertainty about the cost of supply, resource accreditation, and demand for capacity. Because a seasonal market depends on a narrower set of conditions, these factors may be more sensitive to year-to-year variation than with an annual market. If this is the case, the benefits of a seasonal market in providing greater accuracy in demand, supply, and resulting market-clearing prices and quantities may be eroded. However, as discussed in **Section III**, a prompt market, where uncertainties are lower, will significantly reduce this concern.

A prompt market would also mitigate the opportunity cost of forward commitments to supply capacity, which may be particularly large for certain resources facing seasonal risks or operational constraints. For example, a prompt-seasonal market would better align capacity market timing with the window for gas-only fired resources to make firm fuel arrangements. Because the value of making these arrangements may depend on short-term market conditions, such as events affecting fuel markets and sources of supply to the region, a prompt market would result in more efficient market outcomes with winter fuel arrangements being made to reflect the most recent market conditions. Further, as described in **Section III.B.4.c**, a prompt market would lower the cost to gas-only fired resources of taking steps to firm-up their fuel supplies.

These considerations suggest that interactions between a prompt and seasonal market are generally complementary, with a prompt market enhancing the benefits of a seasonal market relative to an annual market.

E. Administrative and Operational Considerations

A seasonal market would involve more administrative cost and operational complexity than the current annual market. A substantial portion of this cost and complexity would likely be incurred through the initial development of market rules, market procedures, and software systems to implement a seasonal market. The on-going operation of and participation in a seasonal market would be more complex than an annual market but would not necessarily involve more steps or procedures than the current market. We have not assessed the cost to ISO-NE of making this transition.

To the extent the region pursues a prompt-seasonal market, the increase in market complexity from a seasonal market would be offset (partially, fully or more than fully) by the reduced complexity of a prompt market compared to the current forward market.

RTO experience with seasonal capacity markets is limited, which would increase the cost and effort of making this transition. MISO is in the process of adopting seasonal auctions in its prompt capacity market. This experience will provide some experience to the region, although MISO relies much less heavily on its capacity market to achieve resource adequacy than the New England region.

On balance, while the switch to a seasonal market (with a forward or prompt market) would involve one-time costs and require substantial effort by the region, the resulting market would provide the region with a platform for maintaining resource adequacy for the foreseeable future, as the seasonal market provides flexibility to adapt to evolving market conditions as the region charts a path to the "grid of the future."

F. Considerations for Design of a Seasonal Market

1. Market Features with Seasonal Variation

The FCM has an annual capacity product procured through a single annual auction. The discussion in prior sections assumed the adoption of a seasonal capacity product, seasonal auctions with seasonal demand curves, and supply offers reflecting seasonal quantities (given seasonal capacity accreditation) and seasonal price offers (reflecting seasonal going forward costs). However, in principle, a seasonal market could be developed that adopted only some of these components. An important aspect of the design of a seasonal capacity market would be determining if it is possible to only make some of these elements of the capacity market seasonal while producing a resulting design that does not create perverse incentives in auction bidding or resource operation and retains many of the benefits of a seasonal design such as those outlined above.

2. Number and Duration of Seasons

A key issue in the design of a seasonal market is the number of seasons and the duration of each season. Given that the resource adequacy risk appears to currently occur entirely in summer and winter seasons, a two-season market would offer obvious advantages in accounting for these two periods of primary risk and creating markets and prices to incentivize resources to provide capacity in each season. Alternatively, the MISO market has developed four seasonal markets (summer, fall, winter, spring) in light of future reliability issues it foresees for its system (see **Section II.C.3.b**). Given this option, some consideration to the number of seasons might be provided in the early stages of development of a seasonal market (if pursued) to assess whether the two-season or four-season model is appropriate for the region. MISO adopted a four-season market to reduce the capacity obligations of load serving entities ("LSEs") in shoulder seasons, provide appropriate incentives to coordinate scheduled outages during shoulder seasons, and provide greater flexibility regarding the timing of resource retirement. However, there are many differences between the ISO-NE and MISO capacity market that may diminish the value of these factors, particularly in light of the added complexity, cost and risk of a four-season market. In particular, ISO-NE relies much more heavily on its capacity market to achieve resource adequacy, whereas seasonal requirements in MISO are primarily achieved by each LSE, with the capacity market balancing needed supplies that are not self-supplied. In addition, adopting a four-season market could add significant complexity if the region pursues a simultaneous auction design (discussed below), because it would require search over a much larger set of potential combinations of awards to determine the optimum market outcome.

3. Auction Design

An important step in developing a seasonal market would be developing the auction structure for the market. One key auction design issue is whether to run seasonal auctions sequentially or simultaneously. If run sequentially, auctions could occur shortly before each season to procure capacity for that season and no others. With a sequential auction, each season's capacity is procured independently of all other seasons. If run simultaneously, capacity for each season in the year would be cleared in one auction that is designed to procure capacity across all seasons in the year at the lowest cost. Thus, with a simultaneous auction, capacity across seasons is procured in one integrated fashion. Another key auction design issue is whether to retain the current descending clock auction or to adopt an alternative auction structure (e.g., sealed bids). These issues were discussed in **Section III.F.3**. Both of these decisions would depend on other key design decisions including whether the market retains its current forward structure or adopts a prompt market structure.

There are several important considerations in the choice of auction and procurement structure with a seasonal market. In theory, a simultaneous auction can achieve lower costs than a sequential auction because the simultaneous auction optimizes the choice of resources over the entire year, rather than over individual, independent seasons. In particular, a simultaneous auction can better account for resources' annual, non-divisible costs – that is, costs that are only avoidable if supplying in none of the seasons. Annual, non-divisible costs may be particularly large for many generation facilities. While some costs may be incurred month-to-month and thus could be avoided if the resource did not operate (e.g., certain labor, ongoing maintenance, services and materials costs), other costs may be not avoidable with seasonal shutdowns (e.g., certain maintenance, insurance, property taxes) and thus would need to be recovered regardless of whether the resource supplied capacity in one or all seasons.

To achieve this lower cost outcome, a simultaneous auction would need to be designed to accommodate offers reflecting both an annual component (paid if the resource clears in any season) and a seasonal component (paid if the resource clears in particular seasons). This offer structure allows recovery of total fixed operating costs if the resource clears for any individual season because it would earn (at minimum) both the annual and seasonal components of its offer.

With a sequential auction, a resource that clears in one season but not the following season may not cover these annual costs when its offer reflects only its seasonal going forward costs. Thus, the sequential auction poses the risk that resource compensation may not cover on-going costs needed to sustainably retain the resource. This risk may also lead to strategic bidding that may cause inefficiencies.[133] These risks may be mitigated partially through information provided by ISO-NE (along with information from prior market clearing) that can help assess *ex ante* which seasons a resource is likely to be awarded CSOs. Moreover, the scope of this concern may not be wide if most resources can reliably assess the seasons in which they will be awarded CSOs. If the region pursues a seasonal market and is considering a sequential structure, further assessment of these issues can be undertaken.

Careful evaluation of the feasibility, cost, complexity and potential tradeoffs of a simultaneous auction that allows offers with annual and seasonal components would be a key first step in the development of a seasonal market. Auctions in other sectors use structures that enable complex interactions between auctioned goods and their value to bidders. Thus, these auctions demonstrate that similar auction design challenges have been successfully met. For example, spectrum auctions allow offers for combinations of spectrum, where the value of an individual spectrum depends on its complementarity with other spectrum.[134] A seasonal auction has a similar complementarity, because the value of a CSO to a particular resource would depend on the seasons during which it has a CSO. This complementarity is simpler than in spectrum auctions, although a capacity market has other features that differ from spectrum auctions (e.g., rationable and non-rationable offers, and capacity zones). A careful assessment can determine the feasibility of a simultaneous auction, whether use of simultaneous auction introduces other tradeoffs

[133] Revenue adequacy risks create uncertainties for the optimal bidding strategy. If offer prices are set to just cover annual costs, revenues may not be adequate to cover costs if the resource clears for one but not all seasons. However, if the resource submits a seasonal offer sufficient to recover its full year's costs, the offer may not be awarded a CSO when it otherwise might have been awarded a CSO in all seasons had it offered at a lower price.

[134] *See,* e.g., Ausubel, Jesse and Oleg Baranov, "A Practical Guide to the Combinatorial Clock Auction," *The Economic Journal* 127:334-350, October 2017.

(e.g., bidder strategy), and the tradeoffs for efficiency, complexity, and cost with other less complex auction structures, particularly sequential auctions.[135]

4. Development of Seasonal Demand Curves

If the region pursues a seasonal market, the development of seasonal demand curves will be an important part of the design process. While we do not develop a complete methodology for such demand curves, we note several design principles that can guide the development of these curves.

First, as described above, demand curves should reflect the underlying reliability risks in each season. Due to differences in reliability risks between seasons (and potential differences in the value of lost load between seasons), the resulting demand for capacity will differ depending on the value provided in each season. In practice, it is reasonable to expect that these curves may differ materially between seasons given the observed differences in seasonal resource adequacy risks from recent ISO-NE modeling. For example, recent modeling indicates that summer reliability risks represent 70% to 90% of total reliability risks, with winter risks representing 10% to 30% of this total.[136]

Given differences in the reliability benefits provided by capacity across seasons, it is sensible that the resulting prices reflect these differences in the value of capacity in respective seasons. For example, in the illustrative example shown above (**Figure 13**), winter prices are approximately $6 per kW-month while summer prices are approximately $8 per kW-month. These differences in value reflect the fact that the contributions to reliability from summer capacity are four times that of winter prices (at comparable levels of capacity).

Second, when translating MRI curves into a demand curve, it is economically sensible to use scaling factors in each season that reflect the relative value of reliability risks in each season.[137] Assuming the objective of compliance with the 1-in-10 resource adequacy requirement, reliability risks should be valued equally across seasons, which implies the same scaling factor should be used in all seasons.

Third, as with the annual demand curve, the scaling factor would be selected to achieve the resource adequacy criterion – that is, the criterion that revenues be sufficient for new capacity to enter the market when system reliability is at or below the 1-in-10 reliability criterion. With an annual capacity market, this criterion leads to a unique outcome – i.e., the demand curve passes through the single point reflecting Net ICR achieving the 1-in-10 criteria and Net CONE. However, with a seasonal capacity market, this criterion is more complex because reliability reflects outcomes in both the summer and winter market and revenue adequacy for the reference unit reflects both summer and winter revenues.

---

[135] Levin, Jonathan and Andrzej Skrzypacz, "Properties of the Combinatorial Clock Auction," *American Economic Review* 106(9): 2528-2551, 2016.

[136] ISO-NE, "Resource Capacity Accreditation in the Forward Capacity Market, FCA16 Baseline Accreditation Case," NEPOOL Market Committee, April 11-13, 2023, p. 22.

[137] It can be shown that, if scaling factors differ between seasons, the same level of resource adequacy can be attained for a lower cost by substituting capacity in the season with a lower demand scaling factor for capacity from the season with a higher demand scaling factor. In effect, the higher scaling demand factor causes the capacity in that season to be over-valued compared to capacity in the season with the lower demand scaling factor.

5. Market Mitigation

As noted above in **Section IV.C.1**, a seasonal market would require changes to market mitigation given the change in offers under a seasonal market. These changes would include apportioning of avoidable costs across seasons and formation of annual and seasonal offer components under a simultaneous auction. A seasonal market may introduce new opportunities for the exercise of market power that would need to be evaluated when developing rules for offer mitigation.

V. Quantitative Analysis of Market Outcomes Under Alternative Market Designs

A. Overview of the Model

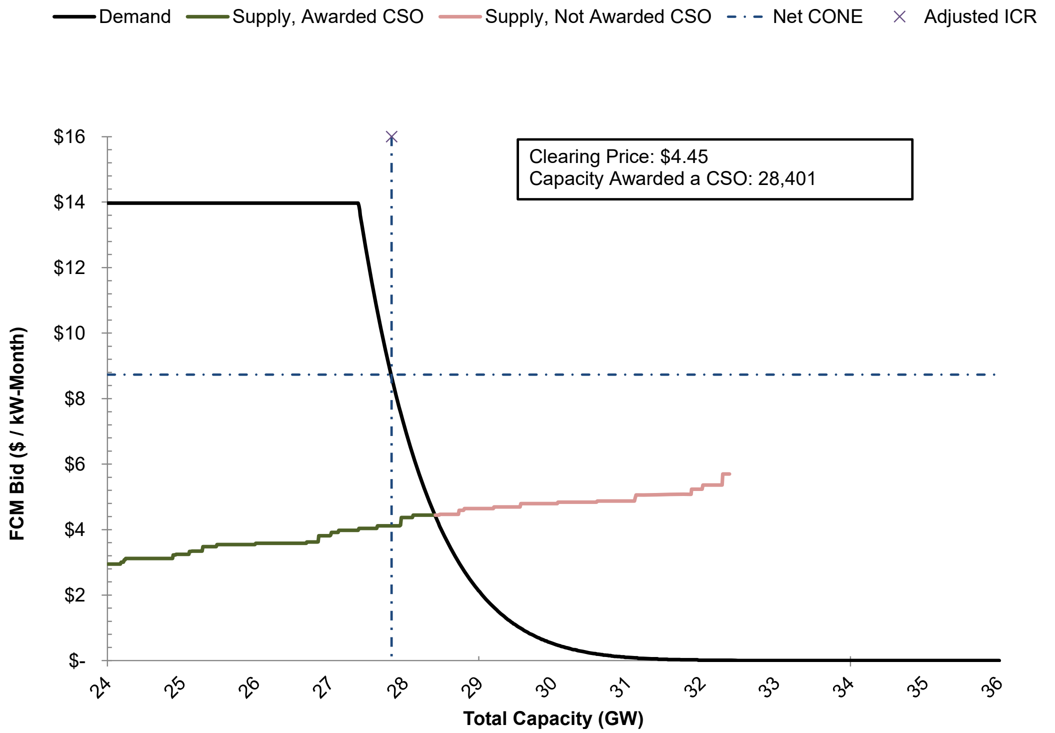
To provide information on the potential impacts of the prompt and seasonal market concepts, Analysis Group evaluated these options using a market simulation model of ISO-NE's capacity market. The model first constructs supply and demand curves and then "clears" the market by determining the prices and quantities that correspond with the intersection of the supply and demand curves. **Figure 14** illustrates market clearing for one particular scenario: the forward-annual market structure for the 2028-29 commitment period. The supply curve reflects the assumed resource mix and the factors discussed below in **Section V.C.1** that determine their offers. The demand curve, as discussed in **Section V.C.2**, is based on the adjusted Net ICR and Net CONE values. The market clears at the intersection of the two curves, which determines the clearing price and the quantity of capacity awarded a CSO.[138] Capacity resources on the supply curve to the left of the intersection are resources that are awarded a CSO in the auction, and resources on the supply curve to the right of the intersection are units that are not awarded a CSO.

In this section, we provide the details of how these supply and demand curves are determined.

In our analysis, we compare outcomes under the current status quo (forward-annual) market structure against hypothetical prompt and seasonal market structures, including prompt-annual, forward-seasonal, and prompt-seasonal markets. Our analysis focuses on the *differences* between these alternatives and is not intended to be a *forecast* of future market outcomes. Future market outcomes are uncertain, but by holding constant assumptions across alternatives we can develop reliable assessments of the impacts of market alternatives despite uncertainty about market dynamics. Thus, when evaluating outputs of the simulations, including market clearing prices and quantities, we consider differences in outcomes as indicative impacts of moving from the current market structure to each of the aforementioned design concepts. Where feasible, the model captures salient differences between the current forward-annual market and these alternative market design concepts, but not all aspects and changes are quantifiable. The quantitative analysis complements our analytic and qualitative assessment of these alternatives in **Sections III and IV**.

[138] This description of market-clearing is simplified from the actual auction process, which is more complex due to non-rationable offers.

Figure 14. Simulated Forward-Annual Capacity Market, 2028-29 Commitment Period



To simplify the analysis, we assume the entire region is represented in a single capacity zone.[139] The model's flexibility allows the analysis of different scenarios – below, we describe scenarios with different assumed resource mixes (i.e., two resource mixes for 2034 representing different levels of electricity sector decarbonization) and varying assumptions about potential differences between forecasted and realized installed capacity requirements. To simulate market clearing, the model orders the relevant competitive supply bids of individual resources and solves for the market clearing price and quantity awarded CSOs given the relevant demand curve. The supply and demand curves in each market design incorporate current rules and account for the proposed changes based on the Resource Capacity Accreditation ("RCA") marginal reliability impact ("MRI") design and associated revisions to the resource accreditation factors. The revised resource accreditation factors measure a resource's contribution to resource adequacy (its MRI) relative to that of a *perfect* resource. These factors ("rMRIs") are assumed to vary based on the market design and are explained in greater detail below and in **Sections III.B.1.b and IV.A.**

To account for changes in market structures, the model adjusts the demand and supply curves as needed. When considering a shift from the current forward-annual capacity market to a prompt-annual market, changes in the supply curve include accounting for reduced deficiency and commitment risk, changes in resource accreditation factors, and exclusion of annualized capital costs for new resources. The model assumes no variation in the underlying parameters of the demand curve between a forward and a prompt market structure except for scenarios with

[139] Across auctions, the ISO-NE capacity market has generally cleared at one price for all zones including the most recent auction and six of the last eight auctions.

differences in assumed Net ICR. When considering a shift to a forward- or prompt-seasonal capacity market, changes in the supply curve include accounting for differences in going forward costs in each season (given assumed winterization costs) and seasonal resource accreditation (i.e., rMRI). Changes in the demand curve stem from adjustments to reflect differences in reliability risks between seasons.

B. Scenarios Evaluated

To better understand potential outcomes of a shift to a prompt and/or seasonal market, multiple scenarios reflecting a variety of market circumstances were evaluated. These scenarios are performed to evaluate the sensitivity of the modeling results to different input assumptions. More details on the input assumptions consistent across all scenarios and on the differences between scenarios are provided in **Section V.C.**

We evaluate two future commitment periods: 2028-2029 and 2034-2035. Two alternative resource mixes for the 2034-35 commitment period are evaluated given the uncertainties in projecting the resource mix more than a decade into the future. The two alternatives reflect different levels of decarbonization of the electricity sector. Both alternatives assume levels of storage and renewables consistent with state legislated procurements and legislated targets. The less aggressive "high carbon" mix makes no assumptions about additional retirements beyond those currently announced and no assumptions about resource additions beyond the state legislated procurements and targets. The more aggressive "low carbon" mix assumes resources designated as "at risk of retiring" by ISO-NE[140] are no longer in-service by the 2034-35 commitment period and that these retiring resources are replaced by a similarly accredited mix of renewables and battery storage resources. The "low carbon" resource mix is expected to result in lower total carbon emissions than the "high carbon" mix. We evaluate these scenarios in order to evaluate if the model's results are sensitive to how aggressive the region decarbonizes the electricity sector.

C. Data and Assumptions

The capacity market simulation model requires many data inputs and assumptions to simulate differences between the different market constructs. This section discusses the inputs and assumptions used to construct the two key components of the capacity market auction: (1) the offer supply curve, consisting of resource offers, and (2) the ISO-NE administrative demand curve for capacity to meet resource adequacy. Additional details on the inputs and assumptions are available in the Appendix.

1. Supply Curve

a. Going Forward Costs

The supply curve comprises bids from individual resources. When resources participate in the capacity market, they base their offers on estimates of additional revenues needed to cover their costs and achieve a financial break-even point. Under the current market rules – i.e., a forward-annual market construct – this offer reflects a resource's going forward costs ("GFC") which equal estimated avoidable costs less expected net revenues:

$$Net\ GFC\ = Fixed\ Costs - NEAS\ Revenues - Net\ PFP\ Revenues + Risk\ Premium$$

[140] ISO-NE, "Power Plant Retirements," available at https://www.iso-ne.com/about/what-we-do/in-depth/power-plant-retirements.

The fixed costs – i.e., fixed O&M costs and on-going capital investment costs – represent the costs that could be avoided if the resource were to de-list. For new resources in a forward market, these could include annualized capital costs. In the model, estimates of each of these costs are based on publicly available sources.[141] Net energy and ancillary service ("NEAS") revenues are based on energy and ancillary services revenues net of variable and fuel costs. An energy market simulation ("EMS") model is used to estimate resource-specific net revenues. The EMS model minimizes total systems costs to meet hourly demand under assumptions of load and fuel prices consistent with the future modeled commitment periods.[142]

Net pay-for-performance ("PFP") revenues reflect expected pay-for-performance revenues calculated as:

$$Net\ PFP\ Revenues = PPR * (Average\ Performance - Balancing\ Ratio) * Scarcity\ Hours$$

where PPR is the capacity performance payment rate.[143] Average performance refers to how well the resource performs on average over the course of the year during reserve shortages, and scarcity hours is a measure of the expected number of reserve shortage hours.[144] Balancing ratio is an estimate of the average balancing ratio during reserve shortages over the course of the commitment period.[145] Depending on the resource, net PFP revenues may be positive or negative.

The premium accounts for reduced optionality and deficiency payment risk taken on by market participants under the current forward market structure when they commit resources three years in advance:

1. *Reduced Optionality and Increased Financial Risk*. Under the current forward market structure, the forward structure imposes certain costs on resources. First, the need for resources to commit capacity supply three years in advance diminishes resource value by limiting flexibility to retire, mothball, or supply capacity to another market in the future. Second, the need to take a forward position three years in advance imposes uncertainty on resources that introduces financial risk. To account for these costs of limiting the flexibility of resources to take any of these actions in the future, forward market offers include a premium calculated as 10 percent of a resource's going forward costs.[146] We will test the sensitivity of our results to an alternative assumption of a premium of 5% or 15% of a resource's going forward costs.

---

[141] Further details on fixed costs and sources are provided in the Appendix.

[142] Additional details on the EMS model are provided in the Appendix.

[143] The current capacity performance payment rate is $9,337 / MWh. ISO-NE, "Market Rule 1," Section 13, Docket #: ER22-1528-000, May 30, 2022, p. 205, available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf.

[144] ISO-NE, "Estimated Hours of System Operation Reserve Deficiency for the 2027-2028 Capacity Commitment Period," October 19, 2023, available at https://www.iso-ne.com/static-assets/documents/100004/a04_2023_10_18_pspc_reserve_deficiency_hours_ccp2027-2028.pdf. We do not vary the PFP revenues seasonally.

[145] Capacity balancing ratio is calculated by ISO-NE using the formula (Load + Reserve Requirement)/Total Capacity Obligation. For further discussion of the calculation of PFP revenues, *see* ISO-NE, "Market Rule 1," Section 13, Docket #: ER22-1528-000, May 30, 2022, available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf.

[146] Some analyses find large increases in plant value when accounting for the option value of mothballing, although these values would be context and assumption dependent. For example, Rogues, Fabien, William Nuttal and David Newbery, "Using Probabilistic Analysis to Value Power Generation Investments under Uncertainty," CWPE 0650 and EPRG 065, July 2006. For example, in PJM, capacity resources are allowed to apply a 10 percent cost adder to their offers, *see* PJM, "PJM Open Access Transmission Tariff," Attachment DD. 6.8 Avoidable Cost Definition available here https://pjm.com/directory/merged-tariffs/oatt.pdf. In ISO-NE, resource offers are allowed to include any additional risks and opportunity costs that are not reflected in their going forward costs but that can be quantified and supported analytically. ISO-NE, "Market Rule 1," Section 13.1.2.3.2.1.4-5, Docket # ER23-911-000, Effective Date: March 21, 2023. By contrast, in the NYISO ICAP market, offers should not exceed a resource's going forward costs, which includes no provision

2. *Deficiency Payment Risk*. Under the current market rules, if a resource has taken a CSO but is not in-service by the corresponding commitment period, the resource faces a risk of deficiency penalties if they are not able to sell out of their commitment.[147] To account for the deficiency risk in a forward market, offers of certain unit types are increased based on the frequency of significant generator derates in ISO-NE from 2018-2023.[148]

Capacity supply offers in the model include a minimum offer reflecting PFP risk. When a resource takes a CSO, it forgoes capacity performance payments. When taking a CSO, a rational resource would take into consideration such foregone expected revenues. To account for this in the model, a resource's offer equals or exceeds a minimum offer[149] equivalent to these foregone expected revenues calculated as:

$$Minimum\ offer = PPR * Scarcity\ Hours * Balancing\ Ratio$$

For simplicity, we assume that all offers are rationable (i.e., resources may be awarded a CSO for a quantity of capacity less than their full offer).

b. Capacity Accreditation

Under the current market rules, the capacity market is a market for qualified capacity. However, ISO-NE is undertaking enhancements to the procedures for capacity accreditation through its RCA project. While proposed changes are under development, we assume implementation of RCA enhancements based on the design principles developed by ISO-NE. Under these principles, the capacity market in the future will be a market for qualified marginal reliability impact capacity ("QMRIC").[150] In order to be consistent with the upcoming changes to capacity accreditation, the model defines resource offers, and capacity, in terms of QMRIC. Below describes the general process for determining each resource's rMRI value. As described in **Section III.B.1.b,** the rMRI values for certain unit types are expected to differ between the forward and prompt markets. The modeling assumptions that capture differences between the forward and the prompt are discussed further in **Section V.C.1.d**. In addition, as described in **Section IV.B**, the rMRI values will differ for certain unit types between the annual and seasonal market structures. The modeling assumptions that capture seasonal differences are discussed further in **Section V.C.1.e**.

Resource capacity is translated into QMRIC by scaling each resource's accreditation relative to that of a perfect resource. However, ISO-NE's ongoing RCA MRI analysis reported only preliminary resource accreditation factors, rMRIs, for the FCA-16 capacity commitment period (2025-26). The RCA MRI analysis is ongoing and rMRIs will be updated in the coming year. Thus, the model uses proxy values for seasonal and annual rMRIs that vary from year-to-year and seasonally (i.e., summer/winter) consistent with assumed changes to the mix of capacity resources in

---

for amounts other than avoided costs associated with mothballing (for one year) or retirement. NYISO, "NYISO Tariffs," Section 23.2.1, 23.4.5.2-3.

[147] Deficiency risks are discussed in more detail in **Section III.B.1.c**.

[148] For more on deficiency risk calculations, see **Appendix Section VII.A.3.e**.

[149] The EMS does not simulate revenues outside of the energy and ancillary service markets. To simplify the analysis, we assume that certain resource types that expect significant revenues outside of the energy simulation – i.e., resources that receive state subsidies or contracts (e.g., renewables and battery storage) and resources with alternative sources of revenue (e.g., biomass and municipal solid waste) – offer capacity at the minimum offer. Thus, these resources are assumed to be inframarginal to the market-clearing offers.

[150] ISO-NE, "Resource Capacity Accreditation in the Forward Capacity Market," MRI-based conceptual design, July 12, 2022, p. 41, available at https://www.iso-ne.com/static-assets/documents/2022/07/a02a_mc_2022_07_12-14_rca_iso_presentation_conceptual_design.pptx.

the system. Using these proxy values, we can capture variation in capacity accreditation for the prompt, annual and seasonal market structures evaluated. The resulting proxy rMRI values are consistent with design principles and available analyses (from multiple RTOs) but are not forecasts of rMRI values and do not reflect on-going work in the RCA project.

The model makes the following assumptions in estimating proxy rMRI values for the 2028-29 commitment period under the current market structure (forward-annual auction):

- For all thermal resources (except for some natural gas-only resources which are assumed to not have firm fuel contracts), imports, active demand response, and dispatchable hydro, rMRI is approximated using resource class historical EFORd values.[151]
- For natural gas-only resources that are assumed to not have firm fuel arrangements, rMRI is reduced to reflect the possibility of limited gas availability for some part of the year.
- For renewable resources, the latest annual values from ISO-NE's marginal reliability analysis for FCA 16 are used as a starting point.[152] In the model, rMRI values are changed to account for expected resource additions between 2025-26 and 2028-29. Publicly available data from other RTOs is used to inform the adjustment in rMRI values due to expected resource additions.[153]
- For 2-hour energy storage, the rMRI values come from the latest annual values from ISO-NE's marginal reliability analysis.[154] 4-hour storage rMRIs are derived from the difference between 2-hour and 4-hour rMRIs as depicted by a hypothetical storage rMRI curve in the latest ISO-NE marginal reliability analysis.[155]

The assumed proxy rMRIs for the 2028-2029 commitment period under a forward market structure are shown in **Table 4** and discussed in more detail in **Section IV.B.** The basis and assumptions for the accreditation values used in the other market scenarios/commitment periods are described in **Sections V.C.1.d and V.C.1.e** below. Additional detail and the resulting rMRI values for resources for which accreditation is assumed to change between commitment periods and across different market structures can be found in the Appendix.

c. Resource Mix

For the 2028-29 commitment period, the resources participating in the capacity auction include: (1) existing units that offered into FCA 17 without announced retirement dates, (2) new units that cleared capacity in FCA 17, and (3) additional storage and renewables consistent with state legislated procurements and legislated targets. **Table 6** summarizes the resources in this third category.

Table 6 also summarizes the differences between the 2028-29 resource mix and the two alternative resource mixes for the 2034-35 commitment period. The first, a high carbon resource mix, assumes that (1) additional battery storage resources will be added consistent with the average annual new capacity cleared in three most recent

[151] ISO-NE, "NERC GADS EFORd Class Averages as used by ISO New England", p. 3, available at https://www.iso-ne.com/static-assets/documents/genrtion_resrcs/gads/class_ave_2010.pdf.

[152] ISO-NE, "Resource Capacity Accreditation in the Forward Capacity Market, FCA16 Baseline Case Accreditation," NEPOOL Markets Committee, April 11-13, 2023, pp. 31-33.

[153] Details on the methodology used to derive these factors can be found in the **Appendix Section VII.A.1**.

[154] ISO-NE, "Resource Capacity Accreditation in the Forward Capacity Market, FCA16 Baseline Case Accreditation," NEPOOL Markets Committee, April 11-13, 2023, pp.31-33.

[155] ISO-NE, "Resource Capacity Accreditation in the Forward Capacity Market, FCA16 Baseline Case Accreditation," NEPOOL Markets Committee, April 11-13, 2023, p. 36.

capacity auctions and (2) additional renewable resources will be added consistent with current State policies. No additional retirements beyond those currently announced are assumed in the high carbon mix.

Table 6. Assumed Capacity Market Supply Additions Incremental to Existing Units and New Units with a CSO Consistent with State Legislated Procurements and State Environmental Goals

	Nameplate Capacity Additions by Resource Class (MW)				
Commitment Period	**Solar**	**Storage**	**Offshore Wind**	**Onshore Wind**	**NECEC**
2028-2029	2,921	405			1,090
2034-2035 High Carbon	1,460	2,392	7,096		
2034-2035 Low Carbon	6,460	6,892	18,096	2,000	

Notes:
[1] NECEC stands for New England Clean Energy Connect.
[2] 2028-2029 and 2034-2035 High Carbon capacity additions are based on existing state legislated procurements and environmental goals. Capacity additions in 2034-2035 High Carbon and 2034-2035 Low Carbon scenario are incremental to 2028-2029 capacity additions.
[3] 2034-2035 Low Carbon scenario additionally assumes fuel oil and coal generators identified as "at risk" by ISO-NE retire prior to the commitment period. 2034-2035 Low Carbon capacity additions are calculated to replace QMRIC of coal and some oil units which are assumed to be retired by 2034 in the low carbon scenario.
Sources:
[A] U.S. Department of Energy, "2022 Offshore Wind Market Report," August 2022, available at https://www.energy.gov/sites/default/files/2022-08/offshore_wind_market_report_2022.pdf.
[B] "About Revolution Wind – Project at a glance," available at https://revolution-wind.com/about-revolutionwind.
[C] Beiter, Philipp, et. al., "Comparing Offshore Wind Energy Procurement and Project Revenue Sources Across U.S. States," National Renewable Energy Laboratory, June 2020, available at https://www.nrel.gov/docs/fy20osti/76079.pdf.
[D] Massachusetts Governor's Press Office, "Governor Baker Signs Climate Legislation to Reduce Greenhouse Gas Emissions, Protect Environmental Justice Communities," March 26, 2021, available at https://www.mass.gov/news/governor-baker-signs-climate-legislation-to-reduce-greenhouse-gas-emissions-protectenvironmental-justice-communities; Massachusetts Department of Energy Resources, "Solar Massachusetts Renewable Target (SMART) Program," 2021, available at https://www.mass.gov/info-details/solar-massachusetts-renewable-target-smart-program.
[E] Connecticut Office of Governor Dannel P. Malloy – Archive, "Gov. Malloy Announces Zero-Carbon Resource Selections," December 28, 2018, available at https://portal.ct.gov/Malloy-Archive/Press-Room/PressReleases/2018/12-2018/Gov-Malloy-Announces-Zero-Carbon-Resource-Selections.
[F] RI.gov, "Raimondo calls for up to 600 MW of new offshore wind energy for Rhode Island," October 27, 2020, available at https://www.ri.gov/press/view/39674; Faulkner, Tim and ecoRI News staff, "Massive Solar Facility Would Displace Farmland, Forest," November 25, 2020, available at https://www.ecori.org/renewableenergy/2020/11/23/conn-solar-farm-criticized-for-displacing-farmland-and-woodlands.
[G] "Power Purchase Agreement for Firm Qualified Energy from Hydroelectric Generation between NSTAR Electric Company d/b/a Eversource Energy and H.Q. Energy Services (U.S.) Inc.," Exhibit JU-3-A, June 13, 2018, available at https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9636857.
[H] ISO-NE, "Power Plant Retirements," available at https://www.iso-ne.com/about/what-we-do/in-depth/power-plant-retirements.

The second, a low carbon resource mix, assumes a more aggressive level of electricity sector decarbonization that may better align with the states' long-term environmental objectives. This resource mix assumes that the coal and oil-fired generation units designated as "at risk" by ISO-NE retire prior to the 2034-35 commitment period.[156] This amounts to 4.5 GW of nameplate capacity and 3.9 GW of QMRIC. The retired QMRIC capacity is replaced by an approximately equivalent amount of QMRIC capacity of new storage and renewable resources that takes into

[156] ISO-NE, "Power Plant Retirement," available at https://www.iso-ne.com/about/what-we-do/in-depth/power-plant-retirements.

account that rMRIs for these resources are adjusted to reflect their increased capacity additions in this scenario. This adjustment is performed in the same way as the adjustment under the high carbon 2034-35 resource mix. Given the lower renewable and storage rMRIs in a more decarbonized scenario, to replace the retired QMRIC, the low carbon resource mix assumes an additional 11 GW of offshore wind, 2 GW of onshore wind, 5 GW of solar, and 4.5 GW of 4-hour storage.

For both commitment periods, we assume that 2 GW of gas-only generators make offers with commitments to obtain firm fuel arrangements for the winter. The remaining gas-only generators are assumed to make offers without firm fuel commitments. In addition, we assume no entry of additional units.

d. Changes in Supply Offers Moving from a Forward to a Prompt Market Structure

Under a prompt market, the capacity auction occurs closer to the commitment period than under a forward market. Given this difference in timing, we assume two changes in the modeled supply curve offers under a prompt market structure relative to a forward market structure.

First, with a prompt market, resources face less uncertainty and less financial risk regarding their ability to fulfill their CSO and do not forgo optionality constraints of cleared forward market offers. Given these changes, the forward market adjustments in the offers that account for greater financial risk, reduced optionality and deficiency payment risk are removed given that the decision to commit to providing capacity is taken closer to the delivery period. The result is that offer prices are lower under a prompt than a forward market. See **Section III.B** for further discussion.

Second, accreditation factors will differ for certain unit types between a forward and a prompt auction. Under a forward market, rMRI values are fixed between the time of the FCA and the commitment period. However, resource rMRIs may differ depending on whether calculated ahead of a forward or prompt auction. As is discussed in **Section III.B.1.b**, the rMRI values under a prompt auction will tend to be a more accurate reflection of a resources reliability value as they reflect more up to date information about the overall resource mix, system demand, and other factors that may affect rMRI values. For intermittent renewable resources and storage resources we assume that rMRI values would be expected to decrease given increasing amounts of similar resources assumed to enter the system.[157] Therefore, for a given commitment period, rMRI values are assumed to differ in a prompt market structure relative to a forward market structure for intermittent renewable and storage resources. The assumed rMRI values for the prompt market for the 2028-29 commitment period that differ from the forward (shown in **Table 4**) are shown in **Table 7** below and for the 2034-35 commitment period (high carbon and low carbon scenarios) are presented in the Appendix. In each case, the reduction in rMRI values in a prompt auction result in lower QMRIC quantities and higher offers for intermittent renewable resources and storage.

[157] See **Section III.B.1.b** for a qualitative discussion in support of this assumption.

Table 7. Assumed Accreditation Factors by Resource Class for 2028-29 Commitment Period Prompt Market Structure that Differ from 2028-29 Commitment Period Forward Market Assumptions

	rMRI		
Resource Class	**Annual**	**Summer**	**Winter**
2 hour ES	0.494	0.529	0.386
4 hour ES	0.754	0.809	0.570
Offshore Wind	0.301	0.212	0.339
Onshore Wind	0.157	0.112	0.175
Solar	0.109	0.148	0.011

Notes:
[1] Acronyms: ES-energy storage.
[2] Energy storage rMRIs are based on ISO-NE's latest marginal reliability analysis results and reduced to account for differences in accreditation between a forward and prompt capacity market.
[3] Onshore and offshore wind values are calculated using ISO-NE's blended wind results from the latest marginal reliability analysis and PJM's breakdown shape from their 2026-27 capacity market proposal. Offshore wind values are reduced in the 2028-29 forward market to account for the rest of Vineyard Wind coming online by 2025. Likewise, offshore wind 2028-29 prompt market values above are reduced compared to 2028-29 forward market values assuming that Revolution Wind comes online by 2028.
[4] Solar values are calculated using ISO-NE's results from the latest marginal reliability analysis and reduced to account for assumed solar PV additions coming online by 2028 and for differences in accreditation between a forward and a prompt capacity market.
[5] The methodology used to calculate prompt market rMRIs using forward market rMRIs as starting points is described in **Appendix Section VII.A.1**.
Sources:
[A] ISO-NE, "Resource Capacity Accreditation in the Forward Capacity Market: FCA16 Baseline Case Accreditation," available at https://www.iso-ne.com/static-assets/documents/2023/04/a05f_mc_2023_04_11-13_rca_impact_analysis.pptx.
[B] Capacity Market Reform: PJM Proposal, Slide 61,available at: https://www.pjm.com/-/media/committees-groups/cifp-ra/2023/20230727/20230727-item-02a---cifp---pjm-proposal-update---july-27.ashx.
[C] Velocity Suite.
[D] PJM, "Interconnection Queue Data," available at https://www.pjm.com/planning/service-requests/services-request-status.
[E] Potomac Economics, "2022 Assessment of the ISO New England Electricity Markets," June 2023.

e. Changes in Supply Offers for Moving from an Annual to a Seasonal Market Structure

The model under a seasonal market structure simulates two seasons – summer and winter – to represent the seasonal market structure. In principle, more than two seasons could be modeled, but two are assumed for simplicity.

Differences between the supply offer curves of annual and seasonal market structures are driven by seasonal differences in (1) NEAS revenues, (2) fixed costs, and (3) rMRIs. Other components of going forward costs, such as expected PFP revenues, are assumed to be split evenly between seasons, although in practice they may differ given difference in between assumed summer and winter risk. See **Section IV.C.2** for further discussion of seasonal differences in going forward costs that are not captured by our model.

First, resources differ in their seasonal revenues. For summer, NEAS revenues are estimated for May through October. For winter, NEAS revenues are estimated for November through April. For most units, net revenues in the EMS are higher in the winter than in the summer because fuel prices – and thus electricity prices – are higher in the winter than in the summer. Thus, holding all else constant, offers for most units are higher in the summer and lower in the winter. See **Section IV.C.2** for further discussion.

Second, fixed costs are assumed to be 10% higher in the winter than the summer due to additional operations, capital investments, and maintenance associated with winterization. See **Section IV.C.1** for further discussion.

Third, as discussed in **Section IV.B**, resource accreditation factors differ between seasons for certain unit types. Under a seasonal market structure, a resource's accreditation is expected to be based upon the reliability that the resource provides during each season. These differences are evident particularly for intermittent renewable resources and storage, whose output is tied to weather and system conditions. As weather patterns vary across seasons, the accreditation of these resources is assumed to vary accordingly. In addition, gas-only resources without firmed-up fuel supply are assumed to receive season-specific accreditation, with lower accreditation in the winter. This adjustment reflects the dependency of their output on gas availability, which can be limited in New England during cold winter days. Seasonal accreditation for other unit types is equivalent to their annual value. The seasonal differences for the forward market for the 2028-29 commitment period are summarized in **Table 4**. Differences for these values for the prompt market are summarized in **Table 7**. Differences for the 2034-35 commitment period are summarized in the Appendix. Details on specific data used and assumptions made in calculating seasonal rMRIs for each commitment period and market scenario can be found in the Appendix. Differences in rMRI values translate to both vertical and horizontal shifts in the offer curve.

2. Demand Curve

The capacity market in ISO-NE clears the supply of resource offers against a downward sloping demand curve that is determined based on the system's reliability and the net cost of new entry. Under the current rules, the downward sloping demand curve is determined by a non-linear function that reflects the marginal reliability impact of increasing capacity. ISO-NE applies the GE MARS model to derive the MRI values as a function of capacity to define this curve. The MRI-quantity curve is then converted to a price-quantity curve by scaling in a way such that the price at the intersection of the curve with the Net ICR equals the cost of new entry for a reference unit. The final parameter defining the curve is a price cap set at 1.6 times Net CONE.[158]

The model adopts the same MRI-quantity curve structure where the starting values used to construct the demand curve in each of the market designs are the FCA 18 system-wide MRI values published by ISO-NE.[159] The reference unit is assumed to be a simple combustion dual fuel turbine in accordance with recommendations from the most recent Net CONE/offer review trigger price ("ORTP") Study.[160] Net ICR is set at the forecasted Net ICR in the ISO-NE 2023 Regional System Plan for the 2028-29 commitment period.[161] The forecast is used to extrapolate Net ICR for the 2034-2035 commitment period. In each market design, the demand curve is scaled to create a QMRIC-

[158] ISO-NE, "Market Rule 1," Section 13, available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf. In the model, Net CONE is assumed to be equal to the 2026-2027 CCP Net CONE, available at https://www.iso-ne.com/static-assets/documents/2015/09/fca_parameters_final_table.xlsx.

[159] ISO-NE, "FCA 18 Demand Curve Values," revised August 14, 2023, available at https://www.iso-ne.com/static-assets/documents/2023/08/a03_2023_08_23_pspc_fca_18_demand_curves.xlsx.

[160] ISO-NE, "ISO-NE Net CONE and ORTP Analysis. An Evaluation of the Net Cost of New Entry Parameter to be used in the Forward Capacity Auction FCA-16 and Forward," September 3, 2020, p. 9, available at https://www.iso-ne.com/static-assets/documents/2020/09/a6_a_iii_draft_report_net_cone_and_ortp_analysis.docx.

[161] ISO-NE, "2023 Regional System Plan," Appendix Table 23, available at https://www.iso-ne.com/static-assets/documents/100004/rsp23-datasets-appendix-10-2023-draft-rsp23-public-meeting.xlsx.

based curve in accordance with the RCA design.[162] The demand curve will be anchored by an adjusted Net ICR which results from scaling Net ICR by the rMRI of the resource mix. The Appendix provides more details on the steps taken to convert the demand curve to the QMRIC-based demand curve.

a. Differences in the Demand Curve for a Forward and Prompt Market

The demand curve parameters are assumed to be unchanged between a forward and prompt market with the exception of Net ICR.

An important difference between forward and prompt markets is certainty of demand used to clear supply. With a forward market, the Net ICR reflects demand forecasts that will be higher or lower than the realized demand that would be the basis for a Net ICR in a prompt market. Thus, even if on *average* the Net ICR is similar between the forward and the prompt, in practice the forecast will be imprecise due to normal forecast uncertainty. This difference is discussed further in **Section III.B.2.**

In order to capture the uncertainty of the Net ICR for a forward relative to the prompt market, three forward scenarios with different Net ICR values are modeled: (1) no difference in Net ICR between prompt and forward, (2) Net ICR 1,000 MW *greater* in forward than prompt, and (3) Net ICR 1,000 MW *less* in forward than prompt. The differences in Net ICR will result in horizontal shifts in the demand curve.

The assumption that the distribution of forecast uncertainty is centered at zero may be conservative given the historical relationship between ICR forecasts for the FCA and the final ICR estimates prior to the commitment period. We have not, however, undertaken assessment to determine whether an expected difference between FCA and final ICR values would be appropriate for two reasons. First, as discussed in **Section III.B.2,** there have been many complex factors that affected historical forecasts, and not all these factors would be informative about "predictable" future forecast uncertainty. Second, looking forward, there are other potential factors not observed historically that may impact forecast uncertainty, such as changes in demand for electricity due to policy ambitions for economy-wide decarbonization.

b. Differences in the Demand Curve for an Annual and Seasonal Market

Under a seasonal capacity market framework, each seasonal demand curve reflects the reliability needs for that season. As a result, if there are differences in reliability risks between the seasons, there will be differences in the demand curves between seasonal and annual markets. Below, we outline an approach to deriving seasonal demand curves that we use for our modeling assumptions. The approach described below is not the only possible approach. If the ISO chooses to pursue seasonal demand curves, further assessment would be necessary to determine the preferred approach for the region. See **Section IV.A** for further discussion of seasonal demand for resource adequacy.

For the 2028-29 commitment period, it is assumed that 70 percent of the reliability risk is in the summer and 30 percent of the reliability risk is in the winter.[163] Net CONE in the model is adjusted to reflect the differences in

[162] ISO-NE, "Resource Capacity Accreditation in the Forward Capacity Market. Continued Discussion on Conceptual Design," NEPOOL Markets and Reliability Committees, September 13-14, 2022, available at https://www.iso-ne.com/static-assets/documents/2022/09/a05a_mc_2022_09_13-14_rca_conceptual_design_presentation_.pptx.

[163] Assessments of the seasonal risk in the region are ongoing, however the values presented in the April 2023 ISO-NE marginal reliability analysis suggested around 80 percent reliability risk in the summer and 20 percent in the winter. ISO-NE, "Resource Capacity

reliability risk between the seasons.[164] Summer Net CONE, on a $/kw-month basis, is higher than the winter Net CONE to reflect the higher reliability risk, and higher than the annual Net CONE to account for the fact that in the model's seasonal market structure, resources generate revenue for half a year. Therefore, summer Net CONE is calculated by multiplying the annual Net CONE value by two, and then multiplying by 0.7. This change in Net CONE has two implications for the summer demand curve:

1. The auction price cap will be higher in the summer market compared to the annual and the winter market. This results in an upwards shift of the demand curve.
2. Under our set of assumptions, the slope of the demand curve calculated as the ratio of Net CONE to MRI "at criteria" will be steeper because an increment of capacity will be able to reduce unserved load by a greater amount.

For the winter market for the 2028-2029 commitment period, winter Net CONE is calculated by multiplying annual Net CONE by two, and then multiplying by 0.3. This results in winter Net CONE being lower than the annual Net CONE. The change in Net CONE has two implications for the winter demand curve:

1. The auction starting price will be lower in the winter market compared to the annual and the summer market. This results in a downwards shift of the demand curve.
2. Under our set of assumptions, the slope of the demand curve calculated as the ratio of Net CONE to MRI "at criteria" will be flatter because an increment of capacity will be able to reduce unserved load by a lesser amount.

For the 2034-35 commitment period, due to greater integration of renewables and further increasing winter peaks relative to summer peaks, more reliability risk is assumed to shift to the winter period. Thus, 60 percent of reliability risk is assumed in the summer and 40 percent is assumed in the winter, as opposed to 70 percent and 30 percent, respectively, for the 2028-29 commitment period. Calculations of the annual and seasonal demand curves for the 2034-35 commitment period are otherwise performed the same as the 2028-29 commitment period. However, in the case of the 2034-35 commitment period, the contrast between seasonal curves is less pronounced given that summer and winter reliability risks are more similar.

D. Results

This section summarizes the results the quantitative modeling of the capacity market under the prompt and seasonal alternative market structures. We begin by discussing the features of the model within the context of the results for the current market structure – a forward-annual capacity market – for the 2028-29 commitment period. Second, we develop insights about the choice between forward and prompt alternative designs. Third, we assess the annual and seasonal design. Finally, we compare the forward-annual with a prompt-seasonal. We provide tables and figures summarizing results, with further detail available in the appendix.

Accreditation in the Forward Capacity Market, FCA16 Baseline Accreditation Case," NEPOOL Market Committee, April 11-13, 2023, slide 22. These results are for FCA 16. Given expected increasing winter peaks relative to summer peaks, the model assumes that more reliability risk shifts to the winter by 2028-29.

[164] In practice, a move to a seasonal market would require further assessment of whether seasonal Net CONE values are needed or if it would remain exclusively an annual value. For our analysis, we break the annual value into summer and winter components, which we refer to as Summer and Winter Net CONE.

1. *Summary of Central Results*

The results of our central scenarios are summarized in **Table 8**. The table reports the clearing price, quantity of capacity awarded a CSO, and total auction payments (i.e., the clearing price multiplied by the quantity of awarded CSOs). Across all scenarios, capacity market prices range from $4.00 to $5.05 per kW-month, higher but consistent with recent market outcomes. Total payments range from $1.36 to $1.83 billion, with the average payment per MWh ranging from $8.69 to $10.44 per MWh. Across alternatives, the capacity market procures about 350 MW to 650 MW of capacity in excess of adjusted ICR.[165]

Table 8. Summary of Price, Quantities and Payments for Alternative Markets Structures

	Clearing Price ($/kW-month)	Capacity Awarded a CSO (MW)	Total CM Payments ($ M)	Avg. CM Payment ($/MWh)	Capacity Above Adjusted ICR (MW)
2028-2029					
Forward-Annual	$4.45	28,401	$1,515	$10.19	583
Prompt-Annual	$4.12	28,466	$1,406	$9.46	649
Forward-Seasonal	$4.28	28,352	$1,456	$9.80	534
Prompt-Seasonal	$4.00	28,410	$1,362	$9.17	592
2034-2035 High Carbon					
Forward-Annual	$4.62	30,278	$1,680	$9.56	390
Prompt-Annual	$4.19	30,327	$1,526	$8.69	439
Forward-Seasonal	$4.53	30,277	$1,646	$9.39	389
Prompt-Seasonal	$4.26	30,307	$1,551	$8.84	420
2034-2035 Low Carbon					
Forward-Annual	$4.83	30,255	$1,754	$9.98	368
Prompt-Annual	$5.05	30,232	$1,834	$10.44	344
Forward-Seasonal	$4.56	30,274	$1,656	$9.45	386
Prompt-Seasonal	$4.65	30,263	$1,689	$9.62	376

Table 9 compares price, quantity and total payments for each alternative market (i.e., prompt-annual, forward-seasonal, prompt-seasonal) to the forward-annual model run for the corresponding year/resource mix, while **Figure 15** provides these comparisons on percent terms in a figure.

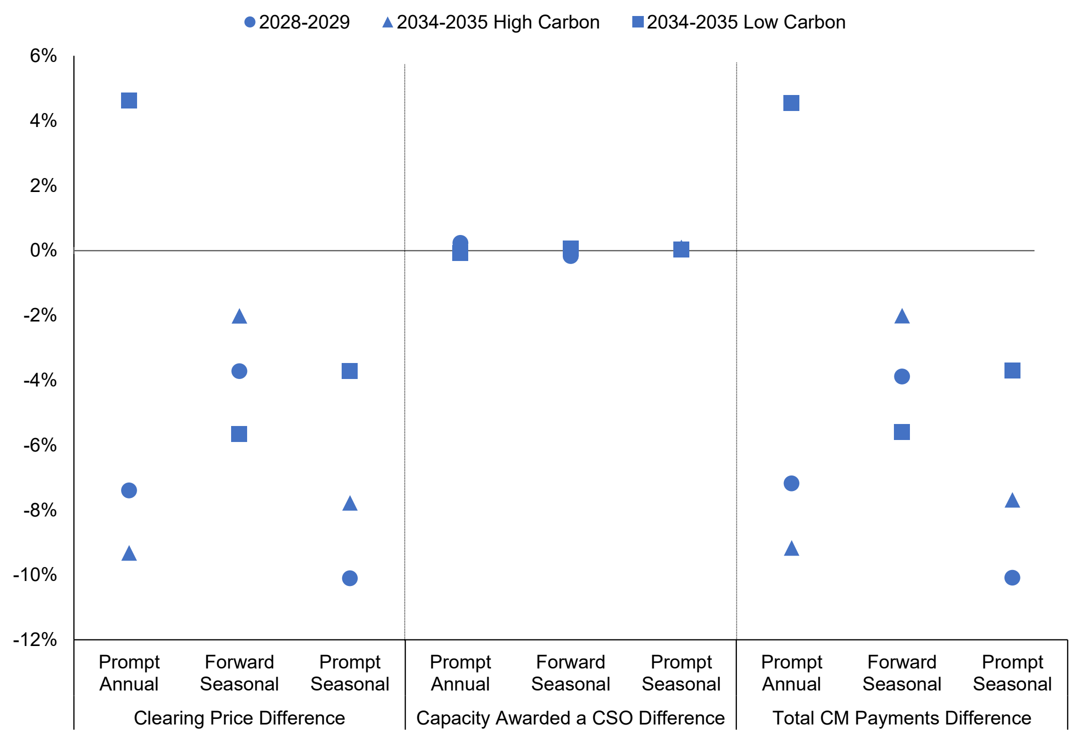
The prompt and seasonal market alternatives to the current FCM tend to lower prices and total payments, while producing comparatively small changes in the quantity of CSOs awarded. Across the nine scenarios presented in **Table 9**, prices and payments are lower in 8 of 9 scenarios, with prices and payments increasing for only the prompt-annual market in the 2034-35 Low Carbon scenario.

[165] In the discussion of the quantitative results, references to "adjusted ICR" or "ICR" refer to the Net ICR adjusted to be in terms of QMRIC instead of qualified capacity.

Table 9. Change in Prices, Quantities and Payments Relative to Forward-Annual Market Outcomes

	Clearing Price Difference ($/kW-month)	Capacity Awarded a CSO Difference (MW)	Total CM Payments Difference ($ M)	Clearing Price Difference (%)	Capacity Awarded a CSO Difference (%)	Total CM Payments Difference (%)
2028-2029						
Prompt-Annual	-$0.33	66	-$109	-7.39%	0.23%	-7.18%
Forward-Seasonal	-$0.17	-49	-$59	-3.72%	-0.17%	-3.89%
Prompt-Seasonal	-$0.45	9	-$153	-10.11%	0.03%	-10.09%
2034-2035 High Carbon						
Prompt-Annual	-$0.43	49	-$154	-9.32%	0.16%	-9.16%
Forward-Seasonal	-$0.09	-1	-$34	-2.01%	0.00%	-2.01%
Prompt-Seasonal	-$0.36	30	-$129	-7.78%	0.10%	-7.68%
2034-2035 Low Carbon						
Prompt-Annual	$0.22	-23	$80	4.62%	-0.08%	4.54%
Forward-Seasonal	-$0.27	18	-$98	-5.65%	0.06%	-5.59%
Prompt-Seasonal	-$0.18	8	-$65	-3.71%	0.03%	-3.70%

Figure 15. Percent Change in Prices, Quantities and Payments Relative to Forward-Annual Market Outcomes



Across scenarios, changes in prices and payments are generally very similar because the changes in quantity across scenarios are proportionately small (i.e., less than 0.25%). This is not unexpected because while the demand curves are sloped, they are still inelastic. Thus, a change in price directly translates into a change in payment by relatively little change in quantity procured.

- For the prompt-annual market alternative, prices and costs are 7% and 9% lower in two cases (2028-29, 2034-35 High Carbon) and 5% higher in one case (relative to the FCM). These results are shown in the left column of **Figure 15**. Changes in total annual payments across scenarios are range from a reduction of $154 million to an increase of $80 million.
- The forward-seasonal market reduces prices and total payments in all central scenarios, with price and payment reductions ranging from 2 to 6 percent. Changes in total annual payments for these alternatives range from $34 to $98 million.
- The prompt-seasonal market alternative results in the lowest prices and total payments, on average – across scenarios, prices are lower by $0.33 per kW-month (7%) and payments are lower by $116 million annually (7%). Across scenarios, prices and payments are reduced by 3.7% to 10% compared to the current FCM.

The Average FCM Payment column is the Total CM Payments column divided by total load (in MWh).[166] The Capacity Above Adjusted ICR is the Capacity Awarded a CSO minus adjusted ICR, such that a positive value represents that the auction cleared above adjusted ICR, while a negative value indicates the auction cleared below the requirement.

As shown above, the results are sensitive to the assumed year and resource mix tested. Below, we further test the sensitivity of results to alternative assumptions for one key assumption: the forward premium. However, these tests encompass only a subset of relevant uncertainties. As noted above, our analysis makes certain conservative assumptions, such as those regarding forward demand forecasting uncertainty and winter gas firming. Our analysis does not account for all differences between market alternatives and does not account for certain market dynamics (e.g., entry/exit in response to changes in prices), and thus does not account for the full range of potential outcomes.

The next three subsections provide further details on the results for each of the alternative market concepts: prompt market, seasonal market, and combination of prompt and seasonal market.

2. *Assessment of Forward vs. Prompt Capacity Market Structure*

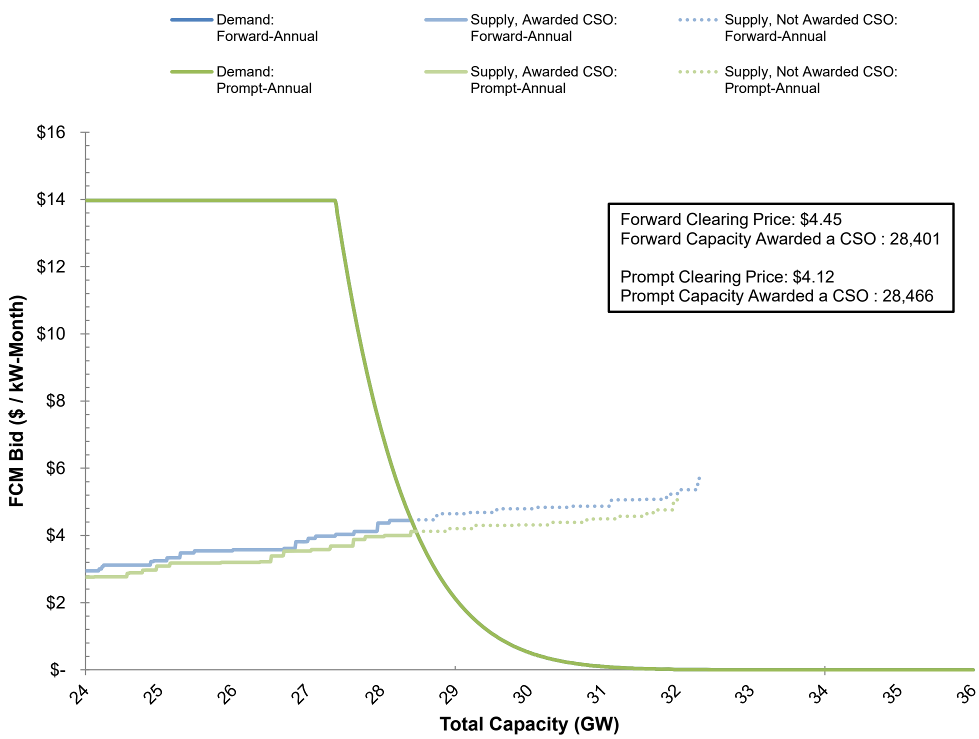
We first examine the prompt market structure, focusing on comparisons of the forward-annual and prompt-annual market structures. **Figure 16** shows market clearing for the forward-annual and prompt-annual for the 2028-29 commitment period. Changes in market outcomes reflect only differences in the supply curves between the forward and the prompt market, which are driven by two factors: lower opportunity costs and deficiency risk (shifting the offer supply curve downward) and reduced qualified capacity from lower rMRIs (thus shifting the offer supply curve to the left). As a result, prices are lower and quantities are higher with a prompt market (compared to a forward market). In each case, the supply curves are relatively flat at the intersection with the demand curve, resulting in proportionately smaller changes in quantity relative to price.

While we account for the effect of lower prompt market rMRIs on market-clearing, we have not yet quantified the corresponding degradation in capacity procured in the forward market as compared to the prompt market. That is,

[166] Total load is based on CELT forecasts from the 2023 report. The forecast data ends in 2032, thus 2034-35 load is extrapolated through 2035 based on 2023-2032 growth rates. ISO-NE, "2023 CELT Report," sheet "1.5.2 Energy."

the effective reliability achieved in the two auctions is not comparable due to the differences in rMRIs used to calculate capacity in each auction. Further analysis will investigate this effect.

Figure 16. Prompt-Annual Market (Compared to Forward-Annual), 2028-29 CCP



As discussed in **Section III.B.2**, a forward market relies on forecasts of demand made more than three years prior to the commitment period, while a prompt market relies on estimated demand shortly before the commitment period. To test the consequences of this uncertainty in comparison to a prompt market, we simulate forward market outcomes assuming three different levels of forecast uncertainty (- 1,000 MW, 0 MW, + 1,000 MW) and compare outcomes to the prompt market. This range bookends a range of uncertainty for ICR forecasts made three years in advance under a forward market. **Figure 17** presents the results visually for the 2028-29 commitment period, showing that a difference in Net ICR results in a horizontal shift in the demand curve. When Net ICR is lower than the original forecast, this is represented by a leftward shift in the demand curve, while when Net ICR is higher than originally forecasted, this is represented by a rightward shift in the demand curve. The supply curve is identical for all three forward scenarios.

Figure 17. Forward-Annual vs. Prompt-Annual Capacity Market, Forward with +/- 1,000 Net ICR Relative to Prompt, 2028-29 CCP

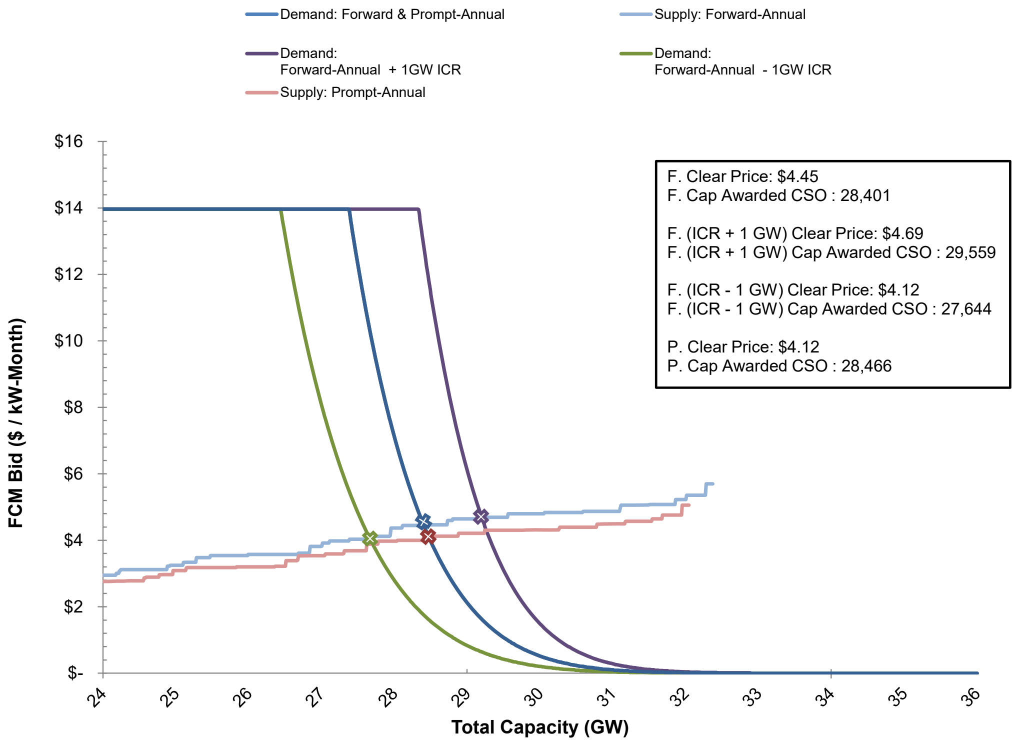


Table 10 provides the results of the analysis of forecast uncertainty. **Table 10** includes an estimate of the capacity above *final* ICR – that is, ICR prior to the commitment period. This measures how much capacity is procured in the forward auction compared to what is eventually needed at the commitment period. (This quantity differs from “Capacity Above Adjusted ICR” in **Table 8**, which measures procured capacity relative to ICR set for the auction.)

Table 10 shows that, across scenarios, uncertainty in forecast demand in a forward market creates uncertainty in market outcomes. When the forward market is run using forecast ICR that is “too low” *ex post* compared to final ICR, the clearing price, quantity of capacity awarded a CSO, and overall cost are all lower than the corresponding prompt market.[167] By contrast, when forecast ICR is higher than final Net ICR, the clearing price, quantity of capacity awarded a CSO, and overall cost are all higher.

[167] Figures analogous to **Figure 17** for other forward vs. prompt comparisons are presented in **Appendix Section VII.B.**

Table 10. Summary of Impact of Demand Forecast Uncertainty (± 1,000 MW) on Forward and Prompt Market Outcomes (with an Annual Market)

	Clearing Price ($/kW-month)	Capacity Awarded a CSO (MW)	Total CM Payments ($ M)	Avg. CM Payment ($/MWh)	Capacity Above Final Adjusted ICR (MW)
2028-2029					
Forward-Annual (Forecasted ICR < Final ICR)	$4.12	27,644	$1,366	$9.19	-174
Forward-Annual (Forecasted ICR = Final ICR)	$4.45	28,401	$1,515	$10.19	583
Forward-Annual (Forecasted ICR > Final ICR)	$4.69	29,559	$1,663	$11.19	1,742
Prompt-Annual	$4.12	28,466	$1,406	$9.46	649
2034-2035 High Carbon					
Forward-Annual (Forecasted ICR < Final ICR)	$4.02	29,546	$1,427	$8.12	-342
Forward-Annual (Forecasted ICR = Final ICR)	$4.62	30,278	$1,680	$9.56	390
Forward-Annual (Forecasted ICR > Final ICR)	$4.70	31,090	$1,755	$9.99	1,202
Prompt-Annual	$4.19	30,327	$1,526	$8.69	439
2034-2035 Low Carbon					
Forward-Annual (Forecasted ICR < Final ICR)	$4.49	29,482	$1,588	$9.04	-405
Forward-Annual (Forecasted ICR = Final ICR)	$4.83	30,255	$1,754	$9.98	368
Forward-Annual (Forecasted ICR > Final ICR)	$5.15	31,050	$1,918	$10.92	1,163
Prompt-Annual	$5.05	30,232	$1,834	$10.44	344

These differences in prices, quantities and payments are potentially large. **Table 11** provides the differences in price, quantity, and payment between the forward market with different degrees of forecast uncertainty and the corresponding prompt market. For example, payments under the prompt market can be as much as $256 million lower or $246 higher than with the forward market. Similar tables for the seasonal markets are provided in the appendix, and the results are qualitatively similar.

Figure 18 shows the variation in prices, quantity and cost arising from the forecast uncertainty (relative to the forward auction with a forecast delta of zero) across all of the annual and seasonal scenarios. The figure shows that use of a forward auction introduces variation in prices and payments ranging from a decrease of 13% and 15% to an increase of 10% and 12% respectively, while the quantity varies from a decrease of 3% to an increase of 4%.

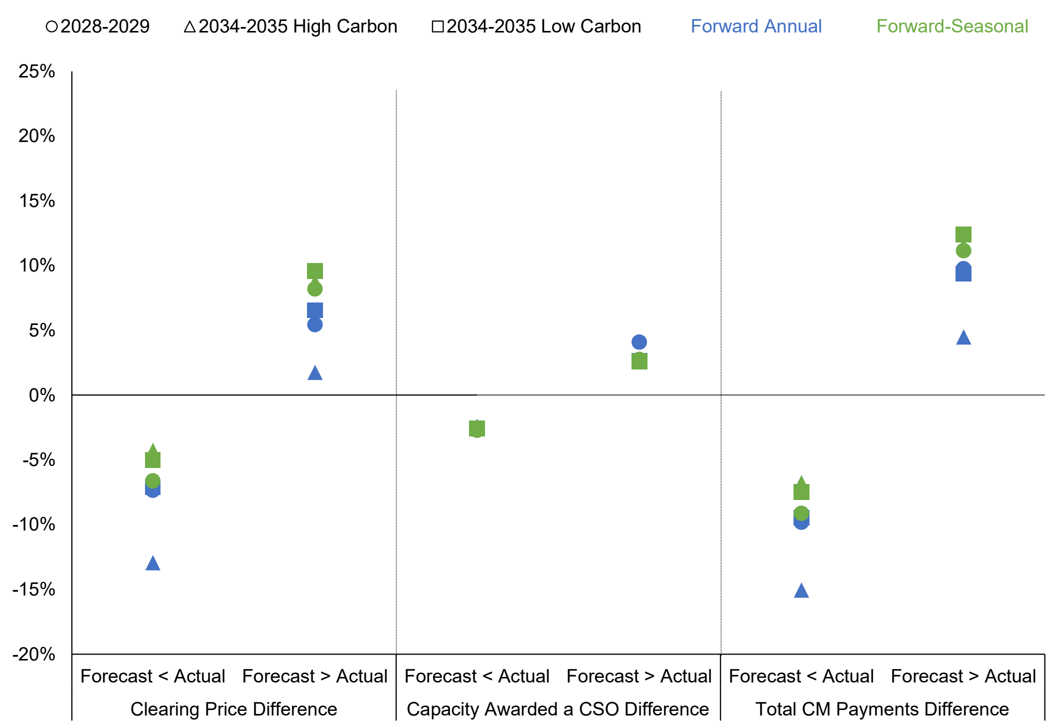
While variation in the quantity of resources is modest, the levels of procured capacity in the forward market can be lower than final ICR if the forecast is lower than the final demand. For example, as shown in **Table 10**, with the forward-annual market, when the forecast is 1,000 MW lower than the final ICR value, the procured capacity is 174 MW below ICR. Across the scenarios, these deficits range from 174 to 405 MW. If not made up through other means, such as the ARAs, the under-forecast could lead to reliability problems. While these differences may be mitigated by the ARAs to some degree, as discussed in **Section III**, likely adjustments are constrained by a number of factors such as the willingness of participants awarded CSOs to sell them back and potential supplies of new short-run capacity.

A prompt market effectively mitigates the forecast risk in a forward market. With the prompt market, demand is estimated shortly before the commitment period, thus avoiding the three years gap between the forward auction and the commitment period.

Table 11. Summary of Price and Cost Differences: Prompt-Annual Relative to Forward-Annual Market (Demand Forecast Uncertainty Scenario)

	Clearing Price Difference ($/kW-month)	Clearing Price Difference (%)	CM Payment Difference ($ M)	CM Payment Difference (%)
2028-2029				
Forecasted ICR < Final ICR	$0.00	-0.05%	$40	2.93%
Forecasted ICR = Final ICR	-$0.33	-7.39%	-$109	-7.18%
Forecasted ICR > Final ICR	-$0.57	-12.17%	-$256	-15.42%
2034-2035 High Carbon				
Forecasted ICR < Final ICR	$0.17	4.00%	$99	6.93%
Forecasted ICR = Final ICR	-$0.43	-9.32%	-$154	-9.16%
Forecasted ICR > Final ICR	-$0.51	-10.89%	-$229	-13.07%
2034-2035 Low Carbon				
Forecasted ICR < Final ICR	$0.57	12.63%	$246	15.50%
Forecasted ICR = Final ICR	$0.22	4.62%	$80	4.54%
Forecasted ICR > Final ICR	-$0.09	-1.81%	-$85	-4.41%

Figure 18. Forecast Uncertainty: Price, Quantity and Payment Difference Between Forward Market with Uncertain Demand (± 1,000 MW) Relative to FCM where Forecasted ICR = Final Adjusted ICR

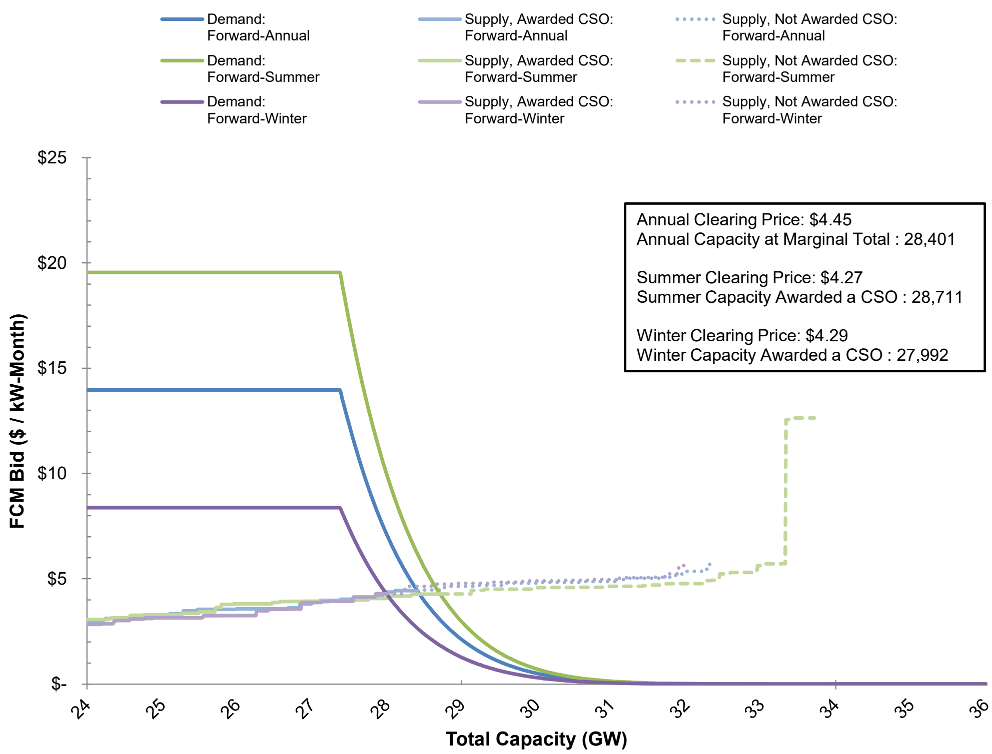


3. Assessment of Seasonal Capacity Market Structure

The current annual capacity market is tied to the summer period, procuring the same amount of capacity in each season. A shift to seasonal markets would account for differences in reliability risk across seasons, potentially resulting in a greater quantity of capacity awarded a CSO during periods of high reliability risk. The model under a seasonal market structure simulates two seasons – summer and winter. In principle, more than two seasons could be modeled, but two are assumed for simplicity.

Figure 19 compares results of the capacity auction simulation for a forward-annual with a forward-winter and forward-summer market structures for the 2028-29 commitment period. Figures illustrating market clearing for the 2034-35 scenarios are provided in the appendix. The differences between the summer and winter demand curves reflect the assumed differences in the importance of summer and winter reliability risks (with summer and winter accounting for 70% and 30% of reliability risk, respectively, for the 2028-29 commitment period).[168] For example, the summer curve is above the winter curve (and annual curve, reflecting the average of summer and winter risks) because for any given level of quantity, the marginal value of capacity is greater in the summer than the winter given the greater preponderance of risks in that season.[169]

Figure 19. Forward-Seasonal Market (Compared to Forward-Annual), 2028-29 CCP



[168] For the 2034-35 commitment period, winter reliability risk is assumed to increase relative to summer, resulting in a steeper winter curve, and a flatter summer curve, relative to the 2028-29 period.

[169] The assumed summer and winter curves have the same shape along the horizontal axis because of simplifying assumptions we make for the analysis. In practice, seasonal curves would likely have different shapes given the season-specific marginal value of capacity (as measured by the GE MARS simulations).

In addition, there are several differences between the supply curve under annual and seasonal markets as discussed in **Section V.C.1.e.** Ex ante, the net effect of the assumed differences in the seasonal supply curves relative to the annual supply curve is ambiguous – that is, they do not necessarily result in simple vertical or horizontal shifts in supply. However, at least for the units near the margin shown in **Figure 19**, the supply curves are very similar.[170]

With the seasonal market, annual market outcomes reflect outcomes of the summer and winter markets. **Table 12** illustrates these annual outcomes for the 2028-29 CCP, where all outcomes reflect averages across summer and winter seasons except for total CM payments, which is the sum of summer and winter payments. In each central scenario (including the 2034-35 scenarios), more capacity is procured in the summer compared to the winter. As shown in **Figure 19**, more quantity is procured in the summer because the demand curve is shifted to the right/upward, indicting a higher value of capacity in the summer versus the winter. In each season, the market clears capacity until the offer prices equal the demand curve. Given the relatively flat offer curves, price differences between seasons are relatively small. Any difference in relative prices reflects both (1) differences seasonal offer prices for a given level of supply (which is complex given the many factors affecting offers), and (2) the higher price from procuring summer than winter capacity (given that price rises with quantity, all else equal). Across the seasonal scenarios (including forward and prompt markets, shown in **Appendix Table 19**), summer prices are higher in 3 scenarios and lower in 3 scenarios.

Across scenarios, the average amount of seasonal capacity above Net ICR is similar to the annual in each scenario. However, these comparisons do not control for potential differences in the marginal value of capacity procured in summer, winter and annually.

Table 12. Summary of Seasonal Capacity Market Results: 2028-2029 Commitment Period

	Clearing Price ($/kW-month)	Capacity Awarded a CSO (MW)	Total CM Payments ($ M)	Avg. CM Payment ($/MWh)	Capacity Above Adjusted ICR (MW)
Forward-Annual	$4.45	28,401	$1,515	$10.19	583
Forward-Summer	$4.27	28,711	$736	$10.00	893
Forward-Winter	$4.29	27,992	$720	$9.60	175
Forward-Seasonal (Avg./Total)	$4.28	28,352	$1,456	$9.80	534
Prompt-Annual	$4.12	28,466	$1,406	$9.46	649
Prompt-Summer	$3.96	28,771	$684	$9.30	954
Prompt-Winter	$4.03	28,048	$678	$9.04	230
Prompt-Seasonal (Avg./Total)	$4.00	28,410	$1,362	$9.17	592

[170] Analogous figures for other annual vs. seasonal comparisons are presented in **Appendix Section VII.B**.

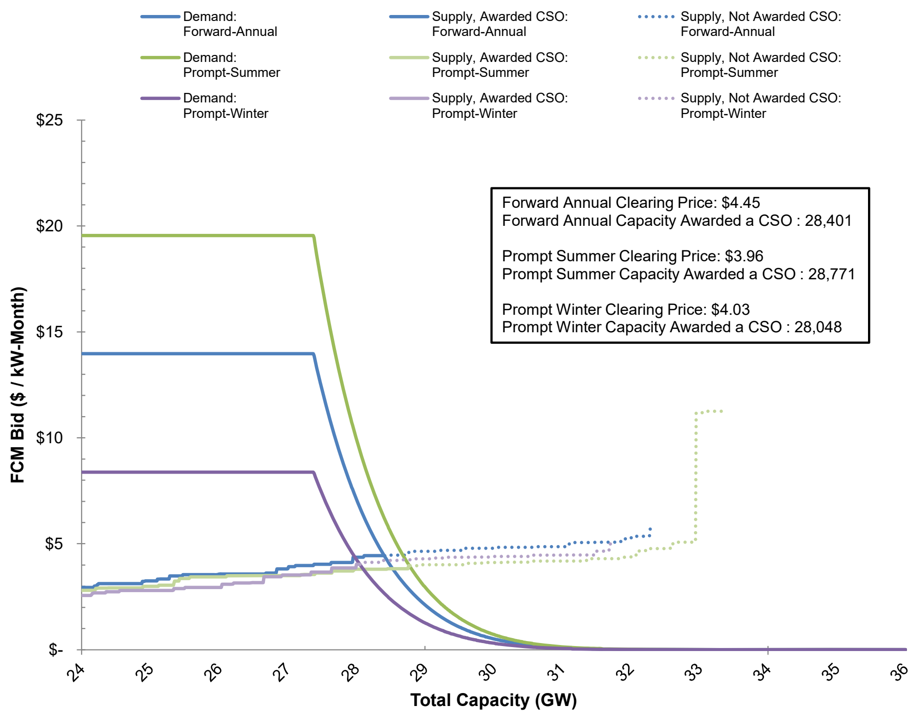
4. Assessment of Prompt-Seasonal Market Structure

The prompt-seasonal market structure combines the features of the forward and seasonal market structures. Consistent with the benefits – lower prices and payments – of prompt and seasonal market structures when used individually, the combined prompt-seasonal market results in the lowest prices and total payments, on average, among all alternatives. **Figure 19** shows the change in prices, quantities and payments for the prompt-seasonal market relative to the FCM for the three central scenarios. Across these scenarios, prices and payments are reduced by 3.7% to 10% compared to the current FCM. On average, prices are lower by $0.33 per kW-month, a 7% reduction, while payments are lower by $116 million annually, also a 7% reduction. In per MWh terms, the cost reductions range from $0.37 to $1.03 per MWh. Moreover, these economic benefits do not account for the reliability benefits of using more-current rMRI values when measuring qualified capacity for the auctions.

Figure 19. Prompt-Seasonal Market (Compared to Forward-Annual)

Figure 20 illustrates market clearing for the prompt-seasonal market structure for the 2028-29 commitment period. Like the prompt-annual market, the prompt-seasonal awards a greater quantity of capacity a CSO during the season with greater reliability risk (summer), but seasonal prices are sometimes higher in summer and sometimes higher in winter. Compared to the current FCM, prices are lower by $0.18 to $0.45 per kW-month and total payments are lower by $65 to $153 million annually (**Table 9**). Thus, overall, our modeling results suggest that the shift from a forward-annual to a prompt-seasonal market has the potential for significant cost savings.

Figure 20. Prompt-Seasonal Market (Compared to Forward-Annual), 2028-29 CCP



5. *Sensitivity to Inputs: Forward Premium*

As discussed in **Section V.C.1.a**, for the forward market runs we assume a 10 percent premium is added to a resource's going forward costs to account for reduced optionality and increased financial risk of making a commitment three years in advance. We test the sensitivity of our results by analyzing a premium of 5 percent and 15 percent. **Figure 21** shows the change in prices, quantities and payments (in percent terms) for alternatives (relative to the FCM) assuming a 5%, 10%, and 15% premium for the forward market supply offers. In the central case (10% forward premium), alternatives reduce prices (relative to the FCM) in 8 of 9 scenarios, with impacts ranging from a reduction of 10% to an increase of 5%. With a 5% forward premium, alternatives reduce prices in 7 of 9 scenarios, with impacts ranging from a reduction of 6% to an increase of 9%. Thus, the change in forward premium assumption shifts price impacts approximately 5 percentage points (relative to the FCM). Results are similar when a 15% premium is assumed, with larger price reductions from the alternatives.

Figure 22 shows the sensitivity of the results for total payments (in dollar terms). At the 5% premium, the change in total costs from prompt-seasonal alternatives range from a decrease of $31million to an increase of $105 million, with an average of $16 million across scenarios. By contrast, at the 15% premium, the change in total costs from the prompt-seasonal alternatives range from a decrease of $167 million to a decrease of $39 million, with an average of $121 million across scenarios. The appendix provides further detail on these results for each prompt and seasonal alternative evaluated.

Figure 21. Sensitivity of Changes to Price, Quantity and Payments to Assumed Forward Supply Premium (percent)

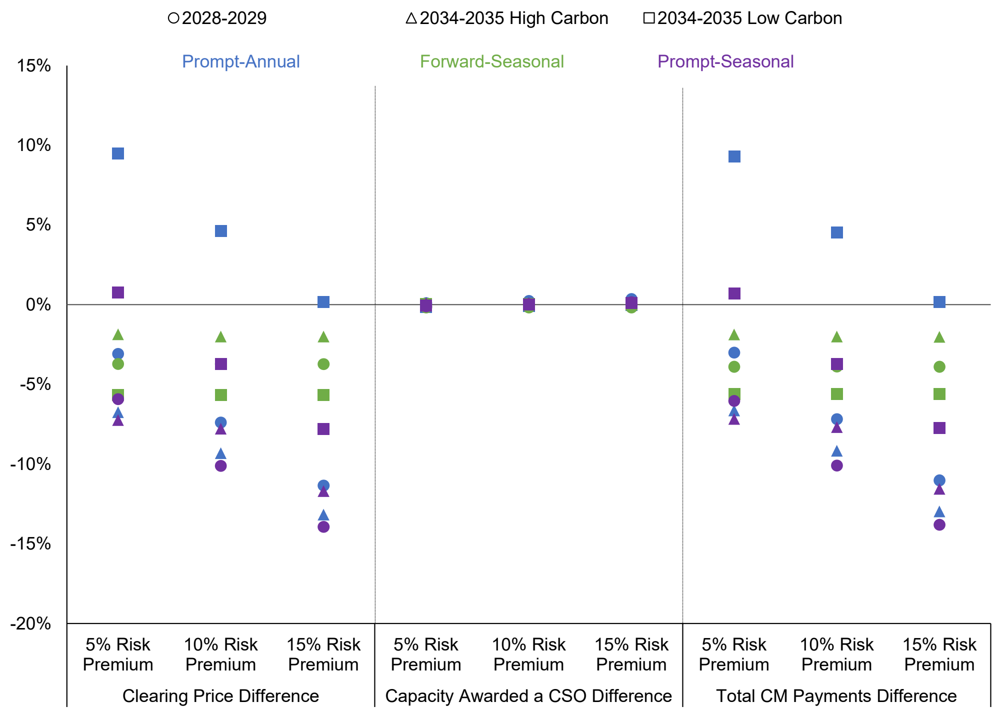


Figure 22. Sensitivity of Change in Total Payments to Assumed Forward Supply Premium ($ Million)

These scenarios illustrate the sensitivity of results, but do not encompass the full uncertainty in the potential impacts of prompt and seasonal market alternatives to the current FCM. As noted earlier, our analysis does not account for all factors that would be expected to affect costs and in some cases our assumptions are likely conservative given unaccounted for factors.

VI. Evaluation of Timing and Phasing of Transition to Market Alternatives

The prompt and seasonal market concepts evaluated in this report would require substantial time and resources to implement, as would the RCA project changes the region is already committed to undertake. Given the scope of potential changes, we evaluate the issues associated with the timing of any transitions to prompt and/or seasonal markets, including whether to undertake market design changes in phases (rather than in one "all at once" step).

A. Transition to a Prompt-Annual Market

If the region pursues a prompt market, but not a seasonal market, the region will need to develop the prompt market and execute the RCA enhancements prior to a prompt auction for the 2028-29 commitment period. Assuming such a prompt auction was run in late 2027 or early 2028 for the 2028-29 commitment period, there appears to be sufficient time to develop a prompt market and execute the RCA enhancements. Thus, we foresee no issues with the timing and implementation of a prompt-annual market.

B. Transition to Forward-Seasonal Market

If the region opts to pursue a seasonal market, but not a forward market, the region could either (1) implement seasonal markets prior to CCP 19 along with RCA or (2) implement seasonal markets for later CCPs (e.g., CCP 20 or later). If the region continues with its forward market, the beginning of the qualification process for the next capacity auction, CCP 19, will be in late 2024, which would provide only one year to implement both RCA and seasonal markets. Given the complexities involved with seasonal markets and lack of development to date, this would not be feasible. Thus, if the region pursues a forward-seasonal market, the development of the seasonal market would need to occur after the implementation of the RCA enhancements and may not occur for several more capacity auctions.

C. Transition to a Prompt-Seasonal Market

If the region pursues both a prompt and seasonal market, two questions arise: (1) is there is sufficient time to develop a prompt-seasonal market, along with the RCA enhancements, to run a prompt-seasonal market for the next 2028-29 commitment period? And (2) would it be sensible to phase the development of the prompt-seasonal market by first undertaking developing the prompt market (for CCP 19) and then later developing the seasonal market?[171]

[171] For the reasons we describe above, it would be infeasible to first transition the annual market to a seasonal market and then later transitioning the forward market to a prompt market.

On the first question, there appears to be adequate time to develop a prompt-seasonal market for CCP 19. If the region takes this path, it will have more than three years to develop the market rules, information technology ("IT") systems and market participant training needed to run a successful auction as early as late 2027. While the market changes would be substantial and require dedication of considerable resources to the project, the available time appears adequate to develop all components of the market. Nonetheless, if the region opts to pursue a prompt-seasonal market, ISO-NE should undertake a thorough evaluation of the transition process to assess time requirements and more comprehensively study and the scope of work necessary to run a successful prompt-seasonal auction for the 2028-29 commitment period.

On the second question, if the region pursues a prompt-seasonal market and the evaluation of the transition process does not uncover any unexpected schedule challenges, for the reasons we describe below, we believe there are benefits to undertaking these changes all at once so that the next auction (for the 2028-29 commitment period) is run under the prompt-seasonal framework.

- *First*, making the transition to a prompt-seasonal market in phases would likely be more costly and complex than if undertaken all at once. In principle, the region could transition to a prompt-seasonal market by first moving to a prompt-annual market and then subsequently moving to a prompt-seasonal market. However, under this approach, the region must develop two sets of market rules and systems – RCA with annual markets and RCA with seasonal markets – rather than just one set of market rules and systems.
- *Second*, making a single transition to the new market framework would promote market stability and may reduce complexity and cost for market participants. The development of a prompt-seasonal market will represent a substantial change to the region's capacity market construct. However, introducing these changes through a phased approach would lengthen the transition period and thus delay the process of adjusting to the new, long-run structure.
- *Third*, a phased approach would delay the benefits from seasonal markets, which would be executed for the 2029-30 commitment period, at the earliest.

Thus, for these reasons, we recommend that if the region pursues a prompt-seasonal market that it aims to make these market changes so a prompt-seasonal auction is used for the 2028-29 commitment period. Note that this evaluation focuses on the value of *implementing* the prompt-seasonal market, along with the RCA enhancements, in a single capacity market commitment period relative to implementing the same changes in a phased manner. Separately, the ISO will need to give consideration to how to develop the design changes for discussion with stakeholders and filing with the Federal Energy Regulatory Commission. As with implementation, the design work itself could proceed in a staged manner or all at once, although we do not consider and our recommendations do not encompass the process of this design work.

VII. Appendices

A. Additional Technical Modeling Details

This section provides further details on the modeling assumptions described in **Section V.C.**

1. rMRI Assumptions

This section provides additional detail on the illustrative accreditation values assumed in our modeling, including those for the forward auction for the 2028-29 commitment period presented in **Table 4**. For each market structure and commitment period, the estimated accreditation factors used in the model (rMRIs) measure the marginal reliability impact of a particular resource type relative to that of a perfect resource.

a. Resource types with consistent rMRI across seasons and modeled commitment periods (thermal units, imports, demand response, and non-intermittent hydro)

For thermal generation (excluding gas-only units), imports, demand response, and non-intermittent hydroelectric units, rMRI does not vary seasonally or across the years.[172] For these units, we assume that rMRI equals one minus estimated EFORd (i.e., 1 – EFORd), where EFORd is sourced from:

- Thermal generation and non-intermittent hydroelectric: Generating Availability Data System ("GADS") EFORd class averages for the latest available period (2017-2021).[173]
- Active demand response: EFORd equals the 4-year performance average EFORd across all ISO-NE load zones.[174]
- Imports: EFORd is calculated as a weighted average by capacity of each tie's forced outage rate.[175]

For passive demand response, we use annual and seasonal rMRI estimates from ISO-NE's latest marginal reliability analysis results.[176]

---

[172] According to ISO-NE's latest marginal reliability analysis results, summer and winter accreditation values are similar for most resource types, except for intermittent resources. *See* ISO-NE, "Resource Capacity Accreditation in the Forward Capacity Market, FCA16 Baseline Case Accreditation," NEPOOL Markets Committee, April 11-13, 2023, p. 35.

[173] ISO-NE, "NERC GADS EFORd Class Averages as used by ISO New England", p. 3, available at https://www.iso-ne.com/static-assets/documents/genrtion_resrcs/gads/class_ave_2010.pdf.

[174] ISO-NE, "Forced Outage Rates (FOR) for Active Demand Capacity Resources (ADCRs)," NEPOOL Power Supply Planning Committee, June 1, 2022, p. 7, available at https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fwww.iso-ne.com%2Fstatic-assets%2Fdocuments%2F2022%2F05%2Fa04_adcr_availabilities.pptx&wdOrigin=BROWSELINK.

[175] ISO-NE "Proposed Installed Capacity Requirement and Related Values for Seventeenth Forward Capacity Auction (FCA17)" Reliability Committee, September 7, 2022, pp. 8 and 52, available at https://www.iso-ne.com/static-assets/documents/2022/08/a02_proposed_icr_related_values_for_fca17.pptx.

[176] ISO-NE, "Resource Capacity Accreditation in the Forward Capacity Market, FCA16 Baseline Case Accreditation," NEPOOL Markets Committee, April 11-13, 2023, pp. 31-33.

b. Energy Storage

For energy storage, rMRI estimates vary depending on each season, commitment period, and assumed resource mixture. We rely on a mixture of accreditation analyses from ISO-NE and NYISO's Market Monitoring Unit to inform estimates of energy storage rMRI values.

In the 2028-29 forward market, rMRI values for 2-hour energy storage are based on ISO-NE's latest marginal reliability impact analysis.[177] For 4-hour storage, annual and seasonal indicative storage rMRI curves from ISO-NE's latest marginal reliability analysis[178] are used to estimate the difference between 2-hour and 4-hour rMRI values. These differences are added to the 2-hour rMRI values obtained from the latest marginal reliability analysis.

For energy storage in the 2034-35 commitment period, the rMRI value of energy storage for the 2028-29 commitment period is adjusted for the increased amount of energy storage in the system.

To estimate the adjustment in rMRI that results from additional storage resources, we use illustrative data from NYISO Market Monitoring Unit analyses. The adjustments to 4-hour storage rMRIs are estimated by examining the illustrative changes in storage MRIs assuming 10 GW of solar penetration.[179] We estimate an accreditation reduction of 30 percent for the high carbon 2034-35 scenario, and 45 percent for the low carbon 2034-35 scenario. We assume that the estimated accreditation reduction for the 4-hour storage is the same for 2-hour storage.[180]

c. Intermittent Renewables

For intermittent renewables – i.e., solar PV, onshore wind, offshore wind, and run-of-river hydroelectric – rMRI estimates vary by season, commitment period, and assumed resource mixture. We rely on a mixture of accreditation analyses from ISO-NE and PJM to inform estimates of rMRI values for these resource types.

i. Renewable Resources in the 2028-29 Forward Market

For the 2028-29 forward market structure and commitment period, for solar, wind, and intermittent hydro resources, values from the latest marginal reliability analysis from ISO-NE are used as starting points in estimating rMRIs.[181] For wind resources, where ISO-NE's marginal reliability analysis does not differentiate between onshore and

---

[177] We assume that the energy storage resources that have cleared to date in ISO-NE's FCAs are 2-hour storage systems. ISO-NE, "Resource Capacity Accreditation in the Forward Capacity Market, FCA16 Baseline Accreditation Case," NEPOOL Market Committee, April 11-13, 2023, pp. 31-33, available at https://www.iso-ne.com/static-assets/documents/2023/04/a05f_mc_2023_04_11-13_rca_impact_analysis.pptx.

[178] ISO-NE, "Resource Capacity Accreditation in the Forward Capacity Market, FCA16 Baseline Accreditation Case," NEPOOL Market Committee, April 11-13, 2023, pp. 36-37, available at https://www.iso-ne.com/static-assets/documents/2023/04/a05f_mc_2023_04_11-13_rca_impact_analysis.pptx.

[179] Potomac Economics, "NYISO Capacity Accreditation: Continued Discussion of Marginal and Average Approaches", August 30, 2021, p. 14, available at https://www.potomaceconomics.com/wp-content/uploads/2022/01/Capacity-Accreditation-Marginal-vs-Average-for-Aug-30-08-25-2021.pdf. This analysis presents illustrative changes in 4-hour storage accreditation for varying levels of solar penetration (0, 5, 10, 15, and 20 GWs).

[180] NYISO's Market Monitoring Unit did not illustrate the impact on 2-hour storage systems.

[181] ISO-NE, "Resource Capacity Accreditation in the Forward Capacity Market, FCA16 Baseline Accreditation Case," NEPOOL Market Committee, April 11-13, 2023, pp. 31-33, available at https://www.iso-ne.com/static-assets/documents/2023/04/a05f_mc_2023_04_11-13_rca_impact_analysis.pptx. We adjust rMRI so that it can be multiplied by resource nameplate capacity and yield the same result as the multiplication of estimated rMRI by resources' FCA 16 qualified capacity.

offshore wind, we use accreditation analyses from PJM to differentiate rMRI values.[182] Wind and solar resource rMRIs are then adjusted to account for expected capacity additions between 2026-27 and 2028-29. In particular, we use PJM's estimated accreditation adjustment rates (accreditation change per 100 MW of incremental capacity of the same technology type) to estimate the accreditation adjustment for expected additions of ISO-NE wind and solar resources through 2028-29.[183]

ii. Renewable Resources in the 2034-2035 Forward Market

For this market structure, we apply the same methodology as described above to adjust rMRI values for the renewable resources additions assumed to enter the system between 2028-29 and 2034-35. We estimate rMRI values for the 2034-35 high and low carbon scenarios using 2028-29 rMRIs as starting values, the calculated change in accreditation values per 100 MW nameplate capacity additions estimated based on PJM's analyses, and expected ISO-NE wind and solar resources additions as shown in **Table 6**. The estimated rMRIs for the low carbon scenario are shown in **Table 13**, and for the high carbon scenario in **Table 14.**

Table 13. 2034-2035 Forward Market rMRIs for Energy Storage (ES) and Renewable Resources: High Carbon Scenario

	rMRI		
Resource Class	**Annual**	**Summer**	**Winter**
2 hour ES	0.344	0.390	0.204
4 hour ES	0.604	0.670	0.384
Offshore Wind	0.211	0.121	0.248
Onshore Wind	0.146	0.098	0.166
Solar	0.096	0.139	0.000

Table 14. 2034-2035 Forward Market rMRIs for Storage and Renewable Resources: Low Carbon Scenario

	rMRI		
Resource Class	**Annual**	**Summer**	**Winter**
2 hour ES	0.194	0.263	0.135
4 hour ES	0.454	0.543	0.315
Offshore Wind	0.149	0.106	0.210
Onshore Wind	0.133	0.098	0.162
Solar	0.069	0.124	0.000

[182] PJM, "Capacity Market Reform: PJM Proposal," p. 61, available at https://www.pjm.com/-/media/committees-groups/cifp-ra/2023/20230727/20230727-item-02a---cifp---pjm-proposal-update---july-27.ashx. We use PJM's onshore and offshore wind accreditation factor variation as a proxy to differentiate illustratively ISO-NE's current onshore and offshore capacity accreditation. This approach provides reasonable proxy results but is not intended to estimate actual future accreditation values.

[183] PJM, "December 2022 Effective Load Carrying Capability (ELCC) Report," January 6, 2023, p. 10, available at https://www.pjm.com/-/media/planning/res-adeq/elcc/elcc-report-december-2022.ashx. We compute the projected change in solar, onshore wind, and offshore wind accreditation values from 2023 to 2032, normalize this value by capacity additions (MW), and then multiply the result by assumed ISO-NE resource class additions to determine the accreditation reduction.

iii. Energy Storage and Renewable Resources in the Prompt Markets

We assume different renewable and energy storage resource rMRIs for the prompt and forward markets. We estimate rMRIs for the prompt market in each commitment period based on the projected reductions in assumed rMRIs for the forward markets between 2028-2029 and 2034-2035. For each resource class we calculate the forward market percent change in rMRI between 2028-2029 and 2034-2035 forward markets. These percentage changes represent the assumed changes in rMRIs over six years. To estimate rMRIs for the prompt market we then reduce forward market rMRIs by one-half of the calculated percent change. This reduction assumes that there will be decline in rMRIs in the three-year time-period between a forward market auction and prompt market auction.

Percent changes applied to obtain prompt market rMRIs, starting from forward market rMRI benchmarks, are illustrated in **Table 15**. The resulting prompt market rMRIs for each commitment period and scenario evaluated are shown in **Table 16**, **Table 17**, and **Table 18**.

Table 15. Percent Change in assumed rMRIs between 2028-2029 and 2034-2035 Forward Markets and Percent Change between Forward and Prompt Markets by Resource Class

Resource Class	Percent Change in rMRI 2028/29 - 2034/35 Forward Markets	Percent Change in rMRI between Forward and Prompt Markets
2 hour ES	0.466	0.233
4 hour ES	0.332	0.166
Offshore Wind	0.323	0.161
Onshore Wind	0.127	0.063
Solar	0.226	0.113

Note: We use these estimated percentage changes in rMRIs over six years to estimate rMRIs for the prompt market (except for offshore wind in 2028-2029 prompt market). We assume that one-half of the percentage reduction show in the table captures a decline in rMRIs in the three-year time-period between a forward market auction and prompt market auction.

Table 16. 2028-2029 Prompt Market rMRIs for Storage and Renewable Resources

Resource Class	rMRI Annual	rMRI Summer	rMRI Winter
2 hour ES	0.494	0.529	0.386
4 hour ES	0.754	0.809	0.570
Offshore Wind	0.301	0.212	0.339
Onshore Wind	0.157	0.112	0.175
Solar	0.109	0.148	0.011

Table 17. 2034-2035 Prompt Market rMRIs for Storage and Renewable Resources: High Carbon Scenario

Resource Class	rMRI Annual	rMRI Summer	rMRI Winter
2 hour ES	0.264	0.299	0.156
4 hour ES	0.504	0.559	0.320
Offshore Wind	0.177	0.102	0.208
Onshore Wind	0.137	0.092	0.155
Solar	0.085	0.123	0.000

Table 18. 2034-2035 Prompt Market rMRIs for Storage and Renewable Resources: Low Carbon Scenario

Resource Class	rMRI Annual	rMRI Summer	rMRI Winter
2 hour ES	0.146	0.198	0.102
4 hour ES	0.283	0.338	0.196
Offshore Wind	0.125	0.089	0.176
Onshore Wind	0.124	0.092	0.152
Solar	0.065	0.117	0.000

2. *Annual Demand Curve*[184]

Below provides additional detail and supplemental information to the modeling assumptions described in **Section V.C.2**.

[184] Seasonal demand curves are also constructed using the principles described in this section. The only difference is that seasonal Net CONE is scaled to reflect each season's assumed reliability risks as described in **Section V.C.2.b**.

a. Net ICR

For the 2028-29 commitment period, Net ICR is set at the forecasted Net ICR for this period by the 2023 Regional System Plan.[185] For the 2034-35 commitment period, we extrapolate Net ICR using the forecasted Net ICR for the 2032-33 commitment period (the last year forecasted) and assume the annual percent change between 2032-33 and 2034-35 is equivalent to the percent change in forecasted Net ICR between the 2031-32 and 2032-33 commitment periods.

b. MRI

MRI values used to construct the demand curve are based on the latest ISO-NE demand curve values for the system-wide zone estimated for FCA 18.[186] In constructing the demand curve, capacity and MRI are scaled by the specific resource mix rMRI ($rMRI_z$) consistent with ISO-NE's RCA MRI design.[187] Each point (QC, MRI) is translated into ($QMRIC_z$, MRI_z) as follows:

$$QMRIC_z = QC * rMRI_z$$

$$MRI_z = \frac{MRI}{rMRI_z}$$

c. Scaling factor

Under each market structure, the demand curve's scaling factor is calculated according to ISO-NE RCA MRI design as:

$$Scaling\ factor = \frac{Net\ CONE'}{MRI'(at\ criterion)}$$

where:

$$Net\ CONE' = \frac{Net\ CONE}{rMRI\ of\ reference\ technology}$$

and $MRI'(at\ criterion)$ is the value where $Adjusted\ ICR = Net\ MRI\ ICR * rMRI_z$ crosses the MRI curve.[188] [189]

[185] *See* ISO-NE, "2023 Regional System Plan," Appendix Table 23, available at https://www.iso-ne.com/system-planning/system-plans-studies/rsp/?file-type=XLS&file-type=XLSX&file-type=CSV&file-type=xls&file-type=xlsx&file-type=csv.

[186] ISO-NE, "Forward Capacity Market Parameters," March 31, 2023, available at https://www.iso-ne.com/static-assets/documents/2023/08/a03_2023_08_23_pspc_fca_18_demand_curves.xlsx.

[187] ISO-NE, "Resource Capacity Accreditation in the Forward Capacity Market. Continued Discussion on Conceptual Design," p. 33, available at https://www.iso-ne.com/static-assets/documents/2022/09/a05a_mc_2022_09_13-14_rca_conceptual_design_presentation_.pptx.

[188] Our model calculates Net CONE for each commitment period by inflating 2026-2027 Net CONE by an assumed 2 percent annual inflation rate. The values for Net CONE for each commitment period can be found at ISO-NE, "Forward Capacity Market Parameters," March 31, 2023, available at https://www.iso-ne.com/static-assets/documents/2015/09/fca_parameters_final_table.xlsx.

[189] ISO-NE, "Resource Capacity Accreditation in the Forward Capacity Market. Continued Discussion on Conceptual Design", p. 34, available at https://www.iso-ne.com/static-assets/documents/2022/09/a05a_mc_2022_09_13-14_rca_conceptual_design_presentation_.pptx.

3. Supply Curve

Below provides additional detail and supplemental information to the modeling assumptions described in **Section V.C.1.** The supply curve comprises bids from individual resources using the equation described in **Section V.C.1.a:**

$$Net\ GFC\ = Fixed\ Costs - NEAS\ Revenues - Net\ PFP\ Revenues + Risk\ Premium,$$

where Net PFP Revenues is calculated as follows:

$$Net\ PFP\ Revenues = PPR * (Average\ Performance - Balancing\ Ratio) * Scarcity\ Hours$$

Additionally, a minimum offer defined according to the formula for CVC:

$$Minimum\ offer = PPR * Scarcity\ Hours * Balancing\ Ratio$$

The components of these equations are discussed in more detail below.

- NEAS Revenues comprise Energy Market Revenues, discussed below in **Appendix Section VII.A.3.b** and Ancillary Services Revenues, discussed below in **Appendix Section VII.A.3.c**.
- Fixed Costs reflect fixed O&M and Annualized Capital Costs discussed in **Appendix Section VII.A.3.a**. and **Appendix Section VII.A.3.d**.
- The forward premium in forward capacity market scenarios reflects in part Deficiency Payment Risk, discussed in further detail below in **Appendix Section VII.A.3.e**.
- Average Performance, PPR, Balancing Ratio, and Scarcity Hours, which are components of the Net PFP Revenues and minimum offer calculations, are discussed in **Appendix Sections VII.A.3.f** and **VII.A.3.g**.

a. Fixed Costs

Fixed Costs are comprised of fixed O&M costs and, for new resources, annualized capital costs (see **Appendix Section VII.A.3.d**). Fixed O&M costs are assigned using a mix of unit-specific estimates and generator-type estimates from publicly available sources.

- Demand response and import resources are assigned a fixed cost of $0/kw-year.
- For all other units for which unit-specific estimates are available from either SNL Energy (“SNL”) or Hitachi Energy Velocity Suite, an average these two sources’ unit-specific fixed cost estimates is used.
- For all photovoltaic, battery, and offshore wind units for which unit-level estimates are not available from SNL or Hitachi Energy Velocity Suite, the U.S. Energy Information Administration (“EIA”) fixed O&M estimate for “Solar photovoltaic (PV) with tracking,” “Battery storage,” and “Wind offshore” is used, respectively.[190]

[190] *See* EIA, “Electricity Market Module,” Table 3, March 2022, available at https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf. The EIA cost estimate is adjusted from 2021 dollars to 2023 dollars using the BLS PPI WPUID612 and BLS PPI WPU1197 indices.

- For all onshore wind units for which unit-level estimates are not available from SNL or Hitachi Energy Velocity Suite, a fixed O&M estimate for onshore wind from the November 2020 ISO-NE Net Cone and ORTP Analysis is used.[191]
- For units that are not demand response, import, nuclear, photovoltaic, battery, or wind, and which do not have unit-specific fixed cost estimates available from SNL or Hitachi Energy Velocity Suite, fixed O&M is imputed based upon the units' vintage (where available), fuel type (where available), and technology type.
- Fixed O&M costs are escalated from 2023 dollars to 2028 and 2034 dollars for the 2028-2029 and 2034-2035 CCPs, respectively, at a 2% inflation rate.

b. Energy Market Revenues

Energy market revenues are derived from an EMS model (see **Appendix Section VII.A.4** for details). Units that are explicitly modeled in the market simulation are assigned revenues according to the energy market model's results. All other units are assigned revenues based on the average revenue per capacity by technology – fuel type combination. Energy market revenues are escalated from 2023 dollars to 2028 and 2034 dollars for the 2028-29 and 2034-35 CCPs, respectively, at a 2% inflation rate.

Due to limitations in how the energy market model simulates battery storage behavior, energy market revenues for battery units are replaced with an estimate from the ISO-New England 2027-2028 ORTP study.[192] This estimate is escalated from 2027 dollars to 2028 and 2034 dollars for the 2028-29 and 2034-35 CCPs, respectively, at a 2% inflation rate.

c. Ancillary Service Revenues

Ancillary services revenues reflect resource-specific operating reserve revenues based on an analysis of actual revenues earned by resources provided by ISO-NE. Resource-specific revenue estimates reflect Forward Reserve Market outcomes (including resource assigned to meet Forward Reserve Market obligations), real-time reserve market outcomes, and appropriate adjustments to FCM revenues. If resource-specific revenue estimates are not available, an average ancillary service revenue by technology and fuel type is applied to each unit. Ancillary services revenue is escalated from 2017 dollars to 2028 and 2034 dollars for the 2028-2029 and 2034-2035 CCPs, respectively, at a 2% inflation rate.

d. Annualized Capital Costs

Annual investment costs in $/kW-month are estimated by technology-fuel type combination.

---

[191] *See* Concentric Energy Advisors, Inc. and Mott MacDonald, "An Evaluation of the Net Cost of New Entry and Offer Review Trigger Price Parameters to be Used in the Forward Capacity Auction," November 2020, Table 41. This cost estimate is adjusted from 2025 to 2023 dollars using the average of the 10-year average annual percentage changes from BLS PPI WPUID612 (2009-2018) and BLS PPI WPU1197 2009-2018. As 2016 and 2017 data are missing from WPU1197, the calculated the three-year compound annual growth rate from 2015 to 2018 is applied to the final three years in the ten-year span (*see* ibid, p. 43).

[192] The ORTP study estimates battery NEAS revenues at $8.937 per kW-month. ISO-NE, "2027-2028 ORTP Study," available at https://www.iso-ne.com/static-assets/documents/2023/03/2027-2028-ccp-forward-capacity-auction-18-iso-offer-review-trigger-price.xlsm.

- Average annual investment is first estimated at the plant – technology type level for all regulated plants in the U.S. on which SNL collects cost data. Annual investment at the plant level is measured as the change year-over-year in Total Cost[193] of the plant. Average annual investment at the plant level is then calculated as the average year-over-year change in total cost from 2017-2018 to 2021-2022, including only years for which the year-over-year change is greater than or equal to zero dollars.
- Average 2018-2022 annual investment per MW of capacity is then computed by technology-fuel type combination.
- Investment costs for gas fired steam turbines are derived from EIA figures.[194]
- Investment costs are escalated from 2023 dollars to 2028 and 2034 dollars for the 2028-2029 and 2034-2035 CCPs, respectively, at a 2% inflation rate.

e. Deficiency Risk

Deficiency risk was calculated at the resource type level. For dispatchable resources (combined-cycle, gas turbines, steam turbines, internal combustion, energy storage, fuel cells, daily and weekly pondage hydropower, pumped storage, biopower, and nuclear) the method detailed below was used. For intermittent resources (hydro, on- and offshore wind, and solar), the weighted average of the deficiency risks of dispatchable resources is used. Deficiency risk for demand response units was assumed to be zero.

For seasonal auction models, each dispatchable resource types' deficiency risk was calculated using season-specific, generator-level qualified capacities, resulting in distinct summer and winter deficiency risks.[195] A qualified capacity weighted average of the summer and winter deficiency risks for each resource type was used for the annual auction models.

A resource type's seasonal deficiency risk was calculated first by summing the total MWs of significant capacity decreases of all generators of the resource type for the given season (summer or winter) across 2018-2023. This total seasonal deficiency was then divided by the same set of generators' maximum potential qualified capacity in the same period. A generator was deemed to have a significant capacity decrease for a given season within a given year if its qualified capacity was either 10% less than, or 40 MW or fewer than, its maximum qualified capacity between 2017 and the year in question.

---

[193] Total cost includes Land and Land Rights, Structures and Improvements, Equipment Costs, and Asset Retirement Costs (*See* FERC Form 1, p. 402). Total Cost used in the analysis is collected by SNL.

[194] The EIA estimates annual capex at $15.96 per KW-Year in 2017 dollars. *See*, "Generating Unit Annual Capital and Life Extension Costs Analysis," EIA, December 2019, Table ES-5, available at https://www.eia.gov/analysis/studies/powerplants/generationcost/pdf/full_report.pdf. The EIA cost estimate is adjusted from 2017 dollars to 2023 dollars using the BLS PPI WPUID612 and BLS PPI WPU1197 indices.

[195] Data came from ISO-NE, "CELT Report[s]" for 2017-2023, tabs "4.3 Qualified & Cleared Capacity," available at https://www.iso-ne.com/system-planning/system-plans-studies/celt.

f. Unit Average Performance

Units' average performance values reflect average unit performance during shortage events. Specifically, average performance is calculated as the sum of all output in a shortage hour divided by the qualified capacity.[196] In the event that a unit does not appear in the data, an average of the average performance by fuel type is applied to each unit. Units' average performance values are a component of the pay-for-performance calculation.

g. Minimum Offer

The minimum offer of each units reflects the product of PPR ($9,337/MWh), Balancing Ratio (81.6%), and Scarcity Hours.[197] Scarcity hours are assumed to differ depending on the amount of excess capacity above Net ICR.[198]

4. Energy Market Simulation

An EMS model is used to estimate net energy market revenues. The model chronologically optimizes energy services dispatch and calculates hourly production costs and clearing prices while simultaneously adhering to a variety of operating constraints. It determines the least cost dispatch of a system of interconnected generators to meet load in every hour of the day in New England.

We run three EMS scenarios that correspond with the 2028-29 commitment period, the 2034-35 commitment period with the "high carbon" resource mix, and the 2034-35 commitment period the "low carbon" resource mix. For simplicity, we assume no transmission constraints (i.e., no congestion). Additional input assumptions are described below.

a. Demand

The EMS uses an hourly load forecast based on a representative historical weather shape. Monthly peaks and energy loads are based on CELT forecasts from the 2023 report.[199] The forecast data ends in 2032, so load is extrapolated through 2035, based on 2023-2032 growth rates.

[196] Units' average performance values are based upon 5-minute settlement data provided by ISO-NE and CSO and qualified capacity information for each unit.

[197] ISO-NE, "Performance Payment Rate and Balancing Ratio are provided in the ISO-New England 2027-2028 ORTP study," available at https://www.iso-ne.com/static-assets/documents/2023/03/2027-2028-ccp-forward-capacity-auction-18-iso-offer-review-trigger-price.xlsm. The Performance Payment Rate is escalated from 2027 dollars to 2028 and 2034 dollars for the 2028-2029 and 2034-2035 CCPs, respectively, at a 2% inflation rate.

[198] Scarcity hours are derived from ISO-New England's estimates for the 2027-2028 CCP, *see* Zeng, Fei, "Estimated Hours of System Operating Reserve Deficiency for the 2027-2028 Capacity Commitment Period (CCP)," October 29, 2023, p. 7, available at https://www.iso-ne.com/static-assets/documents/100004/a04_2023_10_18_pspc_reserve_deficiency_hours_ccp2027-2028.pdf. The 0.9 scarcity hours for the 2028 Forward-Annual scenario assumes a capacity level of approximately 4,000 MW in excess of Net ICR. Given lower prompt market rMRIs, the level of capacity in excess of Net ICR is lower, and more scarcity hours are appropriate. For the prompt-annual 2028 market, we assume 1 scarcity hour. For the forward-annual and prompt-annual 2034 market, 1 and 1.2 scarcity hours, respectively, are assumed. Scarcity hours are assumed to be evenly distributed between summer and winter months.

[199] *See* ISO-NE, "2023 CELT Report," available at https://www.iso-ne.com/system-planning/system-plans-studies/celt.

b. Supply

The resource mix includes the resources that bid into each modeled capacity market described in **Section V.C.1.c** In addition, currently operating resources without announced retirement dates that do not participate in the forward capacity market are sourced from CELT.[200] Dispatch of individual resource types are modeled as follows:

- Intermittent renewables (solar PV, wind, run-of-river hydro) are assumed to follow hourly profiles consistent with the representative weather shape used for the load forecast.
- Fossil units (combined-cycle, gas turbine, internal combustion, steam, biomass, and coal units) are modeled as dispatchable units.
- Nuclear units are modeled as profiles. The hourly profile assumes generation at 97% of nameplate capacity in the summer (June 1st to September 31st) and in the winter (December 1st to March 31st) and at 92% of nameplate capacity in the shoulder season.
- Storage is modeled as arbitrage units with a roundtrip charging and discharging efficiency of 85%.

Fuel prices are derived from publicly available sources. Coal and nuclear fuel prices are derived based on the most recent EIA Annual Energy Outlook.[201] The method of developing the natural gas and fuel oil price series used in the EMS are detailed below.

- ***Natural Gas:*** Natural gas prices are based on Algonquin City Gates Full Value Monthly Forwards provided by S&P Global Market Intelligence.[202]
- ***Fuel Oil:*** Prices for No. 2 and No. 6 Fuel Oil are based on New York Harbor Heating Oil Futures and New York Harbor Residual Fuel Oil 1% Sulfur Futures, respectively, from S&P Global Market Intelligence.[203] The oil price is adjusted using the annual expected growth rate for fuel oil from the EIA Annual Outlook.[204]

---

[200] ISO-NE, "2023 CELT Report," sheet "2.1 Generator List," available at https://www.iso-ne.com/static-assets/documents/2023/05/2023_celt_report.xlsx.

[201] U.S Energy Information Administration, "Annual Energy Outlook 2023," Table 3 Energy Priced by Sector and Source.

[202] S&P Global Market Intelligence, "Natural Gas Forwards & Futures (Data)," as of October 20, 2023.

[203] S&P Global Market Intelligence, "Refined Products Forwards & Futures (Data)," as of October 20, 2023.

[204] U.S Energy Information Administration, "Annual Energy Outlook 2023," Table 3 Energy Priced by Sector and Source.

B. Additional Results from Quantitative Modeling

Table 19. Summary of Capacity Market Model Results by Commitment Period and Market Structure

	Clearing Price ($/kW-month)	Capacity Awarded a CSO (MW)	Total CM Payments ($ M)	Avg. CM Payment ($/MWh)	Capacity Above Adjusted ICR (MW)
2028-2029					
Forward-Annual	$4.45	28,401	$1,515	$10.19	583
Prompt-Annual	$4.12	28,466	$1,406	$9.46	649
Forward-Summer	$4.27	28,711	$736	$10.00	893
Forward-Winter	$4.29	27,992	$720	$9.60	175
Forward-Seasonal (Avg./Total)	$4.28	28,352	$1,456	$9.80	534
Prompt-Summer	$3.96	28,771	$684	$9.30	954
Prompt-Winter	$4.03	28,048	$678	$9.04	230
Prompt-Seasonal (Avg./Total)	$4.00	28,410	$1,362	$9.17	592
2034-2035 High Carbon					
Forward-Annual	$4.62	30,278	$1,680	$9.56	390
Prompt-Annual	$4.19	30,327	$1,526	$8.69	439
Forward-Summer	$4.53	30,378	$826	$9.80	491
Forward-Winter	$4.53	30,175	$820	$8.97	287
Forward-Seasonal (Avg./Total)	$4.53	30,277	$1,646	$9.39	389
Prompt-Summer	$4.29	30,406	$782	$9.28	518
Prompt-Winter	$4.24	30,209	$768	$8.41	321
Prompt-Seasonal (Avg./Total)	$4.26	30,307	$1,551	$8.84	420
2034-2035 Low Carbon					
Forward-Annual	$4.83	30,255	$1,754	$9.98	368
Prompt-Annual	$5.05	30,232	$1,834	$10.44	344
Forward-Summer	$4.63	30,367	$844	$10.02	480
Forward-Winter	$4.48	30,180	$811	$8.88	292
Forward-Seasonal (Avg./Total)	$4.56	30,274	$1,656	$9.45	386
Prompt-Summer	$4.47	30,385	$815	$9.66	498
Prompt-Winter	$4.83	30,141	$874	$9.57	254
Prompt-Seasonal (Avg./Total)	$4.65	30,263	$1,689	$9.62	376

Table 20. Capacity Market Outcomes Relative to Forward-Annual Market Outcomes by Commitment Period and Market Structure

	Clearing Price ($/kW-month)	Capacity Awarded a CSO (MW)	Total CM Payments ($ M)	Avg. CM Payment ($/MWh)	Capacity Above Adjusted ICR (MW)
2028-2029					
Prompt-Annual	-$0.33	66	-$109	-$0.73	66
Forward-Summer	-$0.17	310		-$0.19	310
Forward-Winter	-$0.16	-408		-$0.60	-408
Forward-Seasonal (Avg./Total)	-$0.17	-49	-$59	-$0.39	-49
Prompt-Summer	-$0.48	371		-$0.90	371
Prompt-Winter	-$0.42	-353		-$1.16	-353
Prompt-Seasonal (Avg./Total)	-$0.45	9	-$153	-$1.03	9
2034-2035 High Carbon					
Prompt-Annual	-$0.43	49	-$154	-$0.88	49
Forward-Summer	-$0.09	100		$0.24	100
Forward-Winter	-$0.10	-103		-$0.59	-103
Forward-Seasonal (Avg./Total)	-$0.09	-1	-$34	-$0.18	-1
Prompt-Summer	-$0.33	128		-$0.28	128
Prompt-Winter	-$0.38	-69		-$1.15	-69
Prompt-Seasonal (Avg./Total)	-$0.36	30	-$129	-$0.72	30
2034-2035 Low Carbon					
Prompt-Annual	$0.22	-23	$80	$0.45	-23
Forward-Summer	-$0.20	112		$0.03	112
Forward-Winter	-$0.35	-75		-$1.10	-75
Forward-Seasonal (Avg./Total)	-$0.27	18	-$98	-$0.54	18
Prompt-Summer	-$0.36	130		-$0.32	130
Prompt-Winter	$0.00	-114		-$0.41	-114
Prompt-Seasonal (Avg./Total)	-$0.18	8	-$65	-$0.37	8

Table 21. Summary of Impact of Demand Forecast Uncertainty (± 1,000 MW) on Forward and Prompt Market Outcomes (with a Seasonal Market)

	Clearing Price ($/kW-month)	Capacity Awarded a CSO (MW)	Total CM Payments ($ M)	Avg. CM Payment ($/MWh)	Capacity Above Final Adjusted ICR (MW)
2028-2029					
Forward-Seasonal (Forecasted ICR < Final ICR)	$4.00	27,583	$1,324	$8.91	-234
Forward-Seasonal (Forecasted ICR = Final ICR)	$4.28	28,352	$1,456	$9.80	534
Forward-Seasonal (Forecasted ICR > Final ICR)	$4.63	29,132	$1,619	$10.89	1,314
Prompt-Seasonal	$4.00	28,410	$1,362	$9.17	592
2034-2035 High Carbon					
Forward-Seasonal (Forecasted ICR < Final ICR)	$4.34	29,490	$1,535	$8.76	-397
Forward-Seasonal (Forecasted ICR = Final ICR)	$4.53	30,277	$1,646	$9.39	389
Forward-Seasonal (Forecasted ICR > Final ICR)	$4.92	31,060	$1,835	$10.46	1,172
Prompt-Seasonal	$4.26	30,307	$1,551	$8.84	420
2034-2035 Low Carbon					
Forward-Seasonal (Forecasted ICR < Final ICR)	$4.33	29,492	$1,532	$8.75	-396
Forward-Seasonal (Forecasted ICR = Final ICR)	$4.56	30,274	$1,656	$9.45	386
Forward-Seasonal (Forecasted ICR > Final ICR)	$4.99	31,054	$1,861	$10.61	1,166
Prompt-Seasonal	$4.65	30,263	$1,689	$9.62	376

Table 22. Impact of Demand Forecast Uncertainty (± 1,000 MW) on Forward and Prompt Market Outcomes (with a Seasonal Market)

	Clearing Price ($/kW-month)	Capacity Awarded a CSO (MW)	Total CM Payments ($ M)	Avg. CM Payment ($/MWh)	Capacity Above Final Adjusted ICR (MW)
2028-2029					
Forecasted ICR < Final ICR					
Forward-Summer	$4.07	27,962	$683	$9.28	145
Forward-Winter	$3.92	27,204	$641	$8.54	-613
Forward-Seasonal (Avg./ Total)	$4.00	27,583	$1,324	$8.91	-234
Forecasted ICR = Final ICR					
Forward-Summer	$4.27	28,711	$736	$10.00	893
Forward-Winter	$4.29	27,992	$720	$9.60	175
Forward-Seasonal (Avg./ Total)	$4.28	28,352	$1,456	$9.80	534
Forecasted ICR > Final ICR					
Forward-Summer	$4.51	29,469	$797	$10.83	1,652
Forward-Winter	$4.76	28,794	$822	$10.95	976
Forward-Seasonal (Avg./ Total)	$4.63	29,132	$1,619	$10.89	1,314
Prompt-Summer	$3.96	28,771	$684	$9.30	954
Prompt-Winter	$4.03	28,048	$678	$9.04	230
Prompt-Seasonal (Avg./ Total)	$4.00	28,410	$1,362	$9.17	592
2034-2035 High Carbon					
Forecasted ICR < Final ICR					
Forward-Summer	$4.43	29,595	$786	$9.32	-292
Forward-Winter	$4.25	29,385	$749	$8.20	-502
Forward-Seasonal (Avg./ Total)	$4.34	29,490	$1,535	$8.76	-397
Forecasted ICR = Final ICR					
Forward-Summer	$4.53	30,378	$826	$9.80	491
Forward-Winter	$4.53	30,175	$820	$8.97	287
Forward-Seasonal (Avg./ Total)	$4.53	30,277	$1,646	$9.39	389
Forecasted ICR > Final ICR					
Forward-Summer	$4.81	31,159	$899	$10.66	1,271
Forward-Winter	$5.04	30,960	$936	$10.25	1,073
Forward-Seasonal (Avg./ Total)	$4.92	31,060	$1,835	$10.46	1,172
Prompt-Summer	$4.29	30,406	$782	$9.28	518
Prompt-Winter	$4.24	30,209	$768	$8.41	321
Prompt-Seasonal (Avg./ Total)	$4.26	30,307	$1,551	$8.84	420
2034-2035 Low Carbon					
Forecasted ICR < Final ICR					
Forward-Summer	$4.48	29,588	$796	$9.44	-300
Forward-Winter	$4.17	29,396	$736	$8.06	-491
Forward-Seasonal (Avg./ Total)	$4.33	29,492	$1,532	$8.75	-396
Forecasted ICR = Final ICR					
Forward-Summer	$4.63	30,367	$844	$10.02	480
Forward-Winter	$4.48	30,180	$811	$8.88	292
Forward-Seasonal (Avg./ Total)	$4.56	30,274	$1,656	$9.45	386
Forecasted ICR > Final ICR					
Forward-Summer	$4.93	31,149	$921	$10.93	1,261
Forward-Winter	$5.06	30,958	$940	$10.29	1,071
Forward-Seasonal (Avg./ Total)	$4.99	31,054	$1,861	$10.61	1,166
Prompt-Summer	$4.47	30,385	$815	$9.66	498
Prompt-Winter	$4.83	30,141	$874	$9.57	254
Prompt-Seasonal (Avg./ Total)	$4.65	30,263	$1,689	$9.62	376

Table 23. Forward Premium Sensitivity Results (Annual Market)

	Clearing Price ($/kW-month)	Capacity Awarded a CSO (MW)	Total CM Payments ($ M)	Avg. CM Payment ($/MWh)	Capacity Above Final Adjusted ICR (MW)
2028-2029					
Forward-Annual (5% Premium)	$4.25	28,441	$1,450	$9.75	623
Forward-Annual (10% Premium)	$4.45	28,401	$1,515	$10.19	583
Forward-Annual (15% Premium)	$4.64	28,366	$1,581	$10.63	548
Prompt-Annual	$4.12	28,466	$1,406	$9.46	649
2034-2035 High Carbon					
Forward-Annual (5% Premium)	$4.42	30,300	$1,606	$9.15	413
Forward-Annual (10% Premium)	$4.62	30,278	$1,680	$9.56	390
Forward-Annual (15% Premium)	$4.83	30,256	$1,753	$9.98	368
Prompt-Annual	$4.19	30,327	$1,526	$8.69	439
2034-2035 Low Carbon					
Forward-Annual (5% Premium)	$4.62	30,279	$1,677	$9.55	391
Forward-Annual (10% Premium)	$4.83	30,255	$1,754	$9.98	368
Forward-Annual (15% Premium)	$5.04	30,233	$1,830	$10.42	346
Prompt-Annual	$5.05	30,232	$1,834	$10.44	344

Table 24. Forward Premium Sensitivity Results (Seasonal Market)

	Clearing Price ($/kW-month)	Capacity Awarded a CSO (MW)	Total CM Payments ($ M)	Avg. CM Payment ($/MWh)	Capacity Above Final Adjusted ICR (MW)
2028-2029					
Forward-Seasonal (5% Premium)	$4.09	28,390	$1,394	$9.38	572
Forward-Seasonal (10% Premium)	$4.28	28,352	$1,456	$9.80	534
Forward-Seasonal (15% Premium)	$4.47	28,315	$1,519	$10.22	497
Prompt-Seasonal	$4.00	28,410	$1,362	$9.17	592
2034-2035 High Carbon					
Forward-Seasonal (5% Premium)	$4.34	30,299	$1,576	$8.99	411
Forward-Seasonal (10% Premium)	$4.53	30,277	$1,646	$9.39	389
Forward-Seasonal (15% Premium)	$4.73	30,255	$1,718	$9.80	367
Prompt-Seasonal	$4.26	30,307	$1,551	$8.84	420
2034-2035 Low Carbon					
Forward-Seasonal (5% Premium)	$4.36	30,296	$1,584	$9.04	409
Forward-Seasonal (10% Premium)	$4.56	30,274	$1,656	$9.45	386
Forward-Seasonal (15% Premium)	$4.76	30,252	$1,728	$9.86	364
Prompt-Seasonal	$4.65	30,263	$1,689	$9.62	376

Table 25. Forward Premium Sensitivity Results (Seasonal Market)

	Clearing Price ($/kW-month)	Capacity Awarded a CSO (MW)	Total CM Payments ($ M)	Avg. CM Payment ($/MWh)	Capacity Above Final Adjusted ICR (MW)
2028-2029					
5% Premium					
Forward-Summer	$4.08	28,747	$704	$9.57	929
Forward-Winter	$4.10	28,033	$689	$9.18	215
Forward-Seasonal (Avg./Total)	$4.09	28,390	$1,394	$9.38	572
10% Premium					
Forward-Summer	$4.27	28,711	$736	$10.00	893
Forward-Winter	$4.29	27,992	$720	$9.60	175
Forward-Seasonal (Avg./Total)	$4.28	28,352	$1,456	$9.80	534
15% Premium					
Forward-Summer	$4.46	28,675	$768	$10.43	857
Forward-Winter	$4.48	27,954	$751	$10.01	137
Forward-Seasonal (Avg./Total)	$4.47	28,315	$1,519	$10.22	497
Prompt-Summer	$3.96	28,771	$684	$9.30	954
Prompt-Winter	$4.03	28,048	$678	$9.04	230
Prompt-Seasonal (Avg./Total)	$4.00	28,410	$1,362	$9.17	592
2034-2035 High Carbon					
5% Premium					
Forward-Summer	$4.34	30,400	$792	$9.40	512
Forward-Winter	$4.33	30,198	$784	$8.58	310
Forward-Seasonal (Avg./Total)	$4.34	30,299	$1,576	$8.99	411
10% Premium					
Forward-Summer	$4.53	30,378	$826	$9.80	491
Forward-Winter	$4.53	30,175	$820	$8.97	287
Forward-Seasonal (Avg./Total)	$4.53	30,277	$1,646	$9.39	389
15% Premium					
Forward-Summer	$4.73	30,357	$862	$10.22	470
Forward-Winter	$4.73	30,153	$855	$9.37	265
Forward-Seasonal (Avg./Total)	$4.73	30,255	$1,718	$9.80	367
Prompt-Summer	$4.29	30,406	$782	$9.28	518
Prompt-Winter	$4.24	30,209	$768	$8.41	321
Prompt-Seasonal (Avg./Total)	$4.26	30,307	$1,551	$8.84	420
2034-2035 Low Carbon					
5% Premium					
Forward-Summer	$4.43	30,390	$808	$9.58	502
Forward-Winter	$4.28	30,203	$776	$8.50	316
Forward-Seasonal (Avg./Total)	$4.36	30,296	$1,584	$9.04	409
10% Premium					
Forward-Summer	$4.63	30,367	$844	$10.02	480
Forward-Winter	$4.48	30,180	$811	$8.88	292
Forward-Seasonal (Avg./Total)	$4.56	30,274	$1,656	$9.45	386
15% Premium					
Forward-Summer	$4.84	30,346	$881	$10.45	458
Forward-Winter	$4.68	30,158	$847	$9.27	271
Forward-Seasonal (Avg./Total)	$4.76	30,252	$1,728	$9.86	364
Prompt-Summer	$4.47	30,385	$815	$9.66	498
Prompt-Winter	$4.83	30,141	$874	$9.57	254
Prompt-Seasonal (Avg./Total)	$4.65	30,263	$1,689	$9.62	376

Table 26. Summary of Price and Cost Differences: Prompt-Annual Relative to Forward-Annual Market (Forward Premium Sensitivity)

	Clearing Price Difference ($/kW-month)	Clearing Price Difference (%)	CM Payment Difference ($ M)	CM Payment Difference (%)
2028-2029				
Prompt-Annual (5% Premium)	-$0.13	-3.09%	-$43	-3.00%
Prompt-Annual (10% Premium)	-$0.33	-7.39%	-$109	-7.18%
Prompt-Annual (15% Premium)	-$0.53	-11.33%	-$174	-11.02%
2034-2035 High Carbon				
Prompt-Annual (5% Premium)	-$0.23	-5.11%	-$81	-5.03%
Prompt-Annual (10% Premium)	-$0.43	-9.32%	-$154	-9.16%
Prompt-Annual (15% Premium)	-$0.64	-13.17%	-$227	-12.97%
2034-2035 Low Carbon				
Prompt-Annual (5% Premium)	$0.44	9.47%	$156	9.31%
Prompt-Annual (10% Premium)	$0.22	4.62%	$80	4.54%
Prompt-Annual (15% Premium)	$0.01	0.18%	$3	0.18%

Table 27. Summary of Price and Cost Differences: Forward-Seasonal Relative to Forward-Annual Market (Forward Premium Sensitivity)

	Clearing Price Difference ($/kW-month)	Clearing Price Difference (%)	CM Payment Difference ($ M)	CM Payment Difference (%)
2028-2029				
Forward-Seasonal (5% Premium)	-$0.16	-3.72%	-$56	-3.89%
Forward-Seasonal (10% Premium)	-$0.17	-3.72%	-$59	-3.89%
Forward-Seasonal (15% Premium)	-$0.17	-3.72%	-$62	-3.89%
2034-35 High Carbon				
Forward-Seasonal (5% Premium)	-$0.08	-1.86%	-$30	-1.88%
Forward-Seasonal (10% Premium)	-$0.09	-2.01%	-$34	-2.01%
Forward-Seasonal (15% Premium)	-$0.10	-2.00%	-$35	-2.02%
2034-35 Low Carbon				
Forward-Seasonal (5% Premium)	-$0.26	-5.66%	-$94	-5.59%
Forward-Seasonal (10% Premium)	-$0.27	-5.65%	-$98	-5.59%
Forward-Seasonal (15% Premium)	-$0.29	-5.65%	-$102	-5.59%

Table 28. Summary of Price and Cost Differences: Prompt-Seasonal Relative to Forward-Annual Market (Forward Premium Sensitivity)

	Clearing Price Difference ($/kW-month)	Clearing Price Difference (%)	CM Payment Difference ($ M)	CM Payment Difference (%)
2028-2029				
Prompt-Seasonal (5% Premium)	-$0.25	-5.92%	-$88	-6.04%
Prompt-Seasonal (10% Premium)	-$0.45	-10.11%	-$153	-10.09%
Prompt-Seasonal (15% Premium)	-$0.65	-13.93%	-$218	-13.81%
2034-35 High Carbon				
Prompt-Seasonal (5% Premium)	-$0.15	-3.50%	-$56	-3.48%
Prompt-Seasonal (10% Premium)	-$0.36	-7.78%	-$129	-7.68%
Prompt-Seasonal (15% Premium)	-$0.56	-11.69%	-$202	-11.55%
2034-35 Low Carbon				
Prompt-Seasonal (5% Premium)	$0.03	0.75%	$11	0.69%
Prompt-Seasonal (10% Premium)	-$0.18	-3.71%	-$65	-3.70%
Prompt-Seasonal (15% Premium)	-$0.39	-7.80%	-$141	-7.72%

Figure 23. Prompt-Annual Market (Compared to Forward-Annual), High Carbon 2034-35 CCP

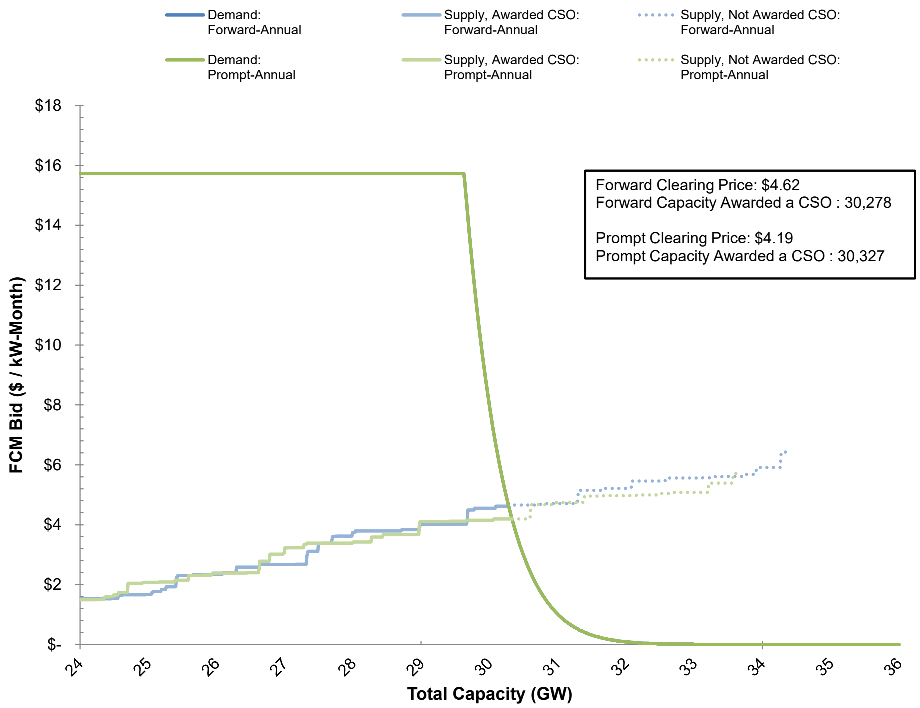


Figure 24. Prompt-Annual Market (Compared to Forward-Annual), Low Carbon 2034-35 CCP

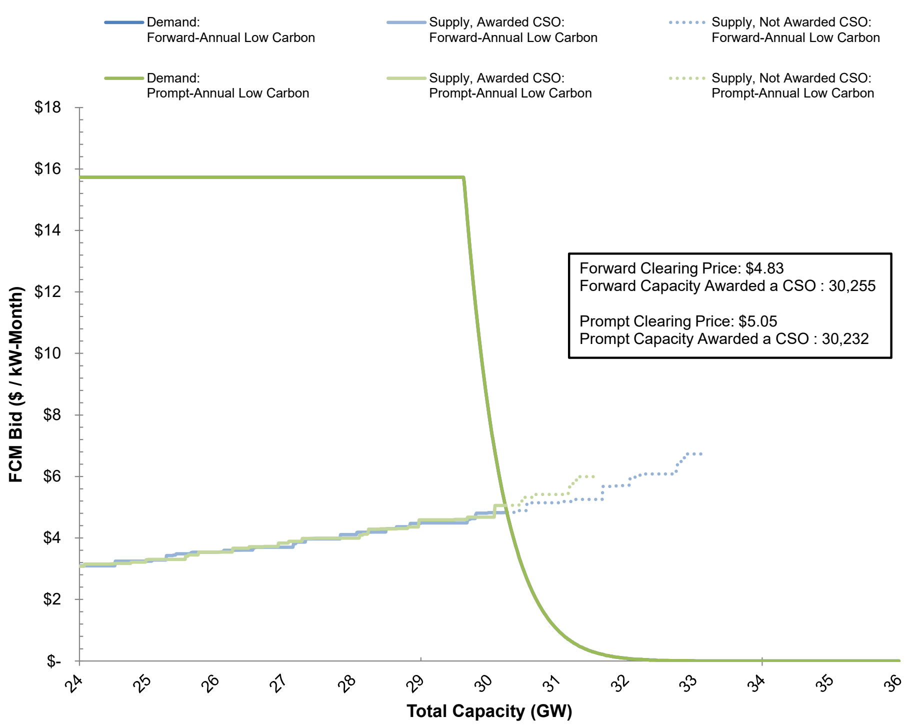


Figure 25. Forward-Seasonal Market (Compared to Forward-Annual), High Carbon 2034-35 CCP

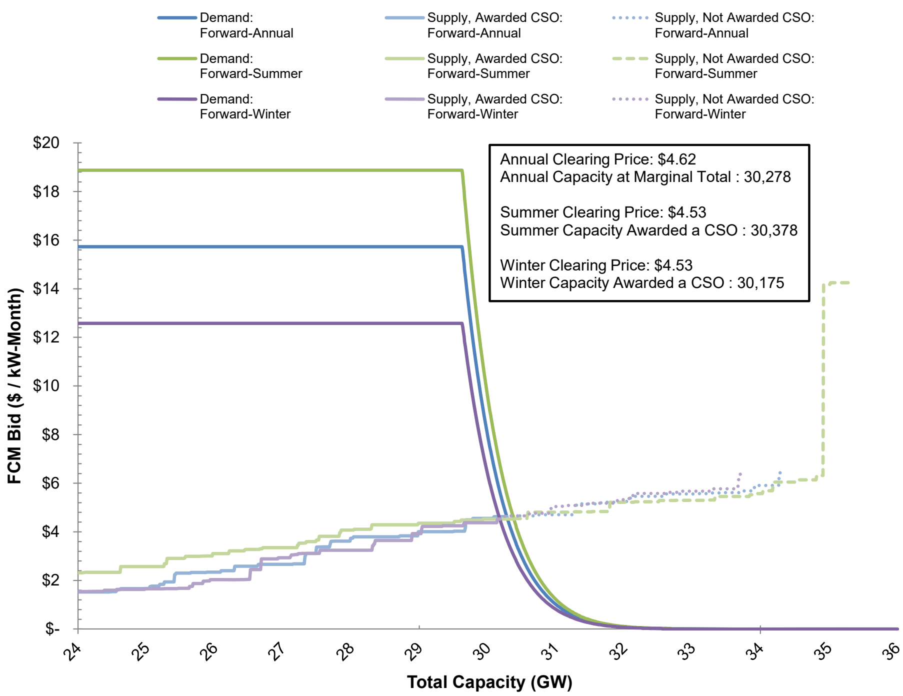


Figure 26. Forward-Seasonal Market (Compared to Forward-Annual), Low Carbon 2034-35 CCP

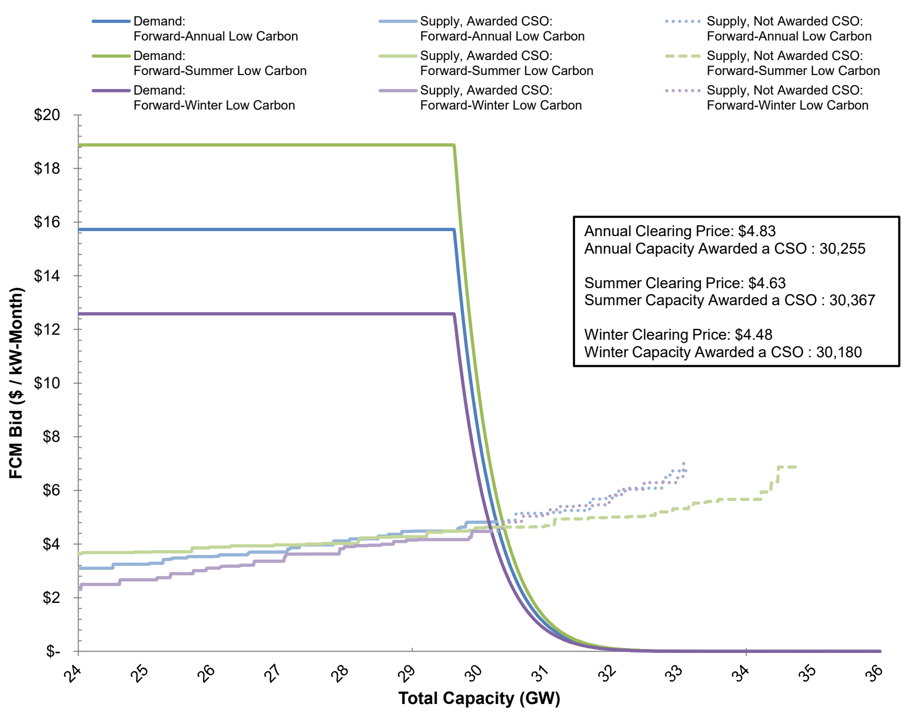


Figure 27. Forward-Annual vs. Prompt-Annual Capacity Market, Forward with +/- 1,000 Net ICR Relative to Prompt, High Carbon 2034-35 CCP

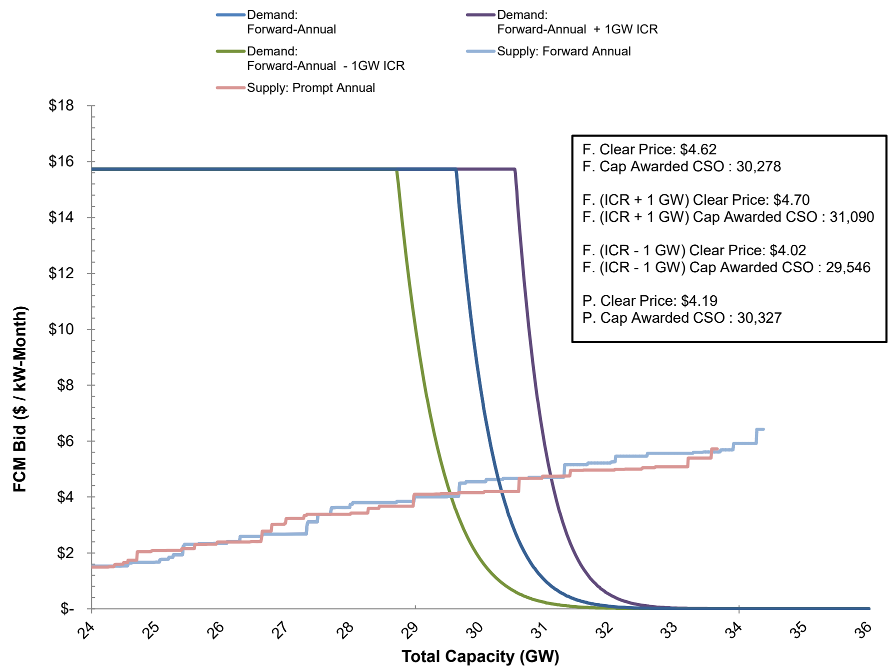


Figure 28. Forward-Annual vs. Prompt-Annual Capacity Market, Forward with +/- 1,000 Net ICR Relative to Prompt, Low Carbon 2034-35 CCP

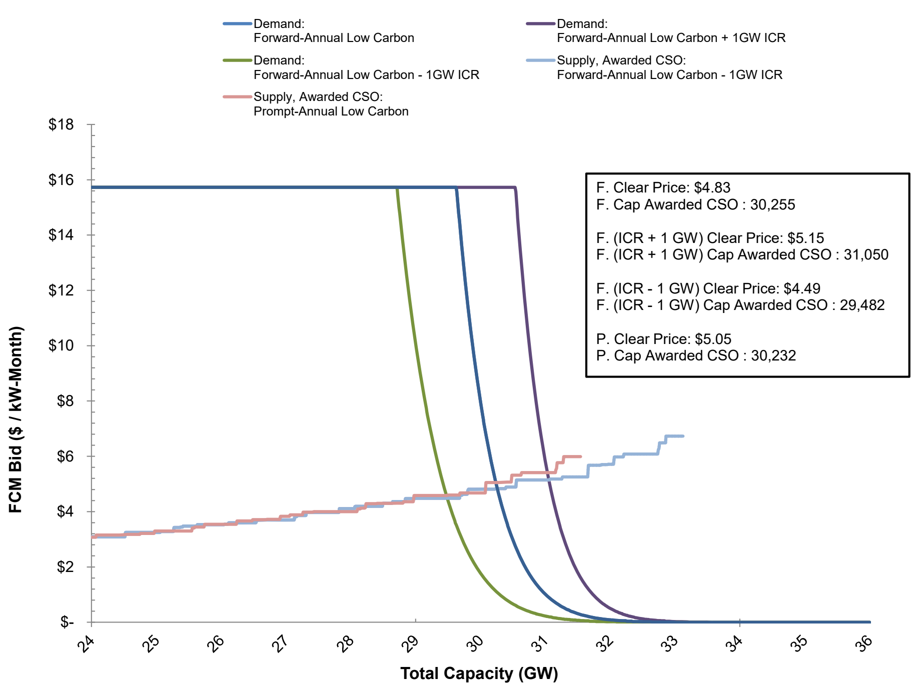


Figure 29. Prompt-Seasonal Market (Compared to Forward-Annual), High Carbon 2034-35 CCP

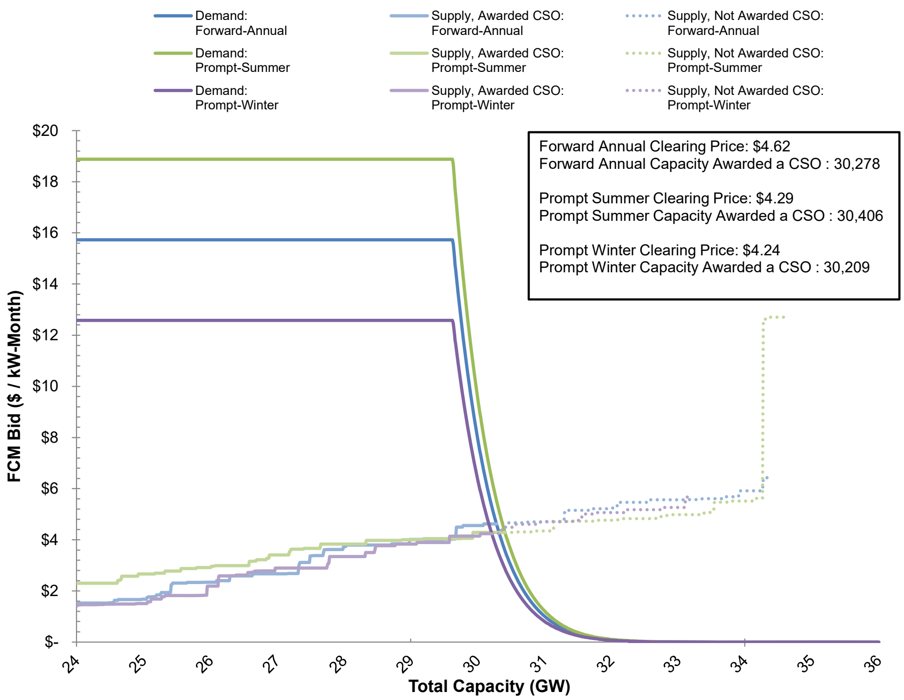
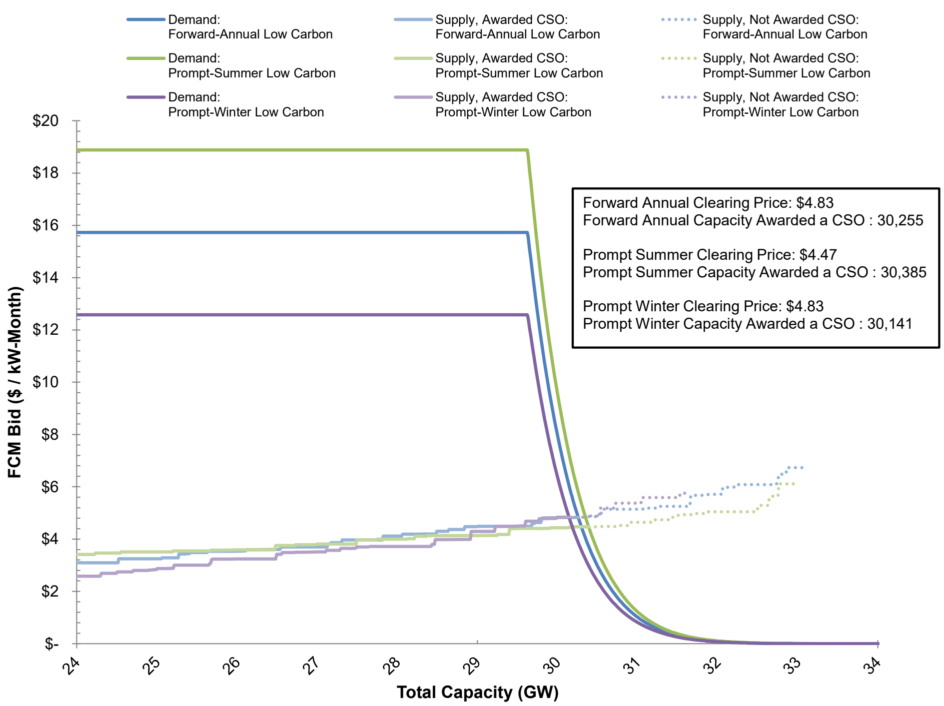


Figure 30. Prompt-Seasonal Market (Compared to Forward-Annual), Low Carbon 2034-35 CCP



C. Sources for Table 1

Plant	Sources
Killingly Energy Center *Killingly, CT*	- Baldwin, Kenneth C., “Re: Applicatin of NTE Connecticut, LLC for the Approval of the Construction, Maintenance and Operation of an Electric Power Generating Facility off Lake Road, Killingly,” Robinson+Cole, August 17, 2016, available at https://portal.ct.gov/-/media/CSC/1_Dockets-medialibrary/Docket470/Application/470ApplicationCoverLetterpdf.pdf - S&P Capital IQ, “Killingly Energy Center: Power Plant Profile,” available at https://www.capitaliq.spglobal.com/web/client#powerplant/powerplantprofile?id=22148 - Spiegel, Jan Ellen, “Proposed Killingly Power Plant Dealt Another Blow,” CT Mirror, March 7, 2022, available at https://ctmirror.org/2022/03/07/killingly-gas-power-plant-iso-new-england-auction-ferc/ - Clark, Kevin, “New England Gas Plant in Doubt After FERC Denial,” Power Engineering, January 6, 2022, available at https://www.power-eng.com/gas/new-england-gas-plant-in-doubt-after-ferc-denial/ - ISO-NE, FCA Obligations data
Salem Harbor Power Station *Salem, MA*	- Department of Environmental Protection, Commonwealth of Massachusetts, “Footprint Power Salem Harbor Development LP: Air Quality Plan Approval,” January 30, 2014, available at https://www.mass.gov/doc/cpa-footprint-14/download - S&P Capital IQ, “Salem Harbor Station NGCC: Power Plant Profile,” available at https://www.capitaliq.spglobal.com/web/client#powerplant/powerplantprofile?id=17012 - Walton, Robert, “Salem Harbor to Pay $17.1M Fine, Disgorge Profits to Settle Allegations It Improperly Received ISO-NE Capacity Payments,” Utility Drive, June 29, 2022, available at https://www.utilitydive.com/news/ferc-investigates-massachusetts-salem-harbor-iso-new-england-capacity-payment-scheme/626090/ - ISO-NE, FCA Obligations data
CPV Towantic Energy Center *Oxford, CT*	- S&P Capital IQ, “Towantic Energy Center: Power Plant Profile,” available at https://www.capitaliq.spglobal.com/web/client#powerplant/powerplantprofile?id=422 - Clean Air Technology Center, US Environmental Protection Agency, “Facility Information: CPV Towantic, LLC, 805 MW Combined Cycle Power Plant,” https://cfpub.epa.gov/rblc/index.cfm?action=PermitDetail.FacilityInfo&Facility_ID=28038 - FCA Obligations data, ISO New England
Peabody Power Plant (MMWEC) *Peabody, MA*	- CELT reports, tabs “2.1 Generator List” - Massachusetts Municipal Wholesale Electric Company, “Project 2015A,” 2023, available at https://www.project2015a.org/the-process/ - Nolan, Erin, “Peabody Power Plant Gets Green Light,” The Salem News, August 12, 2021, available at https://www.salemnews.com/news/local_news/peabody-power-plant-gets-green-light/article_9e476ab5-b669-5a74-9115-a9a7a2f1c1e8.html - Massachusetts Municipal Wholesale Electric Company,” Department of Environmental Protection, Commonwealth of Massachusetts, September 30, 2020, available at https://www.project2015a.org/wp-content/uploads/2021/07/MMWEC-Peabody-Final-Plan-Approval.pdf - Extinction Rebellion, “Extinction Rebellion Boston Holds an Earth Day March Demanding Massachusetts Ban New Fossil Fuel Infrastructure,” April 22, 2022, available at https://xrboston.org/press/freedom-from-fossil-fuels/ - S&P Capital IQ, “MMWEC Simple Cycle Gas Turbine Planet: Power Plant Profile,” available at https://www.capitaliq.spglobal.com/web/client#powerplant/powerplantprofile?id=57842 - ISO-NE, FCA Obligations data
Medway Grid Battery Storage *Medway, MA*	- CELT reports, tabs “4.3 Qualified, Cleared Capacity” - Mass.gov, “Medway Grid Battery Project,” available at https://www.mass.gov/info-details/medway-grid-battery-project - Pro Bid Energy, “Developers Get Zoning Exemptions for 800 MWh Massachusetts BESS Projects After Jurisdiction Dispute,” July 6, 2023, available at https://probidenergy.com/2023/07/06/developers-get-zoning-exemptions-for-800mwh-massachusetts-bess-projects-after-jurisdiction-dispute/ - ISO-NE, FCA Obligations data
Three Corners Solar *Kennebec County, ME*	- CELT reports, tabs “4.3 Qualified, Cleared Capacity” - S&P Capital IQ, “Three Corners Solar Project: Power Plant Profile,” available at https://www.capitaliq.spglobal.com/web/client#powerplant/powerplantprofile?id=54589 - State of Maine Department of Agriculture, Conservation, and Forestry, Land Use Planning Commision, “Commission Determination in the Matter of Maine Department of Environmental Protection Request for Site Law Certification Three Corners Solar, LLC.,” May 11, 2022, available at https://www.maine.gov/dep/ftp/projects/three-corners/slc16_LUPC_Certification_signed.pdf - Longroad Energy, “Notice of Intent to File and Public Informational Meeting,” January 25, 2022, available at https://www.longroadenergy.com/renewable-energy-projects/three-corners-solar-project/three-corners-solar-project-events/ - Sher, Mehr, “Bangor Daily News: Construction Begins on Maine's Largest Solar Farm,” Spectrum News, November 17, 2022, available at https://spectrumlocalnews.com/me/maine/news/2022/11/17/construction-begins-on-maine-s-largest-solar-farm - Wood, Robin, “Three Corners Solar - Bendont, ME,” Reed & Reed, June 1, 2023, available at https://reed-reed.com/three-corners-solar-benton-me - ISO-NE, FCA Obligations data
Farmington Solar Array *Farmington, ME*	- Ohm, Rachel, “490-Acre Solar Farm Proposal Raises Concerns in Farmington,” CentralMaine.com, August 14, 2018, available at https://www.centralmaine.com/2018/08/13/490-acre-solar-farm-proposal-raises-concerns-in-farmington/ - Ohm, Rachel, “Farmington Planning Board Approves Solar Project,” CentralMaine.com, November 19, 2018, available at https://www.centralmaine.com/2018/11/19/farmington-planning-board-approves-solar-project/ - S&P Capital IQ, “Farmington Solar Project: Power Plant Profile,” available at https://www.capitaliq.spglobal.com/web/client#powerplant/powerplantprofile?id=22368 - ISO-NE, FCA Obligations data

Plant	Sources
Number Nine Wind Farm *Aroostook County, ME*	- Maine Public, "Developer Pulls Plug on Aroostook County Wind Power Project," December 5, 2016, available at https://www.mainepublic.org/business-and-economy/2016-12-05/developer-pulls-plug-on-aroostook-county-wind-power-project - S&P Capital IQ, "Number Nine Wind Farm: Power Plant Profile," available at https://www.capitaliq.spglobal.com/web/client#powerplant/powerplantprofile?ID=11766 - Maine Department of Environmental Protection, "2017 State Government Evaluation Act Report," November 2017, available at https://lldc.mainelegislature.org/Open/Rpts/kf4943_z99m34_2017e.pdf - ISO-NE, FCA Obligations data
Bowers Wind Project *Penobscot County, ME*	- Maine Department of Agriculture, Conservation & Forestry, "Champlain Wind/Bowers Mtn.," available at https://www.maine.gov/dacf/lupc/projects/windpower/firstwind/champlain_bowers/Champlain_Development.html - Business Wire, "First Wind Submits New, Smaller Bowers Wind Project Proposal," October 31, 2012, available at https://www.businesswire.com/news/home/20121031005743/en/First-Wind-Submits-New-Smaller-Bowers-Wind-Project-Proposal - Byrne, Matt, "Maine's High Court Puts End to Bowers Mountain Wind Power Plan," Portland Press Herald, December 4, 2015, available at https://www.pressherald.com/2015/12/03/maines-high-court-rejects-penobscot-county-wind-power-project - Associated Press, "Maine DEP Rejects Bowers Mountain Wind Project," Portland Press Herald, August 6, 2013, available at https://www.pressherald.com/2013/08/06/maine-dep-rejects-bowers-mountain-wind-project - S&P Capital IQ, "Carroll Plantation & Kossuth (Bowers Mountain) Plant: Power Plant Profile," available at https://www.capitaliq.spglobal.com/web/client#powerplant/powerplantprofile?id=14402 - ISO-NE, FCA Obligations data
Weaver Wind *Hancock County, ME*	- Maine Department of Environmental Protection, "Findings of Fact and Order In the Matter Of Weaver Wind, LLC," May 16, 2019, available at https://www1.maine.gov/dep/land/projects/weaver-wind/Weaver%20Wind,%20LLC%20L26464knlnmnnn%20Order.pdf - Sambides, Nick Jr., "State Approves 22-Turbine Wind Project for Hancock County," Bangor Daily News, May 28, 2019, available at https://www.bangordailynews.com/2019/05/28/news/state-approves-22-turbine-wind-project-for-hancock-county/ - S&P Capital IQ, "Weaver Wind Project: Power Plant Profile," available at https://www.capitaliq.spglobal.com/web/client#powerplant/powerplantprofile?id=18313 - ISO-NE, FCA Obligations data
Vineyard Wind 1 *Off the coast of MA*	- Bureau of Ocean Energy Management, "Vineyard Wind 1," available at https://www.boem.gov/renewable-energy/state-activities/vineyard-wind-1 - "DEME Installs Vineyard Wind Substation," ReNews.Biz, July 26, 2023, available at https://renews.biz/87182/deme-installs-vineyard-wind-substation/ - Vu, Kaitlyn "Turbines in Trouble: The Controversy Behind Vineyard Wind & Offshore Wind in Massachussetts," Harvard Politics, October 2, 2023, available at https://harvardpolitics.com/turbines-in-trouble/ - S&P Capital IQ, "Vineyward Offshore Wind Project: Power Plant Profile," available at https://www.capitaliq.spglobal.com/web/client#powerplant/powerplantprofile?id=20451 - ISO-NE, FCA Obligations data
Park City Wind *Off the coast of MA*	- Avangrid, "Park City Wind: Permitting & Documents," available at https://www.parkcitywind.com/permitting - Turmelle, Luther, "Avangrid Pulls Contract for Offshore Park City Wind Power Project," CT Insider, October 3, 2023, available at https://www.ctinsider.com/business/article/avangrid-pulls-ct-wind-power-contracts-18403548.php - Avangrid, "BOEM Advances Permitting of Connecticut's Largest Offshore Wind Project," June 30, 2021, available at https://www.avangrid.com/w/boem-advances-permitting-of-connecticut-s-largest-offshore-wind-project - Crowley, Brendan, "Avangrid Cancels Park City Wind Contract, Pays State $16m Penalty," October 3, 2023, available at https://ctexaminer.com/2023/10/03/avangrid-cancels-park-city-wind-contract-pays-state-16m-penalty/ - Tethys, "Park City Wind," available at https://tethys.pnnl.gov/wind-project-sites/park-city-wind - ISO-NE, FCA Obligations data
New England Clean Energy Connect (NECEC) *Built through ME*	- Office of Electricity, US Department of Energy,"Application for Presidential Permit OE Docket No. PP-438 New England Clean Energy Connect Project: Comments and Supplemental Documents," available at https://www.energy.gov/oe/application-presidential-permit-oe-docket-no-pp-438-new-england-clean-energy-connect-project - Iberdrola, "AVANGRID'S New England Clean Energy Connect Receives Final Major Permit and Announces Start of Construction," January 15, 2021, available at https://www.iberdrola.com/press-room/news/detail/avangrid-s-england-clean-energy-connect-receives-final-major-permit-announces-start-construction - Knapschaefer, Johanna, "Embattled Maine Power Line Restarts as Cost Balloons to $1.5B," ENR New England, August 3, 2023, available at https://www.enr.com/articles/56895-embattled-maine-power-line-restarts-as-cost-balloons-to-15b - S&P Capital IQ, "New England Clean Energy Connect Project Profile," available at https://www.capitaliq.spglobal.com/web/client#industry/transmissionProjectProfile?projectid=17448 - ISO-NE, FCA Obligations data