Sub-Annual Capacity Market Construct for PJM

Authors:
Todd Schatzki, Ph.D.
Joseph Cavicchi
Phillip Ross, Ph.D.
Dan Dychala
Claire Paoli
Kirill Rudov, Ph.D.
Aditya Acharya
Sanjam Chhabra

January 6, 2026

Table of Contents

Figures

Tables

I. Executive Summary

To maintain reliable system operations and resource adequacy ("RA"), PJM Interconnection ("PJM") operates a Reliability Pricing Model ("RPM") to ensure that the region maintains sufficient capacity to reliably meet load throughout the year. The current design of the RPM reflects the 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.

However, market and system conditions are evolving due to, among other things, shifting seasonal patterns of energy demand driven by policy and economic forces, expanded deployment of intermittent renewable resources, and increasing fuel supply risk from expanded reliance on gas-fired resources. PJM's markets have begun to evolve in response to these changes, particularly through recent changes to resource adequacy modeling and measurement of resource contributions to resource adequacy (*i.e.*, by Effective Load Carrying Capability, or "ELCC").

This report considers a sub-annual market, another potential modification in response to these changes. We develop the report under an Issue Charge calling for education and assessment of a sub-annual capacity market. The Issue Charge states:[1]

> "PJM and stakeholders have recognized the potential benefits of a comprehensive sub-annual capacity market auction structure for grid reliability and efficiency for many years. Other major RTOs/ISOs have already taken advantage of these significant benefits from a sub-annual approach, which can allow every available megawatt of capacity to be called upon throughout the year by more accurately recognizing real world conditions. In an environment of significant projected load growth and resource constraints, there is a pressing need to implement a sub-annual capacity model, which could provide 'near-term achievable improvements to the market's ability to meet resource adequacy requirements in an efficient, least-cost manner.'"

Given this Issue Charge, this report aims to inform PJM, its stakeholders and the States in the PJM region (the "States") about the potential benefits and costs of developing a sub-annual market and the tradeoffs associated with specific sub-annual market design approaches. The evaluation of tradeoffs is informed by economic analysis of PJM's capacity market, review of sub-annual capacity market designs in other regional transmission organizations ("RTOs") and quantitative modeling to illustrate the design of a sub-annual market and provide indicative measures of potential impacts. Importantly, our evaluation focuses on whether a sub-annual market would provide the means for effectively and flexibly achieving resource adequacy given on-going and expected changes to the region's grid.

---

[1] PJM, "Issue Charge," September 4, 2025, available at https://www.pjm.com/-/media/DotCom/committees-groups/task-forces/sacmstf/postings/sacmstf-issue-charge.pdf.

Potential Benefits and Costs of Sub-Annual Markets

The adoption of sub-annual markets can potentially provide many benefits to PJM:

- **More accurate pricing of capacity to achieve better short-term allocation of resources and long-term investment in capacity resources.** Price signals can incentivize short-term responses of existing flexible resources (*e.g.*, demand response, imports) and long-term capital investment price signals that are better aligned with periods of need. A sub-annual market would achieve more efficient pricing by:
    - more accurately accounting for sub-annual variation in demand across the RTO and within locations (*i.e.*, Locational Deliverability Areas or "LDAs");
    - more accurately accounting for the aggregate performance of the resource fleet in mitigating resource adequacy risks; and
    - more accurately accounting for variation in resource costs of supplying capacity.
- **More accurately accounting for resource and system features that vary across sub-annual periods.** At present, certain resource and system capabilities are not accurately captured in the existing RPM given its focus on annual metrics. One issue is the use of specifications reflecting only summer performance. For example, a resource's installed capacity ("ICAP") value reflects capacity injection rights based on summer ambient conditions, which differ from (and would likely be higher) in winter. A second issue is that locational transmission constraints reflect summer values, although they differ (and would likely be less constrained, on average) at other times of the year. A third issue arises due to measurement of resource ELCC values at the RTO. When RTO-level ELCC values are used to measure ELCCs for resources within an LDA, accuracy is diminished when the RTO and LDA have different seasonal risk profiles (*e.g.*, one with large summer risk and one with large winter risk). A sub-annual market would mitigate this type of measure issue, resulting in more accurate measurement of resource adequacy within LDAs. In general, when RPM parameters reflect both summer and winter performance, year-to-year variation may be introduced from changes in RA risk between seasons. A sub-annual market can mitigate this issue.
- **Better alignment of resource costs and obligations.** A sub-annual market can better account for resource performance, thus making it easier for resources to offer supply. At present, differences between accreditation and actual performance can lead to barriers to participation (*e.g.*, capacity performance risk) that can only be mitigated through matching resources with complementary performance. By better aligning performance across seasons, a sub-annual market would lower the risk and cost to resources of providing supply.
- **Better aligning of resource compensation with the services provided.** With a sub-annual market, resource accreditation can reflect performance in each period (*i.e.*, ELCC), rather than aggregating performance that varies throughout the year. By better aligning compensation with their contributions to resource adequacy, a sub-annual market can improve incentives for investment in new (and existing) resources that reflect those contributions.
- **Reduced year-to-year variability in resource accreditation.** Compared to current annual ELCC ratings, sub-annual ELCC ratings would likely be less volatile, because a sub-annual market would reduce

variability from changes in relative seasonal risk. Variability in ELCCs has been identified as a concern of certain capacity suppliers due to the associated risk and hedging costs.

- **Greater flexibility to adapt the RPM to changing market circumstances.** A sub-annual market can flexibly adapt to changing system conditions as resource adequacy risks shift over the operating year given demand, resource and system changes. At present, although much of the system risk occurs during the winter months, many aspects of the RPM and RA framework reflect summer conditions. A sub-annual market can automatically adjust to shifts in risks across the year and avoid the need for stop-gap market rule changes designed to address inconsistencies between the market design and distribution of RA risk throughout the year.

While providing benefits, the adoption of a sub-annual market would involve additional costs (to PJM and stakeholders) in the form of one-time implementation costs and on-going costs of managing a potentially more complex market. In addition, as we discuss in the following paragraphs, the adoption of a sub-annual market can have certain unintended consequences if not properly designed, and design choices introduce various tradeoffs and risks.

Our quantitative analysis considers a two-season winter/summer market under a variety of market conditions and alternative sub-annual market designs and impact sensitivities. The impact of a sub-annual market reflects the shift from annual to seasonal market clearing, higher winter ICAP for certain thermal resources and higher winter Capacity Emergency Transfer Limits ("CETL") values for LDAs. We consider outcomes consistent with long-run market conditions and current conditions, reflecting tighter market supplies.

- The sub-annual market improves price signals under both current market conditions and past long-run market conditions ("base scenario"), reflecting less tight resource supplies. Under long-run conditions, RTO prices are $77.24 per MW-day in summer and $122.43 per MW-day in winter, consistent with the large share of expected unserved energy ("EUE") risk (95%) in the winter. Under current market conditions, the spread between seasonal prices grows, with RTO prices at $126.27 per MW-day in summer and $279.75 per MW-day in winter.

- Short-run production costs are reduced, as fewer resources (in ICAP) are cleared in the summer relative to the winter. We find that production costs are reduced by $47 million (4%) under long-run conditions, with no change in production costs under current conditions, because all resources clear. Production costs savings in our analysis, based on sequential market clearing, do not necessarily represent efficiency gains, as clearing could differ under an optimized auction. However, these estimates likely understate the total efficiency gains of a sub-annual market, as they do not consider the long-run effect of more efficient capital investment.

- Short-term payments are slightly increased under long-run conditions and reduced under current market conditions. We find that payments are increased by $53 million (1%) under long-run conditions and reduced by $6,523 million (33%) under current market conditions. Reductions in payments are large under current market conditions because the higher winter ICAP for certain thermal resources has a larger impact on prices under the tighter current market conditions.

- We test the sensitivity of the results above to a number of alternative assumptions, including MRI-based demand curves, tighter LDA transmission constraints, tighter supply, assuming no price caps, and a collar on seasonal risk allocation.

- Under long-run conditions, prices and payments range from less than 1% higher to 13% lower with a seasonal market across alternative assumptions. With a seasonal market, short-run production costs are reduced by 4% to 10%.
- Under current market conditions, prices and payments under these alternative assumptions are reduced by 4% to 39% with a seasonal market. Short-run production cost differences range from no difference (when all resources clear in both the annual and seasonal markets) to a 3% reduction with a seasonal market.

Assessment of Sub-Annual Market and Market Design

On balance, we recommend that PJM pursues the development of a sub-annual capacity market. This recommendation reflects our assessment of the substantial potential benefits, the results of our quantitative analysis, and our assessment of how a sub-annual market could be designed and the associated tradeoffs.

Our report assesses the tradeoffs and issues that PJM and its stakeholders would need to consider in designing a sub-annual market. PJM has several different options to pursue that we expect would achieve much of the net benefits offered by a sub-annual market. We generally do not recommend a particular design but identify and discuss the advantages and tradeoffs posed by several approaches. One design recommendation is that we believe a sub-annual market grounded in seasons will provide the greatest net benefits, particularly a two-season winter/summer design.

Our assessment focuses on designs that will achieve the full scope of potential benefits by specifying demand, supply and resulting market-clearing specific to individual periods. These designs offer the best opportunity for PJM to achieve the full opportunity offered by sub-annual markets. By reconfiguring the market toward individual seasons, the market can create prices that signal the value of capacity in each season and resource supply accounting that better reflects a resource's contribution to reducing RA risk in each season.

The two primary options for a sub-annual market are a co-optimized auction and independent auctions, with either sequential or simultaneous clearing.

- With a **co-optimized auction**, the procurement of supply from supply offers to meet RA targets is optimized across periods. The most valuable and practical scope of co-optimization would account for both annual and period-specific supply costs and allow for annual price caps (to complement or potentially eliminate caps for individual periods).
- With **independent auctions**, each auction independently clears demand and supply in each period. Independent auctions forgo potential efficiency gains from co-optimization. Independent auctions can be run sequentially, which affords suppliers with more information prior to making resource commitments, or simultaneously, which provides the opportunity to set an *ex-post* cap on prices *across* auctions over the year.

A co-optimized auction offers many advantages compared to independent auctions, including efficiency gains in clearing supply offers, supplier settlement that ensures cost recovery, and the ability to set an annual cap on prices. However, a co-optimized auction could be more complex and costly to implement compared with independent auctions, which would be comparatively simpler to develop. Given these and other issues (and potentially other factors, such as the operation of prompt markets), neither ISO New England ("ISO-NE") nor Midcontinent ISO ("MISO") are pursuing co-optimization as part of their initial sub-annual market designs.

In choosing a market/auction framework, there are several key considerations. First and foremost is market efficiency and effectiveness. The market should achieve important efficiencies and provide an orderly and functioning market. Any design that is flawed or incomplete will cause problems to market operations that will be detrimental to suppliers and customers and consume PJM and stakeholders in rushed reform efforts.

A second consideration is the scope of enhancements adopted given future opportunities to incrementally develop the market. Since their inception, organized wholesale markets have undergone many evolutions, reflecting both on-going learning and responses to changing loads, resources and system conditions. Sub-annual markets represent a significant opportunity and change for PJM's capacity markets. Design choices embed certain optionality and opportunities to mitigate risks, such as choices related to market structure, period definition and seasonal risk allocation. For example, starting with sequential, independent sub-annual auctions retains optionality to develop co-optimized auctions at a later date.

A third consideration is the overall market design. PJM and its stakeholders are evaluating many enhancements to its markets, particularly the RPM, given evolving systems conditions including the transition in resources supplying services, with more intermittent, limited energy and gas-fired resources, and evolving net loads, given more complex behind the meter loads and growing data center loads. The adoption of marginal reliability impact ("MRI") demand curves and a prompt, rather than forward, market are, for example, two potential enhancements that might be part of holistic roadmap for RPM reform. In the best of worlds, PJM would develop this holistic roadmap for resource adequacy first and then sequence reforms, including sub-annual market reforms, with this framework in mind. This approach has at least two important benefits. First, it prioritizes efforts. Thus, for example, *if* an optimized auction requires more time and effort (which may or may not be the case), pursuing this approach may affect timing of sub-annual reforms and impose opportunity costs on limited PJM and stakeholder resources. Depending on competing priorities, this may crowd out or delay other market initiatives. Second, a holistic design can account for interactions between design elements. For example, while PJM currently operates a forward market, other centralized capacity markets do or will operate as prompt markets. This decision, however, affects the tradeoffs between co-optimized and sequential auctions. In particular, a sequential auction offers certain benefits that are less salient under PJM's current forward market (in particular, a sequential auction clears more frequently and closer to the delivery period, and thus provides market participants with more accurate information about market and resource conditions prior to each auction; by contrast, there is more uncertainty when simultaneously clearing all periods).

Finally, particular design features will affect each of these issues. Importantly, for a sub-annual market, there are multiple other key design issues:

- **Offer Structure and Mitigation.** An important difference between co-optimized and independent auctions is the structure and mitigation of supply offers. Under an annual market, offer prices reflect annual going forward costs. With a sub-annual market, the structure of supply offer prices needs to account for both fixed annual costs that are incurred if the resource supplies in any period and avoidable period costs that can be avoided if a resource does not supply in a period.

With a co-optimized auction, the auction can separately account for annual fixed and avoidable period costs. By separately accounting for each type of cost, a co-optimized auction can achieve more efficient market outcomes by selecting the most efficient mix of capacity resources. The auction can also ensure that resource compensation is sufficient to cover resource costs. If adopted, market rules would need to be developed to distinguish fixed annual costs from avoidable period costs and the degree of flexibility that would be afforded to market participants to specify costs in one category or the other. Offer mitigation rules would thus need to be evaluated.

With independent auctions, offers can only reflect a single cost component, incorporating both fixed annual and avoidable period costs. Market clearing with a single cost component will be less efficient than in a co-optimized auction, because the auction algorithm cannot account for resources' discrete fixed annual costs. Further, auction revenues may not be sufficient to cover a resource's costs if the resource does not clear in all periods. While independent auctions can avoid the need to define market rules that distinguish fixed annual and avoidable period costs, other market mitigation questions arise. One important question is whether market participants' offer prices can reflect the possibility that a resource clears in some, but not all sub-periods. In MISO, for example, resource offers can reflect the recovery of all annual costs in one season. Allowing this offer flexibility provides a resource with the opportunity to ensure all going forward costs are recovered. However, it also creates the possibility that clearing prices result in over-recovery of going forward costs, which may, in turn, prompt a desire to impose an annual caps on prices across seasons (as addressed further in the discussion of price caps).

The quantitative analysis measures the extent to which resources that clear in only one season under-recover their costs. Under the Current Market Scenario, which reflects tighter supply, all resources or virtually all (99.1% or greater) clear in both seasons. Under the Base Scenario, reflecting long-run conditions, the large majority of resources – 96.2% to 98.2% – clear in both seasons, while 1.8% to 3.8% of capacity clear in one but not both seasons (by annual ICAP). On average across the Base Scenario cases and sensitivities, these resources recover 57% to 85% of their annual costs in a single season, with individual resources recovering between 50% and 110% of their costs. In total, under-recovery ranges from $4 million to $90 million annually, depending on assumptions. These estimates do not account for any changes in market clearing prices with a co-optimized auction.

- **Supply Quantities.** With a sub-annual market, resource offers can reflect period-specific estimates of the quantity of capacity supply. We recommend that market rules account for sub-annual supply offer quantities that reflect resource capability given ambient air conditions, resource deliverability, resource performance reflecting (historical) forced outage risks, and contributions to resource adequacy given intermittency and correlated supplies (*i.e.*, marginal ELCC). Accounting for all features that affect resource performance will lead to more reliable outcomes and compensation that better reflects the value of capacity resources to resource adequacy.
- **Number of Periods and Period Definition.** In principle, a sub-annual market can be designed with a range of granularities, including different seasonal specifications (*e.g.*, summer and winter seasons, four seasons, monthly, hourly) and different intra-day specifications (*e.g.*, day/night). All else equal, greater granularity increases benefits by accounting for potential differences in the value of capacity in different periods and resources' ability to deliver resource adequacy contributions. However, increased granularity does not necessarily lead to meaningful differences in outcomes. Granularity that specifies periods with no meaningful risk would not create benefits and granularity that distinguishes periods that are relatively

similar would not create meaningful benefits. Thus, given cost, complications and unintended consequences, greater granularity is not necessarily beneficial.

At present, resource adequacy risk occurs exclusively during certain summer and winter months and there are meaningful differences in resource performance between these seasons. Given this, **a two-season market** would capture relevant variation in risk across the year. This conclusion assumes that resource performance and load profiles are relatively uniform within each season, which is the case, for the most part. If resource adequacy evolves in the future to spread risk more evenly across the year, then differentiating shoulder months from summer and winter may be warranted if it can improve market outcomes. A potential (and maybe the most likely) cause of future shoulder season risks is growing constraints in scheduling planned maintenance outages. However, the likelihood that these risks are meaningful is very uncertain. More importantly, the primary way to manage these risks is through enhanced rules for outage scheduling, rather than through the capacity market, which provides very imprecise incentives to address this particular issue. Given this, further demonstration of these potential risks and their persistence after implementing enhanced rules for outage scheduling is appropriate before pursuing a **three- or four-season market**.[2] A prudent approach initially may be to develop a two-season market and monitor should seasonal risks over time to assess whether further segmentation of periods is warranted.

The advantages of markets with relatively few periods (*i.e.*, two to four seasons) reflect certain unintended consequences of more granular alternatives. In particular, a market with periods that capture little or no RA risk would produce little benefit, while having implications for market pricing, particularly the likelihood of persistently low prices and potential for greater price volatility. While low prices are not *per se* a problem, persistent low prices will diminish the incentives for resources to take on capacity supply obligations in those periods. Capacity performance (“CP”) contributes to incentives to forgo capacity obligations when prices are low. Diminished supply in low-risk periods could have detrimental effects for reliability because, in practice, capacity resources provide reliability services beyond achievement of resource adequacy (*e.g.*, must offer requirements, outage planning). Low prices, reflecting periods of low risk, may also contribute to price volatility and under-recovery of costs by marginal resources in the supply stack. More granular designs may introduce other design issues, such as challenges with establishing reasonable price caps.

Other sub-annual proposals include periods that span the operating day (*e.g.*, day and night periods) to better capture the performance of certain types of resources, particularly intermittent renewables like solar and wind. However, this approach would create substantial complications for clearing resources with interdependent performance across the day, such as battery and pumped storage resources. Given these considerations, we recommend a sub-annual market with a relatively few number of seasonal periods.

If developing a sub-annual market based on seasonal weather conditions, such as the two-season option described above, the market should modify the market’s current calendar, such that each annual cycle

[2] A three-season market would combine spring and fall into one period, while a four-season market would include four seasons: winter, spring, summer and fall.

runs from May 1 through April 30, instead of the current June 1 to May 31. With this approach, under a two-season market, for example, the summer period would run from May 1 to October 31, while the winter period would run from November 1 through April 30 of the following year.

- **Demand Curves.** In principle, a sub-annual market with price discovery for each period requires that demand for capacity resources in each period reflect the value of capacity – customers' willingness-to-pay ("WTP") – for mitigating RA risks. To this end, with a sub-annual market, demand curves can be constructed for each period (*e.g.*, season) at the RTO and LDAs level. In developing these curves, the basic principles and approaches can remain the same, with modifications to capture sub-annual variation in RA risk and the need to achieve the regulatory requirement that, *across all* periods, revenues are sufficient to cover the cost of new entry when reliability, *cumulatively across all periods*, is at the 1-in-10 loss of load expectation ("LOLE") target.

  Analytically, the construction of sub-annual demand curves is relatively straightforward. The first step is determining the regulatory requirement "anchor" points – that is, the resource requirement and net cost of new entry ("Net CONE") – for each period's demand curve. **An economic approach reflects the principle that the cost paid per unit of RA risk (*e.g.*, EUE) should be the same across seasons**. Under this approach, (1) capacity requirements are set to be consistent with the current distribution of risk across periods, as measured by the RA analysis and (2) Net CONE recovery is allocated across periods to reflect the system "scalar" equal to Net CONE divided by system RA risk (*e.g.*, marginal EUE) at the 1-in-10 resource adequacy requirement. Existing rules for RTO and LDA demand curves could be adapted to sub-annual curves. However, alternative options to the economic approach are available and could have implications for price volatility. In particular, options that constrain seasonal risk, either by pre-determining risk allocation (*e.g.*, a 50/50 summer/winter split as ISO-NE is proposing) or constraining risk allocation (*e.g.*, an 65/35 risk collar, as is done in New York ISO ("NYISO")) may support pricing in low risk seasons and reduce price volatility, which may be advantageous in initial market stages.

  The next step then is to develop the demand curve shapes and slopes. While sub-annual demand curves can be developed using the existing Variable Resource Requirement ("VRR") framework, **adoption of an MRI-based approach that directly ties demand curves to RA modeling can provide several important benefits**. *First*, MRI-based demand curves more accurately represent RA risks than current linear VRRs. MRI-based demand curves are based on actual marginal risks as measured by the resource adequacy models, rather than linear approximations, as with the current VRR approach. MRI curves are a standard output of resource adequacy analyses and provide an analytically direct and non-controversial way of developing demand curves. ISO-NE and MISO both rely on this approach.

  Second, MRI-based demand curves would be less burdensome in terms of administration and stakeholder processes. If PJM were to pursue linear VRR-like demand curves for each period, PJM would need to undertake design and stakeholder processes to first develop procedures for determining the shape/slope of each period's VRR curve and then regularly update these shape/slope determinations, like the current quadrennial process. With the adoption of MRI-based demand curves, PJM and its stakeholders could avoid (or simplify) these processes, because the direct use of MRIs allows these steps to be undertaken formulaically given the analytical relationship between MRI curves and demand curves.

  Our proposed adoption of MRI-based demand curves extends a trend of growing reliance on RA modeling in the implementation of the RPM. This trend is common to many RTOs and reflects a growing precision in evaluation and management of resource adequacy. Given this growing reliance on RA modeling, we think it important that PJM in cooperation with stakeholders continue the on-going assessment of model performance and sensitivity of model results to market operations. The move to a sub-annual market can mitigate some of these issues, by reducing variability across time in period/seasonal risks but continued evaluation of sensitivity of market outcomes (*e.g.*, prices) and parameters (*e.g.*, ELCCs) to changing market conditions will be valuable.

- **Price Caps.** The adoption of sub-annual markets would require a reassessment of criteria and formulas for price caps. Price caps establish a maximum price for capacity. With an annual market, price caps are to reflect regulator's estimate of customer's maximum WTP for capacity. In practice, this has been accomplished by setting caps formulaically, as a function of Net CONE and/or Gross CONE.

  With a sub-annual market, one approach to setting caps is to extend current annual caps to individual periods, with each period's cap being a function of Net CONE. There is a sound justification for using this approach because price caps set proportional to each period's marginal risk and allocated Net CONE correspond to a uniform maximum WTP for reductions in risk across periods. With this approach, price caps will be higher in periods with greater risk and lower in periods with lower risk.

  While setting price caps proportional to allocated Net CONE is a principled approach to setting price caps for each period, there are other considerations in setting price caps.

  Price cap *values* for individual periods can be relaxed compared to the current annual price cap without raising expected prices. This result reflects the fact that prices may hit caps in some but not all periods. Given this, setting individual period caps so that their average across the year equals the current annual cap will tend to lower expected prices because prices are unlikely to hit the caps in all periods at the same time. In addition, because resources may clear in some but not all sub-periods in a sub-annual auction, constraining prices in particular periods may contribute to under-recovery of going forward costs for marginal resources. While these considerations suggest advantages to raising the level of price caps for individual periods, price caps set too high clearly create the risk that average prices across the year are too high relative to customers' WTP. For example, we believe it is unnecessary to set prices to allow the reference technology to recover its cost of new entry in a single period.

  Designs with an annual price cap mechanism provide a means to mitigate the risk of excessively high prices across the year. An annual cap mechanism also allows greater flexibility to setting caps on prices in individual periods by mitigating the risk of higher caps on annual average prices. An annual cap mechanism is easier to deploy under a co-optimized auction (with an integrated annual cap) or a simultaneous, independent auction (with an *ex-post* cap). Under either approach, the cap mechanism would need to be designed to determine how price discovery will be limited across periods with high prices.

II. Introduction and Purpose of Study

Wholesale electricity markets in the Pennsylvania-New Jersey-Maryland Interconnection (PJM) were developed at a time when (a) summer peak conditions drove reliability considerations; (b) demand growth was gradual and predictable; and (c) the generation fleet was dominated by legacy fossil fuel resources that performed relatively uniformly across the year.

These conditions have changed, with potentially significant implications for how PJM manages and maintains resource adequacy. Demand growth is accelerating rapidly, driven by large load growth and electrification, while the generation mix includes expanding intermittent resources and greater reliance on gas-fired resources. As a result, resource adequacy risk has grown outside of the summer season and the contributions that asset classes make to resource adequacy have become more complex, reflecting increasing uncertainty around performance during critical system conditions. Complicating matters, changes in market rules to account for certain aspects of these structural challenges (*e.g.*, resource accreditation) were one of multiple factors affecting outcomes of PJM's capacity market auctions, with historically low prices (*e.g.*, $28.92/MW-day in the 2024/2025 Delivery Year) preceding steep price increases in the past three auctions, reaching the cap in the most recent two capacity auctions for the 2026/2027 and 2027/2028 Delivery Years.[3]

PJM has been carefully reviewing the impact of these structural changes on resource adequacy and evaluating enhancements to its capacity market design to manage the new supply and demand challenges while maintaining the reliability.[4] Amongst other reforms, PJM and its stakeholders have been considering a transition to a sub-annual capacity market construct since at least 2021.[5] Initial concepts discussed with stakeholders in 2023 did not proceed to the development of proposals for filing at FERC.

In July 2025, PJM stakeholders approved an Issue Charge brought forth by Governor Josh Shapiro at the July 2025 Markets and Reliability Committee to review PJM's capacity market and evaluate a transition to a sub-annual construct.[6] As a result, Analysis Group was asked to evaluate a sub-annual construct for PJM's capacity market, including a comparative analysis with existing market structures and an analytical and quantitative assessment of design options. This report aims to inform PJM, its stakeholders and relevant States on sub-annual capacity

---

[3] PJM, "2026/2027 Base Residual Auction Report," July 22, 2025, available at https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2026-2027/2026-2027-bra-report.pdf; PJM, "2027/2028 Base Residual Auction Report," December 17, 2025, available at https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2027-2028/2027-2028-bra-report.pdf.

[4] *See*, *for example,* PJM Resource Adequacy Senior Task Force, available at https://www.pjm.com/committees-and-groups/task-forces/rastf; PJM Critical Issue Fast Path – Resource Adequacy. *See also,* PJM Effective Load Carrying Capability Senior Task Force, available at https://www.pjm.com/committees-and-groups/task-forces/elccstf; PJM Deactivation Enhancements Senior Task Force, available at https://www.pjm.com/committees-and-groups/task-forces/destf.

[5] PJM, "Capacity Market Reform," January 26, 2022, available at https://www.pjm.com/-/media/DotCom/committees-groups/task-forces/rastf/postings/rastf-issue-charge.pdf, p. 3.

[6] PJM, "Sub-Annual Capacity Market Issue Charge," August 4, 2025, available at https://www.pjm.com/-/media/DotCom/committees-groups/task-forces/sacmstf/postings/sacmstf-issue-charge.pdf, p. 1.

market design options available to PJM and the relative costs and benefits of each. To this end, this report has the following objectives:

- Identifying the design principles and criteria for a sub-annual capacity market construct (including, for example, sub-annual reliability requirements, demand curves, auction structure, resource accreditation, and price caps);
- Evaluating tradeoffs of the various design options;
- Conducting an impact assessment of the design options;
- Identifying issues that would need to be addressed in implementing the various design options; and
- Providing final recommendations on the design options that PJM should pursue.

To evaluate the sub-annual design options, we rely on a variety of analytical, quantitative and qualitative approaches:

- Economic principles, including factors affecting supply costs, risks and offers; demand for capacity; and market-clearing principles;
- Experience from developments in PJM and other RTOs, including MISO, NYISO and ISO-NE; and
- A quantitative analysis of the impact of different design options on various market metrics, including prices, quantities of capacity and consumer costs.

The evaluation reflects multiple criteria, including economic efficiency, cost-effectiveness, market efficacy and reliability.

We undertake our study in the context of the recent and on-going assessment that PJM and its stakeholders are undertaking of its resource adequacy framework and its capacity market, in particular. While our study focuses on a sub-annual market, a prudent evaluation should not be undertaken in isolation of other enhancements being considered and should be part of a broader process seeking holistic reforms with a long-term design in mind. PJM has recently undertaken reforms related to, among other things, resource adequacy modeling, capacity accreditation and CP. At present, it has on-going processes considering resource accreditation and demand curve design, including the use of MRI curves, and other design options considered in the past – and relevant for the future – include a prompt (rather than forward) market.

Our study does not evaluate these other market design options. However, we do consider interaction between certain other design options with a sub-annual market, and the implications of these interactions for the adoption of these other options.

We believe it prudent to undertake major enhancements, such as a sub-annual market, with a long-run design in mind. While some design enhancements can be evaluated independent of other aspects of market design, often the impact of particular designs features depend on other design elements. A process that evaluates market design elements in a piecemeal, sequential manner does not necessarily lead to the same market design following a holistic reform. However, undertaking a holistic reform does not necessarily imply that all reforms need to be executed at once. In some cases, sequencing the adoption of market features may be prudent given practical constraints on implementation. In other cases, it can be important to implement features at one time, in a coordinated fashion, to avoid an incomplete or flawed market design.

We first discuss the resource adequacy construct in PJM and emerging reliability risks in the region in **Section III**. Next, in **Section IV**, we outline experiences with sub-annual capacity market designs in other RTOs. In **Section V**, we discuss the benefits of a sub-annual capacity market construct in the context of PJM's electricity supply and demand challenges, and evaluate the tradeoffs of several design options. In **Sections VI** and **VII**, we evaluate sub-annual design options analytically and quantitatively by relying on a microsimulation model.

III. Background

A. Context and Changes in System Conditions

1. Resource Adequacy in PJM

PJM operates a capacity market, known as the Reliability Pricing Model, which uses a multi-auction structure to procure resource commitments to satisfy the region's capacity needs. The RPM was first implemented in the 2007/2008 Delivery Year.[7]

The RPM, like other capacity markets, is designed to help PJM comply with resource adequacy standards by ensuring that there are sufficient revenues for new entry under defined FERC reliability standards.[8] A resource adequacy construct ensures that the electricity system reliably and sustainably meets this objective by providing the "missing money" needed for resources to adequately supply capacity and invest in new resources. In particular, capacity markets aim to provide price signals that reflect the marginal value of capacity in reducing reliability risks to guide resources' short-term operational decisions and long-term investments in new generation, thereby aligning individual resource incentives with the system's broader reliability objectives.[9] The RPM includes

---

[7] A Delivery Year corresponds to the planning period for which resources are committed to. For example, the 2007/2008 Delivery Year corresponds to the June 1st 2007 to May 31st 2008 planning period. *See, for example,* PJM, "PJM Manual 18: PJM Capacity Market," July 23, 2025, available at https://www.pjm.com/-/media/DotCom/documents/manuals/m18.ashx (hereafter, "PJM Manual 18: PJM Capacity Market"), p. 238.

[8] PJM relies on several metrics to evaluate resource adequacy. PJM calculates (a) the Loss of Load Expectation ("LOLE"), or the expected number of hours per year that are expected to experience capacity shortfall, (b) the Loss of Load Hours ("LOLH"), or the number of days in a year that are expected to have a single loss of load event, regardless of duration of magnitude, and (c) the EUE, or the number of MWh in a year that are expected to be unserved during loss of load events. *See also,* PJM, "PJM Manual 20A: Resource Adequacy Analysis," May 21, 2025, available at https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2025/20251202/20251202-item-06---3-manual-20a-revisions---redline.pdf (hereafter, "PJM Manual 20A: Resource Adequacy Analysis"), p. 8.

[9] *See, for example,* Joskow, Paul L., "Capacity payments in imperfect electricity markets: Need and design," *Utilities Policy*, Vol. 16, No. 3, October 12, 2007.

a Base Residual Auction ("BRA"), Incremental Auctions and a Bilateral Market.[10] The BRA is a forward auction typically held in May of every year, three years prior to the start of the "Delivery Year," which corresponds to the June 1 to May 31 Planning Period. PJM's BRAs are currently on a condensed schedule as a result of several auction delays that started in 2021 as PJM considered market reforms. Most recently, the 2027/2028 BRA was delayed to December 2025 to allow PJM time to evaluate market rule changes following stakeholder concerns about high clearing prices in the 2025/2026 BRA, held in July 2024.[11]

After the BRA, incremental auctions are conducted to adjust resource commitments (*i.e.*, procure additional resource commitments or release excess quantities) as a result of market changes in the years before the Delivery Year.[12] When the BRA is held three years prior to the Delivery Year, this results in three incremental auctions. Finally, a bilateral market allows resource providers to cover auction commitment shortages and load serving entities ("LSEs") to hedge against the Locational Reliability Charge, and is facilitated through PJM's Capacity Exchange System.[13]

Over the past decade, PJM has been reviewing its capacity market design to address challenges associated with reliability concerns and the transition of the resource mix.[14] In February 2023, the process was accelerated by the establishment of a Critical Issue Fast Path – Resource Adequacy ("CIFP-RA") stakeholder process. This accelerated stakeholder process focused on several issues related to "resource adequacy challenges in the [RPM] or capacity market", including issues of reliability associated with the growth of electricity demand, retirements outstripping new generation, and issues around intermittency.[15,16] This stakeholder process was built on several years of consultations and workshops that sought to review capacity market design given the evolution of the industry.[17] In particular, the stakeholder process considered enhancements of RPM's risk modeling methodology to better account for winter risk and correlated outages, modifications to the Capacity Performance construct,

---

[10] The PJM capacity market also allows load serving entities to participate in the Fixed Resource Requirement ("FRR") Alternative and submit a FRR Capacity Plan to meet a fixed capacity resource requirement, as an alternative to the variable capacity resource requirement included in the RPM. PJM Manual 18: PJM Capacity Market, pp. 11-12.

[11] PJM, 189 FERC ¶ 61,105, Order Granting Waiver Request and Dismissing Motion, November 8, 2024, Docket Nos. ER25-118-000.

[12] PJM Manual 18: PJM Capacity Market, Section 3.5.

[13] PJM Manual 18: PJM Capacity Market, Sections 1.3, 1.4.

[14] PJM, "Critical Issue Fast Path – Resource Adequacy Problem/Opportunity Statement," 2023, available at https://www.pjm.com/-/media/committees-groups/cifp-ra/2023/20230329/20230329-item-02---cifp-ra-problem-statement---final.ashx.

[15] PJM, "Energy Transition in PJM: Resource Retirements, Replacements & Risks," February 24, 2023, available at https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx.

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

[17] PJM, "Capacity Market Reforms to Accommodate the Energy Transition While Maintaining Resource Adequacy," FERC Docket No. ER24-99-000, October 13, 2023, available at https://www.pjm.com/-/media/documents/ferc/filings/2023/20231013-er24-99-000.ashx, pp. 20-21.

adjustments to resource accreditation to improve accuracy, and the synchronization of any RPM changes with other options for securing resource adequacy.[18] The stakeholder process culminated in two filings with FERC, submitted in October 2023, which proposed enhancements to PJM's resource adequacy risk modeling, capacity accreditation and offer caps, including seasonal enhancements.[19]

Within the CIFP-RA, PJM drafted two proposals, one to adopt a fully seasonal market construct for the 2025/2026 BRA (described in more detail in **Section III.B**) and another to incorporate seasonal adjustments into the annual construct. PJM ultimately maintained the forward, annual capacity market structure, following stakeholder feedback to allow more time for discussion on the design and implementation of the sub-annual approach.[20]

Key elements of PJM's current annual capacity market structure include:

- Annual reliability studies to determine an annual Installed Reserve Margin ("IRM") based on ICAP and the 1-in-10 LOLE reliability criterion.[21] The reliability studies also calculate the unforced capacity ("UCAP") requirement as the installed capacity requirement adjusted for the average outage rates of resources in the region, which anchors the demand curves.[22]
- Load deliverability analyses to evaluate which of the 27 LDAs will be modeled within the auctions.[23] PJM resources are required to meet both the PJM-wide and the LDA Reliability Requirements.[24]

[18] PJM, Letter from the Board to Members, February 24, 2023, available at https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20230224-board-letter-re-initiation-of-the-critical-issue-fast-path-process-to-address-resource-adequacy-issues.ashx.

[19] Specifically, PJM adopted a more granular, hourly framework; improved resource accreditation to apply a marginal effective load carrying capability ("ELCC") framework to all generation resources and demand resources; incorporated seasonal requirements in generator testing; amongst other reforms. *See for example,* PJM, "Capacity Market Reforms to Accommodate the Energy Transition While Maintaining Resource Adequacy," FERC Docket No. ER24-99-000, October 13, 2023, available at https://www.pjm.com/-/media/documents/ferc/filings/2023/20231013-er24-99-000.ashx (hereafter "Reliability Enhancements Filing"). *See also,* PJM, "Proposed Enhancements to PJM's Capacity Market Rules - Market Seller Offer Cap, Performance Payment Eligibility, and Forward Energy and Ancillary Service Revenues," FERC Docket No. ER24-98-000, October 31, 2023, available at https://www.pjm.com/directory/etariff/FercDockets/7658/20231013-er24-98-000.pdf ("Markets Enhancements Filing").

[20] For example, "In response to stakeholder feedback, PJM proposed a second, annual capacity market design proposal that contains the vast majority of elements of the seasonal proposal but simplifies the proposal to maintain an annual structure […]." Also, "The Board 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." *See also,* Reliability Enhancements Filing, p. 22; 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, p. 2.

[21] PJM Manual 18: PJM Capacity Market, Section 2.

[22] PJM Manual 18: PJM Capacity Market, Section 2.1.

[23] PJM Manual 18: PJM Capacity Market, Section 2.2.

[24] PJM Manual 18: PJM Capacity Market, Section 2.4.

- Annual, downward-sloping demand curves, VRR, determined system-wide and for each of the constrained LDAs.[25]
- Resource supply offers that reflect installed capacity and resource accreditation based on the ELCC framework, which establishes an Accredited UCAP value to each resource type.[26]
- Clearing prices within the modeled LDAs, determined by the marginal value of system capacity (based on the BRA's unconstrained region) supplemented by locational price adders that reflect locational transmission constraints, resource availability and reliability needs in each LDA.[27]
- PJM assigns zonal obligations based on each zone's share of forecasted peak load. Zonal obligations are then allocated to LSEs within each zone based on LSEs' share of peak load during several peak hours.[28]

Over the most recent three auctions, PJM's capacity market auctions have experienced large price increases (*see* **Figure III-1**). The 2025/2026 BRA cleared at $269.92/MW-Day for the 2025/2026 Delivery Year, a sharp increase from previous years (*e.g.*, the clearing price of the 2024/2025 BRA was $28.92/MW-Day).[29] In the 2026/2027 BRA, the clearing price reached the cap of $329.17/MW-Day for all LDAs and Rest of System.[30] These surges have been attributed by PJM to supply struggling to meet increased demand driven by data center expansion, electrification and economic growth; delayed interconnection of new resources; and the marginal ELCC accreditation reforms introduced in the 2025/2026 BRA.[31, 32] In December 2025, the 2027/2028 BRA also cleared

---

[25] PJM Manual 18: PJM Capacity Market, Section 3.1.

[26] PJM Manual 18: PJM Capacity Market, Section 2.1.

[27] PJM Manual 18: PJM Capacity Market, Section 5.7.2.

[28] PJM, "RPM Cost Allocation Education," July 22, 2025, available at https://www.pjm.com/-/media/DotCom/committees-groups/task-forces/202cstf/2025/20250722/20250722-item-03---202cstf-rpm-cost-allocation-education---presentation.pdf, p. 4.

[29] While a typical BRA is held more than three years before the start of the Delivery Year, this BRA was conducted under a compressed auction schedule whether the auction occurred approximately ten months prior to the start of the Delivery Year. PJM, "2025/2026 Base Residual Auction Report," July 30, 2024, https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-report.pdf, p. 4.

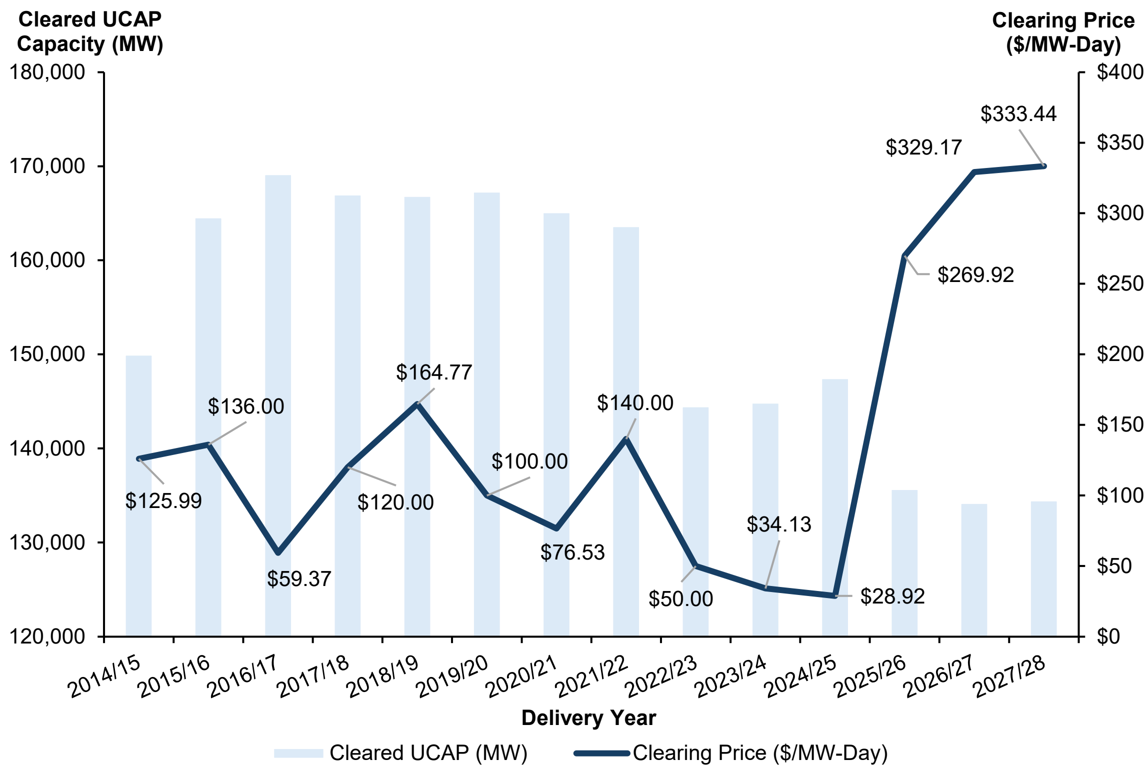
[30] PJM, "2026/2027 Base Residual Auction Report," July 22, 2025, available at https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2026-2027/2026-2027-bra-report.pdf, p. 5.

[31] PJM's accreditation approach based on *marginal* ELCC ("mELCC") for all resources was accepted by FERC in January 2024 and first introduced in the 2025/2026 BRA. The accreditation reform was a result of growing concerns around reliability risk highlighted by Winter Storm Elliot in December 2022, when PJM narrowly avoided rolling blackouts. FERC, 'Order Accepting Tariff Revisions Subject to Condition," January 30, 2024, available at https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20240130-3113&optimized=false, pp. 7-8 ("PJM states that recent operating experiences such as Winter Storm Elliott have demonstrated that modeling approaches focused on peak load conditions and average generator performance do not fully capture all of the risks that impact resource adequacy needs and resource performance.").

[32] PJM Inside Lines, "PJM Auction Procures 134,311 MW of Generation Resources; Supply Responds to Price Signal," July 22, 2025, available at https://insidelines.pjm.com/pjm-auction-procures-134311-mw-of-generation-resources-supply-responds-to-price-signal/ ("electricity demand is growing rapidly […] driven largely by data center expansion, electrification and economic growth," "PJM has processed more than 60% of the transition backlog in its interconnection queue […]"). PJM, "2025/2026 Base Residual Auction Results," August 21, 2024, available at https://www.pjm.com/-/media/DotCom/committees-

at the price cap of $333.44 in all LDAs and Rest of System, as the capacity of resources procured in the auction fell short of PJM's reliability requirement.[33]

Figure III-1: PJM BRA Clearing Quantity and Price[34]
2014/2015 - 2027/2028 Delivery Years



The escalation of prices has drawn scrutiny from regulators and stakeholders concerned about affordability, which has led to the following developments:[35]

---

groups/committees/mrc/2024/20240821/20240821-item-08---2025-2026-base-residual-auction---presentation.pdf, p. 11 ("PJM believes that the CIFP [ELCC marginal accreditation] rules resulted in tightening of the supply/demand balance in the auction.").

[33] PJM, "2027/2028 Base Residual Auction Report," December 17, 2025, available at https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2027-2028/2027-2028-bra-report.pdf, pp. 3, 5.

[34] **Source:** PJM, Base Residual Auction Data, RPM Capacity Market Annual Reports, available at https://www.pjm.com/markets-and-operations/rpm.

[35] NRG, "Special Market Update: PJM's Base Residual Auction for DY '26/27," May 2025, available at https://www.nrg.com/content/dam/nrg/documents/insights/white-papers-and-webinars/webinars/pjm-capacity-market-update-may-2025.pdf.

- In November 2024, FERC approved a delay of the 2026/2027 BRA from December 2024 to June 2025, and PJM proposed capacity market changes such as a change in the reference resource for the demand curve.[36]
- In December 2024, Governor Josh Shapiro also filed a complaint against PJM to reduce the price cap used in PJM's demand curve, and a price collar (*i.e.*, floor of approximately $175/MW-day UCAP and price cap of approximately $325/MW-day UCAP) was approved in April 2025 for the 2026/2027 and 2027/2028 BRAs.[37]

2. Changes in Market and System Conditions in PJM

The PJM region, similar to other regions in the U.S. (*e.g.*, NYISO, ISO-NE, MISO), is undergoing multiple changes that affect, and are anticipated to increasingly affect, both its electricity system and markets. These changes are being driven by multiple factors, including: shifting seasonal patterns of energy demand due to both policy and economic factors, the evolving mix of resources entering and exiting the system, and increasing fuel supply risk due to expanded reliance on gas-fired resources, particularly in the winter.[38, 39] These evolving dynamics present new challenges for ensuring resource adequacy in the region throughout the year, not just in the summer.

a. Rapid growth in demand, with greater growth in the winter relative to summer

The PJM region has historically been a summer-peaking system with relatively slow load growth; in the last two decades, the average annual peak load growth was 0.78%, with an overall increase in peak load of 16% between 2000 and 2024.[40] Recently, however, the gap between the summer and winter peak demand has decreased as a

---

[36] PJM Interconnection, 189 FERC ¶ 61,105, Order Granting Waiver Request and Dismissing Motion, November 8, 2024, Docket Nos. ER25-118-000 and EL24-148-000; PJM, "Consultation With Members Regarding Future 205 Filing on Capacity Market," November 7, 2024, available at https://www.pjm.com/-/media/DotCom/committees-groups/committees/mrc/2024/20241107-special/item-02---capacity-market-adjustments---presentation.ashx.

[37] The price floor and cap are calculated based on the installed capacity of the CT reference resource, with annual adjustments to account for the reference resource's level of capacity accreditation. Gov. Josh Shapiro, "Complaint of Governor Josh Shapiro and The Commonwealth of Pennsylvania," December 30, 2024, available at https://www.pa.gov/content/dam/copapwp-pagov/en/governor/documents/pjm-lawsuit/gov.%20shapiro%20and%20commonwealth%20of%20pa%20complaint(119760108).pdf; PJM Interconnection, 191 FERC ¶ 61,066, Order Accepting Tariff Revisions and Dismissing Complaint, April 21, 2025, Docket No. ER25-1357-000 and EL25-46-000, pp. 6, 26.

[38] PJM, "Capacity Market Reform: PJM's Proposal," available at https://www.pjm.com/-/media/committees-groups/cifp-ra/2023/20230614/20230614-item-02---pjm-cifp-stage-3-proposal.ashx, p. 3.

[39] PJM explains that, historically, the PJM region has been able to maintain resource adequacy by setting target procurement levels (*i.e.*, the Installed Reserve Margin) at the summer peak load plus a reserve margin and accrediting generation resources based on their historical forced outages. However, PJM states that recent operating experiences such as Winter Storm Elliott have demonstrated that modeling approaches focused on peak load conditions and average generator performance do not fully capture all of the risks that impact resource adequacy needs and resource performance. PJM, Capacity Market Reforms to Accommodate the Energy Transition While Maintaining Resource Adequacy, October 13, 2023, FERC Docket No. ER24-99-000, Attachment C, Affidavit of Adam Keech on Behalf of PJM Interconnection, L.L.C. p. 3, available at https://www.pjm.com/-/media/documents/ferc/filings/2023/20231013-er24-99-000.ashx (hereafter "PJM Reliability Enhancements Filing"), p. 10.

[40] On average, summer peak load has increased by 0.78% annually between 2000 and 2024. PJM, "2025 Load Report Tables," available at https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/2025-load-report-tables.xlsx.

result, in part, of the proliferation of large-load facilities (*e.g.*, data centers) and the growth in rooftop solar, which has reduced summer peaks with a minimal impact on winter peaks.[41] This trend is forecasted to accelerate due to the electrification of heating and transportation.[42]

Winter peak loads are growing and forecasted to continue growing relative to summer peak loads. In the PJM region, the difference between the peak summer and winter loads remained relatively stable until the mid-2010s, when the gap started to decline as the winter peak load increased more rapidly than the summer peak load (*see* **Figure III-2**). The decrease in the gap in recent years has been driven in part by the electrification of heating (and transportation) as a result of state regulations and increasingly competitive economics of electrification technologies. In its 2025 Load Forecast study, PJM projects that the winter season will continue to experience a modestly higher load growth compared to the summer season, particularly in the short-term.[43] PJM cites several reasons for this trend. *First*, the forecasted adoption of HVAC technologies, such as heat pumps, will asymmetrically increase electricity demand in the winter season.[44] *Second*, forecasts indicate that the adoption of light-duty electric vehicles ("EVs") in PJM may increase rapidly over the next decade, with the expected number of light-duty EVs in the PJM region increasing from under 2 million in 2025 to circa 10 million by 2035.[45] The adoption of EVs likely asymmetrically increases the winter load due to EV performance differences under ambient air conditions.[46] *Third*, the adoption of behind-the-meter rooftop solar will reduce peak summer load, but have a minimal impact on peak winter load which typically occurs during dusk or nighttime hours.[47] Overall, PJM forecasts that the difference between the summer and winter peak loads will contract, declining from 18,000 MW in 2025 to less than 10,000 MW in 2045 (*see* **Figure III-3**).

[41] PJM, "2026/27 BRA IRM, FPR, and ELCC Class Ratings," March 13, 2025, available at https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2025/20250313-special/2026-2027-irm-fpr-elcc-and-winter-risk.pdf, p. 13.

[42] PJM, "2026/27 BRA IRM, FPR, and ELCC Class Ratings," March 13, 2025, available at https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2025/20250313-special/2026-2027-irm-fpr-elcc-and-winter-risk.pdf, p. 13.

[43] The PJM 2025 Load Forecast study projects an average annual peak load growth rate of 3.8% in the winter and of 3.1% in the summer, between 2025 and 2035. PJM, 2025 Load Forecast Data, available at https://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process.

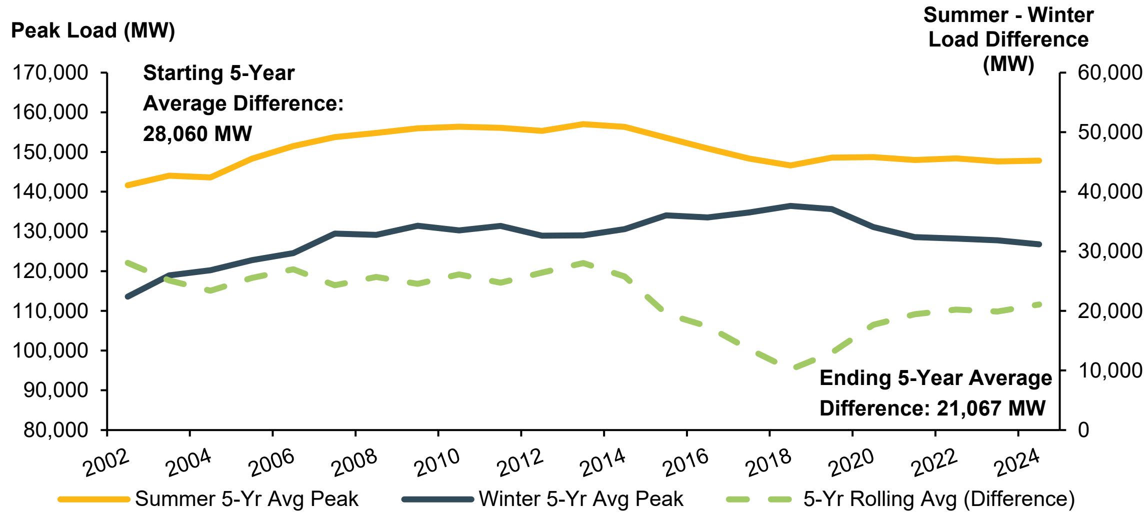
[44] PJM notes that "the demand for electricity is growing at the fastest pace in years, primarily from the proliferation of data centers, electrification of buildings and vehicles, and manufacturing," with faster projected overall growth in the winter peak than the summer peak between 2025 and 2035. PJM, "2025 Long-Term Load Forecast Report Predicts Significant Increase in Electricity Demand," January 30, 2025, available at https://insidelines.pjm.com/2025-long-term-load-forecast-report-predicts-significant-increase-in-electricity-demand/.

[45] S&P Global, Commodity Insights, "Electric Vehicle Charging Power Demand Forecast Assumptions," July 2, 2025, available at https://www.pjm.com/-/media/DotCom/committees-groups/subcommittees/las/postings/ev-forecast-assumptions.pdf, p. 6.

[46] S&P Global, Commodity Insights, "Electric Vehicle Charging Power Demand Forecast, PJM Interconnection," Final Report, October 7, 2024, available at https://www.pjm.com/-/media/DotCom/committees-groups/subcommittees/las/2024/20241125/20241125-reference---item04-spglobal---pjm-ev-forecast.pdf, p. 13.

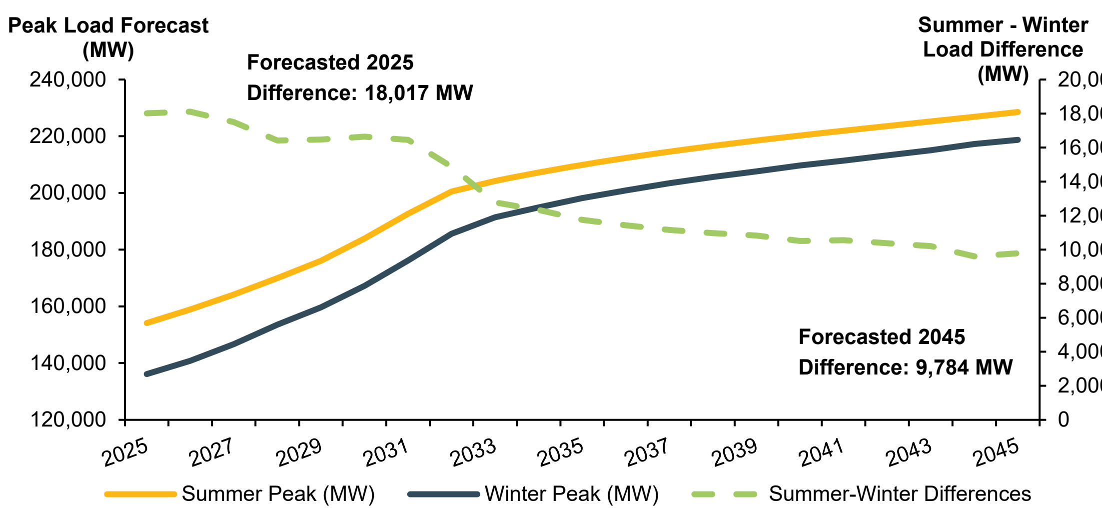
[47] PJM, "2026/27 BRA IRM, FPR, and ELCC Class Ratings," March 13, 2025, available at https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2025/20250313-special/2026-2027-irm-fpr-elcc-and-winter-risk.pdf, p. 13.

Figure III-2: PJM Historical Summer and Winter Peaks, 5-Year Rolling Average[48]
2002-2024



Note: In this chart, the winter 2001/2002 peak load corresponds to the summer 2002 peak load, and so forth.

Figure III-3: PJM Forecasted Summer and Winter Peaks[49]
2025-2045



Note: In this chart, the winter 2024/2025 peak load corresponds to the summer 2025 peak load, and so forth.

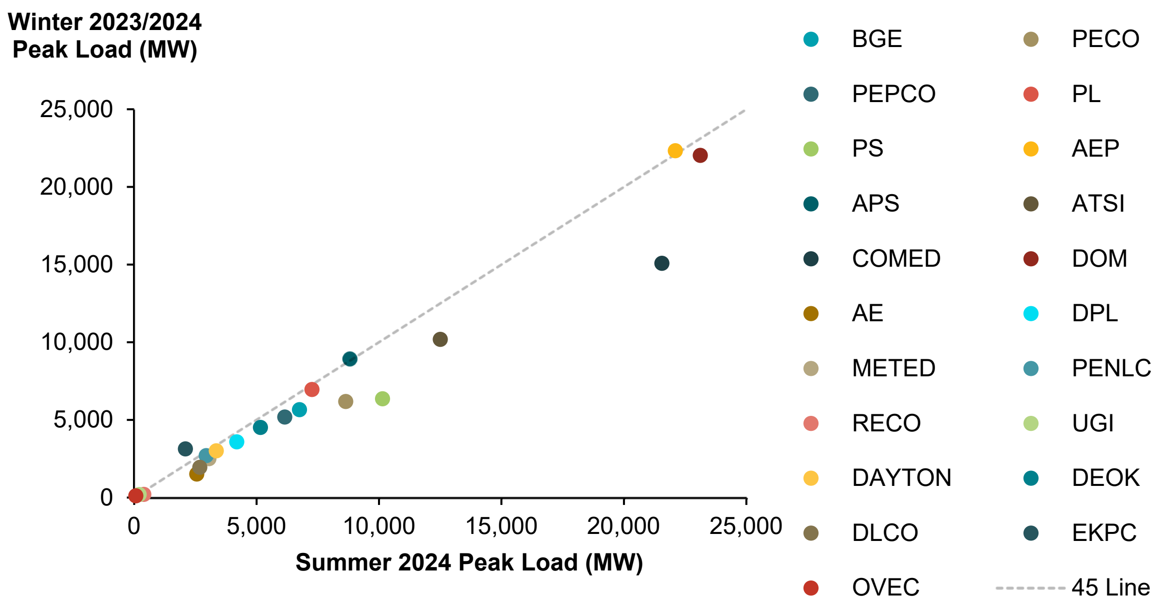
---

[48] **Source:** PJM, "2025 Load Forecast Report Tables," available at https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/2025-load-report-tables.xlsx.

[49] **Source:** PJM, "2025 Load Forecast Report Tables," available at https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/2025-load-report-tables.xlsx.

The growth in winter peaks varies across geographic locations, with several zones projected to be winter peaking. Currently, the gap between summer and winter peaks differs across the PJM geographic footprint. Three out of PJM's 21 zones were winter-peaking in the 2023/2024 Delivery Year: Allegheny Power Systems, American Electric Power, and the East Kentucky Power Cooperative (*see* **Figure III-4**). Across the region, the ratio of summer to winter peak load varies – for example, Commonwealth Edison's summer peak was 43% higher than its winter peak, while East Kentucky Power Cooperative had a winter peak that was 48% higher than its summer peak (2023/2024 Delivery Year).

Figure III-4: Winter versus Summer Peak Load in PJM's Zones[50]



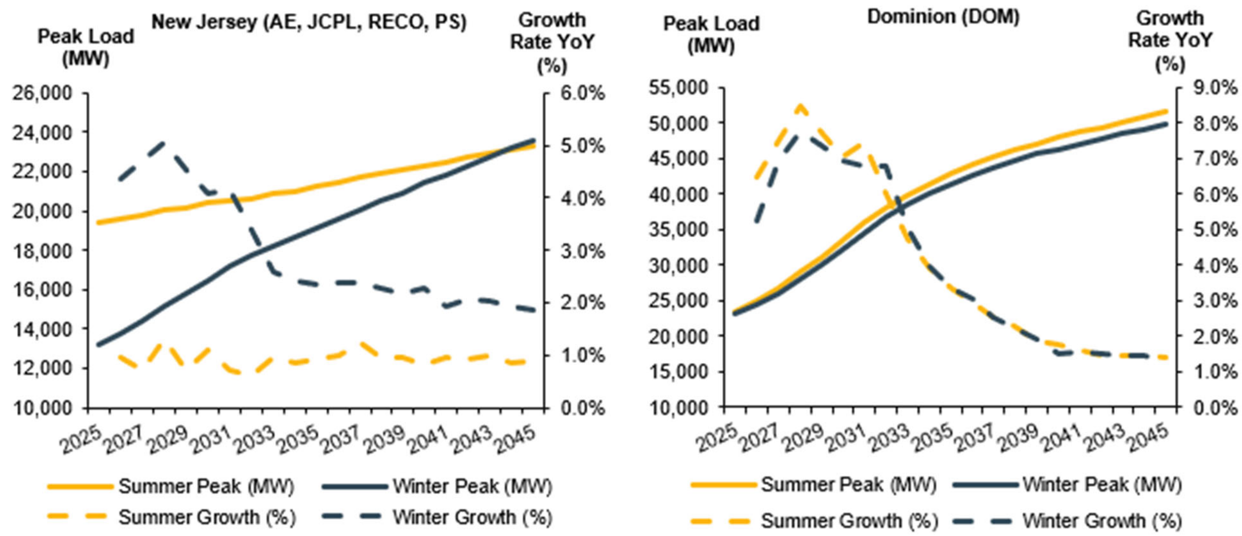
While PJM is forecast to remain summer-peaking through 2045, PJM's baseline projections indicate that the gap between the summer and winter peak loads and the expected pace of electrification differs across zones. For example, New Jersey's state policies mandate targets for the electrification of homes and commercial spaces by 2030.[51] In the New Jersey zones, the increased penetration of heat pumps and electric water heaters is expected to contribute to higher winter peak loads, and these zones are projected to be winter-peaking by the 2040s (*see*

[50] **Source:** PJM, "2025 Load Forecast Report Tables," available at https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/2025-load-report-tables.xlsx.

[51] In 2021, Gov. Phil Murphy of New Jersey announced a mandate to increase the electrification of homes and businesses in New Jersey by 2030. *See, for example,* Phil Murphy, "Executive Order No. 316," 2023, available at https://nj.gov/infobank/eo/056murphy/pdf/EO-316.pdf, p. 4.

Figure III-5).[52] Out of PJM's 21 zones, eight are currently expected to be winter-peaking within the next two decades.[53] Other zones are expected to face rapid and large load growth. For instance, Dominion ("DOM"), which includes Northern Virginia's "Data Center Alley", is forecasted to experience high load growth in both winter and summer, especially in the short-term.

Figure III-5: New Jersey (AE, JCPL, RECO, PS) and DOM Forecasted Peak Load[54]
2025-2045



Notes: [1] In these charts, the winter 2024/2025 peak loads are plotted alongside summer 2025 peak loads, and so forth. [2] The peak load for New Jersey is calculated as the aggregate peak load of the four zones that cover the majority of the state (AE, JCPL, RECO and PS).

Growth of large loads. In addition to electrification, the addition of large loads, primarily through data centers, is forecast to increase demand in PJM. In its 2025 Load Forecast study, PJM projected that data centers could account for up to 12% of summer peak load by 2030.[55] Growth will vary geographically. For instance, the summer

[52] PJM, "Statement on Public Policies Adopted Within the 2025 RTEP," March 31, 2025, available at https://www.pjm.com/-/media/DotCom/committees-groups/state-commissions/isac/2025/20250331/20250331-pjm-statement-on-public-policies-considered-within-the-2025-rtep.pdf, p. 3.

[53] Zones JCPL, PL, PS, UGI, AEP, APS, EKPC, and OVEC are forecasted to be winter-peaking in at least one year between 2025-2045. PJM, "2025 Load Forecast Report Tables," available at https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/2025-load-report-tables.xlsx.

[54] **Source:** PJM, "2025 Load Forecast Report Tables," available at https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/2025-load-report-tables.xlsx.

[55] PJM, "Load Growth in PJM," October 22, 2024, available at https://opsi.us/wp-content/uploads/2024/10/4.-20241022-McGlynn-OPSI-Load-Growth-Slides-Session-4.pdf, p. 8.

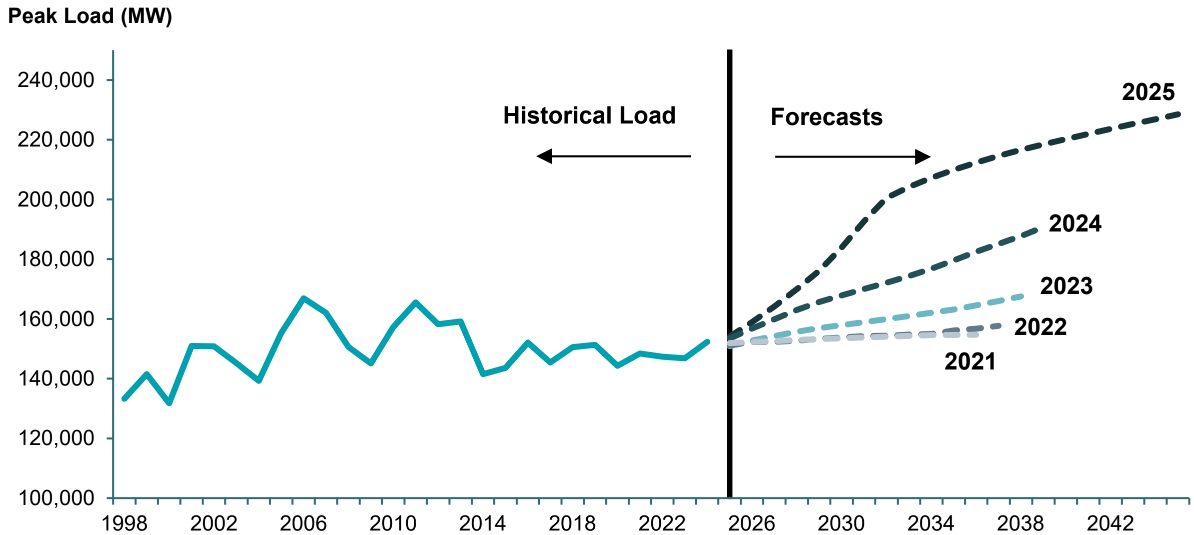
peak load in Dominion is expected to increase by 1.2x between 2025 and 2035 due primarily to data center growth.[56] This rapid increase in expected demand has contributed to the tightening of PJM's capacity market, reflected in the elevated prices of the 2026/2027 BRA.[57] Moreover, the addition of large loads has contributed to uncertainty in PJM's peak load forecasts. As shown in **Figure III-6,** even short-term projections have been significantly revised between the 2021 and 2025 Load Forecast studies. While data center utilization does not exhibit strong seasonal patterns, data center loads may vary seasonally due to differences in heating and cooling loads.[58] Moreover, the type of resources added to the system to help meet new data center loads is uncertain and, depending on the types of resources that are added, could exacerbate issues directly or indirectly affecting resource adequacy. For example, if all data center loads are met with large, baseload resources requiring longer planned maintenance outages (*e.g.*, gas-fired combined cycle units), shoulder-season scheduling of planned maintenance could be further constrained. Thus, notwithstanding the substantial uncertainty around the reliability of data center growth forecasts, the impact of large load additions on sub-annual patterns in resource adequacy risks reflects uncertainties that have not been fully studied.

[56] PJM, "2025 Load Forecast Report Tables," available at https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/2025-load-report-tables.xlsx.

[57] Lower prices ($28.92/MW-day in the 2024/2025 Delivery Year) increased sharply, reaching the cap of $329.17/MW-day in the most recent capacity auction in July 2025 for the 2026/2027 Delivery Year. PJM, "2026/2027 Base Residual Auction Report," July 22, 2025, available at https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2026-2027/2026-2027-bra-report.pdf, p. 5; PJM Inside Lines, "PJM Auction Procures 134,311 MW of Generation Resources; Supply Responds to Price Signal," July 22, 2025, available at https://insidelines.pjm.com/pjm-auction-procures-134311-mw-of-generation-resources-supply-responds-to-price-signal/.

[58] Studies show that data center loads reflect weather conditions due to the type of cooling system used. *See, for example,* Kim, Ji Hye, Dae Uk Shin, and Heegang Kim, "Data Center Energy Evaluation Tool Development and Analysis of Power Usage Effectiveness with Different Economizer Types in Various Climate Zones," *Buildings*, 2024, 14, no. 1: 299, available at https://doi.org/10.3390/buildings14010299; Shehabi, A., Smith, S.J., Hubbard, A., Newkirk, A., Lei, N., Siddik, M.A.B., Holecek, B., Koomey, J., Masanet, E. and Dale Sartor, "2024 United States Data Center Energy Usage Report," 2024, Lawrence Berkeley National Laboratory, Berkeley, California.

Figure III-6: PJM RTO-Wide Summer Peak Load[59]
1998-2045



Note: The year 1998 corresponds with the 1997/98 winter (December to February) and the 1998 summer (June to August). This seasonal mapping is applied across all years, as consistent with PJM's approach in its load forecast reports.

* * *

Overall, the increasing winter loads and heterogeneity of expected load patterns across the PJM region create potential reliability risk outside of the coincident system peak summer load, and these patterns are expected to continue in the next decade.

b. Changing composition of generation resource mix

Increasing resource adequacy risk outside of summer months is also a result of the changing sources of supply of electricity, particularly greater reliance on gas-fired generation and intermittent renewable generation, the retirement of coal-fired generators, and changing import and export dynamics due to the changing resources mix in neighboring regions.[60] Other emerging technologies, particularly battery storage, may grow in the future, although they currently are a small portion in the fleet.

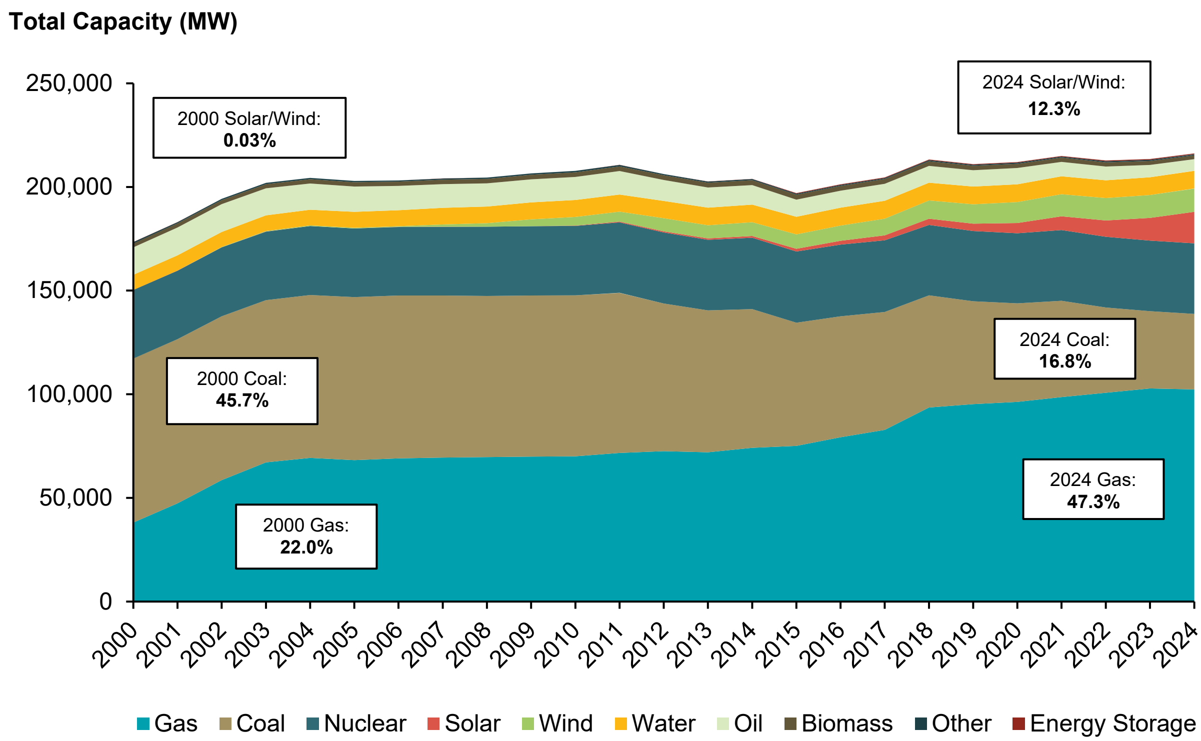
---

[59] This figure relies on historical load data from the PJM's 2025 Load Forecast Table and peak load forecasts from PJM's 2021-2025 Load Forecast Tables. PJM, Load Forecast Data, available at https://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process.

[60] PJM, "Energy Transition in PJM: Flexibility for the Future," June 24, 2024, available at https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2024/20240624-energy-transition-in-pjm-flexibility-for-the-future.ashx, p. 5.

Over the past two decades, the PJM generation resource mix has gradually evolved to rely more heavily on natural gas and less heavily on competing fuels, particularly coal. As a result, gas-fired generation has become the largest source of nameplate capacity and generation in the region, more than doubling in capacity from 2000 to 2024 (*see* **Figure III-7**). In 2024, natural gas provided 46% of generation.[61]

Figure III-7: PJM Nameplate Capacity by Fuel Type[62]
2000-2024



At the same time, capacity from intermittent renewable generators like solar and wind has grown to more than 12% in 2024 and produced 6% of energy in 2024.[63] This growth, driven by falling technology costs and regulatory mandates to decarbonize the grid, is expected to continue in the future. For example, the PJM Independent

---

[61] Monitoring Analytics, "PJM 2024 State of the Market Report," March 13, 2025, available at https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2024/2024-som-pjm-sec3.pdf, Table 3-64, p. 197.

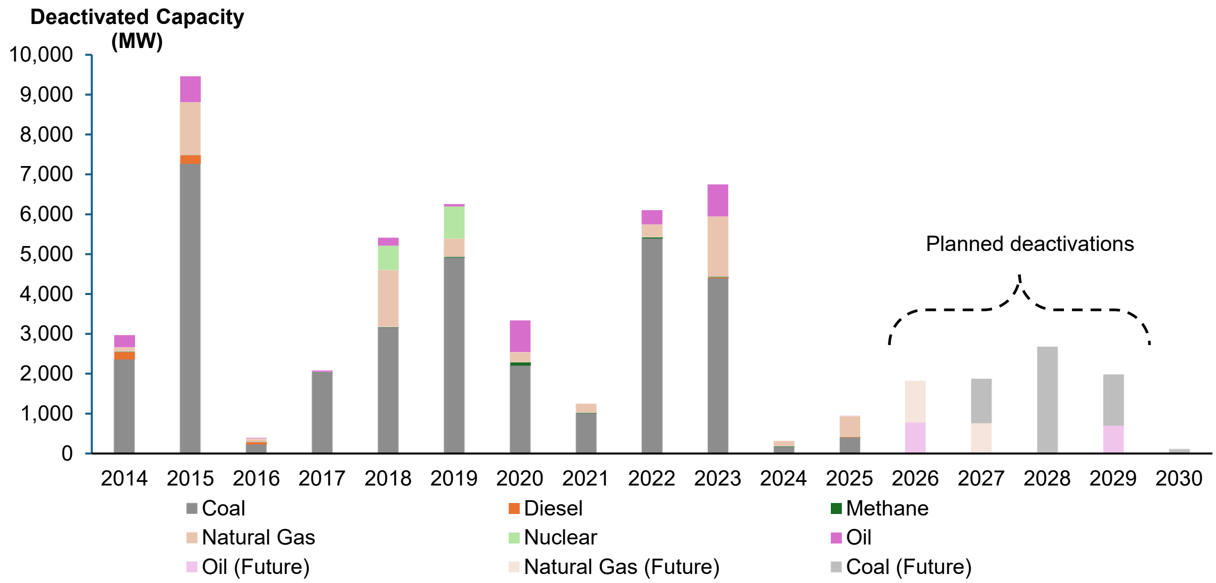
[62] **Source:** S&P Capital IQ, PJM Historical and Future Power Plant Capacity, accessed October 29, 2025.

[63] **Figure III-7.** Monitoring Analytics, "PJM 2024 State of the Market Report," March 13, 2025, available at https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2024/2024-som-pjm-sec3.pdf, Table 3-64, p. 197.

Market Monitor ("IMM") found that, as of December 2024, renewable resources accounted for the majority (82%) of capacity in the generation queue.[64]

The increased reliance on natural gas and renewable resources has coincided with the retirement of a significant portion of PJM's coal fleet, as shown in **Figure III-8**. Higher capacity market prices have reduced and will likely continue to reduce deactivations. As of December 1, 2025, there are requests for deactivation of 8.5 GW of capacity by the end of 2030. Coal and oil resources are the most recent and planned retirements, which include four Reliability Must Run ("RMR") units that are requesting to deactivate in 2029.[65]

Figure III-8: Implemented and Planned Generation Deactivations in PJM[66]
2014-2030



Note: This figure only includes coal, diesel, methane, natural gas, nuclear, and oil retirements. Retirements of biomass, solar and wind resources with a total deactivated capacity of 250.5 MW are excluded. 2 MW of diesel capacity projected for retirement in 2025 is undergoing a reliability analysis.

---

[64] As of December 2024, the IMM stated that ~82% of the interconnection queue capacity (MW) expected to be in-service, based on historical completion rates, was by renewable resources (*i.e.*, 31,649 MW of the total 38,520 MW expected to be in service). Monitoring Analytics, "2024 State of the Market Report for PJM", https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2024/2024-som-pjm-vol2.pdf, p. 649.

[65] PJM, "Generation Deactivations," available at https://www.pjm.com/planning/service-requests/gen-deactivations accessed on December 1, 2025.

[66] "Planned generation deactivations" refer to official deactivation notices received by PJM from the proposed deactivating resource owner, and are posted within 24 business hours of PJM receipt. *See also,* PJM, "Generation Deactivations," available at https://www.pjm.com/planning/service-requests/gen-deactivations accessed on December 1, 2025.

This evolving resource mix has important implications for resource adequacy.

First, resource performance varies across the year. Renewable resources exhibit both seasonal and hourly variability – for example, solar resource supply spans a larger portion of the operating day in summer, while wind resources tend to perform better in the winter. The performance of gas-fired resources also differs throughout the year due to greater operational and fuel deliverability risks during cold winter weather.[67] Thus, individual resource contributions to resource adequacy vary across the year.

Second, in aggregate, the performance of the resource fleet will vary depending on both the performance of resources individually and interactions between resources within the fleet, particularly during periods of greatest resource adequacy risk. The correlated interactions vary across the year and are accounted for within the resource adequacy modeling.

c. Resulting changes in reliability risks and fuel security

As a result of differences in market and system conditions, the characteristics of resource adequacy concerns in PJM differ along important dimensions depending on the time of the year. Summer reliability events are typically of shorter duration and reflect capacity shortfalls, while winter events are generally longer duration and typically reflect energy or fuel shortfalls.

Differences in both daily net load profiles and resource supply constraints across the year lead to reliability risks that vary uniquely across the year.[68] For example, winter load typically increases in the morning and evening hours, while summer demand grows through the day and peaks in the evening.[69] Over each of the past ten years, the summer peak has occurred between 4pm and 6pm, including at 6pm each of the last five years, while over the same period, winter load has occurred at 8am or 9am seven times, and 7pm three times.[70] Summer load profiles are characterized by high, short duration loads that are concentrated in singular afternoon or evening hours. For example, in 2024, PJM's five highest coincident peak demand loads all occurred at 6pm and were above 147,000 MW.[71] The June 2025 heat wave then saw the PJM zone experience a demand of over 160,000 MW (*see* **Figure III-9**), but for a relatively short period. In contrast, PJM's highest coincident peak demand load during the 2024

[67] PJM, "Maintaining Resource Adequacy During a Period of Transition," April 17, 2025, available at https://pioga.org/wp-content/uploads/2025/04/PJM-Stanek-PIOGA-Presentation-Apr-17.pdf, p. 17.

[68] Unless otherwise noted, we mean net load when referring to load, which reflects the performance of behind-the-meter resources, particularly solar.

[69] PJM, "How Energy Use Varies with the Seasons," available at https://learn.pjm.com/three-priorities/keeping-the-lights-on/how-energy-use-varies.

[70] PJM, "Date/Time of PJM Summer and Winter Peaks," available at https://www.pjm.com/-/media/DotCom/planning/res-adeq/pjm-peak-hour-history.ashx, p. 1.

[71] PJM, "Summer 2024 RTO Coincident Peaks," November 11, 2024, available at https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/summer-2024-peaks-and-5cps.ashx, p. 1.

winter months occurred at 8:10am on January 17 with a peak of 134,777 MW,[72] but was in the midst of a multi-day winter storm in which load remained at high levels for sustained periods.[73] **Figure III-10** illustrates a similar pattern during Winter Storm Elliott.

Figure III-9: PJM 2025 Heat Wave Demand[74]

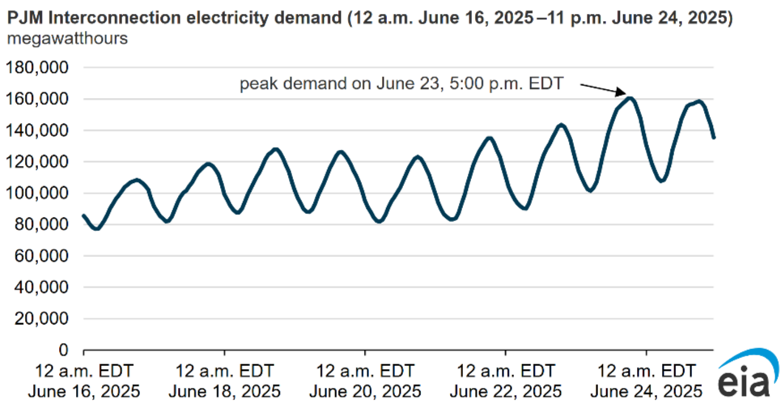
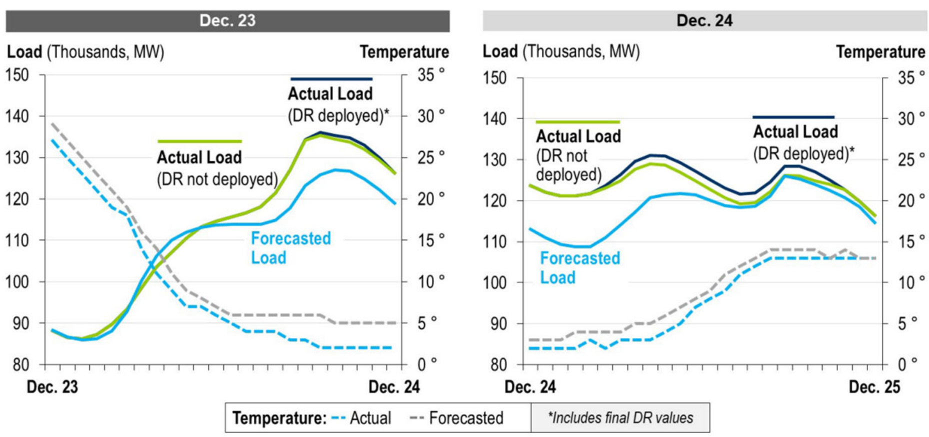


Figure III-10: Elevated Demand during Winter Storm Elliot[75]



[72] This total includes 16,000 MW of forced outages. PJM, "2024 in Review: PJM Operations Maintained Reliability," January 2, 2025, available at https://insidelines.pjm.com/2024-year-in-review-pjm-operations-maintained-reliability/.

[73] PJM, "Winter Storm Gerri Review January 13-18, 2024," January 24, 2024, available at https://www.pjm.com/-/media/DotCom/committees-groups/committees/mrc/2024/20240124/20240124-item-02---winter-storm-gerri-review---presentation.ashx, p. 6.

[74] **Source:** EIA, "Today in Energy," June 27, 2025, available at https://www.eia.gov/todayinenergy/detail.php?id=65604.

[75] **Source:** PJM, "Winter Storm Elliott Analysis and Recommendation," July 17, 2023, available at https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.pdf, p.39.

The combined effect of changes in load and system resources in PJM has shifted risks toward the winter season compared to the historical prevalence of summer risks. This shift is seen in both actual market operations and resource adequacy analysis.

In terms of actual market operations, recent years have seen winter weather events causing increasingly large strains and outages in the PJM system. Events such as the Polar Vortex of 2014 and Winter Storm Elliott in 2022 – extended periods of cold snaps and snowstorms – created large, costly, and impactful strains on the grid. During Winter Stom Elliott, forced outages at gas-fired facilities raised attention to the system's vulnerability to the growing reliance on these resources.[76] Production interruptions came from mechanical failures due to the intensity and length of freezing temperatures, which led to "freeze-offs" in natural gas steam.[77] The event raised awareness to the vulnerability created by the system's common reliance on the upstream natural gas production and transportation system, which was subject to these operational risks during extreme cold events. The reliability consequences of Winter Storm Elliott were one of the factors prompting PJM to evaluate sub-annual market designs in the 2023 CIFP-RA task force.[78]

After accounting for these vulnerabilities, PJM's recent reliability risk analyses have also shown greater winter risk. For the 2027/2028 Base Residual Auction, PJM's reliability risk analysis found that the majority of reliability risk occurred in the winter. For instance, PJM found 75.6% of Loss of Load events occurred in the winter and 95% of EUE occurred in the winter (*see* **Figure III-11**). Therefore, both in terms of the total duration and magnitude of potential energy shortfalls, reliability risks in the near future are expected to be higher in the winter than in the summer.

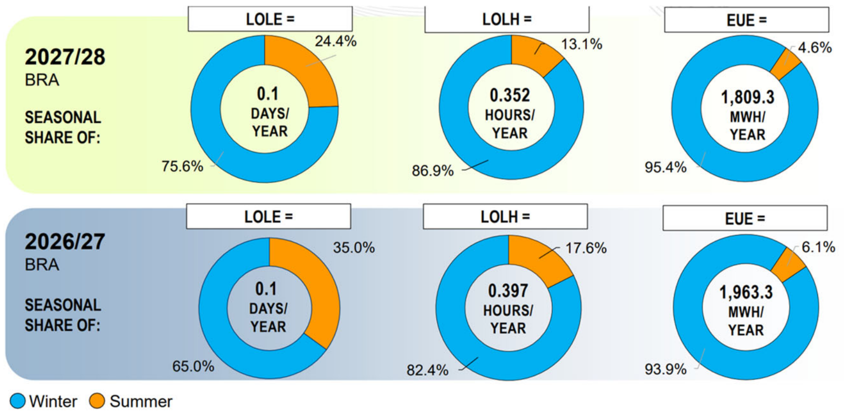
---

[76] Winter Storm Elliott was a period of cold weather and snowstorms between December 23, 2022 and December 25, 2022. The storm impacted the majority of the eastern United States, with the PJM region particularly hard-hit. In PJM, the storm caused outages over multiple days, with 47,000 MW of forced outages, a 24% forced outage rate, mostly from gas-fired resources at the peak of the storm. PJM, "Winter Storm Elliott Event Analysis and Recommendation Report," July 17, 2023, available at https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.pdf, pp. 1-2, 49.

[77] EIA, "Winter storms have disrupted U.S. natural gas production," March 13, 2024, available at https://www.eia.gov/todayinenergy/detail.php?id=61563.

[78] PJM, "Critical Issue Fast Path – Resource Adequacy, Problem/Opportunity Statement," March 24, 2023, available at https://www.pjm.com/-/media/DotCom/committees-groups/cifp-ra/2023/20230329/20230329-item-02---cifp-ra-problem-statement---final.pdf, p. 2.

Figure III-11: Reliability Risk Analysis, PJM 2027/28 BRA[79]



B. Overview of Sub-Annual Capacity Market Designs

At present, the RPM is designed to procure capacity through a single, annual auction. As we describe in **Section III.B.2**, certain sub-annual changes to risk modeling and resource testing requirements have already been introduced in the RPM, such that annual accreditation and reliability requirements currently reflect risk outside of the summer peak (particularly winter risk). However, past proposals to adopt sub-annual markets, which we describe in **Section III.B.3**, have not been adopted. Sub-annual features can be introduced in different components of the capacity market, including the auction frequency, capacity product, auction demand curve, and supply offer terms (both the supply quantity and offer price).

1. Seasonal Capacity Markets

A sub-annual capacity market can incorporate sub-annual features in all or only some components. In particular, a fully sub-annual market could include capacity products for each sub-annual period, and auctions that clear sub-annual supply offers against a sub-annual demand curve, where both the demand curve and offers to supply capacity reflect considerations specific to sub-annual periods.

Demand. With sub-annual demand curves, the demand for capacity in each season – as reflected in administrative demand curves – can be designed to reflect factors specific to sub-annual periods and thus may differ across sub-annual periods. In principle, sub-annual demand curves could reflect the same considerations used in designing annual demand curves – that is, ensuring adequate revenues for new resources to enter the

[79] **Source:** PJM, "Installed Reserve Margin (IRM), Forecast Pool Requirement (FPR), and Effective Load Carrying Capability (ELCC) for 2027/2028 BRA," July 23, 2025, available at https://www.pjm.com/-/media/DotCom/committees-groups/committees/mrc/2025/20250723/20250723-item-04---1-2027-2028-bra-fpr-and-irm---presentation.pdf, p. 9.

market at the annual 1- in-10 reliability criterion while also appropriately pricing additional capacity beyond (and short of) this reliability criterion.[80] This would have several consequences for sub-annual demand curves:

- ***First,* sub-annual demand curves can reflect resource adequacy risks unique to each period.** In principle, there are multiple approaches to account for sub-annual resource adequacy risks. One option is to extend the current framework and to construct sub-annual VRR curves. This would require a new process to determine the shape of each sub-annual curve. Another option is to rely on demand curves that reflect the marginal impact of incremental capacity (MRI curves) on resource adequacy in each sub-annual period. This latter approach has solid economic foundations that translate to the sub-annual framework and flexibly captures differences in marginal reliability impacts across sub-annual periods.
- ***Second,* resource adequacy outcomes reflect the cumulative risks across sub-periods.** Thus, demand curves in each season should be scaled to account for each season's expected contribution to meeting the 1-in-10 resource adequacy criterion. These expected contributions may vary across sub-periods, with some sub-periods having little expected risk (*e.g.*, low EUE) and others have more expected risk.
- ***Third,* revenue adequacy would reflect the total revenues earned from capacity market prices across all sub-annual periods.** Thus, in constructing the demand curves, the curves would need to be calibrated so the new entry reference unit earns sufficient revenues across all sub-periods to cover its costs of entry (at the annual 1-in-10 resource adequacy requirement). Determining this criterion could be more complicated than with the current RPM, as the calibration would reflect market revenues and reliability outcomes over all sub-annual periods, rather than over only a single annual auction. Several questions emerge, including the basis and criteria for price caps.

The implications of these consequences and decisions are discussed further in **Section VI**.

***Supply*.** With a sub-annual capacity market, supply offers can reflect sub-annual costs and contributions to resource adequacy in each sub-annual period. In principle, sub-annual capacity offer prices could reflect the avoidable going forward costs if the unit were not to operate in a given sub-annual period. As we discuss in **Section VI**, sub-annual costs can vary due to many factors: some costs are incurred in some sub-annual periods but not others (*e.g.*, winter weatherization costs); energy and ancillary service revenues can vary across sub-annual periods; and resource accreditation can vary across sub-annual periods, 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 sub-annual periods. Therefore, several questions arise in the design of supply offers, including which costs can be reflected in each sub-annual offer.

Finally, the design of a sub-annual capacity market requires addressing several considerations, including:

---

[80] At present, the annual demand curve is anchored to ensure the recovery of the net cost of new entry ("Net CONE") for the reference technology, at the reliability criterion. PJM Manual 18: PJM Capacity Market, Sections 3.3, 3.4.

- ***The market structure.*** A sub-annual market can be designed to procure capacity through a single auction that clears all sub-annual periods simultaneously (a "simultaneous" auction) or through sequential auctions in which each auction is independently cleared. In addition, sub-annual periods can be cleared independently or jointly (*i.e.,* a "co-optimized" auction).
- ***The number and duration of sub-annual periods.*** In principle, a sub-annual capacity market could be designed for any number of sub-annual periods, with each sub-annual period having equal or varying duration. For example, a sub-annual market could include two seasons (winter, summer), four seasons (winter, spring, summer, fall) or even more sub-annual periods (*e.g.*, hourly). 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.

These aspects and others are discussed in further detail in **Section VI**.

2. PJM's Sub-Annual Market Design Parameters

The RPM currently includes a limited number of sub-annual market inputs, modeling and requirements. These include:

- **Sub-annual modeling inputs for reliability targets and accreditation.** PJM models resource adequacy risk in all hours of the year, accounting for both the probability and severity of outages (in terms of magnitude and duration), rather than evaluating resource inadequacy only during periods historically associated with peak load (*i.e.*, in the summer period). The risk analysis is calibrated using the EUE level corresponding to the 1-in-10 LOLE.[81]
- **Sub-annual resource operational requirements**, including (a) a Seasonal Capacity Performance Test, requiring physical demonstration of both summer and winter capability, and (b) a seasonal Generator Operation Test, requiring generators to test resource capability up to twice in each season and prior to periods of the year where PJM may experience extreme weather conditions to "better ensure that [generators] are capable of operating if and when needed for reliability."[82] These tests are conducted at the discretion of PJM in cases where the RTO feels it needs more information about the availability of resources in emergency conditions.[83]

3. Previously Considered Sub-Annual Design Parameters

PJM has considered sub-annual (seasonal) capacity market designs several times in the past. In 2016, a "Seasonal Resources Senior Task Force" was created to address concerns around the ability of resources with

[81] PJM, Reliability Enhancements Filing, Section II.B.

[82] PJM, Reliability Enhancements Filing, Section IV.A.

[83] PJM, Reliability Enhancements Filing, Section III.

seasonal availabilities to participate in the capacity market.[84] In 2023, within the CIFP, PJM drafted a seasonal market proposal that included the following design elements.[85]

- **Reliability targets that account for sub-annual risk.** Seasonal resource adequacy metrics and targets, including IRMs and CETLs determined for summer and winter.
- **Number of sub-annual periods.** A two-season capacity market structure, in which PJM would meet its annual resource adequacy requirement through procurement of summer (May to October) and winter (November to April) capacity products reflecting resource adequacy differences across seasons.
- **Sub-annual accreditation**. Separate resource accreditation for summer and winter.
- **Auction structure.** An auction structure that allowed resources to offer annual and season-specific offer components and welfare-maximizing resource selection across seasons.
- **Sub-annual demand curves.** Demand curves based on existing VRR curves but anchored so that the full annual reliability standard would be reflected within each season.

IV. Experience in Other RTO Markets

Other RTOs with capacity markets have either implemented seasonal market designs or are in the process of adopting a seasonal market. From the outset, NYISO has used sub-annual (monthly) auctions, although core parameters were largely set at fixed annual values. Recently, however, NYISO has been enhancing its markets to allow for seasonal (summer-winter) parameters, while retaining the monthly auctions. MISO has fully adopted a seasonal capacity market, with seasonal products and auctions. ISO-NE has committed to adopt a seasonal market structure and is currently in the design process. **Table IV-1** summarizes the key features of the seasonal capacity market design in each RTO, followed by further details and discussion of the seasonal market designs in each RTO.

---

[84] PJM, "Seasonal Capacity Resources Senior Task Force," available at https://www.pjm.com/committees-and-groups/closed-groups/scrstf.

[85] PJM, "PJM Seasonal and Annual Proposals," 2023, available at https://www.pjm.com/-/media/DotCom/committees-groups/cifp-ra/2023/20230823/20230823-item-01a---20230823-cifp-stage-4---pjm-exec-summary.ashx, p. 2.

Table IV-1: Seasonal Capacity Market Design Features: Experience in Other Markets

RTO Capacity Markets Comparison		Seasonal Capacity Market Construct	Auction Timing	Num. of Seasons	Auction Structure	Demand Curve	Resource Capacity Accreditation	Capacity Requirements	Load Peak
PJM	Current	No	Annual Forward Auction 3 Years Before Delivery Period (Recently Several Auctions Delayed)	One, Annual	—	Sloped, by Constrained LDA	Annual, MRI-Based, Accreditation Based on Marginal ELCC	Annual Capacity Targets, with Seasonal Modelling Inputs	Summer-Peaking, Higher Peak Load Growth in Winter (2%) vs. Summer (1.7%)
NYISO	Current	Yes	Monthly, Spot Auctions Held Days Before Delivery Period	Monthly Auctions, Two Capability Periods (Winter, Summer)	Independent	Sloped, Administratively-Set, by Locality and Capability Period	Annual, MRI-Based Accreditation	Annual IRMs/LCRs Set by NYSRC	Projected to be Winter-Peaking by 2030s
MISO	Current	Yes	Single, Annual Auction in April Before Delivery Period	Four Seasonal Products	Independent	Sloped, MRI-Based, by Local Resource Zone	Seasonal, MRI-Based, Accreditation Based on Availability in Resource Adequacy Hours, by Season	Relative Position of Capacity Requirements Reflect Seasonal Parameters	Summer-Peaking, with Increased Focus on Winter Preparedness in Light of Extreme Winter Events
ISO-NE	Current	No	Annual Forward Auction 3 Years Before Delivery Period (Delayed)	One, Annual	—	Sloped, Annual, MRI-Based, by Location	Qualified Capacity Based on Performance during Select Hours	Annual Capacity Targets	Summer-Peaking, Projected to be Winter-Peaking by 2030s
ISO-NE	Proposals	*Yes*	*Seasonal, Prompt Construct*	*Two Seasons (Winter, Summer)*	Independent	*Sloped, Seasonal, MRI-Based, by Location*	*Seasonal, MRI-Based Accreditation*	*Equal Seasonal Split of LOLE Risk*	

A. NYISO

1. Background

The New York Independent System Operator ("NYISO") operates an Installed Capacity ("ICAP") market to meet resource adequacy requirements within the state, which are set to ensure that loss-of-load events occur no more frequently than one-in-ten years on average. Unlike markets in ISO-NE and PJM, the NYISO market employs compulsory monthly spot auctions held two days prior to the start of each month in a capability year (*i.e.*, May 1st to April 30th). This auction is one of several mechanisms available for load-serving entities to procure capacity, including bi-lateral contracts[86] and two voluntary auctions: a voluntary strip auction that clears six-month strips of capacity, and an additional voluntary, monthly auction. The six-month capability periods include a Summer Capability Period (*i.e.*, May 1st to October 31st) and a Winter Capability Period (*i.e.*, November 1st to April 30th).[87] Because resource adequacy needs are met through a combination of forward, bilateral arrangements, ICAP forward markets and the ICAP spot market, this approach differs generally from resource adequacy in PJM, where the RPM is the primary mechanism to ensure resource adequacy across the region.[88]

NYISO's spot auctions clear offers for capacity supply against administratively-set ICAP demand curves. These demand curves reflect the forecasted peak summer load and an annual installed reserve margin ("IRM") necessary to achieve the one-in-ten resource adequacy standard. The market accounts for transmission constraints for four nested locational areas: New York City ("Load Zone J"), Long Island ("Load Zone K"), the G-J Locality ("Load Zones G-J"), and the wider New York Control Area ("NYCA"), representing the entire NYISO system.[89]

Like neighboring regions, NYISO's ICAP market is designed to procure sufficient capacity to meet a forecasted summer peak plus annual installed reserve margin, with core design parameters reflecting annual resource adequacy and summer peak conditions. In particular, demand curves have historically been based on parameters designed to meet resource adequacy needs in the summer, including the annual state-wide IRM and locality-specific Locational Capacity Requirements ("LCRs").[90]

---

[86] NYISO, "Installed Capacity (ICAP) Market," October 21-24, 2025, p. 63.

[87] *See, for example,* NYISO, "Installed Capacity (ICAP) Market," October 21-24, 2025, pp. 73-75.

[88] Some PJM utilities procure bilaterally or through the Fixed Resource Requirement ("FRR") Alternative. PJM Manual 18: PJM Capacity Market, pp. 12, 14-15.

[89] 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.

[90] The New York State Reliability Council's annual capacity requirement study results in an annual IRM that establishes the state-wide installed capacity requirement relative to peak summer demand. The study also results in the annual minimum locational capacity requirements for the New York City and Long Island localities. *See, for example,* New York State Reliability Council, LLC, "New York Control Area Installed Capacity Requirement For the Period May 2025 to April 2026," December 6, 2024, available at https://www.nysrc.org/wp-content/uploads/2024/12/2025-IRM-Study-Technical-Report_Final_12062024_clean.pdf.

In recent years, NYISO has introduced seasonal parameters to better account for reliability risk outside of the summer peak; these parameters are described in the next section. Further seasonal enhancements have been proposed and are currently under consideration.[91]

2. Seasonal Market Design Parameters

While the NYISO ICAP has operated monthly spot auctions since its inception, auctions have generally reflected annual features (*e.g.*, annual capacity requirements).[92] Before the 2025/2026 capability year, seasonal considerations were limited to two parameters, both related to the quantity of capacity a resource can offer:

- **Seasonal ICAP values.** ICAP is determined based on seasonal Demonstrated Maximum Net Capability ("DMNC") testing, which measures the performance of thermal resources in summer and winter, and generally results in higher ICAP in winter than summer.
- **Seasonal ICAP-to-UCAP Adjustment.** ICAP is translated to UCAP based on adjustment factors (*i.e.*, accounting for forced outages) that are calculated for each six-month capability period.[93] Derating factors account for individual resources' average forced outage rates.

Within the ICAP market, prior to the 2025/2026 capability year, these changes affected only:

- **Supply Offer Quantity.** Supply offer quantities vary seasonally due to both (1) seasonal DMNC, used to determine ICAP values,[94] and (2) seasonal derating factors used to translate capacity from ICAP to UCAP).[95]
- **Supply at Level of Excess ("LOE").** The ICAP market accounts for the price-depressing impact of new entry at the reliability requirement by increasing the requirement to account for entry of the net CONE (reference) technology (the "level of excess"). The LOE adjustment varies by season because the UCAP of the fleet varies by season (as measured by the "winter-summer ratio" or "WSR"), which affects market-clearing quantities at the one-in-ten criterion in each season.[96]

---

[91] Since January 2025, NYISO has been considering winter reliability capacity enhancements, as described in ICAP Working Group meeting presentations. *See*, *for example,* NYISO, "Installed Capacity (ICAP) Working Group," available at https://www.nyiso.com/icapwg.

[92] The first ICAP spot market auction using a sloped demand curve was conducted in April 2003, for the first month of the 2003 – 2004 capability year (*i.e.,* May 2003). Previously, supply cleared against a vertical demand curve. *See*, *for example,* NYISO, "ICAP Demand Curve," November 5-6, 2025, p. 4.

[93] NYISO, "Installed Capacity Manual," December 2025, available at https://www.nyiso.com/documents/20142/2923301/icap_mnl.pdf, p. 64.

[94] NYISO, "Installed Capacity (ICAP) Market," October 21-24, 2025, p. 27.

[95] NYISO, "Installed Capacity (ICAP) Market," October 21-24, 2025, pp. 42-43.

[96] 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

Thus, prior to the 2025/2026 capability year, seasonal adjustments were relatively limited. On the supply-side, offers were adjusted to account for seasonal differences in the operational capability of thermal resources and derating factors, but did not include seasonal Capacity Accreditation Factors ("CAFs"), which account for intermittency and correlated output effects.[97, 98] On the demand-side, seasonal adjustments were limited to the WSR, which adjusted reference point prices to account for seasonal differences in operational capability of the generation fleet to ensure the peaking plant can recover its costs at LOE conditions over the course of the year.

Beginning with the 2025/2026 capability year, NYISO enhanced seasonal demand curves for the summer and winter capability periods to better account for seasonal differences in capacity availability and seasonal reliability risks.[99] **Figure IV-1** shows NYISO's summer and winter ICAP demand curves, which include the following new seasonal demand curve components:

- **Seasonal Reference Point Prices.** The reference point price reflects the monthly value of annual Net CONE (*i.e.*, the annual levelized cost of new entry of a peaking plant, net of energy and ancillary services revenues). Seasonal reference point prices are calculated using each season's share of total annual LOLE, subject to a minimum seasonal share of 35% and a maximum seasonal share of 65%.[100] This adjustment apportions the reference technology's annual cost recovery to the summer and winter capability periods in proportion to seasonal risk (subject to floors and ceilings on the share of cost recovery in a given season).[101]

---

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.

[97] New York State Reliability Council, LLC, "New York Control Area Installed Capacity Requirement For the Period May 2024 to April 2025," December 8, 2023, available at https://www.nysrc.org/wp-content/uploads/2023/12/2024-IRM-Study-Technical-Report-11-28-23_ICS_284_clean_bp-approved-12-8-2023.pdf, p. 15.

[98] NYISO, "2025 – 2026 Capacity Accreditation Factors and Peak Load Window," February 4, 2025, available at https://www.nyiso.com/documents/20142/49572424/2025-2026%20Final%20CAF%20and%20PLW_%202.4.2025_Final.pdf/a22de6b1-1be3-b732-0976-ee8503146514.

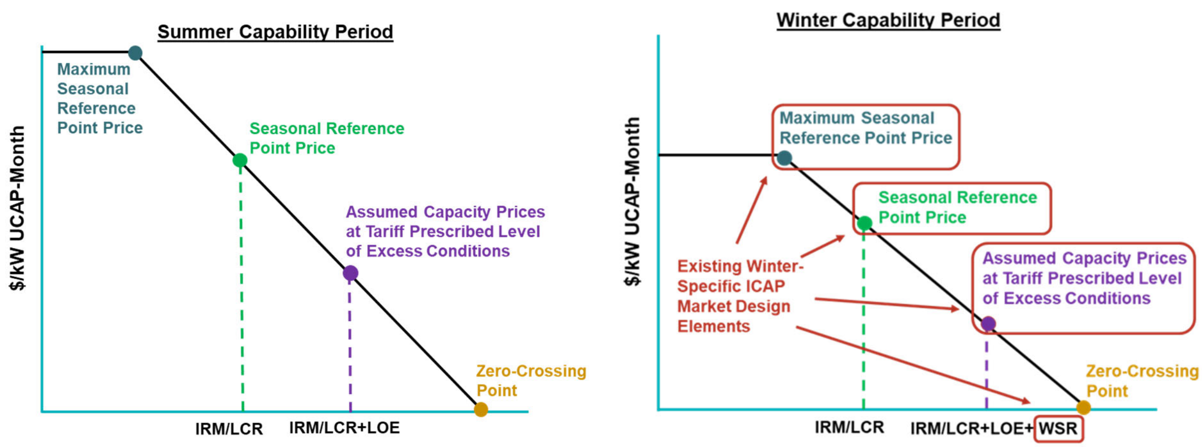
[99] NYISO, "ICAP Demand Curve," November 5-6, 2025, p. 11.

[100] NYISO, "2025 – 2029 ICAP Demand Curve Reset: Seasonal Reference Point Price Proposal," June 27, 2023, available at https://www.nyiso.com/documents/20142/38423065/3%202025-2029%20DCR%20Reference%20Point%20Price%20Proposal%20-%20ICAPWG%2006272023.pdf, p. 6.

[101] NYISO, "2025 – 2029 ICAP Demand Curve Reset: Seasonal Reference Point Price Proposal," June 27, 2023, available at https://www.nyiso.com/documents/20142/38423065/3%202025-2029%20DCR%20Reference%20Point%20Price%20Proposal%20-%20ICAPWG%2006272023.pdf, p. 25. With the proposed development of distinct seasonal IRMs and LCRs, the seasonal capacity availability adjustments would no longer be required.

- **Seasonal Maximum Reference Point Prices and Maximum Clearing Prices.** Maximum seasonal reference point prices are determined as 1.5 multiplied by seasonal gross Cost of New Entry ("CONE"), translated to a monthly value.[102]

Figure IV-1: Illustrative ICAP Demand Curve[103]



Note: Seasonal reference point prices are directly adjusted by the WSR and its inverse, the summer-winter ratio ("SWR"). Specifically, this figure omits the SWR as seasonal reference point prices are adjusted by the maximum of zero and (SWR – 1), therefore in practice the SWR adjustment does not affect the summer demand curve.

Since adopting these modifications, NYISO has continued to evaluate the need for further adjustments to account for seasonality. The continued investigation reflects on-going concerns about a combination of factors, including the expectation of increased winter resource adequacy risk due to regulatory changes (*e.g.*, the Climate Leadership and Clean Power Act mandating a 100% greenhouse gas emission-free electrical power system by 2040), a resource mix increasingly reliant on intermittent wind and solar generation, and increasing load due to the electrification of transportation and space heating.[104] In fact, the NYCA is forecasted to become a winter-peaking

[102] NYISO, "2025 – 2029 ICAP Demand Curve Reset: Seasonal Reference Point Price Proposal," June 27, 2023, available at https://www.nyiso.com/documents/20142/38423065/3%202025-2029%20DCR%20Reference%20Point%20Price%20Proposal%20-%20ICAPWG%2006272023.pdf, p. 7.

[103] Seasonal reference point prices are directly adjusted by the WSR and its inverse, the summer-winter ratio (SWR). NYISO, "2025 – 2029 ICAP Demand Curve Reset: Seasonal Reference Point Price Proposal," September 27, 2023, available at https://www.nyiso.com/documents/20142/40182694/6%202025-2029%20DCR%20Reference%20Point%20Price%20Proposal.pdf, p. 26.

[104] NYISO, "Winter Reliability Capacity Enhancements Issue Discovery Report," December 2024, available at https://www.nyiso.com/documents/20142/48542026/Winter%20Reliability%20Capacity%20Enhancements%20ID%20Report_Final.pdf, p. 3.

system by 2039/2040, while the ICAP market construct currently sets reliability requirements based on the summer peak.[105]

Following the publication of an Issue Discovery Report that assessed potential further enhancements to the ICAP market to address such concerns, in January 2025, NYISO launched a stakeholder consultation process, the 2025 Winter Reliability Capacity Enhancement Project. The consultation process focused on enhancements to improve market outcomes in a winter-peaking system, such as (a) winter ICAP requirements and demand curves, (b) capacity accreditation factors, and (c) seasonal elections.[106] The stakeholder process is expected to culminate in the fourth quarter of 2025 with proposed tariff revisions.[107]

As of December 2025, conclusions of the stakeholder consultation process and proposed tariff revisions include:

- **Developing winter ICAP requirements**, including winter reserve margins. The winter ICAP requirement would be calculated based on the available capacity in the winter peak month of the final (annual) IRM study. For example, the winter NYCA ICAP requirement would be calculated against the winter NYCA forecasted peak load value.[108] With this change, NYISO is removing seasonal capacity availability adjustments (*i.e.*, the WSR) adopted in 2024/2025, used in determining demand curves maximum clearing prices and reference point prices, as these adjustments are accounted for in the new seasonal ICAP requirements.[109]
- **Developing winter transmission security limits and LCRs**. Seasonal transmission security limits would account for seasonal differences such as load forecast and bulk power transmission limits. Winter

---

[105] According to the baseline forecast, NYISO projects that the region will be winter-peaking by the 2039/2040 winter. NYISO, "2025 Load & Capacity Data - Gold Book," April 2025, available at https://www.nyiso.com/documents/20142/2226333/2025-Gold-Book-Public.pdf, p. 17.

[106] In preparation for each upcoming capability year, resources submit 'election information' (*i.e.,* how much new capacity is eligible for supply in the auctions) to NYISO for use in reliability studies that determine the IRM. *See, for example*, NYISO, "2025 Winter Reliability Capacity Enhancements: Seasonal Elections," April 9, 2025, available at https://www.nyiso.com/documents/20142/50769536/2025%20Winter%20Reliability%20-%20Seasonal%20Elections%204.9.25%20Final.pdf, p. 7.

[107] NYISO, "2025 Winter Reliability Capacity Enhancements: Project Kick-off," January 30, 2025, available at https://www.nyiso.com/documents/20142/49408264/04%202025%20Winter%20Reliability%20Kick-off%20Presentation.pdf, p. 9.

[108] NYISO, "Winter Reliability Capacity Enhancements: Concept Proposal," July 29, 2025, available at https://www.nyiso.com/documents/20142/52778669/2025%20Winter%20Reliability%20-%20July%2029%20ICAPWG%20MDC_Final.1.pdf, pp. 12-14.

[109] NYISO, "2025 Winter Reliability Capacity Enhancements: Proposed Demand Curve Changes," August 19, 2025, available at https://www.nyiso.com/documents/20142/53269544/Winter%20Reliability%20-%20Proposed%20Demand%20Curve%20Changes%20Final.pdf, pp. 8, 14-15.

LCRs would be derived from availability capacity in each Locality in the winter peak month of the final IRM case.[110]

- **Retaining annual CAFs**. Although NYISO considered the adoption of seasonal CAFs, its reliability modeling estimated zero/low CAFs for certain technologies in the winter months, particularly non-firm natural gas-fired resources.[111] As such, to maintain price signals reflecting the value provided by these capacity resources (given the reliability benefits provided beyond resource adequacy) and sufficient to retain this capacity in the winter months, NYISO is proposing the continued use of annual, rather than seasonal, CAFs.[112]
- **Requiring seasonal elections**, whereby generators would submit distinct elections for summer and winter capability periods. NYISO is further considering must-offer requirements for all months in a season in which a generator elects to participate, to avoid misalignments between proposed seasonal requirements and available supply in a given delivery month.[113]
- **Seasonal zero crossing points**. NYISO is proposing the creation of distinct zero crossing points for the summer and winter demand curves.[114] The zero-crossing point is a key parameter determining the slope of the demand curve. However, the current zero crossing point percentages will be retained until changes in zero crossing points have been studied for their impact on reliability. Moving to seasonal zero crossing points is intended to provide a framework for using distinct seasonal zero crossing point percentages in the future.

---

[110] NYISO, "Winter Reliability Capacity Enhancements: Concept Proposal," July 29, 2025, available at https://www.nyiso.com/documents/20142/52778669/2025%20Winter%20Reliability%20-%20July%2029%20ICAPWG%20MDC_Final.1.pdf, p. 16.

[111] Since 2022, NYISO has relied on the MRI-based accreditation framework. In 2024, NYISO incorporated fuel security enhancements, including (a) requiring natural gas and dual-fuel units to disclose how much of their capacity is backed by firm fuel contracts vs. non-firm supply, (b) accounting for weather impacts on units' capability, and (c) requiring suppliers to substantiate firm / non-firm fuel election with documentation. In July 2025, FERC approved additional revisions to refine firm fuel election requirements, including by requiring suppliers making firm fuel elections to commit to have fuel available to run for 56 hours over any consecutive seven-day period from December through February. NYISO, "Winter Reliability Capacity Enhancements: Analysis of Seasonal Capacity Accreditation Factors," August 19, 2025, available at https://www.nyiso.com/documents/20142/53269544/2025%20Winter%20Reliability%20-%20August%2019%20ICAPWG_CAF%20Analysis.pdf, p. 6. NYISO, 192 FERC ¶ 61,049, Order Accepting Tariff Revisions and Dismissing Waiver Request, July 14, 2025, Docket Nos. ER25-2245-000 and ER25-2257-000, available at https://nyisoviewer.etariff.biz/ViewerDocLibrary/FercOrders/20250714-3044_ER25-2245-000_37339.pdf.

[112] NYISO, "Winter Reliability Capacity Enhancements: Analysis of Seasonal Capacity Accreditation Factors," August 19, 2025, available at https://www.nyiso.com/documents/20142/53269544/2025%20Winter%20Reliability%20-%20August%2019%20ICAPWG_CAF%20Analysis.pdf, pp. 6-7.

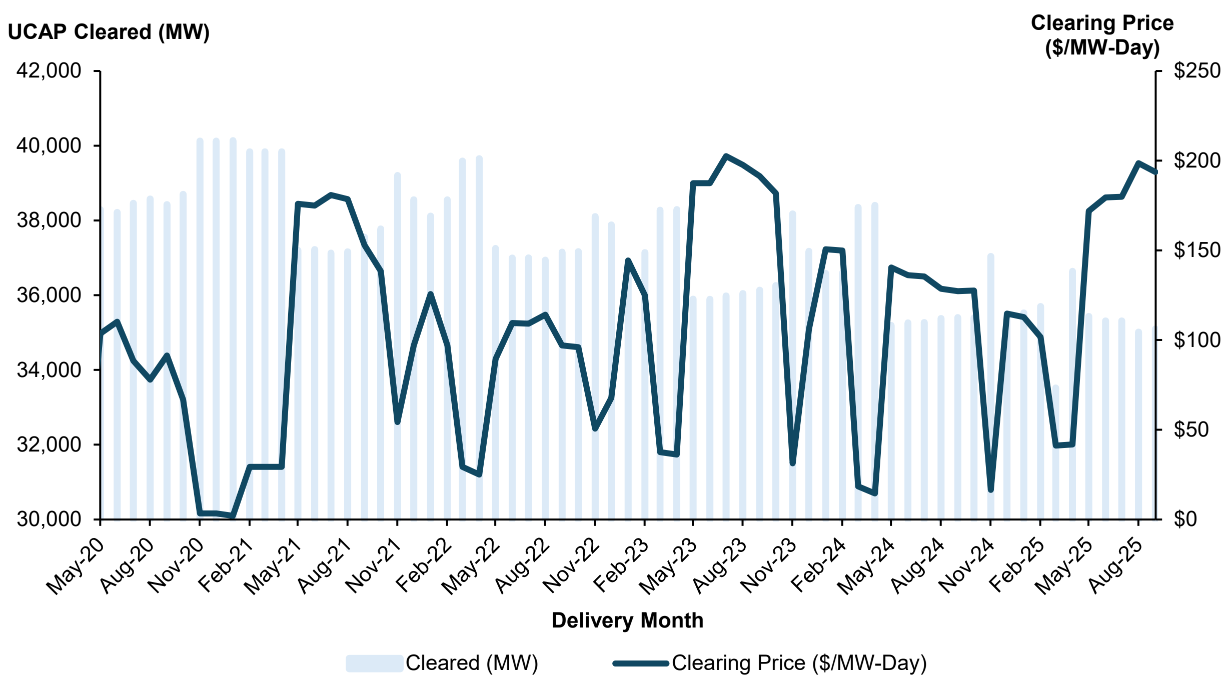
[113] NYISO, "Winter Reliability Capacity Enhancements: Concept Proposal," July 29, 2025, available at https://www.nyiso.com/documents/20142/52778669/2025%20Winter%20Reliability%20-%20July%2029%20ICAPWG%20MDC_Final.1.pdf, pp. 8-10.

[114] NYISO, "Winter Reliability Capacity Enhancements: Final Market Design Concept Proposal," September 22, 2025, available at https://www.nyiso.com/documents/20142/53966122/2025%20Winter%20Reliability%20-%20September%2022%20Final%20MDC%20-%20Reposted_Final.pdf, p. 21.

Finally, NYISO allocates capacity obligations to LSEs based on their share of peak load, with capacity requirements specified by Locality based on each LSE's locational peak load.[115]

Figure IV-2 shows historical ICAP market clearing prices ("MCPs") from May 2020 to August 2025. On a monthly basis, there is substantial variation in prices reflecting monthly changes in cleared supply. These changes in supply reflect several factors, including (1) exit and entry of capacity, and (2) seasonal differences in offered supply due to the seasonal adjustments described above (*i.e.*, forced outage rates and seasonal thermal plant capabilities).

Figure IV-2: NYCA Monthly Spot Auction Clearing Prices[116]



B. MISO

1. Background

MISO has implemented substantial seasonal features in its capacity market, the Planning Resource Auction ("PRA"). Prior to recent changes, MISO's capacity market included an annual capacity product and one prompt market auction per year, whereby capacity was procured to meet the planning reserve margin ("PRM") for the

[115] Capacity obligations are adjusted to include capacity procured outside of the ICAP market. NYISO, "Installed Capacity (ICAP) Market," October 21-24, 2025, pp. 64-69.

[116] **Source:** NYISO, Installed Capacity Data, Monthly UCAP Reports, available at https://www.nyiso.com/installed-capacity-market.

upcoming planning year (*i.e.*, between June 1st and May 31st). Starting with the 2023/2024 PRA, MISO has operated a seasonal market, with a single capacity auction held in April that simultaneously clears capacity for four distinct seasons: Summer (June to August), Fall (September to November), Winter (December to February), and Spring (March to May).[117]

Unlike other centralized capacity markets, the MISO PRA only clears a small proportion of the resources needed for resource adequacy. As MISO is comprised largely of vertically integrated and regulated utilities, most of MISO's supply need (*e.g.*, more than 90% in the 2022/2023 planning year) is met by self-scheduled or bilaterally contracted capacity, while the capacity auction procures the residual supply needed to clear the market.[118] Nonetheless, the challenges and experiences in MISO are informative for potential changes to PJM's RPM.

Dating back to the 2014 Polar Vortex, MISO has been considering a shift to a seasonal market construct.[119] Prior to adopting its current seasonal market, MISO had experienced reliability risks in all seasons, including shoulder seasons. As highlighted in its November 2021 filing to FERC, MISO found that, since 2016, 63% of the 41 declared Maximum Generation Emergencies ("MaxGen Events") occurred outside of the summer season, and 38% occurred in the shoulder seasons (spring or fall).[120] MISO noted that MaxGen Events were, "[…] 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 outages, including multiple polar vortex and Arctic storms."[121] While MISO noted that it "has experienced notable reliability challenges in the Winter Season", it highlighted resource adequacy risks across all seasons.[122]

---

117 MISO, "Resource Adequacy," available at https://www.misoenergy.org/planning/resource-adequacy2/resource-adequacy/#t=10&p=0&s=FileName&sd=desc. MISO, Midcontinent Independent System Operator, Inc.'s Filing to Include Seasonal and Accreditation Requirements for the MISO Resource Adequacy Construct, November 30, 2021, Docket No. ER22-495-000 (hereafter "MISO 2021 Seasonal Market Filing"), p. 4.

118 ICF, "Making sense of MISO's recent capacity auction," April 27, 2022, available at https://www.icf.com/insights/energy/miso-capacity-auction-2022-23, Exhibit 3a.

119 MISO 2021 Seasonal Market Filing, Prepared Direct Testimony of Scott Wright, p. 3 ("These reforms, especially a seasonal construct, have been considered by MISO and its stakeholders since the polar vortex in January 2014").

120 MISO, 180 FERC ¶ 61,141, Order Accepting Proposed Tariff Revisions Subject to Condition, August 31, 2022, Docket Nos. ER22-495-000 and ER22-495-001 (hereafter "FERC Order Accepting MISO Seasonal Market Construct"), pp. 3-4; A MaxGen event is a Maximum Generation alert (*e.g.*, heat weather alerts, conservative operations), warning or event (*e.g.*, units derated). *See, for example,* MISO, "MISO's Response to the Reliability Imperative," updated January 2022, available at https://downloads.regulations.gov/EPA-HQ-OLEM-2022-0335-0029/attachment_9.pdf.

121 FERC Order Accepting MISO Seasonal Market Construct, pp. 3-4.

122 MISO 2021 Seasonal Market Filing, Prepared Direct Testimony of Jameson Smith, p. 10 ("In Summer, extreme heat can raise load above expectations and drive correlated forced outages that reduce operating margins to emergency levels. In Winter, extreme cold combined with correlated forced outages due largely to insufficient Winterization and fuel supply issues have resulted in prolonged emergency periods. In the Spring and Fall shoulder Seasons a combination of unseasonably hot or cold weather, low renewable generation levels, and high levels of planned outages produce capacity challenges on days throughout the Season.")

With growing risk throughout the year, MISO concluded it should not operate its capacity market solely around summer peak conditions. To remedy this, MISO proposed to transition to a four-season capacity market construct for the PRA in November 2021, and the proposal was accepted by FERC in August 2022.[123,124]

Below, we describe the features of the seasonal market and results of initial seasonal auctions.

2. *Seasonal Market Design Parameters*

MISO's seasonal capacity market reform replaced the prior single annual resource adequacy requirement with four seasonal requirements. With this change, MISO adopted seasonal products, demand curves and auctions, and implemented seasonal, availability-based resource accreditation. Several factors motivated the adoption of a seasonal market structure. First, MISO shifted to a seasonal resource adequacy construct to "align regional resource accreditation with seasonal resource availability", stating that such a "resource adequacy construct more accurately represents resource capabilities at different times during the year, improves certainty of Resource availability outside the Summer Season, provides better incentives for resources to be available when needed, establishes seasonal reserve requirements that better align with risks, and delivers additional visibility into risks throughout the Planning Year."[125] Second, MISO argued that the lower non-summer peak loads in some of the four seasons would result in non-summer reserve requirements that would reduce cleared capacity in non-summer seasons and allow for cost savings related to seasonal resource operation.[126]

MISO operated its first auction with the seasonal capacity market construct in April 2023, for the 2023/2024 planning year. Key design parameters of MISO's seasonal market are discussed in the remainder of this section.

Number of Seasons: MISO opted for a four-season construct to provide a more granular representation of seasonal resource adequacy risk, given the year-round distribution of reliability risks, and to ensure that excess capacity is not procured, for example, in shoulder seasons with lower demand.[127] MISO's expert testimonies accompanying its November 2021 filing credit the urgency of shifting towards a seasonal construct to the increased incidence of MaxGen events, which occurred year-round.[128] MISO's independent market monitor, Potomac Economics, discussed two further benefits to the four-season structure in its comments submitted to FERC. First, Potomac noted that a four-season construct would provide the appropriate availability compensation

---

[123] MISO 2021 Seasonal Market Filing.

[124] FERC Order Accepting MISO Seasonal Market Construct.

[125] FERC Order Accepting MISO Seasonal Market Construct, p. 10. MISO 2021 Seasonal Market Filing, p. 13.

[126] FERC Order Accepting MISO Seasonal Market Construct, p. 12.

[127] FERC Order Accepting MISO Seasonal Market Construct, p. 29 ("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.").

[128] MISO 2021 Seasonal Market Filing, Prepared Direct Testimony of Shawn McFarlane, p. 4 ("[T]he urgency of implementing the proposed Tariff enhancements is evidenced by the increased incidence of capacity emergency maximum generation alerts, warnings, and events (collectively referred to as 'MaxGens'), particularly in the Seasons outside of Summer.").

for each season and aid in the coordination of planned outages: “[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. However, MISO’s shoulder season requirements would ensure that excessive outages are not planned in any one season.”[129] Second, Potomac noted that the four-season construct would provide flexibility for retirements and suspensions: “[r]esources retiring mid-year would have more flexibility to select a retirement or suspension date without having to procure significant replacement capacity to satisfy post-retirement capacity obligations.”[130]

Demand Curve. Like PJM, MISO’s current PRA relies on a sloped demand curve for each Local Resource Zone (“LRZ”) in each season. MISO’s sloped demand curves are based on the marginal reliability impact approach, in which demand for capacity reflects the marginal impact of additional resource capacity on system reliability.[131] Sloped demand curves are a new addition to the PRA. They were approved in June 2024, as part of a broader Resource-Based Demand Curve (“RBDC”) design that more accurately reflects the marginal reliability improvements from securing additional capacity.[132] The downward-sloping demand curves were utilized for the first time in the 2025/26 PRA for the 2025/2026 planning year.[133]

Under the current seasonal design, the market clears in each season against seasonal demand curves, with separate demand curves for MISO North/Central and MISO South. These demand curves reflect planning reserve

---

[129] 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.

[130] 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.

[131] MISO, Reliability Based Demand Curve, September 29, 2023, Docket No. ER23-2977-000, available at https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20230929-5322 (hereafter “MISO 2023 RBDC Filing”); MISO, 187 FERC ¶ 61,202, Order Accepting MISO’s Sloped Demand Curve, June 27, 2024, Docket Nos. ER23-2977-000, ER23-2977-001, ER23-2977-002, available at https://cdn.misoenergy.org/2024-06-27_187%20FERC%20%C2%B6%2061,202_Docket%20No.%20ER23-2977-000,et%20al636773.pdf (hereafter “FERC Order Accepting MISO Seasonal Demand Curve”). The sloped demand curves, proposed by MISO in 2023 following its transition to a seasonal construct, replaced the previously vertical demand curves set at the PRMs with price caps.

[132] The sloped demand curves were proposed so that auction clearing prices would more accurately value incremental capacity and properly incentivize investments and retirement decisions, following periodic instances of understated capacity prices, and capacity shortages that led to sharp increases in prices. For example, the April 2022 resource auction had a capacity deficit of 1,230 MW in MISO's northern and central regions that led to a sharp price increase from $5/MW-day to $236.66/MW-day. FERC Order Accepting MISO Seasonal Demand Curve, p. 5 (“MISO states that analysis from the Market Monitor indicates that in the 2019/2020, 2020/2021, and 2021/2022 Planning Years, and efficient Auction Clearing Price would have ranged from just over $100/MW-day in 2019/2020 to $175/MW-day in 2020/2021, whereas the actual Auction Clearing Price for those Planning Years in all but one Zone was less than $7/MW-day. The Market Monitor estimates that nearly five GW of resources retired prematurely primarily because of understated capacity prices.”).

[133] MISO, “MISO’s Planning Resource Auction indicates sufficient resources,” April 28, 2025, available at https://www.misoenergy.org/meet-miso/media-center/2025---news-releases/misos-planning-resource-auction-indicates-sufficient-resources/.

margins ("PRMs") for each season and corresponding Local Clearing Requirements ("LCRs") for each resource zone that are calculated in an annual LOLE study conducted by MISO.[134]

- The PRMs are set to reflect both (1) season-specific resource adequacy risk, subject to a minimum risk threshold, and (2) aggregate requirements needed to obtain the 1-in-10 (0.1 day per year) resource adequacy requirement across seasons. In particular, the LOLE model is first solved to achieve an annual 1-in-10 LOLE value across seasons. A second step adjusts seasonal requirements if the LOLE value in any season is less than 0.01 LOLE. This adjustment is achieved by adding negative capacity in the season or seasons with less than 0.01 LOLE until 0.01 LOLE is reached.[135] Thus, in principle, the total annual requirement could exceed the 1-in-10 day per year LOLE requirement.
- Each RBDC is constructed by multiplying the MRI curve (in MWh/MW-day) by the scalar/normalization value (in $/MWh) required to support the achievement of prices equal to seasonal Net CONE at the 1-in-10 LOLE reliability target.[136]
- Seasonal price caps are set so that the reference resource can earn all annual revenues needed to cover the cost of new entry in one season. The seasonal price cap is calculated as annual CONE divided by the number of days in the season.[137]
- RBDCs are not developed for individual localities. Instead, market clearing in each LRZ is subject to vertical demand curve clearing in the event of capacity shortage or near-shortage conditions.[138] The price adjustments that are applied to LRZs facing shortage conditions are further discussed below.

Auction Timing and Sequence: Under the seasonal capacity market construct, capacity is procured and cleared separately for each of the four seasons in the annual PRA auction process to meet seasonal system-wide PRMs based on a 1-in-10 day per year LOLE requirement.[139] As with the previous annual construct, the PRA is held in the spring, prior to the start of the summer season, and establishes an auction clearing price for each of the ten

---

[134] *See*, *for example,* MISO, "Planning Year 2026-2027 Loss of Load Expectation Study Initial Report," available at https://cdn.misoenergy.org/PY%202026-2027%20LOLE%20Study%20Report728909.pdf.

[135] MISO Tariff, Module E, 68A.2.1, available at https://docs.misoenergy.org/miso12-legalcontent/Module_E-1_-_Resource_Adequacy.pdf.

[136] MISO 2023 RBDC Filing, p. 18.

[137] FERC Order Accepting MISO Seasonal Demand Curve, p. 73 ("MISO also indicates that there is no change to the seasonal Auction Clearing Price cap, which is seasonal CONE, calculated as Annual CONE divided by the number of days in the Season"). MISO, Resource Adequacy Business Manual, p. 163 ("Price cap is 1 x Cost of New Entry (CONE, or Gross CONE) in each season, and 4 x CONE in total across the four seasons").

[138] FERC Order Accepting MISO Seasonal Demand Curve, p. 73 ("MISO notes that, as in the current Tariff, LCRs for each Zone will continue to be subject to vertical demand curve clearing in the Auction in the event of a capacity shortage or near-shortage within a Zone").

[139] MISO 2021 Seasonal Market Filing, pp. 10-11.

LRZs and for each of the four seasons in the year.[140] All resources submit offers for all seasons during a window in the last four days of March.[141] Then, MISO runs the PRA over the first 20 days of April, clearing requirements separately and independently for each season (without co-optimization or integration across seasons).[142]

Compared to sequential auctions that are cleared separately and at different times of the year (like NYISO's 12 monthly spot auctions per year), MISO's approach of clearing all four seasons simultaneously creates greater uncertainty about market conditions and greater risk of undesirable market positions (*e.g.*, clearing in the "last" season of the capability year, but not the first three seasons).[143] In its comments to FERC, Potomac Economics suggested that simultaneous auctions "unnecessarily increase uncertainty regarding the supply and demand of capacity in any given Season," and that sequential, rather than simultaneous, auctions "would allow the decisions and offers in the remaining Seasons to be informed by results of the initial Seasons."[144] These concerns were echoed by FERC's Commissioner Clements' dissent in relation to FERC's Order accepting MISO's seasonal construct, stating that the simultaneous clearing is a "novel" construct which "may provide an opportunity for capacity sellers to exercise market power," and adds "complexity beyond that involved in conducting a single annual auction or sequential seasonal auctions [.. such that …] this ambiguity may provide a basis for excessive market offers."[145] These concerns therefore centered around the risk that market participants might include, in each seasonal auction offer, their full annual going forward costs, as a hedge against the possibility of only clearing in one season.

---

140 FERC Order Accepting MISO Seasonal Market Construct, p. 12.

141 MISO 2021 Seasonal Market Filing, p. 14.

142 MISO conducts the PRA in the first 20 days of April and publishes results at the end of April, ahead of planning year between June and May. MISO 2021 Seasonal Market Filing, p. 14.

143 For example, Potomac Economics, in its recommendations to the MISO in its 2014 – 2015 State of the Market Report, had suggested prompt seasonal auctions so that "participants could make auction decisions with less uncertainty", as opposed to a simultaneous auction that could clear capacity "immediately in advance of the summer season, but more than 6 months ahead of the winter season." Potomac Economics, "State of the Market Report for the MISO Electricity Markets", June 2022, available at https://cdn.misoenergy.org/20220622%20Markets%20Committee%20of%20the%20BOD%20Item%2004%20IMM%20State%20of%20the%20Market%20Report625261.pdf, p. 85.

144 FERC Order Accepting MISO Seasonal Market Construct, p. 15 ("While Potomac Economics supports the transition to a seasonal construct, it suggests that conducting four simultaneous auctions unnecessarily increases uncertainty regarding the supply and demand for capacity in any given Season. Potomac Economics contends that sequential, rather than simultaneous, auctions would allow the decisions and offers in the remaining Seasons to be informed by results of the initial Seasons. Potomac Economics submits that this can be highly beneficial for suppliers that are making retirement and/or suspension decisions based on the seasonal capacity auctions they clear. As an example, Potomac Economics states that a resource that clears in the Summer Auction and covers its going-forward costs is likely to be willing to offer at a lower price in the remaining Seasons than in a simultaneous auction where the supplier is uncertain in which Season(s) the resource will clear, if any. Potomac Economics states that likewise, a supplier considering a suspension or seasonal shutdown may make a different decision or offer at the different level in one Season depending on whether the resource cleared in the prior Season.").

145 "Commissioner Clements Dissent Regarding Midcontinent Independent System Operator, Inc.," August 31, 2022, Docket Nos. ER22-495-000 and ER22-495-001, available at https://www.ferc.gov/news-events/news/commissioner-clements-dissent-regarding-midcontinent-independent-system-operator.

MISO pursued a single auction to clear all four seasons separately as a first step in its transition to a seasonal market. As discussed above, previously, MISO ran one annual auction. Thus, rather than changing both the number and sequence of auctions, MISO opted to first adopt seasonal markets and maintain the existing frequency of auctions. MISO will continue to consider auction timing and sequence as it gains more experience with the seasonal market construct. Future potential designs to consider include sequential seasonal auctions that allow resources to submit offers sequentially after seeing previous season auction clearing results, or co-optimized seasonal auctions.

Other Seasonal Parameters: In addition to the above key design parameters, MISO has adopted the following types of seasonal market inputs, modeling, and requirements in parallel:

- LOLE modeling improvements to utilize seasonally sensitive variables, including seasonal LOLE risk allocation, modeling of planned outages, modeling of non-firm external imports and hourly modeling of intermittent resources.[146]
- Seasonal resource accreditation, whereby specific resources are accredited based on availability in resource adequacy hours in each season.[147]
- Seasonal capacity import and export limits.[148] Transmission studies perform transfer analyses for each season, resulting in the maximum amount of capacity that can be imported or exported to or from a zone. In conjunction with the LCRs, these determine the Local Reliability Requirements ("LRRs") for each LRZ.[149]

Coordination of Outages: MISO updated its capacity replacement policy for resources on scheduled/maintenance outages to align more closely with the seasonal market construct and avoid capacity shortages due to planned outages. Before the seasonal market construct, MISO required capacity replacements only for capacity suspensions and retirements, and precluded resources planning to be unavailable for 90 days or more of the first 120 days in the planning year from participating in the auction.[150] Under the revised capacity replacement policy, owners of any resource with a planned outage lasting for more than 31 days in a cleared

[146] FERC Order Accepting MISO Seasonal Market Construct.

[147] FERC Order Accepting MISO Seasonal Market Construct, pp. 34-38. Starting with the 2028/2029 planning year, MISO will adopt a Direct Loss of Load accreditation methodology, which reflects a resource's expected contribution to reliability using expected class-level performance (probabilistic approach) and historical resource level performance (deterministic approach). Performance during critical hours (*i.e.,* hours with the most difficult operating conditions) will be more heavily weighted (at 80%). *See*, *for example*, MISO, "Resource Accreditation White Paper", March 2024, available at https://cdn.misoenergy.org/Resource%20Accreditation%20White%20Paper%20Version%202.1630728.pdf, p. 8.

[148] FERC Order Accepting MISO Seasonal Market Construct, p. 12.

[149] FERC Order Accepting MISO Seasonal Market Construct, p. 12. MISO, "Planning Year 2025 - 2026 Loss of Load Expectation Study Report", available at https://cdn.misoenergy.org/PY%202025-2026%20LOLE%20Study%20Report685316.pdf?v=20250313114401, p. 6.

[150] MISO, 170 FERC ¶ 61,066, 2020 Summer Outage Order, 2020. MISO 2021 Seasonal Market Filing, Prepared Direct Testimony of Shawn McFarlane, Docket No. ER22-495-000, p. 38.

season must either provide replacement capacity (for days beyond the 31-day threshold) or not offer the resource into the auction.[151] In addition, MISO incorporated a daily financial charge for resource owners who do not replace resources that retire or suspend operations during a season, or experience planned outages longer than 31 days.[152] These policies further incentivize resources with long-lasting planned outages to either not offer supply into that season's auction or to procure replacement capacity for the outage days beyond the 31-day threshold.[153] MISO also modified its market monitoring and mitigation provisions, removing provisions that prohibited resources that expected outages of more than 90 of the first 120 days of the planning year from participating in the auction and allowing resources planning outages longer than 31 days to seek permission from the Market Monitor to decrease offered capacity.[154] Finally, MISO incentivizes the coordination of planned outages by providing exemptions that prevent certain outages from negatively impacting a resource's seasonal accredited capacity. For example, if a generator's first planned outage is scheduled at least 120 days in advance, these outages do not impact the resource accreditation.[155]

Auction Clearing Prices: The auction clearing price for each season and LRZ is determined by first clearing supply against the regional RBDC, subject to the seasonal price caps. Clearing prices for zones may differ from the region-wide price if the LRZ faces a shortage of capacity ("shortage" or "near-shortage" conditions"). Here, shortage conditions occur when the amount of ZRCs (*i.e.*, capacity) that clear the market is not sufficient to meet the planning reserve requirement in the LRZ.[156] When shortage conditions occur, the *ex-post* zonal adjusted clearing price equals to the lower value between (a) the initial shortage condition zonal auction clearing price, and

---

[151] FERC Order Accepting MISO Seasonal Market Construct, pp. 135-136 ("MISO's capacity replacement provisions afford resource owners sufficient flexibility, as it permits them to determine whether it is more cost effective to: (1) perform necessary maintenance within the 31-day period; (2) opt out of participating in the capacity market for a Season and perform maintenance over the course of that Season; or (3) perform maintenance for a period longer than 31 days and procure replacement ZRCs for the time period beyond the 31-day threshold. In addition, we note that MISO's proposal permits a resource owner to schedule maintenance straddling two Seasons, which would allow for a resource be on a 62-day outage while still participating fully in both Seasons. This may be particularly useful for resources with longer maintenance periods that are planned far in advance.").

[152] FERC Order Accepting MISO Seasonal Market Construct, p. 114. ("MISO proposes a Capacity Replacement Non-Compliance Charge for Resource owners that do not replace Planning Resources that retire or suspend during a Season, or are on planned outage or planned derate for more than 31 days in a Season. MISO states that the Capacity Replacement Non-Compliance Charge will be a daily charge, equal to the amount of ZRCs that failed to be replaced multiplied by sum of the Auction Clearing Price and the daily CONE value. MISO states that the Capacity Replacement Non-Compliance Charges will be distributed to Market Participants representing LSEs on a pro rata basis, based upon the LSE's share of total Reserve Requirements for the MISO Region.").

[153] FERC Order Accepting MISO Seasonal Market Construct, p. 134.

[154] FERC Order Accepting MISO Seasonal Market Construct, p. 13.

[155] FERC Order Accepting MISO Seasonal Market Construct, pp. 37-38.

[156] FERC Order Accepting MISO Seasonal Market Construct, p. 13 ("ZRC Near-Shortage Conditions occur in a Zone in any Season that has sufficient volume of ZRC Offers to cover that Zone's Reserve Requirements, but the Season's Auction Clearing Price is greater than the daily CONE value."). MISO 2021 Seasonal Market Filing, Prepared Direct Testimony of Shawn McFarlane, Docket No. ER22-495-000, p. 41 ("An *ex-post* adjustment will set reduced Auction Clearing Prices when more than one Season clears in ZRC Shortage Conditions or ZRC Near-Shortage Conditions. The final Auction Clearing Price will be set based on annual CONE and the number days in all applicable Seasons when an LRZ, group of LRZs, or the MISO footprint clear with less than the required number of ZRCs or the Season's initial Auction Clearing Price clears above daily CONE in a Planning Resource Auction.").

(b) the sum of the system/regional marginal cost of capacity plus a price adder equal to the zone's annual CONE value divided by the number of days in all applicable seasons when a zone clears insufficient capacity.[157,158]

MISO also has provisions to address potential excess prices if a location clears at shortage prices in multiple seasons.[159] Specifically, *ex-post* pricing adjustments are made if an LRZ clears at Shortage or Near-Shortage Conditions in more than one season.[160] When this occurs, *ex-post* adjustments are made to limit total revenues across seasons that clear at Shortage or Near-Shortage Conditions to CONE. That is, the daily price is set to fully recover CONE over the all seasons clearing at Shortage or Near-Shortage Conditions. MISO adjusted this rule, however, because it could have led to differences in seasonal prices for LRZs facing similar financial constraints, where some LRZs experienced adjustments to prices because there was more than one Shortage or Near-Shortage Condition whereas other LRZs faced no adjustment in prices because there was only one season with a Shortage or Near-Shortage Condition. Adjustments were implemented to remedy these potential unintended outcomes, including identification of conditions under which seasonal prices between LRZs should be equalized and establishment of an aggregate cap (at 1.75x CONE) for prices in any LRZ with more Shortage or Near-Shortage Conditions in more than one season.

Cost Allocation: MISO currently calculates LSE capacity obligations based on LSE forecast peak load at MISO's peak load in each season.[161] However, MISO recently noted that "shifting system risks drive the need for the PRMR to be allocated to LSEs based on periods with the highest reliability risks" and that "stakeholder feedback emphasized that stability is needed for PRMR allocation to enable better planning."[162] To address these concerns,

---

[157] To address risks of shortage conditions under the previous, vertical demand curve, MISO had introduced a make-whole payment applicable to resources clearing the market at costs above the *ex-post* shortage price adjusted clearing price. This was referred to as the ZRC Offer Revenue Sufficiency Guarantee Credit, which compensated resources for any costs included in their cleared offer that were above the *ex-post* shortage clearing price adjustment. The ZRC Offer Revenue Sufficiency Guarantee Credit was funded by LSEs in the LRZ where the shortage occurred, on a pro rata basis based on the LSE's share of the reserve requirement in the seasons where the *ex-post* shortage pricing adjustment occurred, and we understand from MISO that the use of this provision was uncommon, and only applicable to resources that cleared at a very high offer price. While this make-whole payment is no longer necessary under the system-wide RBDC, it is still available at the local LRZ zone, in the case of shortage conditions. FERC Order Accepting MISO Seasonal Market Construct, p. 14; FERC Order Accepting MISO Seasonal Demand Curve, p. 73; MISO's Response to Deficiency Letter for the Reliability Based Demand Curve, May 13, 2024, Docket Nos. ER23-2977-000 and ER23-2977-001, available at https://cdn.misoenergy.org/2024-05-13%20Docket%20No.%20ER23-2977-002632873.pdf, p. 9 ("We recognize that under the as-filed RBDC Tariff, ZRC Offer Revenue Sufficiency Credits will continue to be possible when LRZ shortages occur, but as was said in the transmittal letter, MISO intends to address LRZ reliability based demand curves at a later date.").

[158] FERC Order Accepting MISO Seasonal Demand Curve, p. 73.

[159] MISO, "Midcontinent Independent System Operator, Inc.'s Shortage and Near-Shortage Pricing Enhancement MISO Resource Adequacy Construct," FERC Docket No. ER23-904-000" *See also* MISO, "Seasonal Shortage Pricing Enhancements," January 17-18, 2023, available at https://cdn.misoenergy.org/20230117-18%20RASC%20Item%2005%20Seasonal%20PRA%20Shortage%20Pricing%20Presentation627475.pdf.

[160] Shortage occurs when cleared supply is less than the requirement and Near Shortage occurs when prices clear at or above CONE.

[161] MISO, Resource Adequacy Business Manual, p. 18.

[162] MISO, "Planning Reserve Margin Requirement (PRMR) Allocation," July 9, 2025, available at https://cdn.misoenergy.org/20250709%20RASC%20Item%2006%20PRMR%20Allocation%20(RASC-2020-4%20and%202019-2)705843.pdf, pp. 2, 4.

MISO is proposing to instead allocate LSE capacity obligations based on a given LSE's share of load during expected high-risk hours (*i.e.*, "Seasonal Expected RA Hours"). To add stability, MISO's proposal envisions these hours to be fixed for three years, and within those RA hours, each LSE's top ten load hours (on non-holiday business days) in the previous year are used to determine its share of PRMR.[163]

Seasonal Auction Results: There have been three sets of MISO PRA capacity auctions under the new seasonal market construct (as shown in **Figure IV-3**): the spring 2023/2024 PRA (for the 2023/2024 planning year), the spring 2024/2025 PRA (for the 2024/2025 planning year) and the spring 2025/2026 PRA (for the 2025/2026 planning year).

The 2023/2024 PRA auction saw substantial drops in capacity prices in all LRZs compared to the previous year, due to an increase in supply and decline in the reserve requirement. Prices cleared in a range of $2 - $15/MW-day across seasons, as compared to prices as high as $236.66/MW-day observed in the annual 2022/2023 PRA across the northern and central MISO regions.[164]

By contrast, the 2024/2025 PRA auction resulted in higher shoulder season prices. While most regions cleared in the range of $0.75 - $34.10/MW-day in each season, in MISO Zone 5 (Missouri), shortage conditions occurred in the fall and spring, resulting in an *ex-post* auction clearing price adjustment of $719.81/MW-day.[165] MISO attributed the shoulder season shortage conditions to power plant retirements and scheduled plant maintenance outages.[166] While this information is not publicly available, if any Zone 5 resources cleared the market with costs above $719.81/MW-day, we understand that those resources would be eligible for the ZRC Offer Revenue Sufficiency Guarantee Credit make-whole payment, which guarantees that resources cover their offer costs when the zonal auction clearing price is adjusted *ex-post* due to shortage conditions.

Finally, in the 2025/2026 PRA (the first PRA with a RBDC demand curve), price signals varied dramatically across seasons. The market cleared over 20 times higher in the summer and winter, and prices more than doubled in the shoulder seasons, compared to the 2024/2025 PRA (with the exception of Zone 5). Across all zones, the summer capacity price reached $666.50/MW-day, compared to $30/MW-day in the 2024/2025 PRA. Several factors contributed to the summer price spike, including declining reserve margins (2.6 GW in 2025 compared to 4.6 GW

---

[163] MISO, "Planning Reserve Margin Requirement (PRMR) Allocation," July 9, 2025, available at https://cdn.misoenergy.org/20250709%20RASC%20Item%2006%20PRMR%20Allocation%20(RASC-2020-4%20and%202019-2)705843.pdf, pp. 7-10.

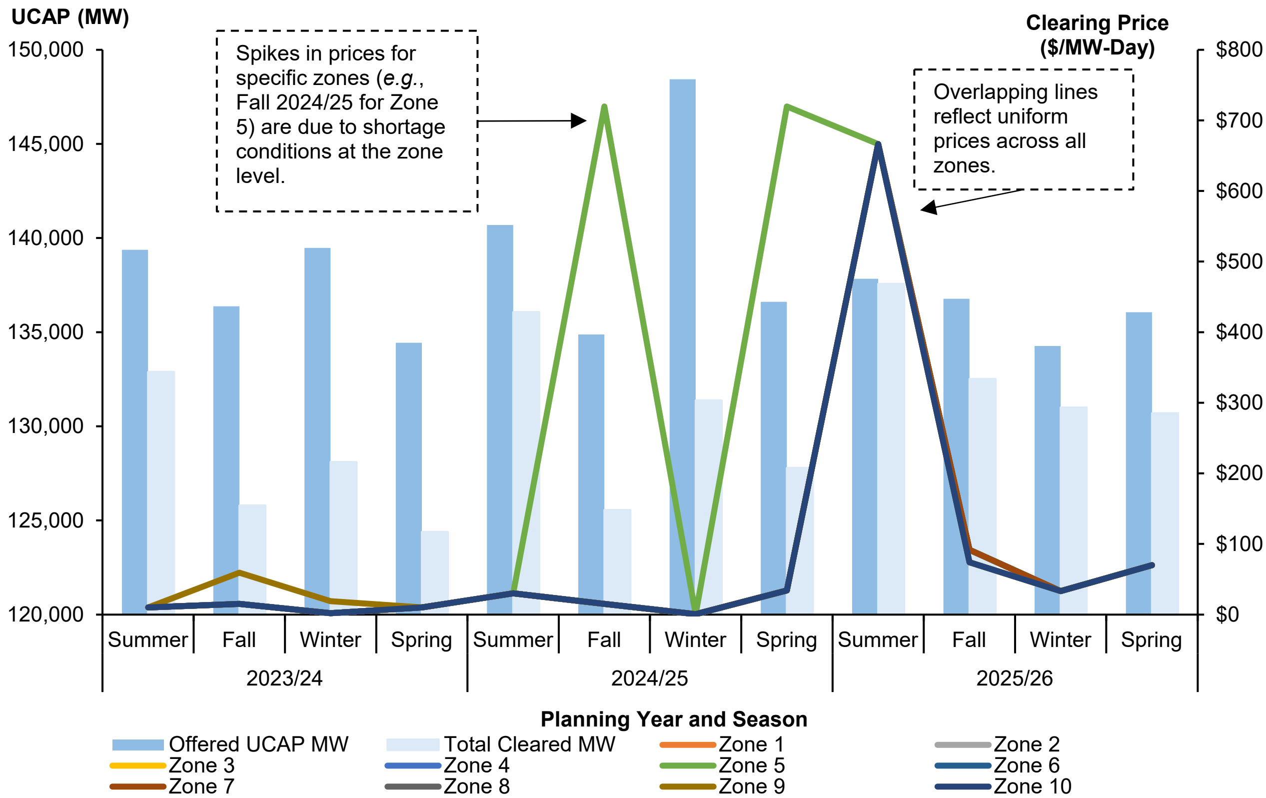
[164] Howland, Ethan, "MISO capacity prices plunge over 93% as generation comes online, demand dips in first seasonal auction", *Utility Dive*, May 19, 2023, available at https://www.utilitydive.com/news/miso-capacity-planning-resource-auction/650727/.

[165] MISO, "Planning Resource Auction Results for Planning Year 2024-25", April 26, 2024, available at https://cdn.misoenergy.org/2024%20PRA%20Results%20Posting%2020240425632665.pdf, p. 26 ("For Zone 5, there were 183 shortage-days (fall and spring); ACP is Annual CONE / # of shortage-days: 131,725 / 183 = $719.81").

[166] As per the 2024/2025 PRA results, prices for MISO's Zone 5, served by Ameren Missouri and Columbia, were set at $719.81/MW-day for the fall and spring seasons of the 2024/25 Planning Year, due to capacity shortfalls triggered by coal plan retirements and power plant maintenance. Potomac Economics, "2023 State of the Market Report for the MISO Electricity Markets", June 2024, available at https://www.potomaceconomics.com/wp-content/uploads/2024/06/2023-MISO-SOM_Report_Body-Final.pdf, p. 73.

in 2024), power plant suspensions and retirements (similarly to the 2024/2025 PRA) and reduced accreditation following a change in methodology.[167]

Figure IV-3: MISO Seasonal Clearing Prices and Capacity[168]
Delivery Years 2023/24-2025/26



Notes: [1] Clearing prices across MISO's External Resource Zones are not included in this figure. [2] Capacity (MW) is measured as UCAP.

[167] SYSO Technologies, "MISO's 2025/26 Capacity Auction: New Curve, Higher Prices, Shrinking Surplus," May 15, 2025, available at https://www.sysotechnologies.com/2025/05/15/miso-2025-2026-capacity-auction-results/.

[168] **Source:** MISO, "Planning Resource Auction Results for Planning Year 2025-26," April 2025, available at https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.

Table IV-2: MISO Planning Resource Auction Data[169]
Delivery Years 2023/24-2025/26

Auction Date	Delivery Year	Season	MISO-Wide Price	Offered UCAP MW	Cleared UCAP MW	Calculated Offered ICAP	Calculated Cleared ICAP	UCAP Reserve Margin	ICAP Reserve Margin	ICAP/UCAP Reserve Margin Ratio
Apr. 2023	2023/24	Summer	$10.00	139,373.9	132,891.2	150,404.4	143,408.7	7.40%	15.9%	1.08
		Fall	$15.00	136,377.2	125,795.4	149,314.6	137,729.0	14.90%	25.8%	1.09
		Winter	$2.00	139,478.7	128,104.2	156,927.4	144,130.0	25.50%	41.2%	1.13
		Spring	$10.00	134,433.4	124,389.1	150,414.2	139,175.9	24.50%	39.3%	1.12
Apr. 2024	2024/25	Summer	$30.00	140,688.9	136,064.4	151,918.2	146,924.6	9.00%	17.7%	1.08
		Fall	$15.00	134,878.6	125,551.4	147,870.4	137,644.8	14.20%	25.2%	1.10
		Winter	$0.75	148,438.0	131,376.8	174,070.9	154,063.5	27.40%	49.4%	1.17
		Spring	$34.10	136,615.1	127,790.6	151,818.5	142,012.0	26.70%	40.8%	1.11
Apr. 2025	2025/26	Summer	$666.50	137,836.3	137,559.3	147,800.4	147,503.3	7.90%	15.7%	1.07
		Fall	$91.60	136,775.5	132,515.8	149,155.5	144,510.3	14.90%	25.3%	1.09
		Winter	$33.20	134,261.9	130,999.5	157,168.1	153,349.1	18.40%	38.6%	1.17
		Spring	$69.88	136,060.6	130,699.5	150,720.0	144,781.2	25.30%	38.8%	1.11

Notes: [1] "MISO-Wide Price" is the auction clearing price ($MW-Day, cleared using UCAP) across zones, excluding zones that experienced shortages. These were Zone 5 in Fall/Spring 2024/25, Zone 9 in Fall/Winter 2023/24, and Zones 8-10 in Fall 2025/26. [2] Seasonal ICAP is calculated using the seasonal UCAP offered and cleared, adjusted by the ratio of seasonal reserve margin in UCAP and ICAP terms, *i.e.*, UCAP x (1 + ICAP PRM / 1 + UCAP PRM).

C. ISO-NE

1. Background

ISO-NE achieves resource adequacy primarily by procuring capacity through capacity market auctions. ISO-NE's capacity market, known as the Forward Capacity Market ("FCM"), has historically operated a Forward Capacity Auctions ("FCA") held annually, three years in advance of the Capacity Commitment Period (June 1st to May 31st). During the FCA, ISO-NE procures capacity for the region and for each Capacity Zone – subregions of ISO-NE that reflect transmission constraints – from resources that assume must-offer Capacity Supply Obligations ("CSOs"). Supply is cleared against administratively-determined demand curves reflecting forecasts of future capacity

[169] **Sources:** [A] MISO, "Planning Resource Auction Results for Planning Year 2025-26," April 2025, available at https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf. [B] MISO, "Planning Year 2025-2026 Planning Reserve Margin (PRM) and Local Reliability Requirement (LRR) Results," October 24, 2024, available at https://cdn.misoenergy.org/20241024%20LOLEWG%20Item%2003%20PY%202025-2026%20LOLE%20Study%20Results654956.pdf. [C] MISO, "2023-2024 PY Planning Reserve Margin and Local Reliability Requirement Results," September 6, 2022, available at https://cdn.misoenergy.org/20220906%20LOLEWG%20Item%2003%20PY%202023-24%20Preliminary%20LOLE%20Study%20Results626211.pdf. [D] MISO, "Planning Year 2024-25 Planning Reserve Margin (PRM) and Local Reliability Requirement (LRR) Results," October 17, 2023, available at https://cdn.misoenergy.org/20231017%20LOLEWG%20Item%2003%20PY%202024-25%20LOLE%20Study%20Results630538.pdf.

needed to meet the reliability criterion.[170] Between the FCA and the Capacity Commitment Period, additional auctions and contract opportunities exist for resources to procure or shed their capacity supply obligations to reflect changes in supply, including annual and monthly auctions and monthly bilateral contracts.[171]

Key features of the FCM include:

- An initial phase of resource qualification prior to the FCM, including the qualification of new resources and retiring and deactivating resources.
- Systemwide and zonal administratively-determined, sloped MRI demand curves. The MRI values are set to reflect an annual 1-in-10 LOLE reliability criterion.
- Capacity obligations are allocated to zones and LSEs based on their share of annual coincident peak load.[172]
- Capacity prices are set at the systemwide level and supplemented by congestion prices for capacity-constrained zones (congestion prices are positive for import-constrained zones and negative for export-constrained zones).
- Price caps are set to the greater of CONE and 1.6x Net CONE.[173]

ISO-NE is in the process of transitioning from a forward-annual market construct to a prompt, seasonal construct. To facilitate this transition, the next FCA (FCA 19) has been delayed to early 2028 to allow design of the prompt and seasonal market components, including stakeholder consultations. The prompt market design is being developed in 2025, and the seasonal market design is planned for development in 2026.[174] The discussion below reflects the current status of the seasonal market design.

[170] ISO New England Inc. Transmissions, Markets, and Services Tariff (ISO-NE Tariff), Section III.13, available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf.

[171] ISO-NE, "About the FCM and Its Auctions," available at https://www.iso-ne.com/markets-operations/markets/forward-capacity-market/fcm-participation-guide/about-the-fcm-and-its-auctions.

[172] Capacity obligations are adjusted to include capacity procured outside of the FCA. ISO-NE, "Lesson 6C: Supplier-Side Settlement," October 26-28, 2023, available at https://www.iso-ne.com/static-assets/documents/100005/20231024-fcm101-lesson-6c-art_print.pdf, pp. 14-20.

[173] ISO-NE, "CAR-SA – Design Kickoff Discussion," September 9-10, 2025, available at https://www.iso-ne.com/static-assets/documents/100027/a02.2a_mc_2025_09_09_10_introduction_car-sa_presentation.pdf, p. 21.

[174] ISO-NE, "Capacity Auction Reforms – Prompt/Deactivations (CAR-PD)," August 12-14, 2025, available at https://www.iso-ne.com/static-assets/documents/100026/a03.1b_carpd_continued_discussion_on_qualification_processes_under_the_prompt_timeframe.pdf, p. 35.

2. Seasonal Market Design Parameters

Recent challenges, such as increasing winter weather risks and the integration of renewable sources, led ISO-NE to initiate a consultation process in July 2023 around the review of capacity market components and assessment of a proposal to shift towards a prompt, seasonal market.[175]

An initial stakeholder review process culminated in a January 2024 report by Analysis Group recommending shifting towards a prompt and seasonal market construct.[176] On April 5, 2024, ISO-NE, supported by the New England Power Pool, filed a proposal to delay FCA 19 by two years (beyond a one-year delay already accepted by FERC), until February 2028, to allow ISO-NE and regional stakeholders the time to fully design and implement a prompt and seasonal capacity market framework and compatible capacity accreditation reforms based on the current MRI approach.[177] FERC accepted this proposal.[178]

Stakeholder Review of Design Elements: ISO-NE's on-going Capacity Auction Reforms ("CAR") project aims to (a) transition the annual market to a seasonal market "to better address the distinct reliability challenges of winter and summer, as well as variations in resource performance from season to season"; (b) adopt a prompt market structure, and (c) incorporate enhancements to the resource capacity accreditation methodology to "more accurately reflect resource contributions to resource adequacy."[179]

In its April 5, 2024, filing, ISO-NE noted its approach to evaluating the design of a seasonal market in the following two years. In particular,

- ISO-NE stated that the core objective of its capacity accreditation reforms is to better capture the impact of natural gas pipeline constraints on the capacity accreditation values and compensation. After evaluating possible reforms, ISO-NE concluded that the "optimal way of capturing this constraint [*i.e.*, by modeling the supply constraint in the capacity auction similarly to other transmission constraints are

---

[175] ISO-NE, "Capacity Auction Reforms Key Project," available at https://www.iso-ne.com/committees/key-projects/capacity-auction-reforms-key-project.

[176] ISO-NE, Revisions to ISO New England Transmission, Markets and Services Tariff to Further Delay the Nineteenth Forward Capacity Auction and Related Capacity Market Activities, April 5, 2024, Docket No. ER24-1710-000, available at https://www.iso-ne.com/static-assets/documents/100010/rev_to_further_delay_19th_fca.pdf, Attachments A and B.

[177] ISO-NE, Revisions to ISO New England Transmission, Markets and Services Tariff to Further Delay the Nineteenth Forward Capacity Auction and Related Capacity Market Activities, April 5, 2024, Docket No. ER24-1710-000, available at https://www.iso-ne.com/static-assets/documents/100010/rev_to_further_delay_19th_fca.pdf, p. 3 ("[…] numerous prompt seasonal market design elements that will require careful assessment before a prompt seasonal market design proposal can be filed with the Commission. Substantial work must also be done to further refine ongoing capacity accreditation and compensation reforms to ensure compatibility with this new capacity market framework").

[178] ISO-NE, 187 FERC ¶ 61,083, Order Accepting Tariff Revisions, May 20, 2024, Docket No. ER24-1710-000.

[179] ISO-NE, "Capacity Auction Reforms Key Project," available at https://www.iso-ne.com/committees/key-projects/capacity-auction-reforms-key-project.

captured] is, likely, only reasonable within a seasonal market construct."[180] The reforms build on the proposed MRI-based accreditation approach, which already supports the development of seasonal demand curves and, in conjunction with improved capacity credits that resource receive, will improve resource adequacy.

- ISO-NE is currently evaluating the design elements needed for such a transition. These include, among other factors, evaluating the number of seasonal auctions, whether to implement these auctions sequentially or simultaneously, the applicability and function of seasonal demand curves, and the accompanying capacity accreditation reforms.[181]

Since July 2024, ISO-NE has initiated a stakeholder process to develop the scope of market reforms. ISO-NE is planning to make a first filing proposing the adoption of a prompt market structure in the fourth quarter of 2025, and a second filing proposing resource accreditation and seasonal market structure in the fourth quarter of 2026, effective in the second and third quarters of 2027.[182]

While ISO-NE is initially focusing on developing the prompt auction, ISO-NE has considered certain elements of a seasonal market design, including:

- **The number of seasons.** ISO-NE has proposed a bi-annual construct consisting of a summer season (May 1st to October 31st) and a winter season (November 1st to April 30th). ISO-NE considered the following factors in determining the number of seasons: (a) seasonal availability of natural gas and demand (gas pipeline demand is greatest in the winter period, spanning November through April); (b) ISO-NE's modeling indicates that resource adequacy risks are concentrated during peak summer and winter conditions; (c) economic efficiency; (d) administrative simplicity; and (e) alignment with NYISO's construct, which facilitates participation across neighboring regions.[183]
- **The auction sequence.** ISO-NE has proposed an independent, sequential auction (*i.e.*, auctions occur immediately ahead of each season), rather than a simultaneous auction (*i.e.*, auctions for multiple seasons are cleared at one time). ISO-NE's preference for a sequential auction is driven by (a) the feasibility of implementing such a model, given its reliance on pricing mechanisms similar to the annual design and access to experience of other RTOs; (b) relative simplicity. ISO-NE has stated that it will

---

[180] ISO-NE, Revisions to ISO New England Transmission, Markets and Services Tariff to Further Delay the Nineteenth Forward Capacity Auction and Related Capacity Market Activities, April 5, 2024, Docket No. ER24-1710-000, available at https://www.iso-ne.com/static-assets/documents/100010/rev_to_further_delay_19th_fca.pdf, p. 5.

[181] ISO-NE, Revisions to ISO New England Transmission, Markets and Services Tariff to Further Delay the Nineteenth Forward Capacity Auction and Related Capacity Market Activities, April 5, 2024, Docket No. ER24-1710-000, available at https://www.iso-ne.com/static-assets/documents/100010/rev_to_further_delay_19th_fca.pdf, p. 18.

[182] ISO-NE, "Capacity Auction Reforms: Discussion of Project Scope, Schedule, and Introduction of Future Roadmap," October 16, 2024, available at https://www.iso-ne.com/static-assets/documents/100016/a05_mc_2024_10-16_car_presentation.pdf, p. 25; ISO-NE, "CAR-SA – Design Kickoff Discussion," September 9-10, 2025, available at https://www.iso-ne.com/static-assets/documents/100027/a02.2a_mc_2025_09_09_10_introduction_car-sa_presentation.pdf, p. 2.

[183] ISO-NE, "CAR – Seasonal/Accreditation (CAR-SA) Key Design Direction," March 11-12, 2025, available at https://www.iso-ne.com/static-assets/documents/100021/a04_mc_2025_03-11-12_season_definition_iso_presentation.pdf, pp. 2-8.

continue to evaluate the costs and benefits of a simultaneous, co-optimized auction after the CAR project.[184]

- **The accreditation methodology.** ISO-NE has proposed an MRI accreditation framework, whereby resources will be accredited based on their expected performance during simulated hours where resource adequacy is at risk, based on the GE Vernova Resource Adequacy software.[185]
- **Winter gas constraint.** ISO-NE has proposed to develop a market-based gas constraint to reflect the region's limited gas infrastructure and reflect the marginal reliability value of gas resources without a firm contract.[186] Thus, firm and non-firm gas resources would receive the same accreditation, but non-firm resources would be subject to the gas constraint, which may result in lower clearing prices, whereas firm resources would not be subject to the constraint.
- **Demand curves.** ISO-NE anticipates seasonal demand curves for each capacity zone that will continue to be based on capacity's MRI value for that season, with MRI curves reflecting resource adequacy risks specific to each season.[187] ISO-NE has proposed to set seasonal capacity requirement at values that evenly split the LOLE between seasons (*i.e.*, at a capacity quantity that yields a LOLE of 0.05). ISO-NE stated that the even split represents a "simple, transparent, and stable approach," and that it will consider refinements to the LOLE split methodology as it gains experience with the seasonal procurement.[188]
- **Offers and prices.** ISO-NE anticipates that competitive offers will continue to be based on costs and revenues associated with resources' next best alternative if they do not sell capacity.[189]

---

[184] ISO-NE, "Capacity Auction Reforms," November 13, 2024, available at https://www.iso-ne.com/static-assets/documents/100017/a03_mc_2024_11-13_capacity_auction_reforms_iso_presentation_nov_mc.pdf, pp. 4-14.

[185] ISO-NE, "CAR-SA – MRI Framework for Accrediting Resources," September 9-10, 2025, available at https://www.iso-ne.com/static-assets/documents/100027/a02.2b_mc_2025_09_09_10_accreditation_presentation.pdf. *See also,* ISO-NE, "Marginal Reliability Impact (MRI) Framework for Accrediting Capacity Resources," September 3, 2025, available at https://www.iso-ne.com/static-assets/documents/100027/a02.2b_mc_2025_09_09_10_accreditation_memo.pdf.

[186] ISO-NE, "CAR-SA – Overview of Gas Design," November 12-13, 2025, available at https://www.iso-ne.com/static-assets/documents/100029/a03.2.a_mc_rc_2025_11_12_13_car-sa_gas_constraint_conceptual_overview.pdf.

[187] ISO-NE, "CAR-SA – Design Kickoff Discussion," September 9-10, 2025, available at https://www.iso-ne.com/static-assets/documents/100027/a02.2a_mc_2025_09_09_10_introduction_car-sa_presentation.pdf, p. 18.

[188] ISO-NE, "CAR-SA – Seasonal LOLE Split and Related Parameters," December 9-10, 2025, available at https://www.iso-ne.com/static-assets/documents/100030/a04.1.c_mc_rc_2025_12_09-10_seasonal_concepts_risk_split_determination.pdf, pp. 23-24.

[189] ISO-NE, "CAR-SA – Design Kickoff Discussion," September 9-10, 2025, available at https://www.iso-ne.com/static-assets/documents/100027/a02.2a_mc_2025_09_09_10_introduction_car-sa_presentation.pdf, p. 20.

3. Other Considerations

To address winter energy security challenges, ISO-NE has historically implemented separate winter reliability programs, starting in the winter of 2013 – 2014.[190] For example, during the 2023 – 2024 and 2024 – 2025 winters (December to February), ISO-NE offered the Inventoried Energy Program ("IEP"), a voluntary, interim process aimed at enhancing winter energy security by providing incremental compensation to resources "that maintain inventoried energy for their assets during extreme cold periods when winter energy security is most stressed."[191,192]

ISO-NE does not plan to continue the IEP during the winter of 2025 – 2026, focusing instead on the capacity market reforms.[193] Specifically, ISO-NE noted that energy adequacy risk is low in the near term, and reforms to accreditation based on reliability contributions and a move to a prompt capacity market will provide a more direct means to procure the reliability attributes delivered through the IEP.[194]

---

[190] ISO-NE, "Winter Reliability Program Updated," September 25, 2015, available at https://www.iso-ne.com/static-assets/documents/2015/09/final_gillespie_raab_sept2015.pdf, pp. 3-5; ISO-NE, "Winter Reliability Solutions for 2015/2016 to 2017/2018 Key Project," available at https://www.iso-ne.com/committees/key-projects/implemented/winter-reliability-solutions.

[191] ISO-NE, Inventoried Energy Program (IEP), October 31, 2024, available at https://www.iso-ne.com/participate/support/participant-readiness-outlook/inventoried-energy-program-iep.

[192] Participants could have opted into either a forward and spot component, or a spot-only component. Forward component participants received daily base payments for committing to specific inventory levels, with spot payments or charges determined based on real-time inventory data during declared Inventoried Energy Days (IEDs), defined by temperatures at or below 17°F. Spot-only participants, exempt from financial assurance obligations, were eligible solely for spot payments during IEDs and did not receive base payments. The costs of the program were borne proportionally by market participants based on their real-time load obligation (RTLO) in the energy market. ISO-NE Tariff Appendix K: Inventoried Energy Program, effective 8/2/2023, FERC Docket No. ER24-492-000, available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_k.pdf, Section III.K.4.

[193] ISO-NE's Internal Market Monitor, "Winter 2025 Quarterly Markets Report," June 4, 2025, available at https://www.iso-ne.com/static-assets/documents/100024/2025-winter-quarterly-markets-report.pdf, p. 30 ("As currently envisioned, the Resource Capacity Accreditation (RCA) proposal should provide a more direct means to procure the reliability attributes currently delivered through the IEP, which may ultimately fulfill the goals of the IEP."); ISO Newswire, "Cold winter drove higher energy prices, market monitor finds," June 11, 2025, available at https://isonewswire.com/2025/06/11/cold-winter-drove-higher-energy-prices-market-monitor-finds/.

[194] ISO-NE, "Winter 2025 Quarterly Markets Report," June 4, 2025, available at https://www.iso-ne.com/static-assets/documents/100024/2025-winter-quarterly-markets-report.pdf, p. 30. ISO-NE, "Inventoried Energy Program Memo," February 4, 2025, available at https://nepool.com/wp-content/uploads/2025/02/NPC_2025.02.06_5b_IEP_Memo.pdf, p. 1.

V. Potential Sub-Annual Market Benefits, Costs and Tradeoffs

In the past, resource adequacy in PJM has been maintained through the annual procurement of capacity to address resource adequacy risks arising primarily in summer months. Moreover, PJM's generation fleet largely consisted of fossil-fuel resources with relatively uniform across performance the year. Therefore, an annual capacity market grounded in the summer season provided sufficiently accurate price signals for address system resource adequacy risks.

As discussed in **Section III.A.2**, however, multiple changes in PJM's system conditions have both spread reliability risks across the year and led to varied resource contributions to reliability across the year, such that a capacity market grounded in the summer season no longer provides adequate incentives for resources to generate capacity to meet the system's reliability targets at the lowest economic cost. As a result, differences in market features across sub-annual periods have emerged with important implications for resource adequacy:

- The value of incremental capacity in reducing resource adequacy risks differs across sub-annual periods;
- The ability of different resources to mitigate resource adequacy risks differs across sub-annual periods; and
- Resources incur different costs to supply capacity across sub-annual periods.

A sub-annual capacity market design can more accurately reflect differences in these factors across sub-annual periods. Generally, in commodity markets, providing more differentiated ("granular") products – such as introducing temporal variation – can provide several benefits, including more accurate price signals and thus more efficient economic outcomes. However, increasing market granularity also entails higher administrative and operational complexity, which may offset some of the efficiency gains relatively to a more aggregated, annual market structure.

Therefore, a sub-annual capacity market design can achieve resource adequacy more cost-effectively and improve reliability outcomes compared to an annual capacity market. A sub-annual market may also improve reliability by incentivizing a resource mix that is better suited to the evolving sub-annual reliability risks and that adjusts for evolving patterns of sub-annual risks over time, without the need for manual modifications. In particular, we describe three key benefits to switching to a sub-annual market:

- A sub-annual market can lower costs by accounting for differences in resources' net "going forward costs" across sub-annual periods, thus procuring capacity when resources can most cost-effectively supply it.

Offsetting these potential benefits are the administrative and operational burdens of transitioning to and maintaining a more granular, complex market, particularly in the short term. Other issues (*e.g.*, market mitigation, risk of unintended consequences) also need to be considered.

In the following sections, we evaluate these potential benefits and costs of sub-annual capacity markets. Then, we assess the trade-offs of various sub-annual design options, including the design of market structure, demand curve and supply offers.

A. Potential Benefits of Sub-Annual Capacity Markets

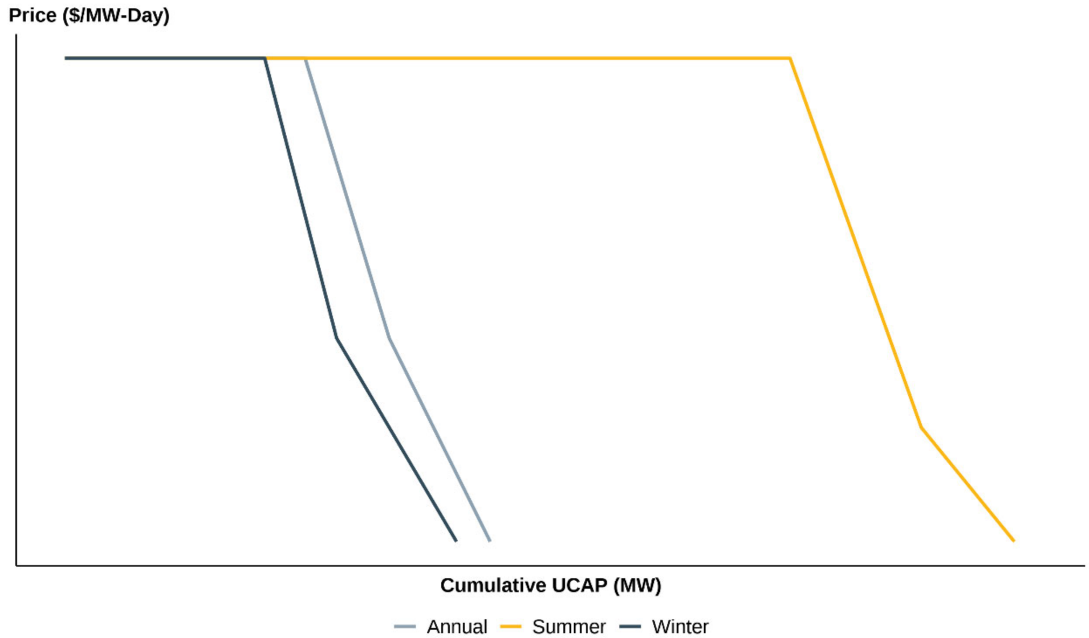
1. Accounting for Sub-Annual Variation in the Value of Capacity

To reliably and efficiently manage resource adequacy risks, a capacity market must accurately account for these risks. As resource adequacy risks outside of the summer increase (as described in **Section III.A.2**), an annual market reflecting only summer conditions no longer achieves this. A market that reflects average conditions across the year may improve on performance but still misses potential efficiencies from differentiating demand across seasons. A sub-annual market can better address risks dispersed and evolving across the year by adjusting the demand for capacity to reflect risks in each sub-annual period. By procuring a quantity of capacity in each sub-annual period to reflect the magnitude of risks in each period, a sub-annual market can achieve a more cost-effective supply of resources across seasons *(i.e.*, improve allocative efficiency).

Figure V-1 illustrates how a sub-annual market accounts for variation in the value of capacity across sub-periods through demand curves unique to each sub-period. The illustration shows both annual and two sub-annual demand curves, for summer and winter seasons.[195] In this case, as winter peak loads are lower than summer peak loads, a lower cumulative UCAP capacity would be expected in the winter than the summer, to meet reliability requirements. In addition, the slope of the demand curve, which reflects the willingness to pay for capacity below and above the capacity requirement, might also differ between the summer and winter. For example, historically, the summer demand curves could have been steeper than winter demand curves reflecting the different peak load risk, with lower capacity procurement causing sharper price increases.

[195] For the purposes of this figure, the annual demand curve is a weighted average of the summer and winter impacts, where the summer and winter demand impacts are assumed to account for 40% and 60% of the annual impacts, respectively. For the purposes of this illustration, the demand curves also assume the same price cap across sub-periods.

Figure V-1: Illustrative Annual and Seasonal Demand Curves



2. Accounting for Sub-Annual Variation in Resource Performance

A sub-annual market can better account for differences in resource accreditation values across sub-annual periods. As discussed in **Section III** and in the following sections, resource technologies perform differently across sub-annual periods, thus affecting their ability to mitigate resource adequacy risks. **Table VII-1** shows these differences, as reflected in class ELCC values. For example, tracking solar resources have a 6% winter ELCC but 28% summer ELCC. A sub-annual market can account for differences in each resource's capacity accreditation across sub-periods, which has multiple effects:

First, sub-annual accreditation better aligns compensation and incentives with the value of the service provided by resources. More accurately aligning resource accreditation with resource performance creates better incentives for market participants to take actions and undertake investments to address resource adequacy risks. When, for example, resource adequacy risks occur primarily in one period, such as in the winter, accreditation and compensation directly reflecting winter performance from other times of the year will create more accurate incentives for market participants to take actions and make investments that contribute to winter resource adequacy. While PJM's current accreditation methodology relies on an hourly probabilistic model that accounts for certain risks throughout the year, resources are accredited using a single, annual ELCC value. This single value less accurately reflects resources' contributions to resource adequacy in each period compared to period-specific values. For example, tracking solar resources contribute to mitigating resource adequacy risks more in the summer rather than the winter, but the current annual ELCC values largely reflect their performance during winter high-risk hours because the majority of resource adequacy risk occurs in winter. A different winter and summer ELCC value would better align compensation and incentives for resource investment and retention with the marginal contributions of these decisions for resource adequacy.

Second, a sub-annual market can improve representation of certain resources with greater non-summer performance. At present, resource accreditation is limited to Capacity Injection Rights ("CIRs"), which are based on summer resource performance. In general, the capacity of thermal resources is greater in winter than summer because of differences in performance under ambient air conditions. A sub-annual market would simplify the process of accounting for these differences in summer and winter performance, allowing the higher capability of these resources in winter to be reflected in RPM market outcomes. PJM has an on-going task force evaluating these issues.[196]

Third, sub-annual accreditation may reduce year-to-year variability in resource accreditation. The current annual ELCC ratings show some year-to-year variability. **Table V-1** shows annual ELCC values across three Delivery Years. For example, tracking solar resources' ELCC fell from 14% in 2025/2026 to 8% in 2027/2028. This variability is driven largely by changes in the relative share of seasonal risk due to, for example, large load additions and changing load profiles. Variability in ELCCs has been identified as a concern of certain capacity suppliers.

A sub-annual market will reduce variability from changes in relative seasonal risk, likely diminishing ELCC year-to-year variability. Lower ELCC variability would reduce resource quantity risk and thus benefit market participants by simplifying arrangements to financially hedge PRM positions.

Fourth, a sub-annual market can improve the representation of resource adequacy within LDAs by improving the accuracy of resource accreditation for resources within LDAs. At present, ELCC values for all resources – inside and outside LDAs – reflect an RTO-level system and risk patterns, and not performance reflecting transmission constraints, system conditions and risk patterns specific to each LDA. Thus, the ELCC values used in calculations (reflecting RTO conditions) may differ from the actual ELCC values within the LDA if differences between RTO and LDA sub-annual risk profiles and system/resource conditions meaningfully affect ELCC estimates.[197]

A sub-annual market would mitigate differences between RTO and LDA ELCC values that reflect differences in risk across sub-periods. For example, differences between RTO and LDA ELCC values may arise because the RTO experiences large winter risks, while the LDA faces large summer risks. With an annual market, ELCC values in the LDA would largely reflect performance in the winter, rather than summer. However, with a sub-annual market, ELCC would more reliably reflect performance in the respective season.

---

[196] PJM, "Effective Load Carrying Capability Senior Task Force," available at https://www.pjm.com/committees-and-groups/task-forces/elccstf; PJM Effective Load Carrying Capability Senior Task Force, "Problem/Opportunity Statement: Capacity Accreditation Enhancements – Unit-Specific Performance," available at https://www.pjm.com/-/media/DotCom/committees-groups/task-forces/elccstf/postings/elcc-capacity-accreditation-methodology-problem-statement.pdf.

[197] PJM Effective Load Carrying Capability Senior Task Force, "Problem/Opportunity Statement: Capacity Market Enhancements – CETL," available at https://www.pjm.com/-/media/DotCom/committees-groups/task-forces/elccstf/postings/cetl-problem-statement.pdf.

Improved alignment of accredited UCAP within LDAs can lead to more accurate LDA pricing and improved investment signals, by more accurately representing the impact of deliverability constraints and the locational value of resources.

Table V-1: Evolution of PJM ELCC Values[198]
Delivery Years 2025/2026-2027/2028

Technology	DY 2025/26	DY 2026/27	DY 2027/28
4-Hr Battery Storage	59%	50%	58%
6-Hr Battery Storage	67%	58%	67%
8-Hr Battery Storage	68%	62%	70%
10-Hr Battery Storage	78%	72%	78%
Coal	84%	83%	83%
Demand Resource	76%	69%	92%
Diesel Utility	92%	91%	92%
Fixed-Tilt Solar	9%	8%	7%
Gas Combined Cycle	79%	74%	74%
Gas Combustion Turbine	62%	60%	61%
Gas Combustion Turbine Dual Fuel	79%	78%	77%
Hydro Intermittent	37%	38%	39%
Landfill Intermittent	54%	50%	48%
Nuclear	95%	95%	95%
Offshore Wind	60%	69%	67%
Oil-Fired Combustion Turbine	N/A	N/A	80%
Onshore Wind	35%	41%	41%
Steam	75%	73%	72%
Tracking Solar	14%	11%	8%
Waste to Energy Steam	N/A	N/A	83%

Fifth, a sub-annual market may increase resource supply by better aligning resource obligations with costs and risks. In the current annual market, differences in resource capability and performance across seasons can create asymmetric financial risks because a resource's expected performance and its financial obligation and risk with CP are not aligned. For example, for solar resources, the risk-reward tradeoff to accepting

[198] **Sources:** [A] PJM, "ELCC Class Ratings for the 2027/2028 Base Residual Auction," available at https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2027-28-bra-elcc-class-ratings.pdf. [B] PJM, "ELCC Class Ratings for the 2026/2027 Base Residual Auction," available at https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2026-27-bra-elcc-class-ratings.pdf. [C] PJM, "ELCC Class Ratings for the 2025/2026 Base Residual Auction," available at https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2025-2026-bra-elcc-class-ratings.pdf.

an annual capacity obligation may be skewed because most risk is currently in the winter season, when the marginal performance of solar resources is relatively poor (*e.g.*, with an ELCC = 6%).[199]

Current market rules allow resources facing these risks to combine their offers (in a certain month) with offers from other resources (in the remainder of the year) to form a "matched" offer. While this option provides an opportunity to mitigate these risks, transaction costs and barriers to finding "matches" may constrain the amount of supply willing to use this approach. For example, in the two most recent auctions, certain wind resources did not clear in either auction, in part due to lack of matching opportunities.

By better matching ELCCs with likely performance, a sub-annual market can better align capacity obligation risks with resource capabilities and mitigate the financial risks faced by resources. This approach is likely to be more effective at mitigating these risks than matching of sub-annual offers, and thus may increase liquidity and the quantity of resources willing to offer supply into the RPM.

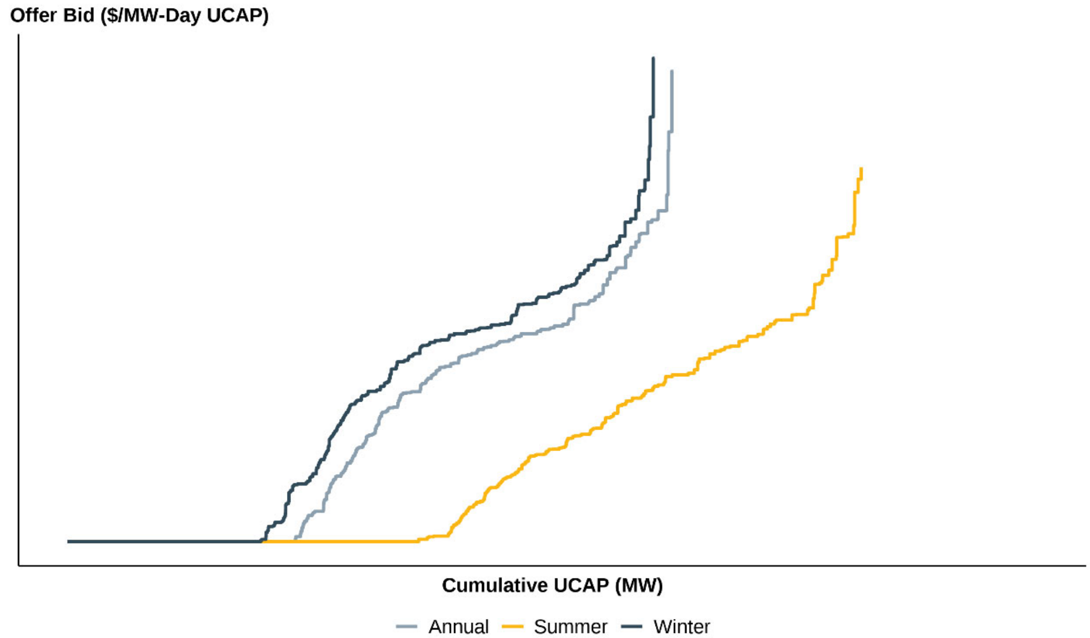
Sixth, with sub-period accreditation, market clearing reflects the aggregate performance of all capacity resources given their actual performance in each sub-period. In principle, potential differences in the performance of resources across sub-annual periods include:

- Forced outage rates
- Thermal performance under different ambient air conditions
- Capacity injection rights
- Intermittent and correlated risks

Given these considerations, resources' aggregate contributions to resource adequacy can vary between periods. At present, for example, the supply offer curves in **Figure V-2** reflect accredited UCAP of 150,698 MW in winter and 177,298 MW in summer. The different UCAP reflects some differences, particularly lower winter accreditation of gas-fire resources, but not all differences, such as thermal performance under different ambient air conditions.

[199] Error! Reference source not found.

Figure V-2: Illustrative Annual and Seasonal Supply Curves



3. Accounting for Sub-Annual Variation in Transmission System Performance

A sub-annual market can more accurately account for the deliverability of resource supplies between the RTO and transmission-constrained LDAs. Under current market rules, the amount of capacity that can be delivered to an LDA is defined by its CETL, which is measured based on summer operating conditions.[200] However, many factors that affect deliverability to a region vary across the year. The electrical capability of transmission lines can vary depending on temperature and other weather conditions and is generally greater in the winter than in the summer. Other system conditions can affect sub-period performance, including the coincident performance of resources within the constrained locality. PJM has an on-going task force evaluating these issues.[201]

With a sub-annual market, deliverability can be more accurately measured in each sub-period, which will lead to more accurate price signals and reliability outcomes for transmission-constraint localities. A sub-annual market can account for these higher ratings in winter, potentially relaxing zonal constraints in the market clearing and more efficiently allocating resources.

---

[200] PJM Effective Load Carrying Capability Senior Task Force, "Problem/Opportunity Statement: Capacity Market Enhancements – CETL," available at https://www.pjm.com/-/media/DotCom/committees-groups/task-forces/elccstf/postings/cetl-problem-statement.pdf.

[201] PJM, "Effective Load Carrying Capability Senior Task Force," available at https://www.pjm.com/committees-and-groups/task-forces/elccstf.

4. Accounting for Sub-Annual Variation in Resource Going Forward Costs

A sub-annual market allows resources to submit offers that reflect going forward costs specific to each sub-annual period. By accounting for going forward costs specific to each sub-annual period, market-clearing reflects costs that more accurately capture the true cost to resources of providing capacity. The sub-annual market can therefore result in a more cost-effective fleet of resources supporting resource adequacy in each sub-annual period, thus lowering costs.

In PJM's capacity market, the Avoidable Cost Rate ("ACR") represents the fixed costs that a resource would avoid if it were to retire or not operate for the Delivery Year, such as labor, taxes, insurance, on-going fixed O&M, and other overhead costs.[202] To determine the portion of these costs that should be recovered through capacity payments, PJM subtracts the expected net revenues that the resource earns through the energy and ancillary services markets (the "Net EAS Offset"). The resulting Net Avoidable Cost Rate ("Net ACR") reflects a resource's residual costs that need to be recovered through the capacity market.[203]

Elements of these going forward costs may vary across the year and could be avoided if the resource did not supply capacity for a portion of the year. For example:

- A resource may avoid certain fixed costs (*i.e.*, ACR) if it did not supply capacity for a portion of the year. These avoidable costs could be related to labor, materials and services.
- A resource's ACR may vary across the year due to costs that are incurred in some periods but not others. For example, resources may face certain costs in winter, such as winter fuel firming costs and weatherization actions, that would not be experienced in summer.[204]
- A resource's cost EAS offset will vary across the year for many reasons, including the expected locational marginal prices ("LMPs"), fuel costs and the timing and quantity of energy supplied. For example, the expected net revenues of intermittent sources depend on seasonal weather conditions, with solar PV resources earning higher expected net revenues in the summer compared to the winter, and the opposite being likely true for wind resources. Finally, natural gas-fired resources' expected net revenues in the winter depend on dual fuel capabilities and other factors affecting access to non-gas fuels.
- Differences in resource accreditation (*i.e.*, UCAP) cause offer prices – measured as costs *per unit of capacity* – to vary. For example, the offer price from a 100 MW ICAP resource with the same fixed cost in each period will be twice as large in a period when it receives a 40 MW UCAP rating as compared to a period when it has an 80 MW UCAP rating.

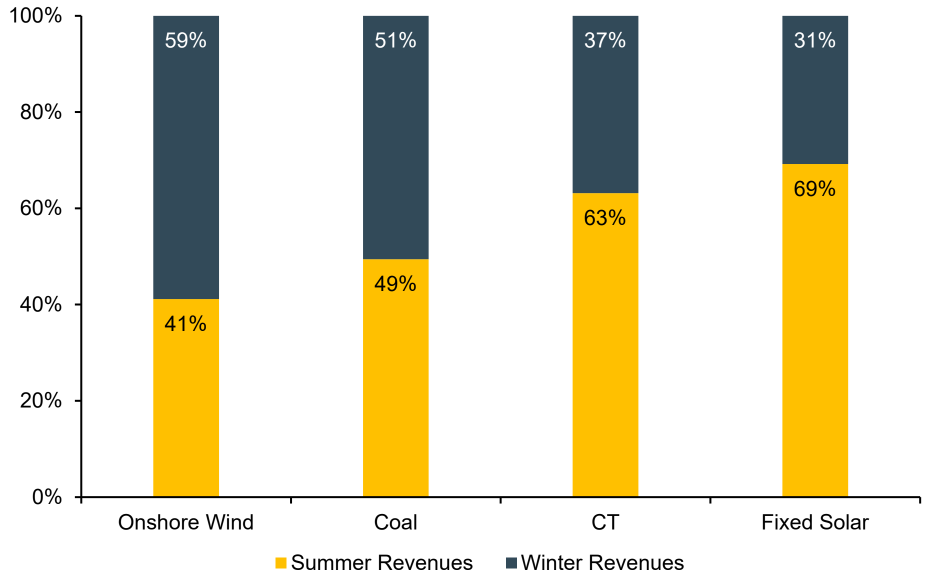
---

[202] PJM, Open Access Transmission Tariff, effective March 24, 2025, available at https://www.pjm.com/pjmfiles/directory/merged-tariffs/oatt.pdf, Attachment DD § 6.8. PJM Manual 18: PJM Capacity Market, p. 123.

[203] PJM Manual 18: PJM Capacity Market, p. 126.

[204] For a discussion of winter weatherization costs, *see* Schatzki, Todd, Joseph Cavicchi, and Phillip Ross, "Capacity Market Alternatives for a Decarbonized Grid: Prompt and Seasonal Markets," January 2024, available at https://www.analysisgroup.com/globalassets/insights/publishing/2024-capacity-market-alternatives-for-a-decarbonized.pdf, pp. 74-76.

Figure V-3: Share of Annual Net EAS Revenues by Season for Select Class Types[205]
Weighted Average Across Zones



Note: Weighted averages are calculated using zonal ICAP as weights.

5. Improving Price Signals and Cost Allocation

With a sub-annual market, market-clearing prices reflect adjustments to both demand and supply to more accurately capture sub-period value of capacity and costs of capacity resource supplies. The resulting market outcomes create price signals that better reflect the marginal value of UCAP in each sub-period.

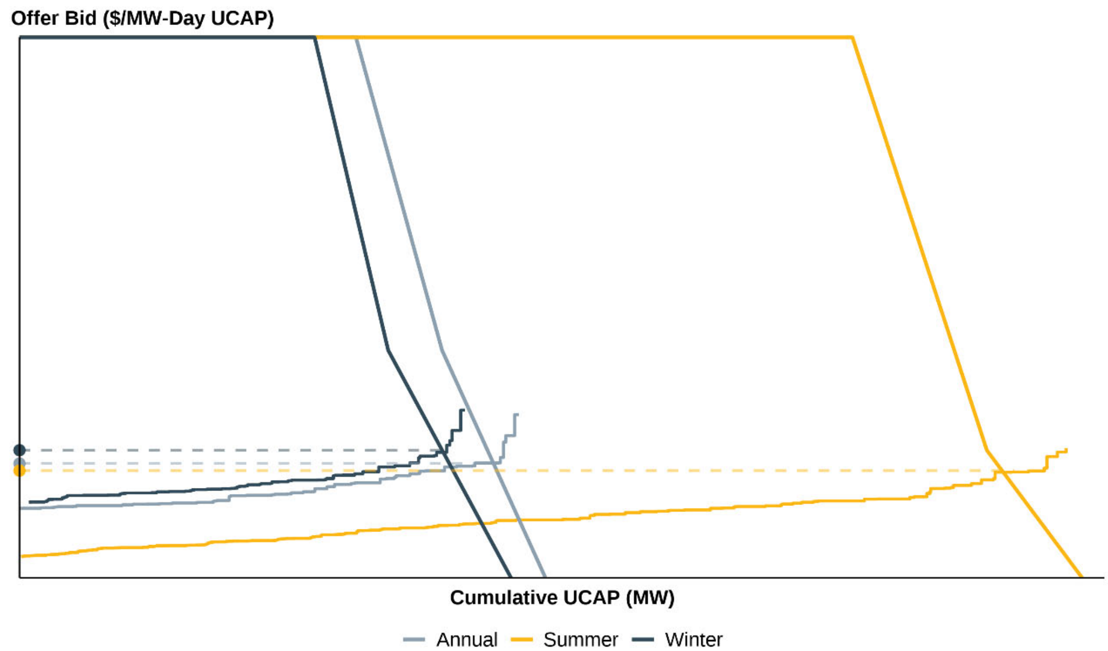
By creating differential price signals, the market can better allocate short-term UCAP procurement according to the value of marginal resources across sub-periods and can improve the efficiency of short-term resource decisions and long-term capital decisions, including both new investment and existing resource retention/retirement. Just as locational constraints provide price signals to incentivize where investments should occur and resources be retained, sub-annual price signals provide price signals to incentivize what types of resources should be developed and retained given their seasonal performance.

Figure V-4 illustrates such price signals, with higher prices/value of UCAP in the winter period compared to the summer period. This creates incentives for technologies that have greater relative UCAP in the winter than the summer, and for supply and investments in greater winter UCAP.

[205] **Source:** Hourly modeled net EAS data by technology type, provided by PJM.

By aligning capacity procurement with sub-annual reliability risk and capacity resource contributions, a sub-annual market can improve economic efficiency – that is, it can reduce total procurement costs for any given reliability target or achieve any given level of resource adequacy at the lowest cost.

Figure V-4: Illustrative Annual and Seasonal Demand and Supply Curves



6. Flexibly Adapting to Changes in Resource Adequacy Risk Across the Year

By accurately accounting for variation in features that affect resource adequacy across the year, a sub-annual market can flexibly adjust to changes in these features and evolving patterns of resource adequacy risk across the year. At present, for example, PJM's resource adequacy risk is largely in the winter, although the market is designed for summer peak loads. In some respects (*e.g.*, resource requirement, ELCCs), the current market accounts for shifts in risks, albeit through market specifications that reflect year-long averages. Yet, some parameters (*e.g.*, CETLs), reflect conditions in one season.

With a sub-annual market, the RPM can better adjust as loads, risks, resources in the fleet, and system capabilities evolve by capturing these effects individually in each period. For parameters reflecting only one season, a sub-annual market reduces the need to anticipate whether the system will face greater summer or winter reliability risk when determining such parameters.

B. Potential Costs of Sub-Annual Capacity Markets

A sub-annual market would involve some change in administrative costs for PJM and market participants, including one-time costs of developing and transitioning to the new system and potential changes in on-going costs. One-time costs would include the initial development of market rules and market procedures, requiring stakeholder and PJM resources, and development of market software, requiring PJM resources. The costs of on-going operation and participation in a sub-annual market could be more complex than an annual market but would not necessarily involve materially different procedures than the current market. To some extent, these costs would depend on the administrative and operational complexity of the new market, which, in turn, would depend on the design features that are ultimately implemented. Certain decisions could increase or decrease costs.

Aside from these transitional costs, the increased granularity provided by a sub-annual market generally offers an opportunity to improve market and reliability outcomes. As we discuss in **Section VI**, realizing these benefits depends on sound market design. While a well-designed sub-annual market can lead to improvements in market and reliability outcomes, not all sub-annual market designs will be welfare-improving. As we discuss below, some designs can lead to problems that offset the gains from better accounting of variation in the value and resource performance across the year. For example, excess granularity may provide little gain but lead to low pricing in some seasons and increased volatility.

In addition, the design of a sub-annual market can lead to various tradeoffs, which different systems and regions may value differently given particular circumstances. For example, some systems may constrain initial designs to promote market stability and ensure meaningful price signals in all seasons. All systems adopting sub-annual markets have taken such steps to some degree: ISO-NE is proposing a 50/50 split in LOLE risk between summer and winter; MISO has a 0.01 LOLE floor on seasonal risk in its four-season market; and NYISO collars the share, based on relative risk, of reference point prices at 35%/65%. These decisions, in part, reflect a recognition that market design can proceed incrementally, allowing the market to adapt to new rules, while maintaining the option to further refine after initial implementation.

C. Recommendation Regarding Sub-Annual Markets

On balance, we conclude that a sub-annual market would provide substantial benefits to the PJM region that far outweigh the limited costs. This recommendation reflects the benefits identified above as well as the results of the quantitative analysis reported in **Section VII**. It also reflects the flexibility of a sub-annual market to automatically adapt to evolving market conditions and improve the PJM's ability to achieve resource adequacy for the foreseeable future.

The potential benefits that the PJM market can realize from a sub-annual market depend on the design adopted. In the following **Section VI**, we discuss the various design options available to PJM, laying out the tradeoffs to design alternatives available to the region.

VI. Evaluation of Sub-Annual Design Options

The decision to adopt a sub-annual market will depend, in part, on market design as it affects the realization of potential sub-annual market benefits as well as other tradeoffs compared to an annual market. In this section of the report, we evaluate key market design decisions with these goals in mind. While this section evaluates sub-annual market design issues in some detail, it neither resolves all design issues nor arrives at a particular design proposal. Instead, the evaluation aims to provide information about the tradeoffs in key design issues useful for PJM and its market participants and stakeholders in evaluating the decision about whether to develop a sub-annual market and decisions about the particular market design. We presume that such decisions would be made in a stakeholder proceeding.

This section proceeds as follows. We start by discussing key issues in a sub-annual market structure, including auction structure, resource offer structure and the number of periods. Next, we discuss how demand curves would be formed under a sub-annual market and then discuss supply offers under a sub-annual market. Finally, we end by discussing cost allocation.

A. Market Structure

Under the current RPM framework, capacity resources are procured through *annual* auctions to meet *annual* capacity obligations on a daily basis. Demand in the auction is specified by an *annual* RA requirement that reflects probabilistic estimates of resources needed to meet the 1-in-10 LOLE requirement and a sloped demand curve that relates quantity of resources (in UCAP) to their value as LOLE risk declines. Supply offers reflect each resource's cost (as reflected by its ELCC resource accreditation) on an *annual* basis. The auction clears supply and demand, resulting in an *annual* capacity price.

In principle, there are many features of the capacity market that could be specified sub-annually: market-clearing and prices; resource supply and accreditation; capacity demand, etc.

Below, we generally consider market designs that assume sub-annual enhancement to all aspects of the capacity market but recognize that reforms could be limited to certain elements. In principle, reforms could be made selectively to recognize that there may be tradeoffs when adopting sub-annual enhancements. That is, certain market elements could remain annual and be modified to sub-annual features at a future date.

1. Auction Structure

At present, the RPM procures capacity through a series of sequential, independent annual auctions. Resource owners are required to offer capacity into each auction (unless excused by PJM). If an existing resource does not clear an auction, it has the option to suspend participation in energy markets temporarily (or permanently) and retains the option to offer capacity at the next auction.

The adoption of a sub-annual capacity market requires the consideration of two features of capacity auction market structures:

- ***Independent versus co-optimized auctions.*** Sub-annual products can be cleared in independent auctions or within a single auction that clears capacity optimally across multiple periods ("co-optimized"). With *independent* auctions, offers for sub-annual products are cleared independently in each sub-annual auction, without consideration for the outcomes in other periods. In a *co-optimized* auction structure, offers for sub-annual products are cleared jointly within a single auction that optimizes welfare across sub-periods. Currently, all RTOs that have implemented or proposed a sub-annual capacity market design (*i.e.*, MISO, ISO-NE and NYISO) operate (or have proposed to operate) prompt markets (not forward, like PJM) that clear sub-annual products independently.
- ***Simultaneous versus sequential auctions***. The sub-annual products can be cleared simultaneously (as part of the same auction) or sequentially. In a *simultaneous* structure, demand and supply for multiple sub-

annual periods are cleared in auction(s) occurring at one point in time. MISO, for example, operates a simultaneous structure, with offers for each of the four seasons clearing in a single auction ahead of the Delivery Year. In a *sequential* structure, sub-annual auctions are cleared sequentially in advance of the capability period, one after the other. For example, NYISO operates monthly, sequential auctions, and ISO-NE has proposed a sequential bi-annual structure.

Given these options, three different auction approaches are available:

- **Co-optimized, Simultaneous.** Co-optimization implies simultaneous clearing of multiple periods.
- **Independent, Sequential.** Independent auctions are run sequentially, one after the other.
- **Independent, Simultaneous.** Independent auctions for multiple sub-periods are run at one time, with no or limited co-optimization across sub-periods.

An overview of these approaches follows.

a. Co-optimized auction

Co-optimization can produce efficiency gains by optimizing resource procurement over multiple periods rather than optimally clearing periods individually. In principle, demand, supply and price caps can all be better optimized by accounting for market outcomes across periods in an integrated, optimized manner. This approach is similar to the manner in which the day-ahead energy market commits resources given fixed start-up costs and other operating constraints (*e.g.*, minimum run times).

*With **demand***, in theory, a co-optimized market could internalize resource adequacy modelling – which determines demand curves – within the auction clearing software. At present, the specification of demand curves and the clearing of demand and supply occur in two separate steps, with demand curves specified first and the market then clearing supply offers against these demand curves. Inefficiencies may emerge if there are inconsistencies between the mix of resources clearing the market and the mix of resources assumed when calculating demand curves.[206] However, integrating these steps is very technically challenging and the magnitude of efficiency gains is uncertain. Thus, we do not further consider demand optimization.

*With **supply***, resource cost recovery is complicated under a sub-annual market for two reasons. *First*, within a sub-annual market, a resource may not clear the market in all periods. *Second*, some resources may incur annual fixed costs that cannot be avoided if clearing in some periods but not clearing in others. In contrast to an annual market in which resources either clear or do not for the entire year, with a sub-annual market, a long-run equilibrium outcome may include retention of units that clear in some periods but not in others.[207] To sustain the

[206] Differences may emerge because of the entry of new resources and existing resources that do not clear. With optimization, the market-clearing and resource adequacy would reflect an internally consistent set of resources. In principle, all resource adequacy parameters, including resource requirements and ELCCs, could be specified within market-clearing.

[207] This conclusion relies on the assumption that seasonality in resource adequacy risks and resource capabilities are sufficiently persistent over long periods of time that they are a feature of the resulting market equilibrium. With this outcome, a resource owner, looking forward, could see a sustained gap between its costs and revenues. Absent such seasonality, the question becomes whether

equilibrium, these resources should recover their costs when cleared in the auction. In principle, optimization can achieve this outcome, which can allow for greater productive efficiency, by selecting the least-cost set of resources, and full cost recovery for all resources clearing in any period. We discuss these issues further in **Section VI.A.2**.

With co-optimization, the market can account for costs that can be avoided if not supplying in a given period ("avoidable period costs") and "fixed annual costs" than cannot be avoided even if not supplying in a given period length (*e.g.*, within a month, six-month period or year).[208] For example, PJM's 2023 proposal included both seasonal (*i.e.*, sub-annual period) components (which could be avoided if the resource did not clear in that period) and an annual component (which could not be avoided so long as the resource cleared in at least one period).[209] The exact nature of these costs will depend on the length of the period and the specific resource circumstances. For example, over a six-month period, a resource might avoid certain costs (*e.g.*, flexible staffing and services, fuel-cost firming costs, certain materials) while not avoiding others (*e.g.*, core staffing, long-term maintenance, and some administrative costs). This issue is discussed in further detail in the preceding **Section V.A.4**.

*Regarding **price caps***, co-optimization provides a means to impose an aggregate cap on prices across seasons, rather than only price caps for each sub-period. This issue is discussed in further detail in **Section VI.B.3**.

Co-optimization of supply and price caps could increase the cost and extend the timing of development of a sub-annual market, given the need to, among other things, resolve analytical optimization problems and develop new software systems. Given these costs and the technical complications, both ISO-NE and MISO have deferred consideration of co-optimization. As a result, there is no roadmap to follow, or experience to benefit from based on other regions. These decisions, in part, reflect the tradeoffs between pursuing co-optimization and pursuing other market initiatives given limited internal resources and stakeholder attention. That said, in 2023 as part of the CIFP, PJM proposed a two-season market that co-optimized the selection of resources across seasons given both fixed annual and avoidable seasonal costs. Thus, PJM has evaluated market design issues required to implement a co-optimized auction.

---

the line between avoidable versus non-avoidable costs meaningfully changes when going from an annual to a sub-annual market. For example, if avoidable costs do not meaningfully change between a six-month and 12-month period, then a sub-annual market may not meaningfully change revenue recovery. From this perspective, the current annual market is an arbitrary choice between sub-annual, annual and multi-annual procurement constructs.

[208] To address the avoidable/non-avoidable nature of resource costs, MISO at one time considered an approach in which resources would offer supply in sub-period "blocks," reflecting combinations of sub-period supply. MISO, "Seasonal PRA Co-optimization and Multi-Season Block Participation Model," Resource Adequacy Subcommittee Workshop, RASC-2019-8, June 5, 2023, available at https://cdn.misoenergy.org/20230604%20PRA%20Workshop%20Multi%20Season%20Participation%20Model%20Presentation629145.pdf. We do not evaluate this approach, as it may inadvertently constrain supply because blocks offered by market participants would likely reflect sub-optimal and constrained assessments of how their resources' operations and costs. Allowing annual and sub-annual price offers better captures the underlying resource constraints and thus would lead to more efficient outcomes.

[209] PJM, "Capacity Market Reform: PJM's Proposal," RASTF-CIFP, June 14, 2023, available at https://www.pjm.com/-/media/DotCom/committees-groups/cifp-ra/2023/20230614/20230614-item-02---pjm-cifp-stage-3-proposal.pdf, p. 27.

b. Independent sequential auction

With independent auctions, auctions clear in sequence, with each auction achieving efficient outcomes for that period. This approach is analogous to the operation of existing ISO/RTO energy markets, in which the market is cleared one-day ahead although, in principle, efficiencies could be achieved by market clearing over multi-day horizons given resources with operational constraints, such as long start-up times and limited energy.[210] As in these cases, an important question is the balance of efficiency gains from the adoption of more complex optimization and the costs in terms of market development and increased market complexity.

In principle, compared to co-optimization, independent auctions could result in less efficient resource allocations, to the extent that co-optimization leads to meaningful short-term and long-term changes in resource decisions to continue operations and participate in the energy market (including entry, exit and mothballing). These differences would only reflect marginal resources that might clear the auction with co-optimization but not clear with sequential and independent (and vice versa), as most resources would clear and operate in the markets in all periods under either approach. While differences in the mix of resources could emerge, they would not be expected to affect the aggregate supply of resources clearing and the aggregate revenues to suppliers, which could be higher or lower than with a co-optimized auction. That is, any inefficiency would be expected to result in a less cost-effective mix of resources, rather than necessarily affecting the overall supply of resources.

Independent auctions may also limit options for developing appropriate locational-LDA price signals when the pattern of risks across periods differ between the RTO and LDAs. We discuss this further in **Section VI.B.4**.

Independent, sequential auctions are comparatively easy to implement and achieve many of the efficiencies offered by sub-annual markets. Independent clearing of sub-annual periods is more straightforward to implement as it would involve processes and auction clearing algorithms similar to the current clearing process in PJM. In this sense, sequential auctions may be simpler and more transparent than a co-optimized auction, even if that comes at some cost of productive efficiency.

c. Independent, simultaneous auction

An independent, simultaneous auction clears multiple independent auctions at one point in time. MISO, for example, takes this approach, clearing four seasonal auctions at the same time each year. In many respects, an independent, simultaneous auction has similar properties to an independent, sequential auction approach. However, there are several potentially important differences.

First, with a simultaneous auction, an annual price cap could be imposed on the outcomes of the independent, sub-period auctions. Absent co-optimization, the annual price cap could be imposed *after* clearing the sub-period auctions. As we discuss further in **Section VI.B.3**, MISO has taken this approach.

Second, sequential clearing of independent auctions reduces uncertainty for suppliers compared to simultaneously clearing multiple independent auctions at one time. Sequential auctions reduce uncertainty by allowing resource

[210] Similar issues arise with the horizons considered when making real-time resource commitments.

owners to adjust offers and operational decisions based on the most recent information about costs, resource operational status and market conditions. The impact of these uncertainties is greater in a prompt auction, such as the NYISO ICAP market, as auctions occur shortly before the delivery period. In a forward auction, such as PJM's current design, these differences may be less important given the smaller difference between the timing of a sequential or simultaneous auction relative to the delivery period.

For example, in NYISO's monthly, sequential auctions, resources are aware of their operational status (*e.g.*, whether they are experiencing a forced outage) and previous auction price outcomes (which may affect temporary shutdowns or permanent deactivation decisions) when submitting offers for the next auction. With sequential clearing, market participants avoid unnecessary capacity commitments that could otherwise be deferred to a future date if the auctions were run sequentially. This reduces delivery risk as resources may experience unexpected plant outages that require the market participant to procure replacement supply.

d. Comparison of auction structure approaches

The choice of auction structure for a sub-annual market entails various tradeoffs. **Table VI-1** Table VI-1summarizes these tradeoffs at a higher level. At a high level, the choice among auction structure revolves around several tradeoffs:

- A co-optimized auction offers greater economic efficiency than independent auctions (sequential or simultaneous);
- The scope and magnitude of potential efficiency gains from optimization is uncertain. In practice, much of the gains from a sub-annual market are likely achieved without co-optimization. These are empirical questions that will depend on, among other things: whether resources under-recover when clearing in a fraction of sub-annual periods, the extent to which modest "under-recovery" meaningfully affects resource decisions given the prevalence of other factors (particularly option values). Independent auctions may also reduce options to develop appropriate pricing in LDAs with risk patterns that differ from the RTO;
- Independent auctions (sequential or simultaneous) may be less costly and time consuming to implement, and may be simpler and more transparent to market participants. Given tradeoffs among competing priorities for market enhancement, implementing independent auctions may allow PJM to better prioritize and sequence market enhancement initiatives. Moreover, if adopting independent auctions, PJM retains the option to pursue co-optimization at a later date, and experience gained with the operation of independent auctions may inform implementation of co-optimization enhancements; and
- Placement of sub-annual reforms within a broader sequencing of market enhancements.

In principle, the tradeoffs between auction structures also depend on other RPM features.

Table VI-1: Summary of Auction Structure Tradeoffs

	Co-Optimized (Simultaneous)	Independent, Sequential	Independent, Simultaneous
Sub-Annual Benefits and Efficiencies	Achieves primary sub-annual benefits and efficiencies	Achieves primary sub-annual benefits and efficiencies	Achieves primary sub-annual benefits and efficiencies
Resource Going Forward Costs	Greater productive efficiency Can better account for and achieve efficiencies associated with fixed/variable avoidable costs	Less productive efficiency Cannot account for differences in fixed/variable avoidable costs	Less productive efficiency Cannot account for differences in fixed/variable avoidable costs
Price Caps	Can impose annual price cap within auction clearing	Cannot readily impose annual price cap	Can impose annual price cap after period market-clearing
Implementation Ease, Cost, Simplicity, Transparency	Greater cost/complexity of implementation	Comparatively easy/lower cost to implement Simpler, more transparent	Comparatively easy/lower cost to implement Simpler, more transparent
Market Information (Most Relevant with Prompt Auction)	Less information and more uncertainty to suppliers (*e.g.*, delivery risk, operational decisions)	Better information and reduced uncertainty to suppliers (*e.g.*, delivery risk, operational decisions)	Less information and more uncertainty to suppliers (*e.g.*, delivery risk, operational decisions)

In particular, the choice among auction structures will depend on whether the market has a forward or prompt market design. The RPM currently is a *forward market*, with the primary auction in principle occurring three years ahead of the delivery period, while a *prompt* market clears capacity shortly before the delivery period. While outside of the scope of our report, we note that, independent of sub-annual markets, there are important differences between forward and prompt markets that affect their performance in procuring capacity to meet RA objectives.[211] The choice between prompt and forward markets introduces multiple tradeoffs related to demand forecast accuracy and risk, capacity resource supply certainty, capacity resource delivery risk, retirement notification, alignment of market with operational decisions affecting resource performance and capability,[212]

211 Schatzki, Todd, Joseph Cavicchi, Phillip Ross, "Capacity Market Alternatives for a Decarbonized Grid: Prompt and Seasonal Markets," prepared for ISO New England, January 2024, available at https://www.analysisgroup.com/globalassets/insights/publishing/2024-capacity-market-alternatives-for-a-decarbonized.pdf.

212 For example, a prompt market would lower the cost to gas-only fired resources of taking steps to firm-up their fuel supplies as it 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

neutral technology market incentives, and market simplicity and cost. Over time, the advantages of a forward market have diminished as the original rationale for a forward market (*i.e.*, coordination and financing of new resources with three-year development periods) is less relevant. Thus, in the long-run, it may be prudent for PJM to consider a prompt market design, although the current moment may not be an optimal time of the transition to a prompt market given the region's current need for new investment and the market uncertainty that can delay investment that can accompany market reforms.

That said, to the extent that PJM chooses to pursue a prompt market design in the future, this could affect decisions about sub-annual auction structure. In particular, if PJM were to move to a prompt market, this would increase the advantages of independent, sequential auctions compared to simultaneous auctions. Specifically, the greater supplier certainty provided with sequential auctions is more valuable under a prompt than a forward market. Information on market conditions (*e.g.*, whether the resource is operational) becomes more accurate the closer the auction occurs to the Delivery Year. Thus, the opportunity afforded by adopting a sequential market structure is more valuable when deployed in a prompt market, as compared to a forward market. Within a forward market, the change in information between sub-periods would be relatively limited, as substantial uncertainty about future market conditions – given the long period of time until the delivery period – would remain.

2. Resource Offers and Offer Structure

An important issue in the design of a sub-annual market is the way in which resource costs are represented and accounted for in market clearing. The change from an annual to sub-annual market would not cause any change to a resource's total avoidable costs over the year. However, the structure of these costs has implications for offer structure and offer mitigation. In particular, some resources may incur both fixed annual costs, incurred if supplying in any one season, and avoidable period costs that can be avoided if not supplying in one period. The treatment of resource cost structure differs between co-optimized and independent auctions, as summarized in **Table VI-2**. Below, we discuss these differences in greater detail.

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.

Table VI-2: Summary of Offer Structure and Mitigation for Co-Optimized and Independent Auctions

	Co-optimized Auction	Independent Auction
Offer Structure	Can separately account for annual fixed costs and avoidable period costs Offer clearing requires compensation for annual and period components	Cannot account for annual fixed costs Offer clearing may not require that compensation covers all annual and period costs
Offer Mitigation	Offer review and mitigation will need to distinguish annual costs from avoidable period costs	Offer review and mitigation issues: • Does owner have discretion in setting offer prices, in both: (1) periods when it expects to clear and (2) periods when it recovers its costs? • Will offers be required to follow uniform offer price rules and assumptions?

As an initial matter, it is important to understand the nature of resource costs that affect sub-annual market outcomes. **Table VI-3** illustrates these costs for three resources in a two-season, winter-summer market. The table also shows each resource's costs when supplying in either summer or winter, or in both seasons.

Resource 1, for example, incurs a fixed annual cost of $70/MW-day for all 365 days and avoidable period cost of $30/MW-day if operating in summer and $50/MW-day in winter. Avoidable costs are only incurred during the relevant season (for ~182.5 days) if operating, while annual costs are incurred over all 365 days of the year if operating in either winter or summer. Given these costs, Resource 1's costs are $110/MW-day, $85/MW-day and $95/MW-day when operating in both seasons, summer only and winter only, respectively, on a 365-day basis.

Table VI-3: Illustrative Resource Cost Structures

Cost Structure ($/MW-day)		Resource 1	Resource 2	Resource 3
Fixed Annual Cost (365 days)	A	$70	$90	$20
Avoidable Summer Cost (182.5 days)	B	$30	$10	$160
Avoidable Winter Cost (182.5 days)	C	$50	$20	$120
Annual Cost Contingent on Market Clearing ($/MW-day)				
Both Seasons	= A + (B + C)/2	$110	$105	$160
Summer Only	= A + B/2	$85	$95	$100
Winter Only	= A + C/2	$95	$100	$85

a. Co-optimized market

A co-optimized auction can be designed to account for both annual fixed and avoidable period costs by allowing resources to separately specify their fixed annual costs and avoidable period costs when offering capacity resources. Having offered these price terms, the auction can ensure that resources would, at minimum, be compensated for both fixed and avoidable offer components.[213] This structure is similar to current energy markets, in which resource offers include energy offers and start-up costs (along with other offer components), and compensation, at minimum, covers both components. In the energy market, if total revenues are less than total energy offers plus startup costs, the deficit is typically made up through uplift to individual resources to ensure they are whole across the operating day.

With an optimized market, offers would reflect resources' underlying costs. Returning to **Table VI-3**, Resource 1's offers would reflect its underlying costs – that is, an annual offer of $70/MW-day, summer offer of $30/MW-day and winter offer of $50/MW-day. When clearing the market, auction software would consider Resource 1's costs contingent on different clearing outcomes – that is, $110/MW-day if clearing in both seasons, $85/MW-day if clearing in summer only and $95/MW-day if clearing in winter only. This structure, as with the current market, creates incentives for market participants' offers to be consistent with their resources' underlying costs, and there is no need for participants to strategize about setting offers given different possible clearing outcomes.

An optimized market accounting for resource fixed annual and avoidable period costs would (1) achieve efficient market outcomes with respect to resource's true costs and (2) provide compensation to resources that would, at minimum, cover all costs for resources providing any supplies.

Because the structure of offer prices would be consistent with resource costs, reasonable market mitigation rules would require that offer prices reflect each resource's annual fixed and avoidable period costs. However, mitigation rules would need to be developed to distinguish annual fixed costs from avoidable period costs. In principle, these rules would need to reflect multiple factors, such as which types of costs are avoidable in a period (*e.g.*, certain labor, materials and services costs, certain maintenance costs, winter fuel firming and operational security costs, etc.)[214] and which are incurred annually regardless of partial clearing across periods; and the extent to which categorization would depend on the resource's particular circumstances (*e.g.*, what kind of discretion would market participants have in distinguishing fixed annual and avoidable period costs).

---

[213] We have not evaluated the precise mechanism by which compensation set to cover costs. If shadow prices on individual resource constraints are not sufficient to cover all costs, including fixed annual and avoidable period costs, then uplift may be required. In practice, this may be an empirical issue.

[214] For example, for resources with maintenance contracts in which costs and maintenance activities are specified formulaically, the avoided costs associated with not operating for a particular period could be estimated.

b. Independent auctions

With independent auctions, only one offer price is submitted for each sub-period. Thus, the structure of offers, with only one price, does not directly correspond to the structure of resource costs, which can reflect both annual fixed and avoidable period costs.

Independent auctions with one offer component may not achieve efficient market outcomes in which welfare is maximized and costs are minimized for a given level of reliability. In **Table VI-3**, note that the least-cost resource depends on whether each resource offers for both seasons, summer only or winter only – that is Resource 2 is least cost if supplying in both seasons, Resource 1 is least cost if supplying only in summer and Resource 3 is least cost if supplying only in winter. However, independent auctions would not necessarily distinguish between these resource costs. While multiple considerations affect market mitigation rules with independent auctions, consider a rule that allows resources to offer at their "average, all-in" cost, such that costs are recovered if supplying in both seasons. For the resources in **Table VI-3,** the average, all-in offer prices would correspond to "Both Seasons" costs.[215] In this case, Resource 2 would be the lowest cost offer, at $105/MW-day, even though Resource 1 and Resource 3 would be preferred if only needed to supply in either winter or summer. If Resource 2 cleared with obligations for either winter or summer only, the loss of efficiency would be $10/MW-day in summer and $15/MW-day in winter.[216]

Compensation to resource owners could also be insufficient to cover owner costs when clearing in only one season.[217] Returning to **Table VI-3** and the assumption that offers reflect average, all-in costs, Resource 1 with an offer of $110/MW-day would earn $55/MW-day if clearing in only one season and being the price-setting offer, which would be below its costs of $85/MW-day and $95/MW-day if clearing summer and winter, respectively. If Resource 1 were not the price-setting offer, compensation would be higher and loss would be smaller.

In principle, under-recovery could cause marginal existing resources to earn lower revenues and thus lead to premature retirement. That said, this outcome would not necessarily meaningfully distort long-run prices, because, with entry and exit, prices in each sub-period would still reflect the long-run cost of capacity, even if the compensation earned by resources toward at the end of their operations is marginally lower.

These issues raise several questions.

---

[215] Average, all-in costs could be adjusted to account for seasonal differences in avoidable costs. For example, Resource 2's offers could be $100/MW-day in summer and $110/MW-day in winter to account for the difference in avoidable costs. For simplicity, we do not consider such offers.

[216] In summer, the loss of efficiency would be the difference between summer only costs of Resource 1 and Resource 2 (= $85/MW-day – $95/MW-day) and, in winter, the loss of efficiency would be the difference between winter only costs of Resource 2 and Resource 3 (= $85/MW-day – $100/MW-day).

[217] In principle, simultaneous independent auctions could provide owns with sufficient compensation to cover costs if partially clearing through uplift. However, given the adverse consequences of uplift for price discovery, a co-optimized auction would better accommodate the desire to cover resource costs.

First, would market participants have offer price flexibility to account for the risk that their resource clears in some but not all periods? For example, could owners set offer prices so that they can recover all costs if clearing in one season but not others? MISO's four-season, independent auctions allow owners to bid and recover full annual costs in one season. While ensuring the resources can cover their full costs, under this structure, it is also possible for resources to clear at prices equal to four times their annual costs, if clearing in all four seasons. As we discuss below, an annual cap mechanism, as adopted in MISO, can mitigate this risk, although such caps can raise complications.

From the resource owner's standpoint, offer price flexibility creates a tradeoff between higher compensation if the resource clears and a greater risk that the resource does not clear due to the higher offer prices. In addition, a higher offer price in particular periods might increase the likelihood that a resource recovers its costs, but it could also lead to an outcome in which compensation exceeds total costs if the resource clears in multiple periods. For Resource 1 in **Table VI-3**, offers at $85/MW-day in summer and $95/MW-day in winter would ensure that it recovers all costs if clearing in only winter or summer. However, if the resource clears in both seasons, it would earn at least $180/MW-day across the year, greater than its annual costs of $110/MW-day. In addition, from the owner's standpoint, the higher offer prices may decrease the likelihood that the resource clears in either season, which would lower the owner's compensation.

From a market standpoint, offer price flexibility raises several issues. One issue is that prices across seasons could be higher than they otherwise would be under an efficient (optimized) market. Such an outcome could occur if, for example, many resources offer at prices designed to recover all costs in one period, and the market clears at many such offers across different periods. An annual cap mechanism might mitigate such prices, but would not necessarily result in efficient pricing. A second issue is that the offer price flexibility could lead to disorderly market clearing if owners submit offers reflecting different strategies. For example, if some resource offer prices are set at average, all-in prices, while others are designed to recover all costs in one period, some resources submitting the higher prices might not clear, even though they may have lower costs than other resources offering at average, all-in costs.

Second, in terms of long-run market impact, outcomes may not meaningfully differ between optimized and independent auctions. Several considerations are relevant to this issue.

Within the fleet, partial clearing of resources with large fixed annual costs, in which a resource clears in some but not all periods, would occur for at most a small fraction of resources.[218] In general, most resources will clear in both seasons. Any under-recovery would occur at the margin, affecting a limited set of older resources at the end of their operational life. Moreover, the extent of under-recovery may be modest and many resources may fully recover their costs even if not clearing in all periods. We discuss these issues further in our quantitative analysis in **Section VII**, which provides estimates of recovered costs.

[218] Resources with low fixed annual costs and high avoidable period costs, such as demand resources, are more likely to clear in some but not all seasons, although such an outcome is unlikely to lead to any reduced efficiency or under-compensation relative to costs. In addition, existing resources that clear only a portion of their capacity also face a corresponding risk of under-recovery.

While independent auctions may partially undercompensate certain resources, the impact on resource retirement decisions is uncertain. In practice, resource owners make retirement decisions based on longer-term financial analyses in which trends in and forecast of capacity revenues (reflecting the likelihood of clearing) are one of many considerations. Thus, sustained under-compensation could affect such end-of-life decisions. This impact, however, at most would be expected to affect the timing of resource exit, potentially occurring earlier than it might otherwise occur. Moreover, other factors can have more salient effects on these decisions. *First*, because retirement is to some extent irreversible, generation plants represent real options.[219] While the capacity market is intended to provide the "missing money," it may be optimal for owners to continue operations if the resource under-recovers if partially clears or does not clear the capacity market at all. Thus, if real option values are large, modest changes in RPM compensation may not meaningfully affect asset retention decisions. *Second*, retirement decisions are often prompted by the need to make new capital investments to overhaul, upgrade or repair equipment to continue operations. Owners may have limited flexibility to delay these decisions, particularly when new investment is needed to replace failed equipment. If future returns are limited, then the investment may not be warranted. Modest changes in RPM revenues for older plants may not affect the economic tradeoffs in making such investments.

Therefore, if adopting independent auctions, there are some clear tradeoffs between approaches to offer structure and mitigation. One option is to mitigate offers using a uniform approach, such as requiring offers at average, all-in costs. This approach retains orderly market clearing with some potential for under-recovery. The other approach is to give market participants flexibility in designing offers, such that offers are designed – in the owner's estimation – to increase the likelihood of recovering costs. Between these two approaches, we recommend the former given the considerations outlined above. In particular, the risk of disorderly market clearing that could occur if resource offers reflect different strategies could result in inefficient market-clearing. By comparison, we view the gains in terms of cost recovery to be modest.

Between optimized and independent auctions, optimized auctions can achieve more efficient outcomes and compensate owners for full resource costs (along with providing other benefits, such as more flexible price caps). While independent auctions do not achieve the same efficiencies, they are nonetheless a reasonable choice of market design, in large part because the gains in efficiency may be modest compared to the overall efficiency gains from moving to a sub-annual market.

In this regard, we note that all current capacity markets use independent auctions. In particular, NYISO has operated monthly independent auctions since its inception without introducing complicated offer mitigation. MISO also operates a four-season independent auction, although flexible offer mitigation has required annual caps to avoid overcompensation. In fact, PJM currently operates an independent auction on an annual basis that provides no compensation to resources that do not clear. From a multi-year perspective, such an approach could be viewed as less efficient than a market taking a longer term view of efficiency and compensation. While seasonality in market conditions provides an economic rationale for the year as an efficient term over which to provide

[219] Real options could reflect uncertainty about energy or capacity market revenues, as well as other unexpected contingencies affecting revenue opportunities.

economic compensation,[220] it is important to appreciate that other designs can recognize intra-year operational flexibility that cannot be realized within an annual, optimized auction.[221]

3. Number of Periods

In principle, a sub-annual market can be developed with varying temporal granularity, such as seasonal, monthly or hourly. In particular, there are multiple seasonal approaches, including two seasons with summer and winter, three seasons with summer, winter, and shoulder seasons, and four seasons with summer, winter, spring, and fall. A sub-annual market could also differ along different temporal dimensions, such as day/night, peak/non-peak, etc.

The tradeoff between the benefits and the greater cost and complication provided by greater granularity is the fundamental issue in evaluating market granularity. Granularity may also introduce unintended consequences, which is the case for the capacity market. We discuss these issues, in turn, below.

a. Tradeoffs in number of periods

As with any commodity market, granularity is valuable when it usefully distinguishes products to account for differences in value and/or cost. In this context, all else equal, increased granularity is beneficial because it can account for relevant differences in the value of capacity and resources' ability to deliver resource adequacy contributions in different periods. These benefits are largest when two things are true. *First*, when there are *meaningful* differences in capacity market supply and demand between sub-periods. If there are no meaningful differences and resource outcomes are the same across sub-periods, then the increased granularity leads to no meaningful differences in outcomes. *Second*, when there is meaningful risk to be mitigated. Differences that are accounted for in periods without meaningful risk will lead to no meaningful changes in resource outcomes or risk mitigation.

Several other issues arise when considering the number of periods. In particular, periods with low risk will tend to result in low prices and relatively lower cleared quantities.

Low prices could have unintended consequences. *First*, low prices may fail to capture all value provided by capacity resources. For example, capacity resources operating under capacity obligations may provide other reliability benefits related to scheduling and operating day must-offer requirements.[222] *Second*, low prices may be insufficient to cover the expected costs (risk and opportunity costs) of CP obligations. If this occurs, capacity suppliers would face net expected costs, which may affect their willingness to supply and may prompt efforts to avoid taking on capacity obligations, which could lead to reliability problems and potentially the exit of resources.

---

[220] While partial clearing is most likely to occur with older, less efficient resources, because of seasonal differences in market conditions, a long-run equilibrium could include resources that supply capacity in some seasons and not others for a multi-year period.

[221] For example, a prompt, seasonal market using sequential auctions can provide incentives to resources reflecting information about on-going market conditions, rather than annual market that would reflect less frequent information.

[222] NYISO, "Winter Reliability Capacity Enhancements: Analysis of Seasonal Capacity Accreditation Factors," August 19, 2025, available at https://www.nyiso.com/documents/20142/53269544/2025%20Winter%20Reliability%20-%20August%2019%20ICAPWG_CAF%20Analysis.pdf/c91e2f6c-cfe1-5e6f-b2f7-d35870f8cb81, pp. 6-7.

While there are options to mitigate these effects (*e.g.*, floors on seasonal risk or prices), these options are not without cost. *Third,* low prices may contribute to price volatility. For this reason, both ISO-NE and NYISO have placed guardrails around seasonal risk, which can provide market stability, particularly in the initial phases of a sub-annual market.

Periods with low risk may also adversely affect marginal resources' ability to fully recover their costs. In particular, with an independent auction (sequential or simultaneous), periods with low risk may clear fewer resources than periods of high-risk periods, which increase the number of resources that partially clear and/or increase the number of periods in which such resources do not clear. The extent to which low-risk periods compound this issue is an empirical question. Other factors may mitigate this effect. For example, if costs are fully or largely recovered in periods of high-risk with high price, then a resource's failure to earn (lower) prices in low-risk periods may not adversely affect cost recovery. Nonetheless, as the number of sub-periods increases, the risk that suppliers clear in only a fraction of auctions could grow, particularly if period definition disaggregates the capacity year into many periods with minimal or no RA risk. In this regard, note that, while the NYISO ICAP market has monthly spot auctions, the market specifies only summer and winter parameters. Thus, the market operates six summer auctions and six winter auctions, where both auctions reflect periods of operational risk and thus meaningful prices.

Design decisions for all existing sub-annual markets reflects a concern for setting risk too low in certain periods. MISO's four-season market, for example, sets a minimum LOLE risk floor of 10% on each season, irrespective of the result of risk modeling. NYISO sets a floor of 35% on the portion of annual gross and net CONE that can be assigned to each season in its two-season market, where this assignment of gross/net CONE informs the reference price (similar to Net CONE) for each seasonal demand curve. These decisions reflect, among other things, a concern about the consequences of outcomes in periods with low risk.

Given these considerations, we consider several of the key proposals raised.

- **Two-season market.** A two-season construct (*i.e.*, two six-month seasons) is a natural candidate for a sub-annual market. As discussed in **Section III.A.2**, there is clear differentiation in both capacity demand and supply between summer and winter months. Moreover, these seasons currently account for the majority of measured risk and, to some degree, resource performance is relatively homogenous within the seasons (particularly during periods with the greatest resource adequacy risk). As a result, a two-season market differentiates the relevant RA risks and resource capabilities, thus accomplishing most of the obvious benefits of a sub-annual market.
- **Three- or four-season market.** A two-season market could be further segmented into a three- or four-season market, in which shoulder seasons are differentiated from summer and winter. Under a three-season market, shoulder seasons are combined into one season, whereas under a four-season market, fall and winter are separate seasons.

While there is currently no modeled shoulder season resource adequacy risk, separate shoulder seasons could capture these risks if they were to emerge in the future.[223] At present, the factor most likely to cause shoulder season risk in the future is planned scheduled plant outages. Planned scheduled outages generally occur during periods of lower seasonal loads because plants are less necessary during these periods. Depending on the number of plants requiring planned outages, the duration of those outages and other factors, the scheduling of planned outages could adversely affect reliability during shoulder seasons. The likelihood that this will occur in the future is an empirical question and we have not undertaken empirical analysis nor are we aware of any analysis that assesses this likelihood.

If planned outage risks emerge as an actual or prospective future risk, the first course of action is to improve market rules and procedures affecting resource owner planned outage. In principle, a sub-annual market with a shoulder period might also contribute to the management of planned maintenance outages. However, much of these benefits might be accomplished by a two-season market (*e.g.*, accounting of outage duration regardless of length). In addition, the capacity market is at best an imprecise mechanism to support better management, as it will not account for the timing of outages or a detailed understanding of how particular outage decisions reflect system operations.

In principle, there are scenarios in which shoulder season risk could rise materially even after deploying improved outage management. For example, if data center loads increase substantially and large numbers of gas-fired combined cycles enter the fleet to meet the new loads, then the demand for planned outages could increase without any corresponding growth in the "trough" in seasonal loads used to schedule planned outages (*i.e.*, the difference between peak winter/summer loads and shoulder peak season loads). Even under such scenarios, it will be important to assess the nature of the risks and resource performance under these conditions to determine if they provide meaningful enough differences from the summer or winter seasons to warrant differentiation to additional seasons in the RPM. Given the uncertainty of this scenario and the option to expand from two to three or four seasons at a future date, a prudent course of action might start with the comparatively simpler two-season market.

MISO's experience with a four-season market provides limited information about its potential benefits to PJM. MISO's clearing prices have been low in most seasons, with certain exceptions when prices hit pricing caps (*see* **Figure IV-3**). These instances are episodic, with vertical demand curves contributing to the volatility until the most recent round of auctions that relied on sloped demand curves.

- **Intraday periods.** While the performance of most resources does not vary over the course of the day, this is not the case for *all* resources. In particular, the performance of renewable resources, such as solar and wind, may differ over the operating day. Solar performance requires sunshine and wind supply can

[223] PJM, "ELCC Education," February 16, 2024, available at https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2024/20240221-special/elcc-education.ashx, p. 22.

vary due to diurnal cycles. Thus, sub-annual proposals have included intraday periods, such as separate night and day periods.[224]

Segmenting the market by, for example, night and day would capture variation important to the accreditation of certain types of resources, such as solar and wind, given predictable variation in performance across the day.[225] However, the benefits of accounting for intraday variation may be limited to these classes of resources.

Despite these potential benefits, intraday segments would create complications for accreditation and market clearing. In particular, the accreditation of limited energy resources, such as pumped storage and storage, would be complex and potentially infeasible to account for across intraday periods. Because limited energy resources involve charging and discharging of energy, their performance is interdependent on these operational decisions made at different times over the course of the day. Thus, determining accreditation for such a resource at one time of the day would depend on what that resource is doing at other times of the day. Accounting for such interactions within the capacity auction would be particularly complex, if it is even feasible. By contrast, a framework that takes the operating day as a whole can account for the full charge-discharge cycle of these resources when determining the resource accreditation in a computationally manageable manner. Given these considerations, we do not recommend that PJM pursue a sub-annual market with intraday periods.

- **More granular (monthly, weekly, daily, hourly).** In principle, a sub-annual market could be designed with more granular periods than individual seasons, such as monthly, weekly, daily or hourly. We do not explore these designs in detail. It is not apparent that there is meaningful differentiation of risk and resource performance within seasons, beyond the four-season design discussed above, although we have not explored the issue extensively.[226] Moreover, more granular market designs would face to an even greater extent the issues discussed above regarding outcomes in periods with low risk.

  PJM's Independent Market Monitor ("IMM") has proposed an hourly capacity market design, referred to as the Sustainable Capacity Market ("SCM").[227] The design includes several core components that deviate from the current RPM, including: market clearing in which hourly resource availability is cleared against

[224] *See, for example*, AES Corporation and Leeward Renewable Energy ("Capacity Coalition 2"), "Long Term Capacity Market Changes," PJM RASTF, August 1, 2023, available at https://www.pjm.com/-/media/DotCom/committees-groups/cifp-ra/2023/20230807/20230807-item-02d---leeward---long-term-capacity-market-final.pdf, p.4.

[225] Given predictable variation or mechanical limitations, resources face CP exposure when they are less likely to produce, thus creating some financial risk. However, it is unclear if there is net risk, particularly because mELCC may overstate performance in periods with low risk. For example, solar resources do not produce at night, but the CP risks are greatest during daytime hours when loads are highest, and they are likely to overperform relative to mELCC values.

[226] While it is the case that risk is currently concentrated within certain periods (weeks) within the summer and winter seasons, it is uncertain if forward-looking risk within seasons is as precisely estimated as represented in existing resource adequacy analysis given reliance on historical data with small samples of extreme weather that drives reliability risk. Further, there is no evidence that resource performance differs within the season.

[227] PJM IMM, "Capacity market design proposal: Sustainable Capacity Market (SCM)," presented to RASTF, CIFP, June 13, 2023, available at https://www.pjm.com/-/media/DotCom/committees-groups/cifp-ra/2023/20230614/20230614-item-03a---informational-item---imm-rastf-proposal---part-2.pdf.

hourly demand curves; market clearing at a single price reflecting the highest cost offer price in any hour; and compensation based on actual resource availability in each hour. Many other features of the proposal are less well defined.

On balance, we do not recommend that PJM and its stakeholders pursue the IMM proposal as it is currently proposed. As we discuss below, we have concerns about the effectiveness of certain core elements of the IMM's proposal and believe that other elements are insufficiently developed to form the basis for the RPM. In particular:[228]

- The IMM proposal has one market clearing price and thus does not provide price signals specific to periods when resources are most valued. By comparison, the sub-annual designs evaluated in this report provide price signals in each period and thus provide more efficient incentives for short- and long-run decisions about resource investment and operations, retention and entry.
- The IMM's proposal provides no demonstration of how it would achieve the current regulatory requirement that the market provide sufficient revenues for new entry at the 1-in-10 requirement.
- Under the IMM's proposal, resource offers reflect expected hourly *availability* and owners are compensated based on actual availability. Availability as a measure of resource supply has limitations that can affect efficacy, including verification of stated availability and differences between availability and performance.[229] Further, the proposal, in effect, compensates resources based on average performance (*i.e.*, availability), rather than its marginal performance, and thus does not send the proper price signal of reflecting resources' marginal contributions to reliability from supplying incremental capacity.[230]
- The IMM proposal includes a novel approach to determining each resource's contributions to achieving resource adequacy.[231] Auction clearing reflects the set of resources that maximizes hourly welfare based estimated availability as compared to hourly demands. The model thus differs from the current RPM framework, in which each accredited capacity reflects a resource's

[228] An element of the IMM's proposal is the elimination of CP, which the IMM claims is "a failed experiment." Under the IMM's proposal, incentives are spread uniformly across the year because resources are compensated for availability equally in all hours. By contrast, under CP, incentives for performance are concentrated during periods when the system faces shortfalls in supply sufficient to trigger emergency events. The IMM claims that its proposal enhances incentives for performance but provides no specific evidence to support this claim. PJM IMM, "Capacity market design proposal: Sustainable Capacity Market (SCM)," presented to RASTF, CIFP, June 13, 2023, available at https://www.pjm.com/-/media/DotCom/committees-groups/cifp-ra/2023/20230614/20230614-item-03a---informational-item---imm-rastf-proposal---part-2.pdf, p. 23.

[229] The IMM proposes a penalty mechanism to incentivize both truthful revelation of availability and performance, although the proposed criteria have no connection to the economics of capacity or resource adequacy, and thus the implications for market outcomes and net compensation is unclear.

[230] With a single clearing price, compensation reflecting actual availability is equivalent to compensation based on average availability.

[231] The IMM's proposal bears some similarity to the "slice of day" approach used for resource adequacy in California, as regulated by the California Public Utilities Commission. *See, for example,* California Public Utilities Commission, "2026 Resource Adequacy and Slice of Day Guide," September 23, 2025, available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/guides-and-resources/2026-ra-slice-of-day-filing-guide.pdf.

marginal ELCC as measured by the resource adequacy analysis given its contributions to reducing resource adequacy risk. While novel, the IMM's proposed reliability mechanism has uncertain properties, and the proposal fails to provide any evaluation that demonstrates the effectiveness of the new mechanism. Thus, there is little information about how well it would perform relative to the current construct, which has been evaluated extensively and is relied on by all RTOs with primary responsibility for resource adequacy.

- The IMM proposal creates uncertain offer incentives for owners when constructing offer prices. Under the current market design, in which offers are supplied for each position (*i.e.*, annual product), resources have an incentive to offer supply at their resources' costs. However, under the IMM proposal, the resource would offer one price that is used to clear in 8,760 hours. In this case, the incentive properties to resource owners in setting offer prices are less clear. For example, resources with no or little availability in hours of high demand likely to set the market clearing price may have the incentive to submit offer prices well below their true costs. Because their supply is limited in price-setting hours, their low offer has little impact on the market-clearing price. However, their low price ensures that they clear in all hours and thus are compensated throughout the year, despite providing little supply in hours when needs are greatest. These incentive properties are important to operating auction mechanisms that achieve efficient market outcomes.

* * *

On balance, we believe that a two-season summer/winter market would provide PJM and the region with meaningful improvements in RA outcomes. The efficacy of further segmenting a two-season market into a three- or four-season market would depend on an assessment of the likelihood that (1) shoulder season risk will be material after implementation of enhanced market rules and procedures to manage planned outages and (2) differentiation of seasons will produce meaningful benefits. These risks would likely reflect further constraints on scheduling of planned outage maintenance given future changes in the peak loads across the year and the demand for outage scheduling.

b. Changes to delivery period calendar schedules

With the development of a sub-annual market, a realignment of the Delivery Year schedule would be required. At present, the Delivery Year is June 1 to May 31 (of the following year). However, this schedule does not align well with the weather conditions that drive the reliability risks. Given this, the Delivery Year schedule for a two-season market that better aligns with these risks includes a summer season (May 1 to October 31) and a winter season (November 1 to April 30). If these periods are adopted, there would be an overlap between the current Delivery Year and the proposed summer period, that would necessitate a one-time modification to the periods. For example, the summer season in the first sub-annual Delivery Year could be shortened by one month, such that that period runs five months starting in June 1 (instead of May 1) through October 31.

If a three-season or four-season market is pursued, then more consideration may be required to define the winter and summer periods. While it may be natural to adopt four three-season markets, such a schedule does not necessarily align with the periods of time when the risk occurs, which may extend beyond a 3-month period.

Under current modeling approaches used by PJM, most risk is currently concentrated in short-duration periods, particularly January and February within the winter and July in the summer.[232] However, in the future, risk may be spread more broadly across the summer and winter periods (or into shoulder periods), such that narrowly defining summer or winter periods (*e.g.*, to three-month periods) may truncate periods of tail risks within these seasons. Thus, for example, the winter period might be more reliably defined as a four-month period (*e.g.*, from December 1 to March 30) to encompass all winter-related risk. Season definitions within a three- or four-season market should thus consider potential increases in scope of risk within these seasons (due to changes in system conditions or changes in RA methodologies) when defining these periods.

B. Demand Curve

In principle, demand curves should reflect customers' willingness-to-pay ("WTP") for incremental capacity given the reduction in risk created by additional resources. With a sub-annual market, basic principles of demand curves remain the same, but demand curves must be specified for each individual period. Thus, for example, in a two-season market, both the summer and winter periods will have separate summer and winter demand curves.

Below, we discuss the details of specifying sub-annual demand curves. As we show, sub-annual demand curves should reflect underlying reliability risks in each period, with the result that demand curves may differ materially between periods. These differences will reflect not only the expected peak loads in each period, but also the extent to which incremental capacity reduces risk. In seasons with higher risk, the contribution of incremental capacity will be larger, and the corresponding price paid for capacity should be greater; by contrast, in periods with lower risk, these contributions will be smaller and the resulting prices should be lower.

1. Regulatory Requirement: Reliability Requirement and Net CONE

In the current RPM, the single annual demand curve is "anchored" at the regulatory requirement that the market support new entry when system risk is at a 1-in-10 LOLE. This anchor point, thus, reflects both a reliability requirement, reflecting the quantity of capacity resources (in UCAP) required to meet the annual 1-in-10 target, and Net CONE. The reliability requirement includes:

- An RTO-wide reliability requirement: the quantity of capacity (in UCAP terms) needed in the RTO to achieve the 1-in-10 LOLE requirement across the system in the Delivery Year given the loads throughout the year and the assumed resource portfolio, reflecting the existing fleet of resources, resources with submitted deactivation notices, Notices of Intent ("NOI") submitted by planned generators, and other available information.[233]

[232] PJM, "ELCC Education," February 16, 2024, available at https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2024/20240221-special/elcc-education.ashx, p. 22.

[233] PJM Manual 20A: Resource Adequacy Analysis, p. 12.

- LDA reliability requirements: set at 40% of the RTO EUE at the 1-in-10 criteria adjusted for a normalizing factor (the ratio of the LDAs forecasted annual net energy to the RTO's forecasted annual net energy).[234]

With a sub-annual market, reliability requirement and Net CONE values need to be set for each period to anchor its demand curve such that the regulatory requirement is achieved over the entire year. Thus, across all periods, the reliability requirements and Net CONE values need to be set to ensure that the reference unit can recover Net CONE when the aggregate risk across all periods is 1-in-10 LOLE.

In an annual market, determining the reliability requirement is relatively straightforward. Because the annual market corresponds to the annual reliability requirement, there is one unique value for the annual reliability requirement. However, with a sub-annual market, the 0.1 LOLE target can be achieved through many potential combinations of reliability requirements for individual periods that cumulatively achieve the 0.1 LOLE target. For example, in a two-season summer-winter market, reliability requirements could be met by splitting risk between the seasons in any combination. One option is a 50/50 split in risk between summer and winter, which each achieve 0.05 LOLE and cumulatively achieve 0.1 LOLE. Alternatively, risk could be split 20/80 between summer and winter, 80/20 between summer and winter, or any number of alternative combinations. Similar to the reliability requirement, in principle, the net revenues to new entry to recover Net CONE could be earned in many combinations over the entire year. For example, in a two-season market, Net CONE could be earned 50/50 in summer and winter, 80/20 in summer/winter, 20/80 in summer/winter, or any other combination.

Whether defining the regulatory requirement or allocated Net CONE, the economically efficient approach sets these values such that the cost per unit of risk (*e.g.*, EUE) is equal across periods. If the cost per unit of risk were not equal across periods, then costs could be reduced with no overall impact on system risk by procuring more capacity in the low-cost period and less in the high-cost period. Thus, setting each period's allocated Net CONE to maintain an equal cost per unit of risk is least-cost.

When applying this principle, the basic relationship can be derived that relates demand to marginal reliability impacts:

$$Demand_{\ Period\ i} = MRI_{Period\ i} * scalar = MRI_{Period\ i} * \frac{Net\ CONE}{MRI_{Annual}}$$

The marginal reliability impact is the change in reliability (*e.g.*, EUE) associated with an incremental change in capacity. We discuss the concept of marginal reliability impact in greater detail in the following section.

This relationship has implications for the reliability requirement and Net CONE. For the reliability requirement, this result implies that an efficient (and straightforward) approach to developing sub-annual reliability requirements is to set the requirements based on the system conditions when meeting the 1-in-10 LOLE requirement annually.[235] In effect, this approach allocates risk across periods consistent with the distribution of risk throughout the year under

[234] PJM Manual 20A: Resource Adequacy Analysis, p. 9.

[235] This outcome derives from the general result that demand = scalar * MRI, where the scalar is defined below.

the current annual market. Specifically, each period's annual requirement is set as the system capacity at the 1-in-10 requirement (in ICAP) adjusted for both the IRM and that period's aggregate ICAP to UCAP conversion (given the fleet's ELCC values in that season). MISO's current market sets reliability requirements using this approach.

Similarly, the relationship implies that each period's Net CONE can be set by multiplying each period's marginal risk (in EUE) by a scalar equal to the ratio of Net CONE and the annual marginal risk – that is:

$$Allocated\ Net\ CONE_{Period\ i} = MRI_{Period\ i} * scalar = MRI_{Period\ i} * \frac{Net\ CONE}{MRI_{Annual}}$$

Here, we use the term "allocated" Net CONE because the value reflects the portion of total Net CONE to be recovered in a given period.

While we describe an economic approach to setting reliability requirements and allocated Net CONE, in principle, other approaches could be adopted that set these values using different criteria. In particular, both ISO-NE and NYISO have either adopted or proposed market designs with some constraints on seasonal risk. ISO-NE is proposing a 50/50 summer-winter risk allocation for its seasonal market, while acknowledging that it will revisit this decision. NYISO's ICAP market includes an 65/35 collar on summer and winter risk. These options provide certain benefits, including support of prices in low-risk periods, greater certainty and reduced price volatility.

2. Curve shape

Having established an anchor point, the next step is to determine the shape of the demand curve. At present, PJM uses linear VRR demand curves. The VRR shape is determined through a "quadrennial" process in which a stochastic (Monte Carlo) analysis informs demand curve performance relative to particular performance metrics (*e.g.*, achievement of the 1-in-10 criteria given demand and cost uncertainties, price volatility, customer cost exposure, etc.).

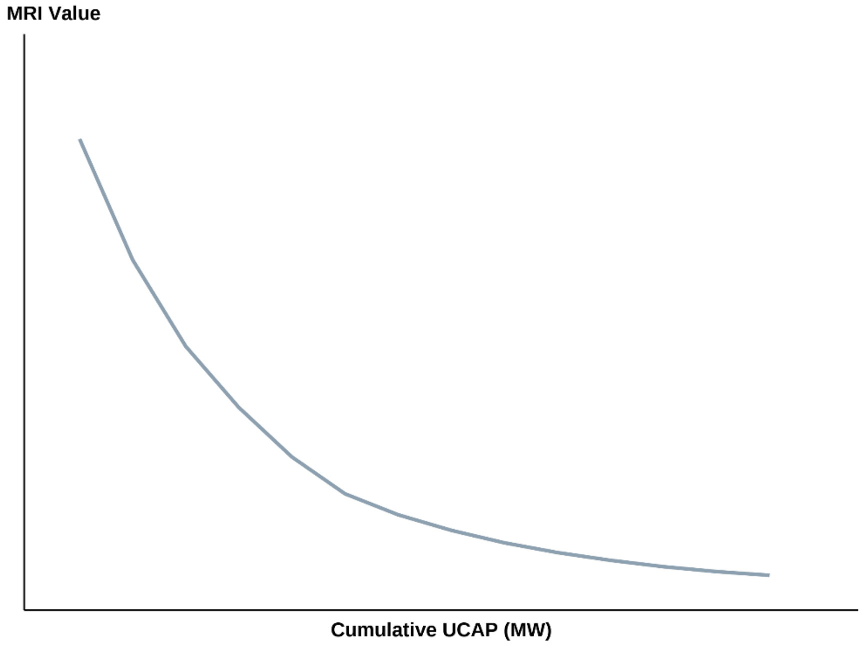
In principle, the shape of the demand curve should reflect customers' WTP for reductions in risk achieved by incremental capacity. This is true for both annual demand curves and period-specific demand curves. Current VRRs are not, however, directly grounded in any empirical relationship between the effect of incremental capacity on risk and customers' value for risk reductions.

Two approaches are commonly used to develop demand curve shapes: linear demand curves, such as the current VRR approach, or MRI-based demand curves. Demand curves for individual periods can be developed using either approach. Below, we discuss each approach, starting first with the MRI-based approach.

a. MRI-based approach

The marginal reliability impact, or MRI, is the change in reliability (*e.g.*, EUE) associated with an incremental change in capacity. MRI value is a standard output of RA modeling, which can provide an MRI curve with MRI values for different levels of capacity. MRI values typically decline with higher levels of capacity, as shown in **Figure VI-1**.

Figure VI-1: Illustrative MRI Demand Curve



The estimation of demand curves from MRIs is straightforward – the demand curve is calculated by multiplying values in the MRI curve by the scalar parameter described above (*i.e.*, the ratio of Net CONE to marginal EUE at the annual 1-in-10 requirement). This approach ensures that capacity markets procure capacity at a uniform cost per unit of reduced risk regardless of the capacity procured. There is substantial experience with the use of MRI curves, which have been used in ISO-NE and MISO to develop both annual and seasonal demand curves (*see* **Sections 0** and **IV.C**).

If a sub-annual market is adopted, one design option is to use MRI-based demand curves in lieu of existing VRRs (and associated processes). For example, with an MRI-based approach, demand curves could be updated annually (rather than quadrennially) as a component of the RA analysis performed to estimate annual RPM capacity requirements.

Our proposed adoption of MRI-based demand curves extends a trend of growing reliance on RA modeling in the implementation of the RPM. This trend is common to many RTOs and reflects a growing precision in evaluation and management of resource adequacy. Given this growing reliance on RA modeling, we think it is important that PJM and stakeholders continue the on-going assessment of model performance and sensitivity of model results to market operations. The move to a sub-annual market can mitigate some of these issues, by reducing variability across time in period/seasonal risks. That said, continued evaluation of the sensitivity of market outcomes (*e.g.*, prices) and parameters (*e.g.*, ELCCs) to changing market conditions will be valuable so that PJM and stakeholders can better understand how a sub-annual market will perform under different market conditions and under different changes in fleet composition (*e.g.*, fleet additions or retirements).

b. VRR curves

With a sub-annual market, PJM could continue to utilize linear demand curves, consistent with the current VRRs. If PJM were to take this path, it would need to develop methodologies to determine the appropriate VRR curves for each sub-period included in the market. Because the current VRR approach reflects an annual market, it would not necessarily be appropriate to simply apply the current methodology to determine annual VRRs to each sub-period VRR. In particular, this approach would not necessarily account for important differences in RA risks between periods. For example, VRRs that are simply extrapolated from an annual curve would not necessarily account for the current differences in winter and summer risks, as they occur in PJM. As described above, these differences include winter risks reflecting longer, smaller losses of energy, and summer risks reflecting shorter, but larger losses of energy.

To develop VRRs for individual periods that reflect underlying differences in risk between seasons, administrative processes – similar to the current "quadrennial" process – could be developed. This process could draw on various sources of information on RA risks, in particular the MRI curves discussed above. However, administrative approaches to utilize MRI (and other) information about RA risks in individual periods to develop linearized demand curves (either formulaically or qualitatively) would need to be developed. Further, periodically, demand curves would need to be updated to account for this new information.

* * *

On balance, an MRI-based approach that directly ties demand curves to RA modeling provides several important benefits. *First*, MRI-based demand curves more accurately represent RA risks than current linear VRRs. MRI-based demand curves are based on actual marginal risks as measured by the resource adequacy models, rather than linear approximations, as with the current VRR approach. Thus, MRI-based curves would be expected to be more efficient and lead to improved reliability.

Second, MRI-based demand curves would be less burdensome in terms of administration and stakeholder processes. If PJM were to pursue linear VRR-like demand curves for each period, PJM would need to undertake design and stakeholder processes to first develop procedures for determining the shape/slope of each period's VRR curve and then regularly update these shape/slope determinations, like the current quadrennial process. With the adoption of MRI-based demand curves, PJM and its stakeholders could avoid these processes, because the direct use of MRI's allows these steps to be undertaken formulaically given the analytical relationship between MRI curves and demand curves.

3. Price Caps and Floors

Capacity market demand curves typically include a price cap set at a maximum WTP for capacity. When there is a shortage of resources, with offers from supply failing to clear demand, capacity markets typically set price at the price on the demand curve that corresponds to the quantity of supply offered – in effect, the market clears at the vertical intercept of the offered quantity and the demand curves. When this occurs, the market clears at a price that reflects both the resource's offer price and a "shortage price," reflecting the incremental value to customers (*see* **The Current** Market Scenario assumes current market information and reflects the current tight supply of capacity relative to demand. This shortage is reflected in the capacity market results for the 2026/2027 BRA, in which virtually all offered supply cleared the market at the temporary market price cap. This shortage can result in "shortage pricing" in which the market clears vertically at the demand curve and capacity is paid shortage pricing. Error! Not a valid bookmark self-reference. illustrates how shortage pricing can occur. In this illustrative example, the supply curve does not reach the demand curve and the market clears supply at the vertical intercept to the demand curve. That is, in order to determine the market clearing price, the end of the supply is traced up vertically until it intersects with the demand curve. The intersection of this vertical line and the demand curve determines the price. We refer to the difference between the highest bid offer on the supply curve and this vertical market clearing price as the shortage price. Shortage pricing reflects the principle that prices should reflect the value to customers, not the cost of suppliers, when there is shortage of supply. By ensuring that prices reflect the value to customers, this approach sends an appropriate price signal to the market to incentivize new entry (and resource retention) when the market is tight on supply.

Figure VII-14 in **Section VII**). A price cap effectively constrains prices under conditions of severe shortage, such that prices exceed a maximum WTP.

With a sub-annual market, price caps can be set for each period's demand curve. In principle, there are many approaches to setting price caps. One approach reflecting economic criteria is to set price caps such that they reflect a uniform maximum WTP for reductions in risk across periods. This can be accomplished by setting the price cap proportional to each period's allocated Net CONE, reflecting the fact that each period's allocated Net CONE is calculated to ensure that the cost per unit of risk reduction is uniform across all periods. This approach has implications for the relative magnitude of price caps across periods. In particular, with this approach, price caps are higher in periods with greater risk, and lower in periods with lower risk. **Figure VII-7** illustrates price caps for a two-season winter-summer market in which there is greater risk in winter than summer.

a. Tradeoffs when setting price cap levels for individual periods

When setting price caps for a sub-annual market, several other considerations can arise. *First*, caps for individual periods can be set higher than the current caps implied by annual prices, without raising expected prices. To see this, consider sub-annual price caps for individual periods set such that the weighted average of these price caps across the year equals the annual maximum WTP. This approach would tend to lower expected prices because caps would not necessarily bind in all periods. When caps in some but not all periods bind, the resulting average prices across periods would be below the annual WTP. Given this, price caps can be raised to allow for better price discovery without increasing the expected prices.

The example in **Table VI-4** illustrates this point. In the annual market, price caps are set at $300/MW-day, which binds, resulting in market clearing prices at $300/MW-day. In Scenario 1A, the two-season market sets caps proportional to the annual cap, with the higher-season-risk winter cap at $400/MW-day and the lower-season-risk summer cap at $200/MW-day. When the auction runs, the caps bind in both seasons, with the market clearing at $400/MW-day in winter and $200/MW-day in summer. Assuming the same winter and summer UCAP, the resulting average annual price is $300/MW-day. In this case, the annual clearing price and average sub-annual price is the same, $300/MW-day.

Table VI-4: Illustration of Impact of Setting Prices Caps on Market Outcomes

	Scenario 1A Price Cap	Scenario 1A Market Clearing	Scenario 1B Price Cap	Scenario 1B Market Clearing	Scenario 2 Price Cap	Scenario 2 Market Clearing
Annual	$300	$300	$300	$300	$300	$300
Two-season						
Winter	$400	$400	$400	$400	$500	$500
Summer	$200	$200	$200	$100	$250	$100
Avg Annual		$300		$250		$300

In Scenario 1B, price caps remain the same, but the market clears below the cap at $100/MW-day in the summer, resulting in an average price of $250/MW-day across the year. Thus, when the seasonal markets do not clear at the price caps in all seasons, the average price is less than the maximum WTP even though the seasonal prices are set at the level implied by the maximum WTP.

Scenario 2 relaxes the price caps to $500/MW-day in winter and $250/MW-day in summer. If the market clears in winter at the winter cap, now $500/MW-day, and $100/MW-day in the summer, then the average price is $300/MW-day. Thus, by relaxing each period's cap, the market clearing outcome is at the maximum WTP.

This example illustrates (1) why sub-annual price caps set to be, on average, equal to the annual maximum WTP will tend to lower average prices (compared to the annual market), and (2) why sub-annual price caps set higher, on average, than the annual maximum WTP can result in expected prices consistent with the annual market (for a given maximum WTP).

Second, with a sub-annual market, some resources may earn revenues in some but not all sub-periods. Thus, price caps for individual periods inadvertently set too low may limit cost recovery, as well as price discovery. This risk is greater in independent auctions, where there is less opportunity to compensate for fixed costs (*e.g.*, through uplift) but can also constrain market clearing in co-optimized auctions (when such payments are endogenized).

Consider the winter and summer prices from **Table VI-4** and a resource with annual avoidable costs of $225/MW-day (on an annual basis) that clears in winter but not summer. In Scenario 1, the resource would earn $400/MW-day in winter, which would correspond to $200/MW-day on an annual basis and is below its costs of $225/MW-day. However, if the price cap were set at $500/MW-day, as in Scenario 2, the resource would earn $250/MW-day on an annual basis and thus cover its annual costs. Thus, higher caps for individual periods can mitigate risks that individual resources fail to cover their costs (absent other mechanisms to mitigate this risk, such as a co-optimized market).

Third, in LDAs (and to a lesser extent the RTO), market clearing outcomes can be very sensitive to the quantity of supply. In LDAs, because the demand for capacity is smaller in absolute terms, the exit or entry of an individual asset (or a few assets), can have a proportionately large impact on price. Given this, price caps set too low in any individual period (*e.g.*, the summer period in **Table VI-4**) may inadvertently limit price discovery if there is a shortage of supply relative to demand. This risk is greatest if resources exit the locality after demand curves are specified, leaving a shortage of capacity not accounted for when developing demand curves. Again, this risk suggests that, all else equal, there is a benefit to setting price caps higher than would otherwise be the case, particularly for periods with low risk.

While these considerations reflect certain advantages to raising caps in individual periods, if price caps for individual periods are set too high, expected prices can increase or average annual prices can exceed the maximum WTP in certain outcomes. For example, in the illustration in **Table VI-4**, if prices cleared at the winter and summer price caps in Scenario 2, average prices would be $375 MW-day (= ($500/MW-day + $250/MW-day) / 2), above the annual $300/MW-day maximum WTP. Thus, setting price caps for individual periods reflects a balance of tradeoffs, where the criteria would differ compared to the current annual market.

Price caps for individual periods do not necessarily need to be set so high that all resources – *e.g.*, a new entrant – can recover all costs in one period. A new entrant is likely to clear in all periods, not a single period (or several periods). Thus, setting price caps to allow for recovery of Net CONE in a single period is unnecessary for the purposes of meeting the regulatory RA requirement. Caps set at such a high level are also unlikely to be necessary for recovery of going forward costs for existing resources.

b. Annual price cap mechanisms

Auction structures that accommodate annual cap mechanisms, such as a co-optimized market or simultaneous independent auction, can mitigate the risk that prices are "too high" while allowing flexibility in setting price caps for individual periods. Moreover, given the flexibility afforded by an annual cap mechanism, when in place, constraints on setting caps in any individual period can be greatly relaxed to provide improved price discovery in individual periods.

There are potentially two approaches to setting annual price caps. Within a co-optimized auction, in principle, an annual price cap mechanism could be integrated into the auction clearing. An integrated annual price mechanism would constrain market-clearing outcomes to account for price outcomes across the year that exceed a pre-defined threshold.

Alternatively, *ex-post* adjustments to prices could be made to account for prices that across the year exceed a pre-defined threshold. This approach is easier with a simultaneous auction, as the results of auctions for multiple periods can be reviewed simultaneously and modified, if needed. However, designing an annual cap mechanism in a simultaneous, independent auctions may raise certain design challenges and complications. With this approach, criteria and algorithms must be specified to adjust market outcomes consistent with the mechanism objectives, while maintaining consistent prices within zones, when appropriate. MISO's initial design required modifications, as it resulted in similarly situated resources earning different prices for providing similar service (*see* **Section IV.B**). This experience suggests potential complications to adopting this approach depending on particular locational features and seasonal design.

* * *

In sum, in practice, establishing price caps within a sub-annual market introduces certain tradeoffs, with particular advantages to increasing price caps above the levels implied by current annual price caps. Such increases must be moderated, however, to the extent that such caps raise expected prices. Auction structures that accommodate annual price cap mechanisms offer the advantages that the risk of excessive annual prices resulting from more relaxed price caps can be mitigated through a mechanism that mitigates prices in each period to reasonable levels.

4. Transmission Constraints and LDA VRRs

Like an annual market, a sub-annual market would need to account for locational constraints necessary to maintain RA to targeted standards across the PJM footprint. Currently, the PJM RPM accounts for transmission-constrained locations, Locational Deliverability Areas ("LDA"), where locational needs and deliverability are measured by a Capacity Emergency Transfer Objective ("CETO") and a Capacity Energy Transfer Limit ("CETL"). **Figure VI-2** shows PJM's zones; PJM's 27 LDAs correspond to zones (*e.g.*, Dominion), sub-regions of zones (*e.g.*, PSEG northern region) or combination of zones (*e.g.*, MAAC).[236] The CETO is the minimum amount of capacity that it must be possible to import into an LDA to maintain reliability during a capacity emergency, calculated through probabilistic reliability modelling. The CETL measures the physical limit – *i.e.*, how much capacity can be feasibly imported into the LDA – and it is determined through engineering studies. If the CETL is lower than 115% of the CETO, the LDA is considered constrained and modeled separately in the RPM auction.[237]

When determining LDA VRRs, the curves are anchored to a reliability requirement (40% of the RTO EUE at the 1-in-10 criteria) and a location-specific Net CONE. LDA VRRs account for RA risk on a "total basis" that reflects the full reliability impact of capacity on loads in the LDA. The resulting overlap in calculating risk at the RTO and LDA levels complicates the auction's market-clearing software.[238]

A sub-annual market could affect the determination of both CETOs and CETLs. With CETOs, PJM would need to assess whether to measure CETOs on an annual or sub-annual basis. At present, CETOs are determined annually, consistent with each LDA's annual reliability criteria. Thus, within the current annual construct, sub-annual CETO values would not differ from the annual values. To the extent that there was interest and potential value in sub-annual CETO values, further analysis would be needed to determine how best to modify CETO measurement.

With a sub-annual market, CETLs should be measured in each period to account for differences in transmission capability across the year. Accurate measurement of CETLs by period will ensure that locational constraints

---

[236] PJM Manual 18: PJM Capacity Market, pp. 22-23.

[237] PJM, "PJM CETO/CETL & Load Deliverability," August 19, 2024, available at https://www.pjm.com/-/media/DotCom/committees-groups/task-forces/destf/2024/20240819/20240819-item-04---ceto-cetl-and-load-deliverability-test.pdf, p. 12.

[238] The auction software uses iterative convergence to account for initial differences between market clearing quantities with and without the LDA supplies.

accurately reflect reliability risks and thus ensure the price signals are sufficiently high when local reliability risks emerge but avoid excess prices when local risks are limited. PJM is evaluating seasonal CETL constraints in a Senior Task Force.[239]

A sub-annual market may also introduce complications for market-clearing in LDAs with risk patterns that differ meaningfully from RTO risk patterns. In particular, if periods of high risk in the LDA differ from the RTO's periods of high risk, pricing in the LDA could reflect greater risk (and thus higher pricing) in both periods. For example, in a two-season market, if an LDA has all of its risk in the summer and the RTO has all of its risk the winter, then the LDA may clear at high prices in both seasons. In the summer, the LDA may clear at a high price because the LDA demand curve reflects high summer risk. In the winter, although the LDA has low risk, the RTO demand curve reflects high risk and thus could result in higher prices. Because the LDA price reflects the higher of "parent and child" pricing, prices in the winter would be at the higher RTO price, not the lower LDA price. Thus, the LDA could experience higher prices in both seasons.

Market designs could take various approaches to addressing this potential issue. In principle, a co-optimized auction could internalize a constraint on LDA prices that accounts for circumstances when LDA and RTO prices are both elevated. A simultaneous auction could adopt *ex-post* adjustments, similar to those used in a price cap mechanism (*e.g.*, akin to MISO's approach). Mitigating such outcomes would be more challenging in a sequential auction.

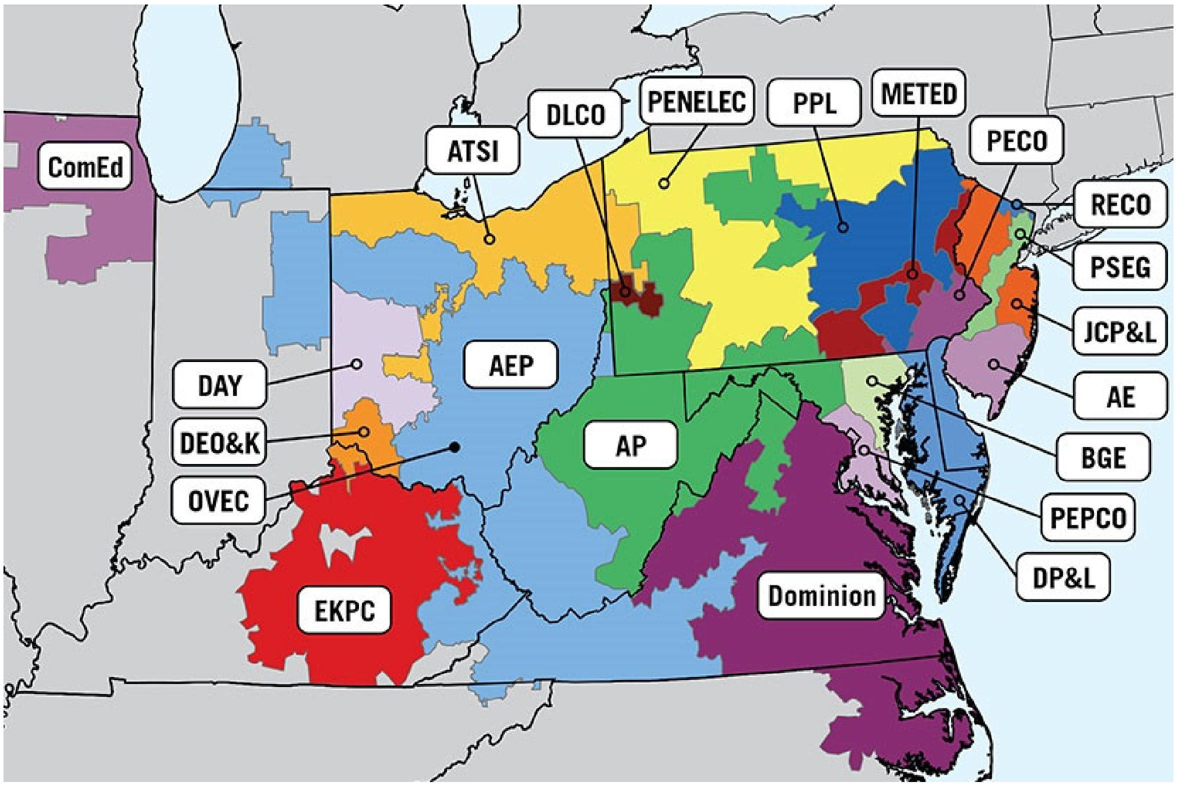
If adopting a sub-annual market, it may be prudent to shift from the existing "total basis" LDA demand curves to incremental LDA demand curves, similar to those used in ISO-NE.[240] There are at least two reasons for this.[241] *First*, use of demand curves reflecting the incremental reliability provided by capacity in the LDA (as compared to in the RTO) can simplify the auction algorithm, thus facilitating the inclusion of other features (*e.g.*, co-optimization). *Second*, when combined with MRI-based demand curves, the adoption of incremental demand curves simplifies the process of maintaining a consistent cost per avoided EUE across locations and periods. With this approach, PJM may need to rely on only the RTO Net CONE values and eliminate use of locational Net CONE values within LDAs. Currently, ISO-NE accounts for its zonal constraints through incremental demand curves derived from MRI curves. This approach has been used in multiple auctions at the annual level and is likely to be maintained in its seasonal market design.

[239] PJM Effective Load Carrying Capability Senior Task Force, "Problem/Opportunity Statement: Capacity Market Enhancements – CETL," available at https://www.pjm.com/-/media/DotCom/committees-groups/task-forces/elccstf/postings/cetl-problem-statement.pdf.

[240] ISO New England, ISO New England Inc and New England Power Pool Participants Committee, Docket No. ER16--000, Demand Curve Design Improvements, April 15, 2016.

[241] Brattle Group, "Sixth Review of PJM's Variable Resource Requirement Curve," April 9, 2025, available at https://www.brattle.com/wp-content/uploads/2025/04/Sixth-Review-of-PJMs-Variable-Resource-Requirement-Curve.pdf.

Figure VI-2: PJM's Zones[242]



C. Supply

1. Accounting for Differences in Resource Accreditation

With a sub-annual market, in principle, all features affecting a resource's performance and ability to contribute to resource adequacy can be accounted for. At present, resource supply offers reflect installed capacity and resource accreditation based on ELCC values. While the current accreditation methodology relies on PJM's hourly resource adequacy model that incorporates certain risks throughout the year, a sub-annual market allows for a greater number of features to be accounted for in resources' ICAP and UCAP. For example, the output of fossil-fired generation is greater during winter than summer because the thermal efficiency of combustion is greater in colder ambient temperatures.

In particular, a sub-annual market can account for the following resource features:

---

[242] **Source:** PJM, "Transmission Zones," available at https://www.pjm.com/library/-/media/B7455E69D97B45FFB390EEFAD84AD50D.ashx, accessed on December 19, 2025.

- **Thermal performance given ambient air conditions.** In particular, fossil resources can have distinct capacity (ICAP) values reflecting summer and winter performance under ambient air conditions.
- **Resource deliverability.** At present, resources offer capacity consistent with CIR, based on deliverability under summer peak conditions.[243] With a sub-annual market, CIR values can reflect deliverability under sub-annual conditions (load flows).
- **Forecast outages.** With a sub-annual market, resource accreditation can reflect (expected) forced outage rates in each season.
- **Intermittency and correlated risks.** With a sub-annual market, resource accreditation can reflect contributions to resource adequacy given intermittency and correlated supply risks (including fuel supply risks) as captured in RA analyses and estimated ELCCs.

Prior attempts to account for these factors in an annual market have not always resolved these issues.[244] With a sub-annual market, however, the complications involved in appropriately addressing sub-annual variability within an annual market are naturally resolved when measuring these features sub-annually.

2. Obligations

With a sub-annual market, the capacity supply obligations taken on by resources can remain unchanged, although obligations would only extend to periods when the resource clears the market and receives compensation. Thus, when the resource clears, it would be subject to must-offer requirements, planned outage and maintenance requirements, and CP market rules. By contrast, when the resource does not clear the market, it would not be subject to must-offer requirements, and planned outage and maintenance requirements. While the resource would not be subject to the CP obligation (*i.e.*, debits corresponding to the balance ratio) but would be able to earn CP payments if supplying during these periods.

With respect to CP, the rules for CP would be consistent with current market rules. In particular, payment rates would reflect the same calculations as under the present annual market. CP risks may vary across the year given differences in the risk of CP events. Thus, in a four-season market, for example, CP risks may be higher in summer and winter periods, as compared to shoulder months. However, these differences reflect variation in the likelihood of CP events across the year, rather than being a consequence of any change in market rules or parameters.

---

[243] PJM Capacity Manual, Manual 21B, p. 20.

[244] PJM is currently reviewing proposals to improve its ELCC accreditation, including incorporating incremental winter capability of thermal generation in the resource adequacy studies. PJM, "ELCCSTF – Accreditation Methodology: PJM Proposal," June 17, 2025, available at https://www.pjm.com/-/media/DotCom/committees-groups/task-forces/elccstf/2025/20250617/20250617-item-02a---elccstf-accreditation-reforms---pjm-proposal.pdf.

D. Cost Allocation

1. *Cost Allocation Based on Regulatory Cost Causation Principles*

In capacity markets, system operators procure capacity to ensure resource adequacy. The capacity costs must be allocated to LSEs – and downstream customers – that benefit from having sufficient resources available to meet reliability standards. Under regulatory cost causation principles, costs should be equitably allocated to those beneficiaries on whose behalf the costs are incurred.[245] In line with cost causation principles, historically, capacity costs have been typically assigned to LSEs based on LSE's contributions to peak demand. Periods of peak demand are expected to align with periods when capacity resources are most needed to ensure system reliability.

With the adoption of a sub-annual market design, PJM and its stakeholders can evaluate the current cost allocation approach to determine if it continues to align cost allocation with customer's marginal impact on the system. Within this analysis, alternative cost allocation metrics that capture sub-annual market definitions can be considered, along with other considerations such as the impact of a change in capacity cost allocation on LSEs' wholesale market settlements and the stability of cost allocators over time. In the following sections, we briefly review current capacity market cost allocators, identify approaches that could be adopted for sub-annual capacity cost allocation, and suggest considerations when evaluating alternative cost allocators.

2. *Capacity Cost Allocation Methodologies*

a. PJM

PJM currently allocates capacity costs to LSEs based on the prior summer's coincident peak loads. First, PJM relies on each zone's share of forecasted peak load to allocate the RTO-wide UCAP to PJM's transmission zones. Then, Electric Distribution Companies ("EDCs") in each zone allocate the prior summer weather normalized peak zonal load to LSEs (*i.e.*, their Daily Zonal UCAP Obligations), typically based on the '5 CPs methodology.'[246] In October of each year, PJM determines the prior summer's zonal coincident peak loads for the five days ("5 CPs") with the highest peaks in the months of June through September.[247] EDCs calculate the peak load contributions ("PLCs") of customers in their zones based on their average 5 CP load contributions, aggregate customer PLCs by

---

[245] Bonbright, James, "Principles of Public Utility Rates," 1961, p. 23 and Part III. *See also*, Morgan Lewis, "DC Circuit Upholds Cost-Causation Principle," January 8, 2024, available at https://www.morganlewis.com/blogs/powerandpipes/2024/01/dc-circuit-upholds-cost-causation-principle. Additional ratemaking cost allocation principles such as ease of implementation, stability and effectiveness are also important.

[246] EDCs are responsible for allocating peak load of zones to LSEs, typically based on the 5 CPs method. The 5 CPs method calculates an LSE's average historical peak load contribution during the non-holiday weekday five hours when PJM's total system load is highest, using hourly unrestricted loads for the period June 1 to September 30. PJM, Manual 19, December 18, 2024, available at https://www.pjm.com/-/media/DotCom/documents/manuals/m19.pdf, p. 19; PJM, "RPM Cost Allocation Education," July 22, 2025, available at https://www.pjm.com/-/media/DotCom/committees-groups/task-forces/202cstf/2025/20250722/20250722-item-03---202cstf-rpm-cost-allocation-education---presentation.pdf, pp. 4, 13.

[247] PJM, "RPM Cost Allocation Education," July 22, 2025, available at https://www.pjm.com/-/media/DotCom/committees-groups/task-forces/202cstf/2025/20250722/20250722-item-03---202cstf-rpm-cost-allocation-education---presentation.pdf, pp. 3, 11, 13.

LSEs, and provide them to PJM.[248] PJM then uses the Daily Zonal UCAP Obligations and final zonal capacity prices to allocate the costs PJM incurs to compensate capacity resources.[249]

b. Other RTOs/ISOs

Historically, other RTOs/ISOs have also relied on peak demand-based allocation methods to assign capacity costs to LSEs. For example, ISO-NE uses the prior year's peak to allocate zonal LSE capacity costs.[250] NYISO's process also relies on peak demand allocation, however, NYISO determines LSE's zonal obligations and then requires LSEs to procure capacity bilaterally or in NYISO administered capacity auctions.[251] Finally, MISO currently allocates capacity costs based on sub-annual (four seasons) peak demands.[252] However, MISO is currently proposing to allocate obligations based on LSE's historical load during high-risk hours, instead of peak demand hours.[253]

3. Cost Allocation Considerations for a Sub-Annual Market

With the adoption of a sub-annual market design, PJM can evaluate the alignment of its current cost allocation methodology with classic ratemaking regulatory principles, particularly cost causation. This report does not explicitly analyze the issues that may arise when evaluating sub-annual cost allocation but instead outlines key principles and relevant considerations that are expected to arise when evaluating sub-annual capacity cost allocation methodologies.

First, the application of the cost causation ratemaking principle is the key consideration for defining a sub-annual cost allocation methodology. The application of the cost causation principle requires the alignment of the costs the consumers impose on the system as reflected by their demands on the system in those hours where reliability is most valuable. Resource adequacy analyses provide the basis for identifying those hours when customer benefits

---

[248] PJM, "RPM Cost Allocation Education," July 22, 2025, available at https://www.pjm.com/-/media/DotCom/committees-groups/task-forces/202cstf/2025/20250722/20250722-item-03---202cstf-rpm-cost-allocation-education---presentation.pdf, p. 11.

[249] PJM, "RPM Cost Allocation Education," July 22, 2025, available at https://www.pjm.com/-/media/DotCom/committees-groups/task-forces/202cstf/2025/20250722/20250722-item-03---202cstf-rpm-cost-allocation-education---presentation.pdf, p. 5.

[250] ISO-NE, "Lesson 6C: Supplier-Side Settlement," October 26, 2023, available at, https://www.iso-ne.com/static-assets/documents/100005/20231024-fcm101-lesson-6c-art_print.pdf, pp. 15-20.

[251] NYISO, "Installed Capacity (ICAP) Market," October 21, 2025, available at https://www.nyiso.com/documents/20142/3037451/8-ICAP.pdf/da39103d-df67-e44c-ecee-8535eaec2a3c, pp. 61-63. In contrast, PJM and ISO-NE procure capacity on behalf of LSEs and then allocate the costs to LSEs.

[252] LSE's obligations for regional resource adequacy are based on LSE's coincident peak load at MISO's peak load multiplied by the PRM. MISO, "Planning Reserve Margin Requirement (PRMR) Allocation," July 9, 2025, available at https://cdn.misoenergy.org/20250709%20RASC%20Item%2006%20PRMR%20Allocation%20(RASC-2020-4%20and%202019-2)705843.pdf, p. 4; MISO, "Planning Resource Auction Results for Planning Year 2025-26," May 29, 2025, available at https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf, p. 36.

[253] *See*, MISO, "Planning Reserve Margin Requirement (PRMR) Allocation, RASC," (Issues RASC-2020-4 and 2019-2), July 9, 2025, available at https://cdn.misoenergy.org/20250709%20RASC%20Item%2006%20PRMR%20Allocation%20(RASC-2020-4%20and%202019-2)705843.pdf.

are most concentrated. These high-risk hours provide a sound basis upon which to define capacity cost allocators. PJM routinely analyses system loss of load risk and identifies the high-risk hours.

High-risk reliability hours can also vary across PJM's large geographic footprint. PJM's capacity market zones provide a natural delineation to evaluate how customer high-risk hours vary across PJM's geography. PJM can rely on its current zonal definitions in evaluating high-risk hours to consider and define cost allocators. With high-risk hours defined geographically, cost allocator identification would then proceed by evaluating zonal demand during high-risk periods.

Second, the definition of cost allocators can be informed by high-risk hour demand, PJM's current capacity cost allocation, and other RTO's/ISO's experience. PJM's high-risk hours will include system peak demands that fall into summer and winter months. PJM can consider adopting a sub-annual 5 CPs cost allocation approach that simply extends its current approach to each sub-annual period. Alternatively, like other RTOs/ISOs, PJM could use only peak demand as a cost allocator in each sub-annual period. Finally, PJM can consider using all high-risk hours to develop cost allocators that then recognize how loss of load risk may be distributed differently in sub-annual periods.

The definition of cost allocators impacts all retail suppliers that are allocated capacity costs in association with directly or indirectly providing consumers retail service. Any change to PJM's capacity cost allocation approach will require EDCs to revise their calculation of PLCs. At a minimum, EDCs will need to modify the processes used to determine PLCs to align with PJM's capacity cost allocators. There will be an associated administrative burden where the newly defined capacity cost allocators would need to be incorporated. An updated process could be relatively straightforward, for example, if PJM elected to use sub-annual 5 CPs for cost allocation. However, a revised process may be more complicated if a larger number of hours was used to determine cost allocation. Moreover, the analysis should consider the possibility that too few cost allocation hours could create an incentive for some customers to adjust their demand during peak periods to decrease capacity payments.

Third, the definition of cost allocators can consider the stability of cost allocation over time as loss of load risk may change.[254] An empirical analysis of historical high-risk hours is a reasonable starting point to evaluate the stability of cost allocators. Using historical data and simulations of how future loss of load risk may vary will provide insight into how cost allocation stability can be balanced against the application of cost causation principles. For example, peak demand hours could become a less stable cost allocator if loss of load risk were spread across a series of hours over one or two months. Moreover, if the distribution of risk across sub-annual periods were materially different over time, it may be necessary to define cost allocators that could change over time. Finally, stability

[254] The stability of cost allocation across sub-annual periods could also be considered. However, capacity cost allocation and recovery must be aligned with PJM's payments to capacity resources. Introducing a misalignment between cost collection and resource payments would result in additional complications that would be inconsistent with sound market design principles.

could be provided by defining intervals at which the cost allocation methodology is reviewed and re-evaluated; metrics could be defined to guide when changes are appropriate.[255]

The adoption of a sub-annual market design will require changes to the current capacity cost allocation methodology. The application of classic ratemaking regulatory principles and empirical analysis of historical high-risk hours will allow PJM and its stakeholders to define a suitable capacity cost allocation methodology.

VII. Quantitative Analysis of Market Outcomes Under Alternative Market Designs

A. Overview of the Model

We develop a market simulation model to quantitatively evaluate the impacts of moving from an annual to a sub-annual capacity market design. Specifically, the model will vary inputs between annual and sub-annual designs in order to account for sub-annual market features, including (1) sub-annual demand and value of capacity; (2) sub-annual resource supply quantity (*i.e.*, accreditation and ELCC/UCAP); and (3) sub-annual resource supply prices (*i.e.*, going forward costs). In addition, the analysis will account for seasonal (winter) resource performance for thermal resources and seasonal transmission system performance.

The simulation model's clearing algorithm follows the logic of the existing BRA optimization formulation.[256] The model first constructs supply and demand curves for RTO and the included LDAs, and then "clears" the market by determining the prices and quantities that maximize total surplus subject to the supply offers, demand curves, and the transmission constraints in each zone (*i.e.*, each LDA's CETL value). The model uses parameter inputs consistent with the 2027/2028 BRA parameters. In addition to an annual market, two sub-annual periods, reflecting a summer (May 1 through October 31) and winter (November 1 through April 30) period are simulated.

We make a number of simplifying assumptions to maintain tractability of the model and focus on the model's intended purposes: to illustrate differences between annual and sub-annual market designs. As such, the model is not a prediction of clearing prices or total customer payments under the current annual market construct or a possible sub-annual market design. The model results are intended to quantify the impacts of the switch to a sub-annual market.

Figure VII-1 provides an illustrative example of how the model clears (assuming no constrained LDAs), where there is excess supply in the market. The model clears the market at the point where the supply and demand

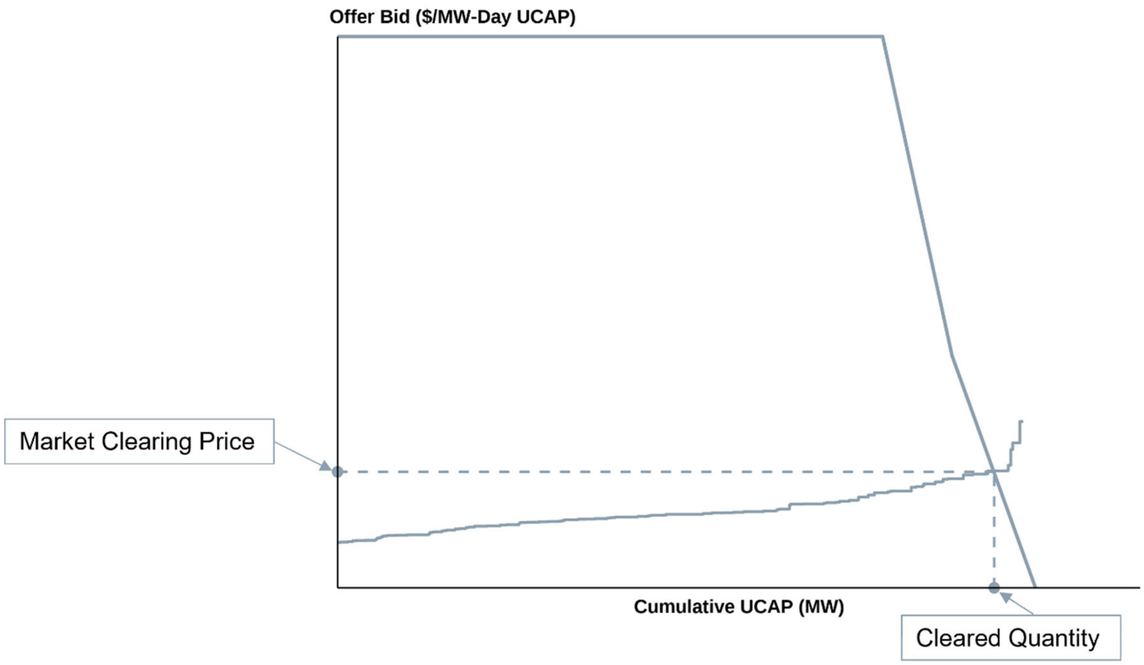
---

[255] For example, MISO is currently evaluating using a pre-defined review interval to help provide cost allocation stability. MISO, "Planning Reserve Margin Requirement (PRMR) Allocation, RASC, (Issues RASC-2020-4 and 2019-2)," July 9, 2025, available at https://cdn.misoenergy.org/20250709%20RASC%20Item%2006%20PRMR%20Allocation%20(RASC-2020-4%20and%202019-2)705843.pdf, p. 8.

[256] PJM, "Base Residual Auction Optimization Formulation," December 12, 2007, available at https://www.pjm.com/-/media/DotCom/markets-ops/rpm/20071212-rpm-optimization-formulation.pdf.

curves intersect. The x-axis at this point represents the quantity of cleared capacity, while the y-axis point is the clearing price.

Figure VII-1: Illustrative Annual Market Clearing

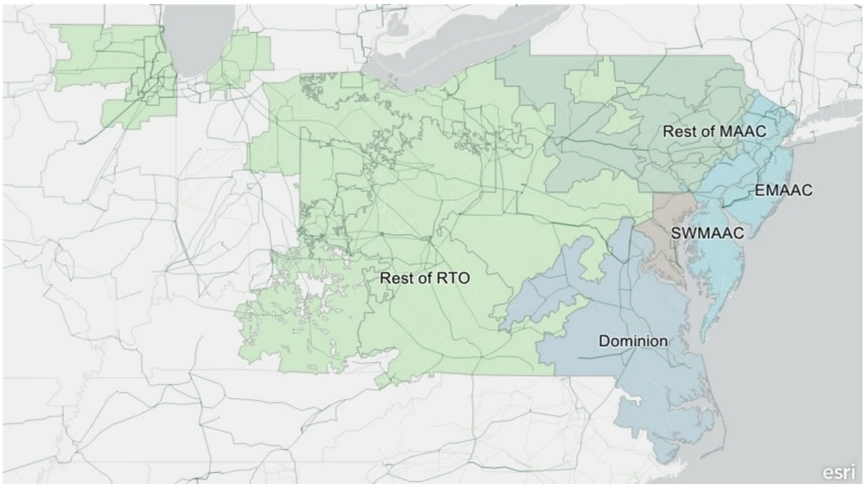


The simulation model includes the RTO and four LDAs: MAAC and two of its subzones, EMAAC and SWMAAC, as well as Dominion ("DOM") (*see* **Figure VII-2**). We include MAAC, EMAAC, and SWMAAC because they are always modeled as constrained LDAs,[257] and we include Dominion as it has a CETL to CETO ratio of less than 115% in the 2027/2028 RPM BRA planning parameters.[258] These LDAs face varied seasonal risks. Specifically, PJM's RA modeling finds that at the PJM-level, 95% of EUE and 76% of LOLE is in the winter, but this share of seasonal risk differs across the modeled LDAs. For example, Dominion has greater than 99% of EUE and LOLE in the winter, while SWMAAC similarly has greater than 99% of EUE and 97% of LOLE in the winter. In contrast, MAAC has 78% of EUE and 67% of LOLE in the summer, and EMAAC has more than 99% of EUE and LOLE in the summer. We do not include additional LDAs that will be modeled as constrained in the 2027/2028 BRA in order to simplify the analysis.

[257] PJM Manual 18: PJM Capacity Market, p. 23.

[258] PJM, "2027/2028 RPM Base Residual Auction Planning Parameters," November 4, 2025, available at https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2027-2028/2027-2028-planning-period-parameters-for-base-residual-auction.xlsx.

Figure VII-2: LDAs Included in Model Simulation



We do not include the temporary price cap and floor that was used in the 2027/2028 BRA, nor do we consider qualifying transmission upgrades. Each sub-period will be solved independently and simultaneously. All supply offers are assumed to be rationable, meaning that the marginal resource may only clear part of its offered capacity.

The simplification of the analysis allows for flexibility of model parameters in order to explore the differences between annual and sub-annual designs. The analysis will include the use of demand curves consistent with the three-point VRR demand curve design reflecting current market rules, as well as MRI-based demand curves. It will also allow for differences in supply offer characteristics, demand curve formulations, and CETL levels.

The model will adjust the demand and supply curves to account for differences between sub-annual periods. For example, changes in the supply curve include accounting for differences in the Net ACR in each season (given seasonal differences in net EAS revenues) and seasonal ELCC accreditation. Changes to the demand curve stem from adjustments to reflect differences in the willingness to pay for avoided EUE in each season due to differences in reliability risks or allocation of reference technology cost recovery between sub-annual periods. In addition, the model will adjust capacity import limits (*i.e.*, CETLs) to account for differences between sub-annual periods.

B. Scenarios Evaluated

To better understand potential outcomes and market design considerations of a shift from an annual to a sub-annual market design, multiple scenarios reflecting a variety of market circumstances and potential design options are evaluated:

1. **Alternative market conditions**
    a. **Base Scenario**, reflecting conditions with excess supply, consistent with all but the most recent BRA auctions.
    b. **Current Market Scenario**, reflecting current market conditions where supply is short.

2. **Demand curve alternatives**
   a. **VRR demand curves**, reflecting the demand curve construct and formulations under current PJM market rules.
   b. **MRI-based demand curves**, that provide a shape and slope directly derived from resource adequacy modeling outputs, rather than the VRR demand curves' three-point formulation. The shape of an MRI-based demand curve reflects the marginal impact of incremental capacity on reliability.

In each scenario, the impacts of a sub-annual market reflect the difference in outcomes between a current markets case and a sub-annual markets case. The sub-annual markets case reflects three changes from the current market:

1. Adoption of a sub-annual market
2. Accounts for seasonal (winter) resource performance of thermal gas-fired resources
3. Accounts for seasonal (winter) transmission system performance (*i.e.*, CETL values)

The section that follows provides more details on all of these assumptions.

C. Input Data and Assumptions

The capacity market simulation model requires many data inputs and assumptions in order to construct supply curves, demand curves, and transmission constraints in order to simulate the differences between an annual and sub-annual market construct. Below, we discuss the key inputs informing the supply curves, demand curves, and LDA CETL values.

1. Supply Curves

a. Sources of data and assumptions for resource mix and sell offers

Resource Mix. The supply curve resource mix consists of (1) the RPM existing resource list for the 2027/2028 Delivery Year,[259] excluding announced deactivations on or before June 1, 2027,[260] (2) the quantity of demand resources and external resources that offered in the 2026/2027 Delivery Year BRA,[261] and (3) additional capacity in order to align with the 2027/2028 assumed resource portfolio used by PJM to derive the planning period

[259] PJM, "RPM Existing Resource List," September 4, 2025, available at https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2027-2028/2027-2028-rpm-existing-resource-list-post.xlsx.

[260] PJM, "Generator Deactivations," available at https://www.pjm.com/planning/service-requests/gen-deactivations, accessed December 1, 2025.

[261] PJM, "2026/2027 Base Residual Auction Report," July 22, 2025, available at https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2026-2027/2026-2027-bra-report.pdf.

parameters for the base residual auction.[262] The resource mix does not include aggregate resources, does not include resources that would offer in a single season, and is not adjusted for FRR entities. Each resource is accredited with an Unforced Capacity (UCAP) value equivalent to its ICAP (or effective nameplate capacity for certain variable renewable resources) times its technology class's ELCC.[263]

Resource Offers. Offers from resources participating in the capacity market include a quantity and price. The quantity of capacity offered reflects the unit's UCAP, calculated as a function of the unit's ELCC and its ICAP or effective nameplate capacity. Offer prices reflect estimated going forward avoidable costs. Under the current market rules, these offers reflect a resource's Net ACR, which equals the difference between a resource's *gross ACR* and its *net energy and ancillary service ("EAS") revenues*.[264] Gross ACR in our simulations is equivalent to the default gross ACR values for the 2027/2028 BRA.[265] Annual net EAS revenues are resource-specific and provided by PJM. Resource class types for which gross ACR data is unavailable are assumed to offer at $0/MW.[266]

Figure VII-3 below shows the resulting supply curve of the resource mix and the associated sell offers for the annual construct for RTO. LDA supply curves are constructed based on the LDA of each resource as specified in the RPM existing resource list.

[262] PJM, "Installed Reserve Margin (IRM), Forecast Pool Requirement (FPR), and Effective Load Carrying Capability (ELCC) for 2027/2028 BRA," July 23, 2025, available at https://www.pjm.com/-/media/DotCom/committees-groups/committees/mrc/2025/20250723/20250723-item-04---1-2027-2028-bra-fpr-and-irm---presentation.pdf.

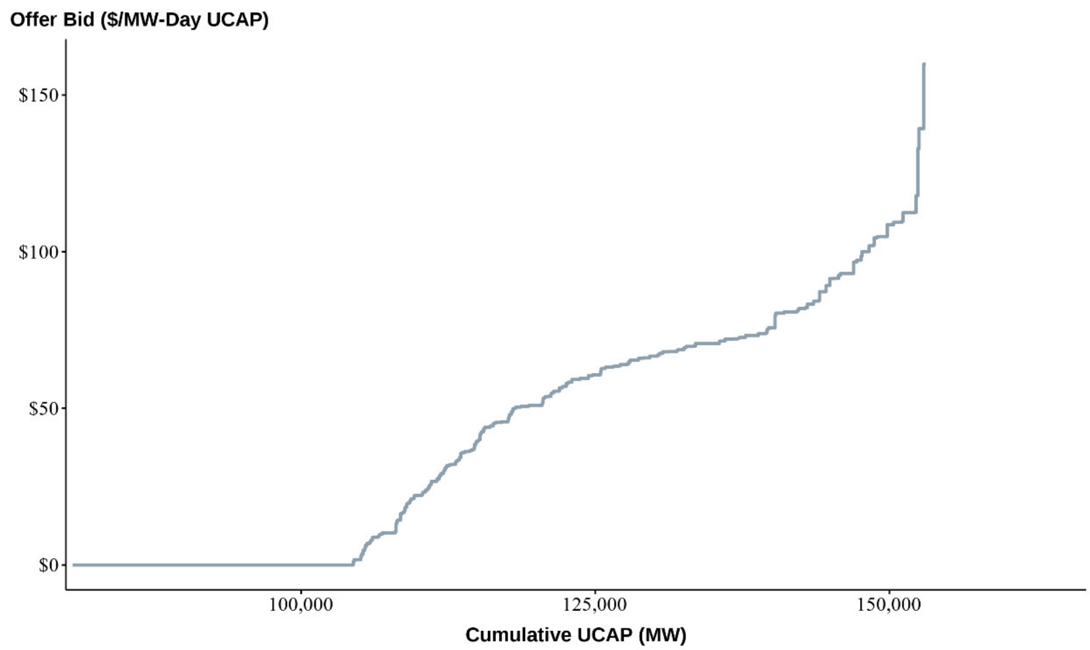
[263] ICAP is derived from the RPM existing resource list, *see, for example,* PJM, "RPM Existing Resource List," September 4, 2025, available at https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2027-2028/2027-2028-rpm-existing-resource-list-post.xlsx. Annual ELCC is consistent with 2027/2028 parameters. PJM, "ELCC Class Ratings for the 2027/2028 BRA," available at https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2027-28-bra-elcc-class-ratings.pdf.

[264] PJM Manual 18: PJM Capacity Market, p. 126.

[265] PJM, "Default Gross ACR for MOPR Prices specified in OATT Attachment DD.5.14(h-2)(3)(B)," available at https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2027-2028/2027-2028-default-gross-acr-values-for-mopr-and-msoc-purposes.xlsx.

[266] These resource class types assumed to offer at $0/MW include offshore wind, storage, demand resource, hydro intermittent, and diesel utility.

Figure VII-3: Annual Capacity Supply Curve (RTO)



b. Changes in supply offers moving from an annual to a sub-annual market structure

First, in order to account for variation in sub-annual accreditation as discussed in **Section V.A.2**, a resource's capacity accreditation (*i.e.,* ELCC) will differ by season. The seasonal ELCC values used in the model are provided by PJM and are the result of the same resource adequacy modeling process used to develop the annual ELCC values for the 2027/2028 BRA. **Table VII-1** below summarizes the ELCC ratings for annual, summer, and winter. Most resource classes have higher ELCC ratings in the summer than winter (*e.g.,* combined cycle, combustion turbine, solar, and demand resources). Certain resource classes (*e.g.,* onshore wind) have significantly higher ELCC ratings in the winter than summer, while others have similar accreditation in both seasons (*e.g.,* nuclear). The different ELCC values result in different UCAP values (*i.e.*, MW) that resources can offer in each season.

Table VII-1: Annual and Seasonal ELCC Values for Selected Class Types[267]

Class Type	Annual	Summer	Winter
4-hr Storage	0.58	0.94	0.54
6-hr Storage	0.67	0.98	0.63
8-hr Storage	0.70	0.93	0.67
10-hr Storage	0.78	0.97	0.76
Coal	0.83	0.87	0.83
Demand Resource	0.92	1.09	0.90
Diesel Utility	0.92	0.97	0.91
Gas Combined Cycle	0.74	0.96	0.72
Gas Combustion Turbine	0.61	0.97	0.56
Gas Combustion Turbine Dual	0.77	0.96	0.75
Hydro Intermittent	0.39	0.39	0.39
Landfill Intermittent	0.48	0.58	0.46
Nuclear	0.95	0.96	0.95
Offshore Wind	0.67	0.22	0.73
Oil Fired Combustion Turbine	0.80	0.96	0.77
Onshore Wind	0.41	0.09	0.44
Solar Fixed	0.07	0.17	0.05
Solar Tracking	0.08	0.28	0.06
Steam	0.72	0.89	0.70
Waste to Energy Steam	0.83	0.92	0.81

Notes: [1] Summer and winter ELCC values derived from same modeling process used to derive annual ELCC and are provided by PJM. [2] Hydro with non-pumped storage, gas combined cycle dual, other unlimited, and complex hybrid resources excluded from this table but not from the model, consistent with the resource types shared publicly by PJM.

Second, in order to account for sub-annual variation in resource going forward costs, as discussed in **Section V.A.4**, a resource's net EAS revenues, and thus its net EAS offset, will differ by season. A resource's seasonal share of the net EAS offset differs in the model by resource type and LDA, reflecting differences in local conditions. **Figure VII-4** below shows the ICAP-weighted share of the net EAS offset for different resource types. For example, on average, onshore wind receives more revenue in the winter than in the summer, while solar and gas resources (*i.e.*, combined cycle, CC, and combustion turbine, CT), have a greater share of the revenues in the summer. Coal, on average, receives about half of its revenues in each season.

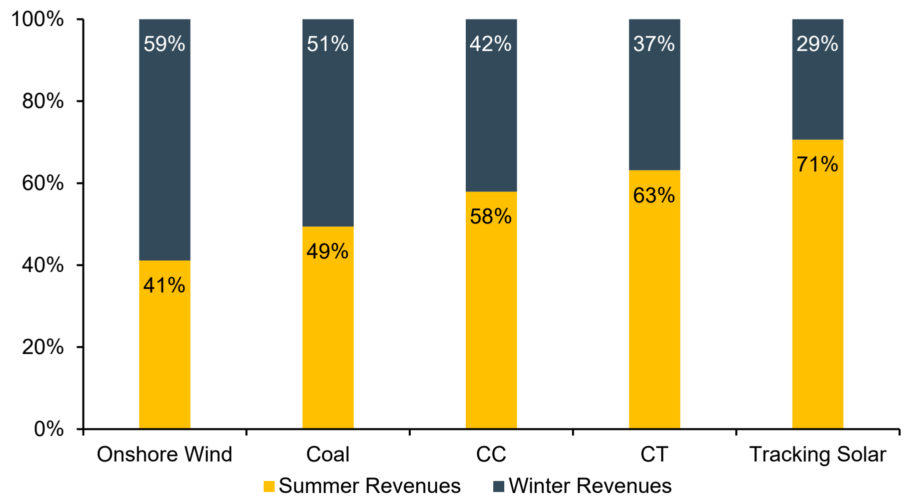
[267] **Sources:** [A] PJM, "ELCC Class Ratings for the 2027/2028 BRA," available at https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2027-28-bra-elcc-class-ratings.pdf. [B] Summer and Winter ELCC values provided by PJM.

Winter and summer offer prices are set to the unit's "average, all-in" price. With this approach, the resource's offer reflects its gross avoidable costs in each season adjusted for seasonal net EAS revenues – that is:

$$Offer\ Price_{season} = \frac{Gross\ Avoidable\ Costs_{season} - Net\ EAS_{season}}{UCAP_{season}}$$

These offers are consistent with an approach to mitigation of capacity market offer prices in which resources offer prices reflecting the assumption that the resources clear in all seasons and that resource owners cannot offer above this price to account for the possibility that its unit clears in one season but not the others. This is one approach to mitigated offers, but not the only approach. It is an approach consistent with market mitigation of NYISO's ICAP market.[268]

Figure VII-4: Share of Annual Net EAS Revenues by Season for Selected Class Types[269]
Weighted Averages Across Zones



Note: Weighted averages are calculated using zonal ICAP as weights.

Third, in order to represent that certain resources will have greater non-summer performance, as discussed in **Section V.A.2**, certain resources' performance that vary with ambient conditions will have adjusted ICAP ratings in the winter. The current RPM ICAP ratings are based on summer performance. However, certain thermal resources, particularly combined cycle and combustion turbine units, have higher potential ICAP ratings in the winter above their current CIR values.[270] Therefore, we increase these thermal resources' ICAP ratings by 50% of

---

[268] NYISO, Installed Capacity Manual 04, December 2025, available at https://www.nyiso.com/documents/20142/2923301/icap_mnl.pdf.

[269] Hourly modeled net EAS data by technology type, provided by PJM.

[270] **Sources:** [A] PJM, "Capacity Accreditation Enhancements – Unit-Specific," available at https://www.pjm.com/-/media/DotCom/committees-groups/task-forces/elccstf/postings/elcc-capacity-accreditation-methodology-problem-statement.pdf. [B] PJM, "ELCC Accreditation Methodology: Update on Sensitivity Analyses," May 22, 2025, available at https://www.pjm.com/-

the difference between their current annual ICAP and winter capacity rating reported to EIA.[271] **Table VII-2** below summarizes the aggregate ICAP rating and higher winter capacity rating for the class types we adjust in the model. We implement a 50% adjustment, rather than the full rating, because we recognize that a higher winter ICAP would impact the resource adequacy analysis, necessitating a change to the demand curves, as well as annual ELCC values.[272] Because we are unable to re-run the resource adequacy and ELCC analysis to obtain the necessary demand curve and updated ELCC parameters, we allow for a partial adjustment that does not account for the likely full increase in winter ICAP values, in order to mitigate that we are not also adjusting the existing annual parameters.[273]

Table VII-2: Total ICAP & Adjusted Winter ICAP for CC and CT Units

Class Type	Total ICAP (MW)	Adjusted Winter ICAP (MW)	Additional Winter ICAP (MW)
Combined Cycle	57,391	59,018	1,627
Combustion Turbine	26,366	28,157	1,791
Total	**83,757**	**87,175**	**3,418**

The resulting supply curves for the summer and winter sub-annual periods are shown below in **Figure VII-5**. Compared to the annual curve, the summer curve is shifted to the right because the resource mix, on average, has a higher ELCC value in summer than annually. Offers for units are generally lower in the summer, on a $/MW-Day basis, as most (but not all) units have higher net EAS revenues in the summer than in the winter, shifting the curve down.

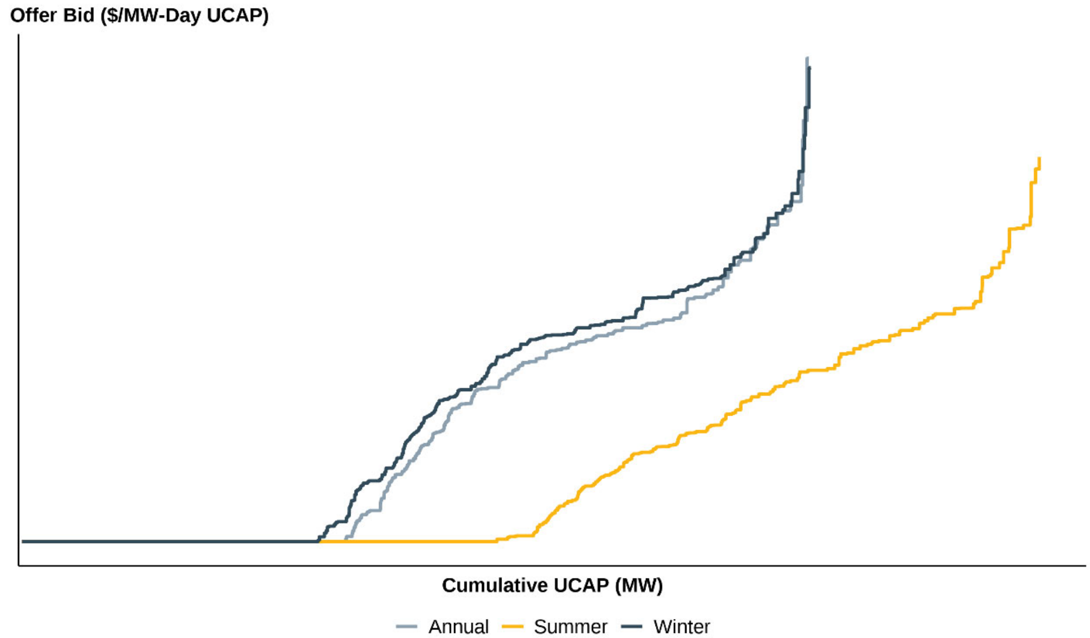
/media/DotCom/committees-groups/task-forces/elccstf/2025/20250522/20250522-item-02---elcc-accreditation-methodology-update-on-sensitivity-analyses---pjm-presentation.pdf, p. 16.

[271] Winter capacity ratings compiled by Hitachi Energy Velocity Suite, which sources the data from EIA Form 860.

[272] For example, preliminary analysis by PJM estimated that allowing for a winter ICAP would reduce the IRM by 1.1% and reduce the winter LOLH risk share by 33%. PJM, “ELCCSTF Accreditation Proposal: PJM Package C (MRC Main Motion),” August 20, 2025, available at https://www.pjm.com/-/media/DotCom/committees-groups/committees/mrc/2025/20250820/20250820-item-04b---1-pjm-elccstf-proposal-c---presentation.pdf, p. 20. Preliminary analysis by PJM also found that a winter ICAP could increase the annual ELCC for CC resources to 0.84, and increase the annual ELCC for CT resources to 0.90. PJM, “ELCC Accreditation Methodology: Update on Sensitivity Analyses,” May 22, 2025, available at https://www.pjm.com/-/media/DotCom/committees-groups/task-forces/elccstf/2025/20250522/20250522-item-02---elcc-accreditation-methodology-update-on-sensitivity-analyses---pjm-presentation.pdf, p. 25.

[273] For example, preliminary analysis by PJM found that winter ICAP of certain resource types was 8,561 MW greater than summer ICAP, compared to the 3,418 MW we assume in our adjusted value. This winter ICAP value used by PJM extended to other thermal resources beyond CC and CT units – *i.e.*, nuclear, coal, diesel, steam, and other thermal resources also had a winter ICAP higher than summer ICAP. PJM, “ELCC Accreditation Methodology: Update on Sensitivity Analyses,” May 22, 2025, available at https://www.pjm.com/-/media/DotCom/committees-groups/task-forces/elccstf/2025/20250522/20250522-item-02---elcc-accreditation-methodology-update-on-sensitivity-analyses---pjm-presentation.pdf, p. 16.

Figure VII-5: Annual and Seasonal Capacity Supply Curves (RTO)[274]



Compared to the summer supply curve, the inverse of above is true in the winter. The winter curve is shifted to the left because the resource mix, on average, has a lower ELCC value in winter than annually. Offers for units are generally higher in the winter than annually as, on a $/MW basis, most units have lower net EAS revenues in the winter than in the summer, shifting the curve up. However, adjusting winter ICAP for CC and CT will have the opposite effect. These units will have their UCAP increased, resulting in a shift of the curve to the right, where these units lie on the curve. Offers for these units will also decrease, as the dollars per MW (UCAP) needed to recover their Net ACR is less given their adjusted higher ICAP values, shifting the curve down. On net, however, the winter supply curve is generally to the left of the annual curve, although the curves are very close to one another, and in fact cross, at the highest bid levels.

[274] Chart displays annual, summer and winter capacity supply curves for PJM. Winter capacity supply reflects a winter ICAP adjustment of 50% for Combined Cycle and Combustion Turbine units. Annual UCAP: 153,092 MW; Summer UCAP: 177,298 MW; Winter UCAP: 153,295 MW. Max bids- Annual: $159.85; Summer: $127.19; Winter: $156.65.

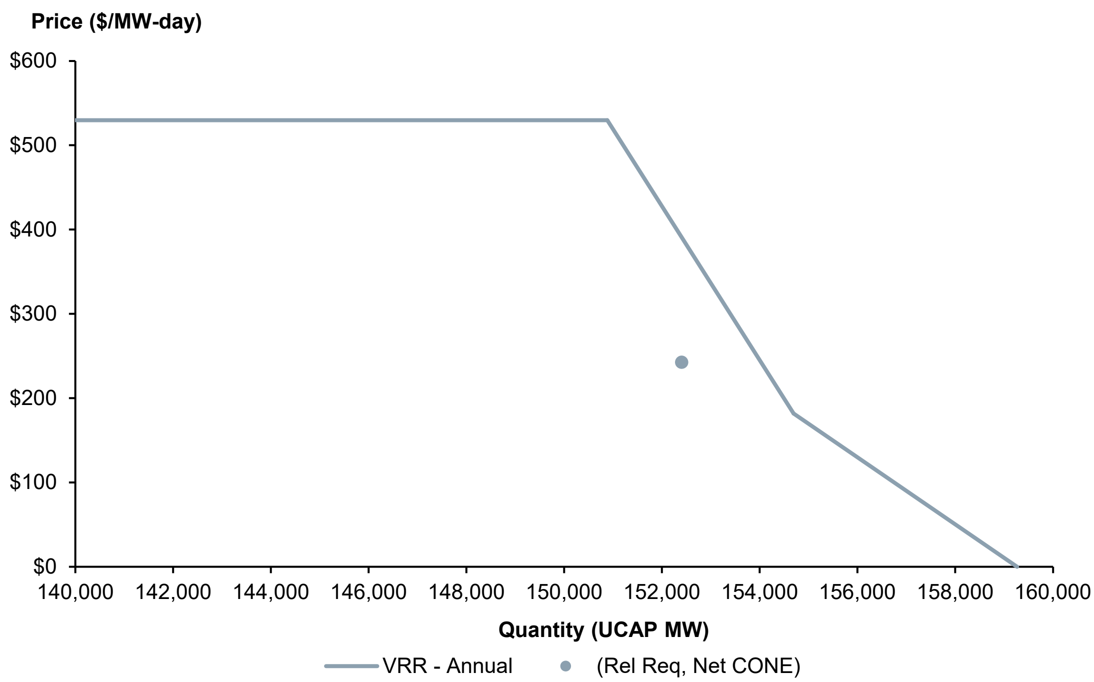
2. Demand Curves

a. VRR demand curves

The PJM RPM capacity market currently clears the supply of resource offers against a downward sloping VRR demand curve that is determined based on the system reliability requirement and the net cost of new entry of a reference resource.[275]

Annual VRR Demand Curves. We construct the three-line annual VRR demand curves following the formulas specified in PJM Manual 18 for the 2027/2028 BRA, except that we do not include the temporary price cap and price floor.[276] **Figure VII-6** below shows the downward-sloping VRR demand curve for RTO constructed using these formulas, which are anchored by the reliability requirement and Net CONE value reported in the 2027/2028 planning parameters. The Base Scenario reduces the reliability requirement by 5 GW. We similarly follow the same formula to develop annual VRR demand curves for each modeled LDA, relying on the LDA-specific parameters (*i.e.*, reliability requirement and Net CONE).

Figure VII-6: Annual RTO VRR Demand Curve



[275] PJM Manual 18: PJM Capacity Market, p. 116.

[276] PJM Manual 18: PJM Capacity Market, p. 34.

Sub-Annual RTO VRR Demand Curves. We develop seasonal VRR demand curves in order to account for the sub-annual variation in the value of capacity, as discussed in **Section V.A.1**, by specifying a curve that preserves the shape of the annual demand curve, but adjusted to be anchored at a seasonal reliability requirement and Net CONE. The seasonal RTO reliability requirements are determined by multiplying the annual reliability requirement by the ratio of the seasonal to annual pool-wide accredited UCAP factor. The seasonal Net CONE values are determined based on the marginal avoided EUE per MW UCAP at the seasonal reliability requirement multiplied by the annual scalar, divided by the number of days in each season. **Table VII-3** reports the annual and seasonal reliability requirements and Net CONE values for RTO.

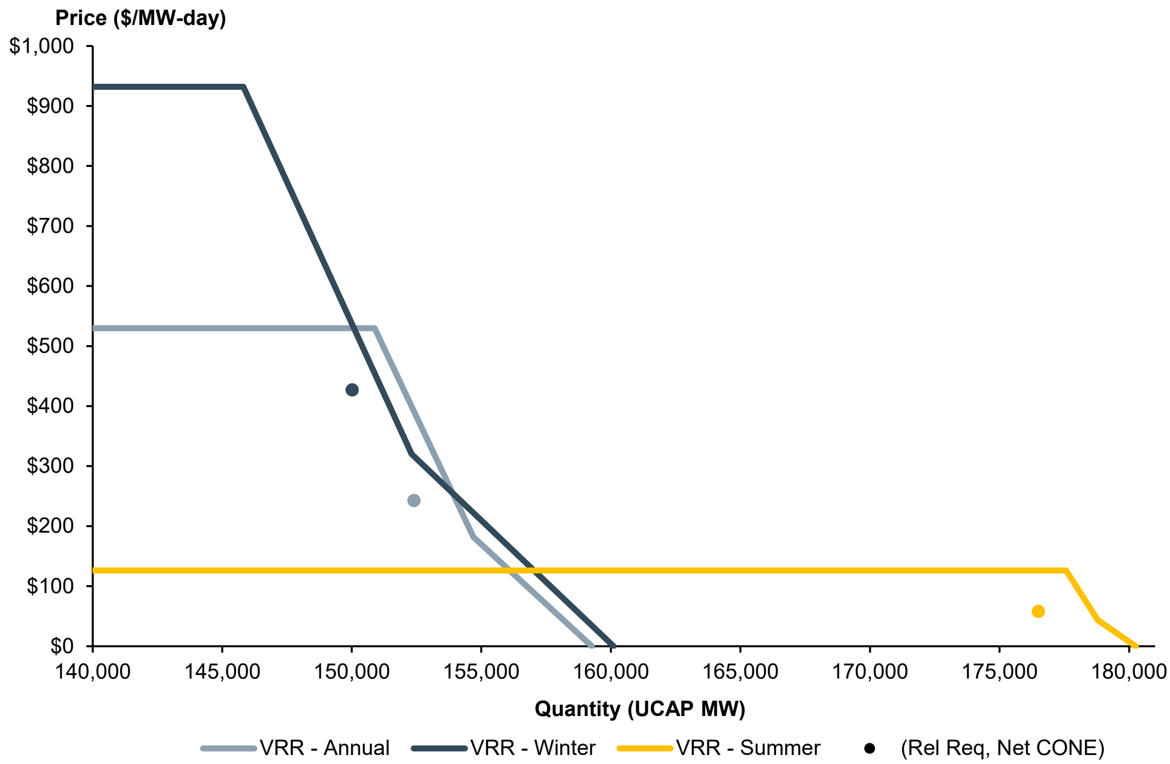
In order to construct the sub-annual demand curves, we take the following steps to adjust the annual curves: (1) shift the B point of the VRR demand curve up/down based on the seasonal Net CONE value (*i.e.*, move the B point up/down to reach 0.75 times the seasonal Net CONE value); (2) shift the B point along the x-axis in each season based on the difference in the seasonal reliability requirement relative to the annual reliability requirement; (3) set the price cap based on the existing formula of max (gross CONE, 1.75*Net CONE), but using the seasonal gross and Net CONE values; (4) extend a line from the B point to the price cap, with the same slope as the A-B line on the annual VRR curve, where this slope is adjusted for the difference in the UCAP factor between annual and the season in order to preserve consistent changes in $ per MW-day; (5) extend a line down from the B point to the x-axis, following a line with the same slope as the B-C line on the annual VRR curve, where this slope is adjusted for the difference in the UCAP factor between annual and the season. Preserving the slope of the A-B and B-C line from annual to sub-annual preserves the marginal willingness to pay for additional capacity across seasons and annually.

Table VII-3: RTO Demand Curve Anchor Points

	Reliability Requirement Base Scenario (MW UCAP)	**Reliability Requirement Current Market Scenario (MW UCAP)**	**Net CONE Both Scenarios ($/MW UCAP)**
Annual	147,400	152,400	$242.52
Summer	170,714	176,505	$57.80
Winter	145,102	150,024	$426.70

Figure VII-7 shows the annual, summer, and winter VRR demand curves for RTO used in the model. As there is more risk in the winter than in the summer, the price cap is higher in the winter and lower in the summer, reflecting a higher willingness to pay for additional capacity in the winter than the summer. Resources generally have a higher ELCC in the summer, and a lower ELCC in the winter, meaning that the pool-wide accredited UCAP factor in the summer is higher than annual, and the winter is lower than annual. Thus, the winter curve is slightly steeper than the annual curve, and the summer curve is slightly flatter than the annual curve.

Figure VII-7: RTO Annual, Summer and Winter VRR Demand Curves



Sub-Annual LDA VRR Demand Curves. The development of sub-annual VRR LDA demand curves follows the approach to developing sub-annual VRR RTO demand curves – *i.e.*, relying on LDA-specific reliability requirements, shares of reliability risk in each season, and seasonal UCAP factors. LDA-specific reliability requirements rely on the sum of internal UCAP values and CETO. Internal UCAP values differ by season and are provided by PJM. We assume that CETO values in each season are equivalent to the annual CETO to ensure the reliability requirement in each season is consistent with the annual reliability requirement. Seasonal price caps are set using the formula used for the system-wide curves or the price cap of the parent LDA or RTO, whichever is greater.[277] The price caps are shown below in **Table VII-4**.

[277] The use of the parent LDA seasonal price cap as a lower bound is due to the nested, non-additive structure of the LDA demand curves. For example, a resource in EMAAC is included in the supply curve towards the demand curve in EMMAC, MAAC, and RTO. If the price cap in EMAAC was lower than MAAC in a season, and MAAC was constrained while EMAAC was not, then resources in EMAAC would prefer to clear in MAAC.

Table VII-4: Price Caps for Annual and Sub-Annual VRR Demand Curves

RTO/LDA	Annual ($/MW UCAP)	Summer ($/MW UCAP)	Winter ($/MW UCAP)
RTO	$ 529.80	$ 126.27	$ 932.16
DOM	$ 542.83	$ 126.27	$1,105.51
MAAC	$ 527.62	$ 616.50	$ 932.16
EMAAC	$ 627.97	$1,081.68	$ 932.16
SWMAAC	$ 523.74	$ 616.50	$1,047.69

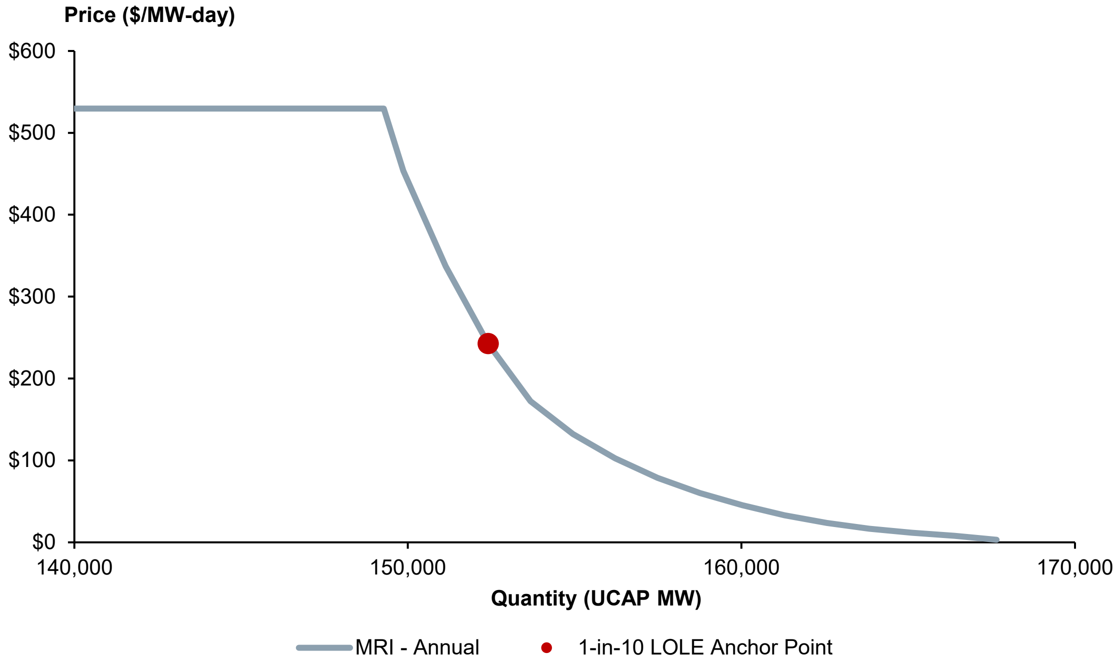
b. MRI demand curves

As an alternative to the VRR demand curves, we also evaluate MRI demand curves in the simulation model. As discussed in **Section VI.B.2**, if a sub-annual market is adopted, MRI demand curves are an option to replace the existing VRR construct.

Annual MRI Demand Curves. We construct annual MRI demand curves using results from PJM's resource adequacy modeling that includes the LOLE and EUE for varying levels of the installed reserve margin (IRM). The curve is derived such that the marginal value of capacity declines as the IRM increases, and the willingness to pay for avoided EUE is constant.[278] The willingness to pay for avoided EUE is tied to the annual Net CONE value of the reference technology. The curve is anchored at the 1-in-10 LOLE point, reflecting the annual reliability requirement and Net CONE value, using the same anchor points as for the VRR demand curves (**Table VII-3**). **Figure VII-8** below shows the annual MRI curve for RTO. LDA annual demand curves are constructed in the same manner, although they are anchored at the more stringent reliability criteria of 40% of the RTO normalized EUE at the 1-in-10 criteria, and the willingness to pay for avoided EUE is derived from the LDA-level Net CONE value as reported in the planning parameters. The price caps used are the same as the VRR demand curves.

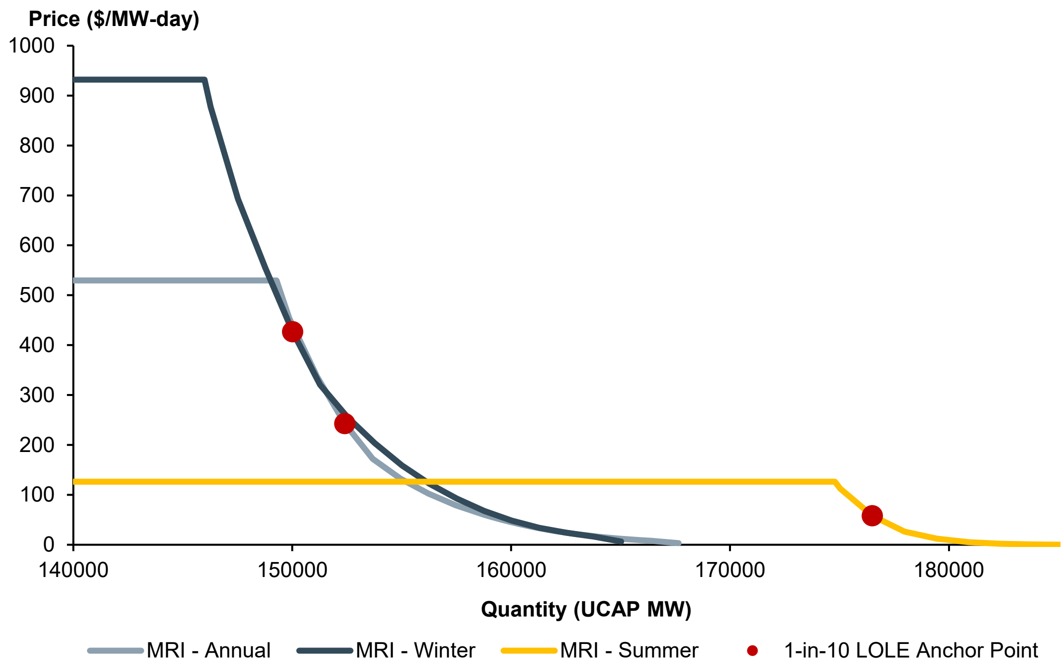
[278] MRI curves are used by other RTOs, such as ISO-NE. ISO-NE, "Capacity Auction Reforms: Seasonal/Accreditation (CAR-SA)," December 9, 2025, available at https://www.iso-ne.com/static-assets/documents/100030/a04.1.c_mc_rc_2025_12_09-10_seasonal_concepts_risk_split_determination.pdf.

Figure VII-8: Annual MRI Demand Curve



Sub-annual MRI Demand Curves. Similar to the VRR demand curves, the sub-annual demand curves are constructed in order to account for sub-annual variation in the value of capacity. The construction is based on the same method as the annual demand curves, anchoring at the same points as the VRR demand curves (**Table VII-3**), where the annual EUE at the annual 1-in-10 LOLE is split between the two seasons. This means that the marginal willingness to pay reflects the difference in the marginal avoided EUE, but the annual WTP per avoided EUE is preserved across each season. The price caps used are the same as the VRR demand curves. **Figure VII-9** below shows the resulting summer and winter demand curves for RTO. The LDA MRI demand curves are constructed similarly.

Figure VII-9: Annual, Summer and Winter MRI Demand Curves



3. LDA Transmission Constraints

Locational constraints caused by transmission facility limitations or voltage limitations are represented in the PJM RPM by an LDA's CETL and CETO, as discussed in **Section VI.B.4**. The CETL value represents the amount of capacity, in MW, that can be imported into an LDA from the rest of PJM during a capacity emergency. The CETO is the minimum amount of capacity that it must be possible to import into an LDA to maintain reliability during a capacity emergency, and is represented as the difference between an LDA's internal UCAP and reliability requirement. The CETL and CETO values as specified in the 2027/2028 RPM planning parameters are used for the annual market. As discussed in the prior section, we assume the annual CETO for the seasonal market.

For seasonal CETL values, we adjust the winter value in order to account for sub-annual variation in system performance, as discussed in **Section V.A.3**. Currently, PJM determines the annual CETL values based on the summer peak values of an LDA. Thus, we assume that summer CETL values are equivalent to the annual values. However, winter CETL values will differ from summer values, and in particular, may be higher due to ambient conditions. PJM is currently evaluating different CETL values for the winter, and thus does not have information available on if, or how much, winter CETL values would differ from the current summer-based CETL values.[279] However, information on differences in winter and summer inter-zonal capacity import ratings from MISO, NYISO, and NERC suggest that it is reasonable to expect that winter CETLs would, on average, be greater than the

[279] PJM, "Effective Load Carrying Capability Senior Task Force," available at https://www.pjm.com/committees-and-groups/task-forces/elccstf, accessed December 3, 2025.

existing summer-based CETL values.[280] In the model, we assume that winter CETL values are 5% higher than the summer CETL values, as shown in **Table VII-5**. In practice, the difference between existing summer-based CETL values and winter CETL values would vary between LDAs based on their specific characteristics, where some may see larger increases, and others may see smaller increases, or even decreases relative to the existing values.

Table VII-5: Annual and Seasonal CETL Values by LDA (MW)

LDA	Annual CETL	Summer CETL	Winter CETL
DOM	6,598	6,598	6,928
MAAC	2,598	2,598	2,728
SWMAAC	6,698	6,698	7,033
EMAAC	8,025	8,025	8,426

4. Limitations and Factors Not Accounted For

Our analysis accounts for multiple important differences in demand, supply, and system performance between the current annual capacity market and a sub-annual alternative. However, our analysis does not account for all of the differences between an annual and sub-annual market, including many important potential benefits and costs identified in **Section V**. In addition, our model is a static snapshot of one year and one set of reliability risks. As such, it does not account for general equilibrium effects of a sub-annual capacity market construct – *i.e.*, increased efficiency due to entry/exit accounting for sub-annual differences that will be achieved over a longer time horizon. In addition, it does not explore outcomes under a different seasonal resource adequacy risk profile (*e.g.,* one with more EUE in the summer relative to winter). Thus, our analysis does not account for the full range of potential outcomes, and under certain market conditions and assumptions, the outcomes could be higher or lower than those reported here. As such, the reader should not interpret any of the results as predictive or indicating a directional change with certainty.

D. Results

This section summarizes the results of the quantitative modeling of the capacity market under the annual and sub-annual market structures. *First*, results from the Base Scenario are discussed. *Second*, we discuss results from the Current Market Scenario. *Third*, we discuss results that disaggregate the impacts of the different components of the sub-annual case. *Fourth*, sensitivities for both scenarios are discussed. *Fifth*, we discuss the results of an exercise showing possible cost recovery of resources clearing in a single season.

[280] MISO, "Planning Year 2025-2026 Loss of Load Expectation Study Report," available at https://cdn.misoenergy.org/PY%202026-2027%20LOLE%20Study%20Report728909.pdf, Table 4-3; "NYISO Operating Study Winter 2024-2025", available at https://www.nyiso.com/documents/20142/47402002/Winter2024-25%20Operating%20Study%20Report%20DRAFT.pdf/9e5188aa-6f9f-0b43-117d-24906bb04ecd; "NYISO Operating Study Summer 2025," available at https://www.nyiso.com/documents/20142/3691300/Summer2025-OperatingStudy-APPROVED.pdf/3aaa5eb6-9fa4-53b5-181a-189e3ac52fcb; NERC, "Interregional Transfer Capability Study (ITCS)," November 2024, available at https://www.nerc.com/globalassets/initiatives/itcs/itcs_part2_part3.pdf, Chapter 7, pp. 74-76.

1. *Summary of Base Scenario Results*

The Base Scenario assumes current market information with certain adjustments to balance supply and demand. It is intended to be one potential scenario and is not intended to represent a preferred, most likely, or most relevant scenario.

a. VRR demand curve

Figure VII-10 below illustrates market clearing for the RTO with VRR demand curves in the Base Scenario. The annual RTO clearing price is $112.43/MW-day, consistent with clearing prices from the 2016/2017 to 2024/2025 BRAs which ranged from $28.92/MW-day to $164.77/MW-day and averaged $85.97/MW-day.[281] The winter clearing price is $122.43/MW-day and summer is $77.24/MW-day. However, these prices are not directly comparable as the MW are denominated in each auction's UCAP values which differ based on the relative accreditation of the units clearing the auction.

Figure VII-10: Base Scenario Market Clearing, VRR Demand Curve

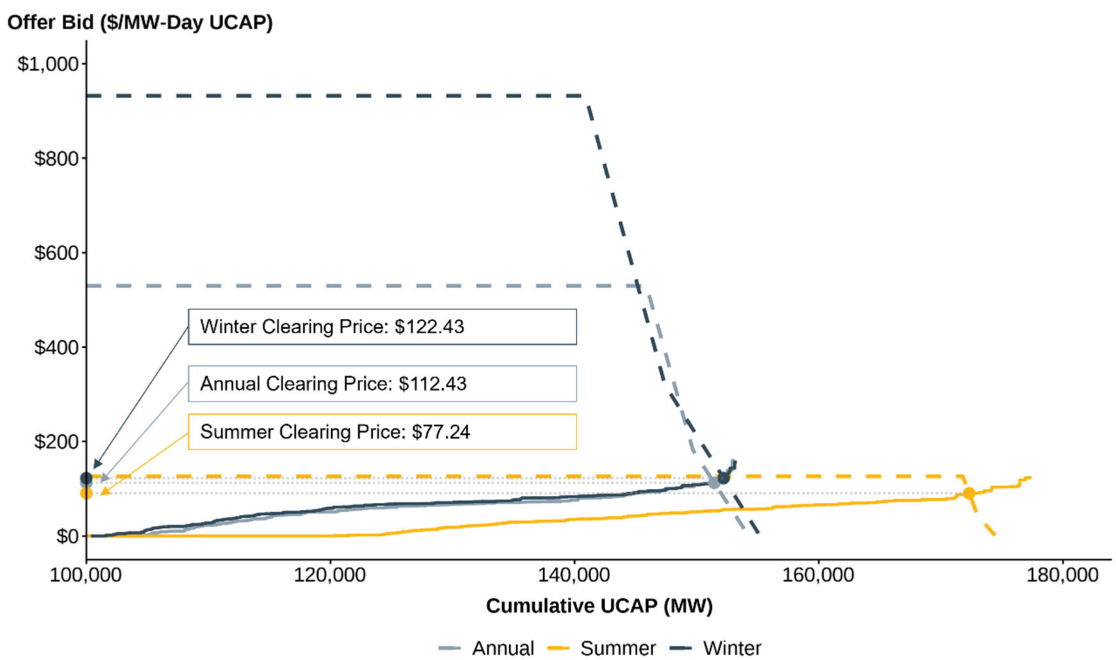


Table VII-6 summarizes the results for the RTO and each LDA, including clearing price, cleared and uncleared capacity, capacity payments, production costs and EUE. **Figure VII-11** summarizes the differences in percentage

281 PJM, Base Residual Auction Data, RPM Capacity Market Annual Reports, available at https://www.pjm.com/markets-and-operations/rpm.

terms for clearing price, capacity payments, production costs, and EUE between annual and sub-annual markets.[282]

Clearing prices in the annual market are $112.43 per MW-day for RTO, and the LDAs clear at the RTO price, as none of the LDAs are constrained. In the summer market, the RTO clearing price is $77.24. Three of the LDAs are constrained, with Dominion clearing at $92.10, MAAC clearing at $103.60, and EMAAC at $118.74. The UCAP-weighted average clearing price for the summer market is $91.17. In the winter market, the LDAs clear at the RTO price of $122.43, as none of the LDAs are constrained. The UCAP-weighted average price for the seasonal market overall, in annual UCAP terms, is $114.26, 2% more than the annual market price.

In the annual market, 151,437 MW of annual UCAP clears and 1,655 MW does not clear. In the seasonal market, 172,506 MW of summer UCAP clears, with 4,792 MW not clearing, and 152,205 MW of winter UCAP clears, with 1,089 MW not clearing. The annual UCAP-equivalent capacity clearing in the seasonal market is 150,294 MW, 0.8% less than in the annual market.

Total capacity payments are $6,232 million in the annual market, which is slightly less than the $6,285 million in total capacity payments in the seasonal market (less than 1% difference), of which $2,894 million is in summer and $3,391 million is in the winter.

In the annual market, total production costs are $1,144 million, compared with $1,098 million in the seasonal market ($451 million in summer and $647 million in the winter), a 4% difference. The difference in production costs reflects differences in the capacity clearing and receiving a full annual capacity commitment between the annual and seasonal markets. Production costs reflect (short-run) going forward costs, as accounted for in resource offers, and do not reflect any return on or of sunk capital investment. These estimates thus do not account for any long-run reduction in production costs due to efficiency gains from more efficient capital investment and retention decisions. However, reductions in production costs do not necessarily correspond entirely to increased efficiencies, because the sequential auctions do not reflect an optimized allocation of assets given their fixed annual costs.

Total EUE is 727 MWh in the annual market, compared to 358 MWh in the seasonal market (31 MWh summer and 327 MWh winter), a 51% difference, reflecting the increase in measured winter capacity. However, this change in EUE is somewhat illusory, as the estimated impact reflects the change in measured capacity, not the change in capacity as it actually performs. Thus, customers currently benefit from the higher performance in terms of reduced reliability, but suppliers are not compensated for that performance.

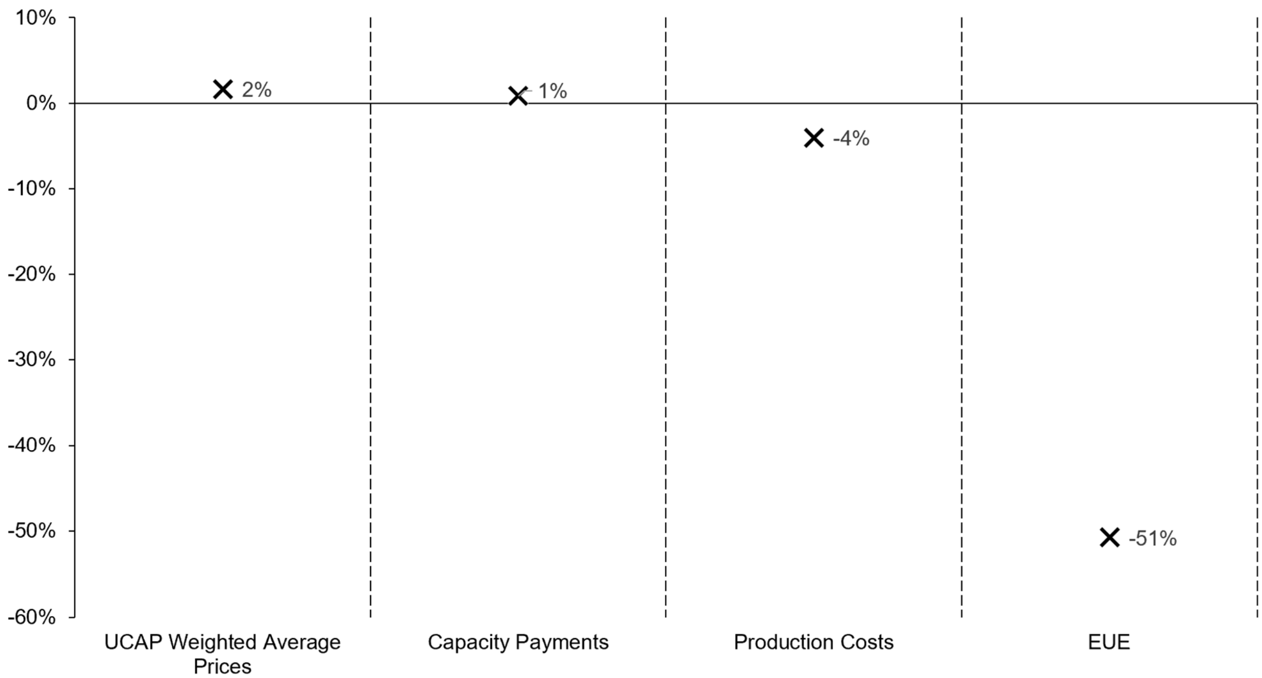
[282] Difference (%) is calculated as (Seasonal – Annual) / Annual.

Table VII-6: Base Scenario Results, VRR Demand Curve

LDA	Clearing Price ($/MW-Day)	Cleared UCAP (MW)	Uncleared UCAP (MW)	Capacity Payments ($M)	Production Costs ($M)	EUE (MWh)
Annual						
RTO	$112.43	151,437	1,655	$ 6,232	$ 1,144	727
Dominion	$112.43	21,641	138	$ 891	$ 74	
MAAC	$112.43	52,214	853	$ 2,149	$ 543	
EMAAC	$112.43	23,732	853	$ 977	$ 196	
SWMAAC	$112.43	6,735	0	$ 277	$ 98	
UCAP-Weighted Average Price	$112.43					
Seasonal						
Summer						
RTO	$ 77.24	172,506	4,792	$ 2,894	$ 451	31
Dominion	$ 92.10	24,600	728	$ 417	$ 20	
MAAC	$103.60	60,863	1,894	$ 1,240	$ 226	
EMAAC	$118.74	28,564	769	$ 624	$ 80	
SWMAAC	$103.60	7,805	0	$ 149	$ 48	
UCAP-Weighted Average Price	$ 91.17					
Winter						
RTO	$122.43	152,205	1,089	$ 3,391	$ 647	327
Dominion	$122.43	21,773	136	$ 485	$ 44	
MAAC	$122.43	51,906	953	$ 1,157	$ 296	
EMAAC	$122.43	23,571	953	$ 525	$ 118	
SWMAAC	$122.43	6,823	0	$ 152	$ 50	
UCAP-Weighted Average Price	$122.43					
Seasonal Total						
Annual UCAP-Weighted Average	$114.26	150,294	**Total**	$ 6,285	$ 1,098	358

Notes: [1] RTO cleared capacity, uncleared capacity, payments, and production costs reflect the RTO-wide totals, inclusive of values within each LDA. [2] MAAC cleared capacity, uncleared capacity, payments, and production costs reflect the MAAC-wide totals, inclusive of values within MAAC's child LDAs. [3] Cleared and uncleared UCAP capacity is in MW UCAP for each market construct (*i.e.*, the summer MW values are in summer UCAP, winter MW values are in winter UCAP), except for the seasonal total which is in annual UCAP.

Figure VII-11: Summary of Base Scenario Differences Annual v. Sub-Annual, VRR Demand Curve



b. MRI demand curve

Figure VII-12 below illustrates the results of the market clearing for RTO with a MRI demand curve. The annual RTO clearing price is $109.69/MW-day, which, as with the VRR demand curve results, is consistent with clearing prices from the 2016/17 to 2024/25 BRAs. Prices in the winter market are $119.76/MW-day and lower in the summer market at $70.47/MW-day.

Figure VII-12: Base Scenario Market Clearing, MRI Demand Curve

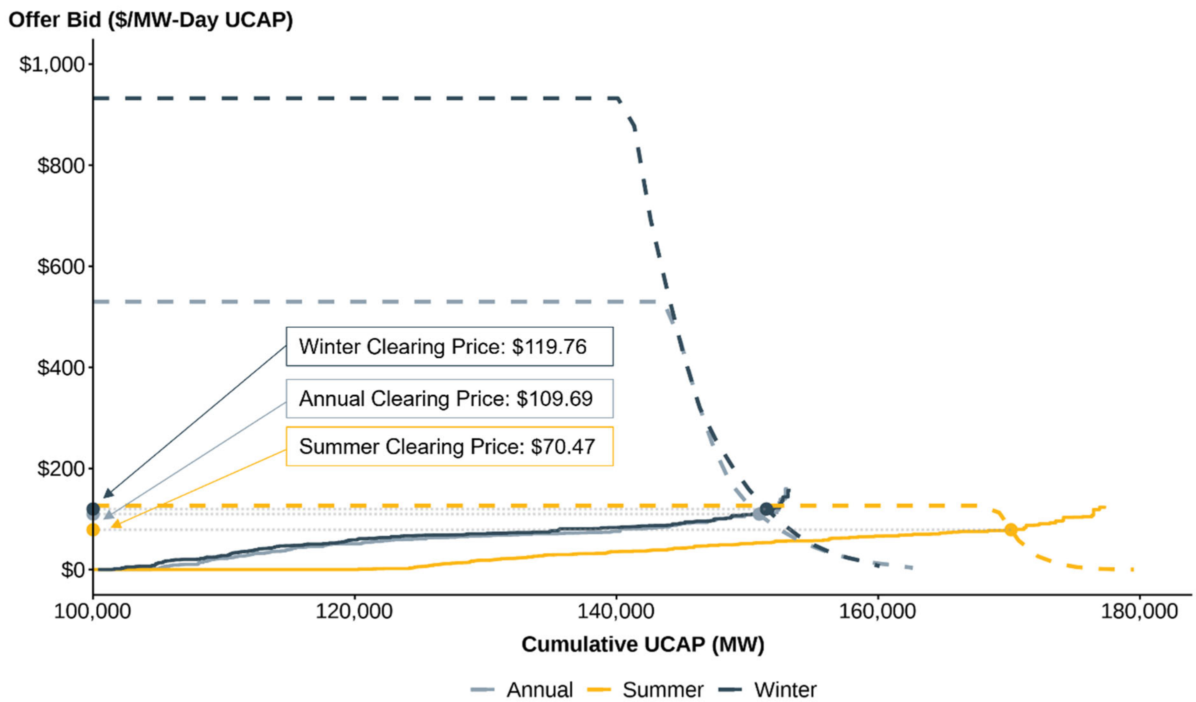


Table VII-7 summarizes the results for RTO and each LDA, including clearing price, cleared and uncleared capacity, capacity payments, production costs and EUE. **Figure VII-13** summarizes the differences in percentage terms for clearing price, capacity payments, production costs, and EUE between annual and sub-annual markets.

Clearing prices in the annual market are $109.69 per MW-day for RTO, and the LDAs clear at the RTO price, as none of the LDAs are constrained. In the summer market, the RTO clearing price is $70.47. Of the LDAs, MAAC is constrained, with a clearing price of $103.60. The UCAP-weighted average clearing price for the summer market is $82.34. In the winter market, the LDAs clear at the RTO price of $119.76, as none of the LDAs are constrained. The UCAP-weighted average price for the seasonal market overall, in annual UCAP terms, is $107.92, 2% less than the annual market price.

Table VII-7: Base Scenario Results, MRI Demand Curve

LDA	Clearing Price ($/MW-Day)	Cleared UCAP (MW)	Uncleared UCAP (MW)	Capacity Payments ($M)	Production Costs ($M)	EUE (MWh)
Annual						
RTO	$109.69	150,910	2,182	$ 6,058	$1,122	825
Dominion	$109.69	21,641	138	$ 869	$ 74	
MAAC	$109.69	51,687	1,380	$ 2,075	$ 521	
EMAAC	$109.69	23,342	1,243	$ 937	$ 180	
SWMAAC	$109.69	6,735	0	$ 270	$ 98	
UCAP-Weighted Average Price	$109.69					
Seasonal						
Summer						
RTO	$ 70.47	170,373	6,925	$ 2,581	$ 410	107
Dominion	$ 70.47	24,412	917	$ 317	$ 17	
MAAC	$103.60	61,042	1,715	$ 1,164	$ 230	
EMAAC	$103.60	28,511	822	$ 543	$ 79	
SWMAAC	$103.60	7,805	0	$ 149	$ 48	
UCAP-Weighted Average Price	$ 82.34					
Winter						
RTO	$119.76	151,453	1,842	$ 3,301	$ 631	398
Dominion	$119.76	21,773	136	$ 475	$ 44	
MAAC	$119.76	51,154	1,705	$ 1,115	$ 279	
EMAAC	$119.76	22,819	1,705	$ 497	$ 102	
SWMAAC	$119.76	6,823	0	$ 149	$ 50	
UCAP-Weighted Average Price	$119.76					
Seasonal Total						
Annual UCAP-Weighted Average	$107.92	148,921	**Total**	$ 5,882	$1,040	505

In the annual market, 150,910 MW of annual UCAP clears and 2,182 MW does not clear. In the seasonal market, 170,373 MW of summer UCAP clears, with 6,925 MW not clearing, and 151,453 MW of winter UCAP clears with 1,842 MW not clearing. The annual UCAP-equivalent capacity clearing in the seasonal market is 148,921 MW, 1.3% less than in the annual market.

Total capacity payments are $6,058 million in the annual market, which is more than the $5,882 million in total capacity payments in the seasonal market (3% difference), of which $2,581 million is in summer and $3,301 million is in the winter.

In the annual market, total production costs are $1,122 million, compared with $1,040 million in the seasonal ($410 million in summer and $631 million in winter), a 7% difference. The difference in production costs reflects differences in the capacity clearing and receiving a full annual capacity commitment between the annual and seasonal markets. Total EUE is 825 MWh in the annual market, compared to 505 MWh in the seasonal market (107 MWh summer and 398 MWh winter), a 39% difference. As noted above, this change in EUE reflects measured performance, not actual performance.

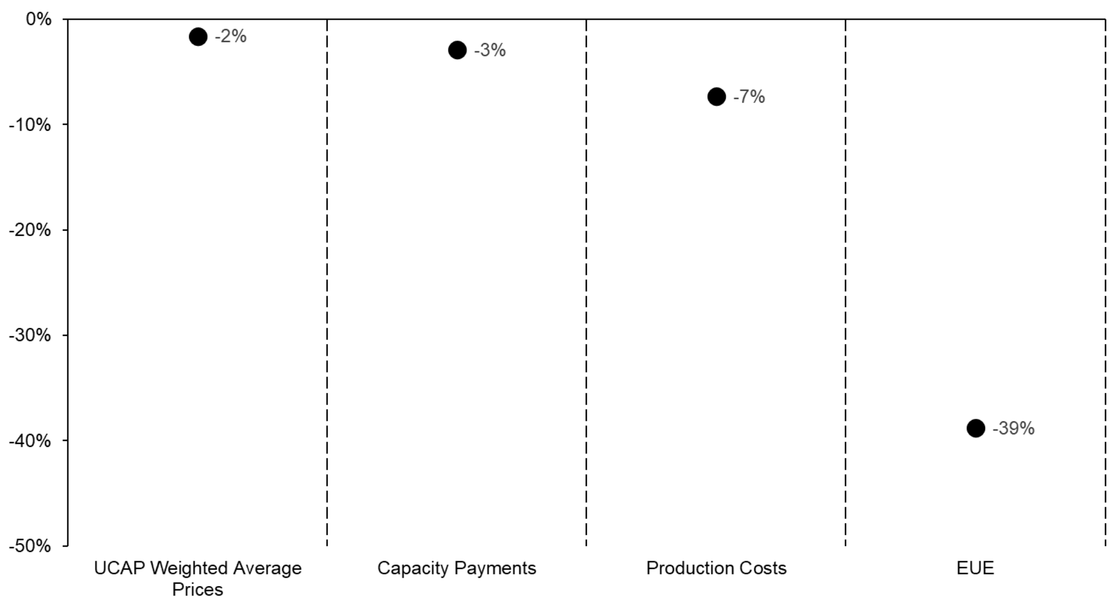
* * *

In sum, impacts of a seasonal market with MRI-based rather than VRR demand curves are comparable under the Base Scenario. Price and payment impacts are modest, with small increases with the VRR curves and small decreases under MRI-based curves, as are production cost impacts, with small decreases with both types of demand curves.

We caution against interpretations of these results as indicating a preference for annual market versus sub-annual markets, as our analysis reflects many assumptions about market designs that could differ from actual designs pursued under either approach. Instead, our analysis should be used to inform the choice between annual and sub-annual market designs, as our analysis is designed to make that comparison on an apples-to-apples basis.

Further, **we caution** against comparisons of costs and outcomes under VRR and MRI-based demand curves to help inform decisions about choice of demand curve approach, because the demand curves reflect different underlying assumptions. In particular, the VRR curves are based on the currently approved demand curves, which are right-shifted relative to the regulatory requirement anchor point (*i.e.*, the reliability requirement and Net CONE). By contrast, the MRI-based curves pass through the anchor points and thus are left-shifted relative to the VRR curves and represent lower demand for capacity. Given these assumptions, it is unsurprising that prices and payments are lower under the MRI-based curves as compared to the VRR curves and thus make comparison of VRR and MRI-based curve results inappropriate.

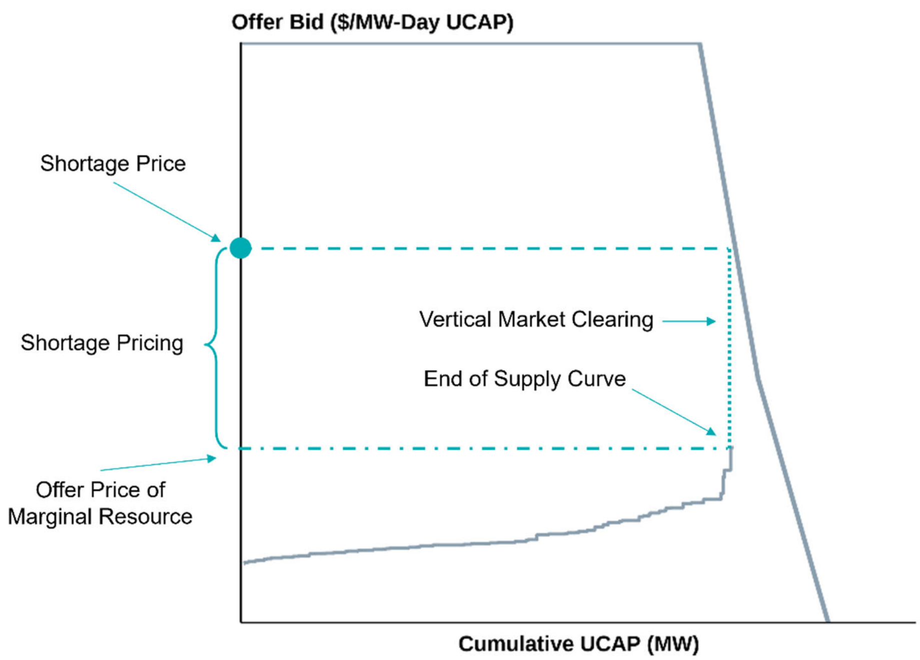
Figure VII-13: Summary of Base Scenario Differences Annual v. Sub-Annual, MRI Demand Curve



2. *Summary of Current Market Scenario Results*

The Current Market Scenario assumes current market information and reflects the current tight supply of capacity relative to demand. This shortage is reflected in the capacity market results for the 2026/2027 BRA, in which virtually all offered supply cleared the market at the temporary market price cap. This shortage can result in "shortage pricing" in which the market clears vertically at the demand curve and capacity is paid shortage pricing. Error! Not a valid bookmark self-reference. illustrates how shortage pricing can occur. In this illustrative example, the supply curve does not reach the demand curve and the market clears supply at the vertical intercept to the demand curve. That is, in order to determine the market clearing price, the end of the supply is traced up vertically until it intersects with the demand curve. The intersection of this vertical line and the demand curve determines the price. We refer to the difference between the highest bid offer on the supply curve and this vertical market clearing price as the shortage price. Shortage pricing reflects the principle that prices should reflect the value to customers, not the cost of suppliers, when there is shortage of supply. By ensuring that prices reflect the value to customers, this approach sends an appropriate price signal to the market to incentivize new entry (and resource retention) when the market is tight on supply.

Figure VII-14: Illustrative Capacity Market Clearing with Shortage Pricing



a. VRR demand curve

Figure VII-15 below illustrates the results of the market clearing for RTO with a VRR demand curve in the Current Market Scenario. The annual RTO clearing price is $327.75/MW-day, consistent with clearing prices from the 2024/25 BRA of $269.92 and 2026/2027 BRA of $329.17. Prices are higher in the winter market than the annual market, at $279.75/MW-day, and lower in the summer market at $126.27/MW-day. The annual and winter markets clear all capacity and are short of the demand curve. Thus, the clearing prices for the annual and winter markets are a result of the market clearing vertically and include shortage pricing. The summer market clears at the price cap for RTO.

Figure VII-15: Current Market Scenario Market Clearing, VRR Demand Curves

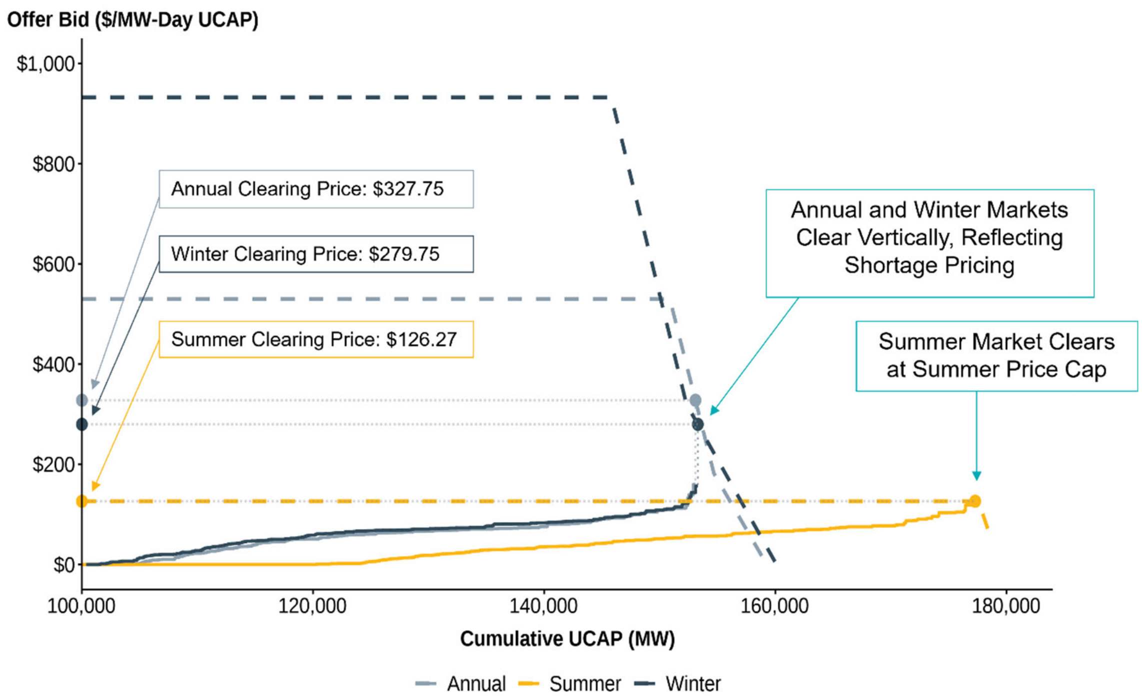


Table VII-8 summarizes the results for RTO and each LDA, including clearing price, cleared and uncleared capacity, capacity payments, production and EUE. **Figure VII-16** summarizes the differences in percentage terms for clearing price, capacity payments, production costs, and EUE between annual and sub-annual markets.

Clearing prices in the annual market are $327.75 per MW-day for RTO, with Dominion and SWMAAC constrained with clearing prices of $496.00 and $446.25, respectively. The UCAP-weighted average clearing price in the annual market is $356.90. In the summer market, the RTO clearing price is $126.27, reflecting the RTO price cap. Of the LDAs, MAAC is constrained, with a clearing price of $260.50. The UCAP-weighted average clearing price for the summer market is $173.78. In the winter market, the LDAs clear at the RTO price of $279.75, as none of the LDAs are constrained. The UCAP-weighted average price for the seasonal market overall, in annual UCAP terms, is $240.48, 33% less than the annual clearing price. All offered capacity clears each of the annual, summer, and winter markets.

Table VII-8: Current Market Scenario Results, VRR Demand Curve

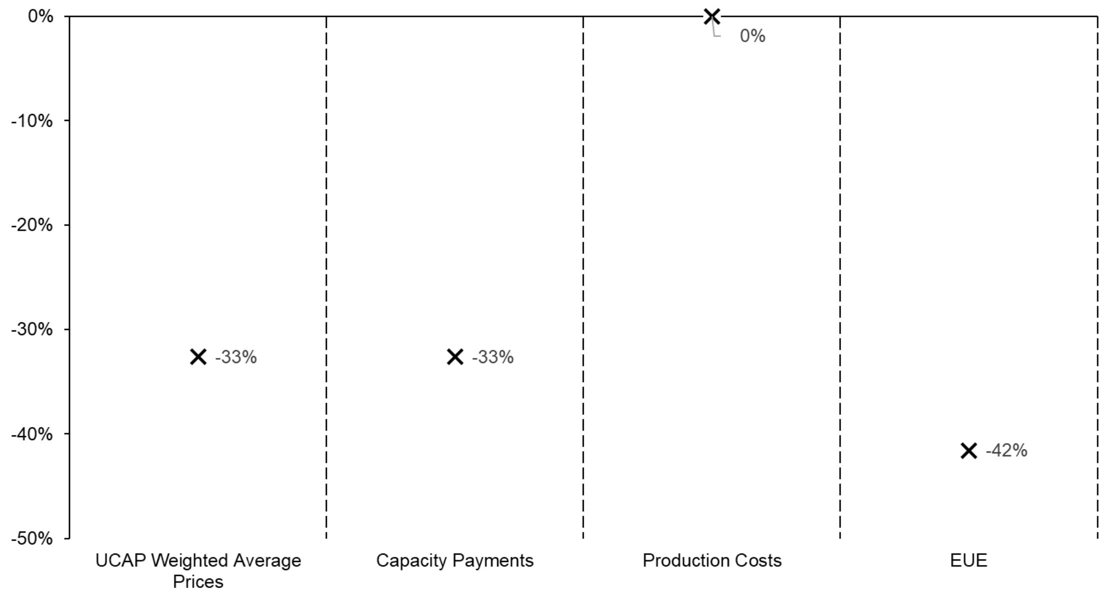
LDA	Clearing Price ($/MW-Day)	Cleared UCAP (MW)	Uncleared UCAP (MW)	Capacity Payments ($M)	Production Costs ($M)	EUE (MWh)
Annual						
RTO	$327.75	153,092	0	$19,998	$ 1,224	1,561
Dominion	$496.00	21,778	0	$ 3,954	$ 81	
MAAC	$327.75	53,067	0	$ 6,658	$ 587	
EMAAC	$327.75	24,585	0	$ 2,949	$ 240	
SWMAAC	$446.25	6,735	0	$ 1,100	$ 98	
UCAP-Weighted Average Price	$356.90					
Seasonal						
Summer						
RTO	$126.27	177,298	0	$ 5,669	$ 549	58
Dominion	$126.27	25,329	0	$ 588	$ 33	
MAAC	$260.50	62,757	0	$ 3,008	$ 267	
EMAAC	$260.50	29,333	0	$ 1,406	$ 97	
SWMAAC	$260.50	7,805	0	$ 374	$ 48	
UCAP-Weighted Average Price	$173.78					
Winter						
RTO	$279.75	153,295	0	$ 7,805	$ 675	854
Dominion	$279.75	21,909	0	$ 1,115	$ 47	
MAAC	$279.75	52,859	0	$ 2,691	$ 320	
EMAAC	$279.75	24,524	0	$ 1,249	$ 143	
SWMAAC	$279.75	6,823	0	$ 347	$ 50	
UCAP-Weighted Average Price	$279.75					
Seasonal Total						
Annual UCAP-Weighted Average	$240.48	153,092	**Total**	$13,474	$ 1,224	912

Total capacity payments are $19,998 million in the annual market, which is greater than the $13,474 million in total capacity payments in the seasonal market ($5,669 million in summer and $7,805 million in the winter), a 33% difference.

In the annual and seasonal markets, total production costs are $1,224 million ($549 million in summer and $675 million in the winter), which are equivalent as all capacity clears in all auctions.

Total EUE is 1,561 MWh in the annual market, relative to 912 MWh in the seasonal market (58 MWh summer and 854 MWh winter), a 42% difference. As noted above, this change in EUE reflects measured performance, not actual performance.

Figure VII-16: Summary of Current Market Scenario Differences Annual v. Sub-Annual, VRR Demand Curve



b. MRI demand curve

Figure VII-17 below illustrates the results of the market clearing for RTO with a MRI demand curve in the Current Market Scenario. The annual RTO clearing price is $204.62/MW-day. Prices are higher in the winter market than the annual market, at $223.65/MW-day, and lower in the summer market at $88.47/MW-day. The annual and winter markets clear all capacity and are short of the demand curve. Thus, the clearing prices in the annual and winter markets are the result of the market clearing vertically and include shortage pricing.

Figure VII-17: Current Market Scenario Market Clearing, MRI Demand Curves

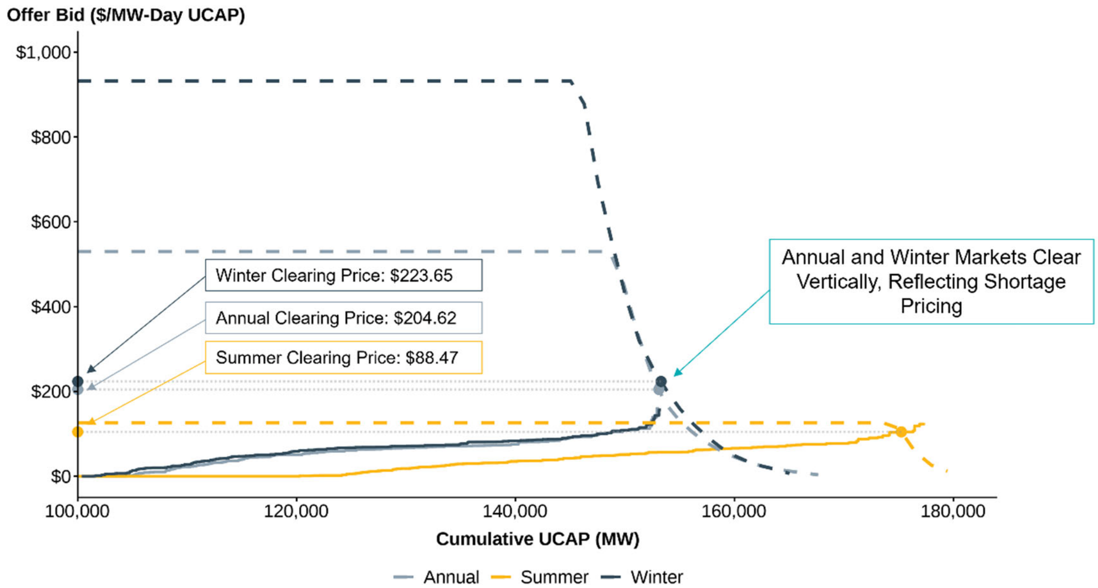


Table VII-9 summarizes the results for RTO and each LDA, including clearing price, cleared and uncleared capacity, capacity payments, production costs and EUE. **Figure VII-18** below summarizes the differences in percentage terms for clearing price, capacity payments, production costs, and EUE between annual and sub-annual markets.

Clearing prices in the annual market are $204.62 per MW-day for RTO, with Dominion and SWMAAC constrained with clearing prices of $277.92 and $250.33. The UCAP-weighted average clearing price in the annual market is $217.06. In the summer market the clearing price is $88.47 for RTO, with Dominion and MAAC constrained with clearing prices of $119.04 and $261.10, respectively. In the winter market, the LDAs clear at the RTO price of $223.65, as none of the LDAs are constrained. The UCAP-weighted average price for the seasonal market overall, in annual UCAP terms, is $201.52, 7% less than the annual market price. All offered capacity clears in the annual and winter markets. 175,681 MW UCAP clears in the summer market, with 1,617 MW not clearing.

Table VII-9: Current Market Scenario Results, MRI Demand Curve

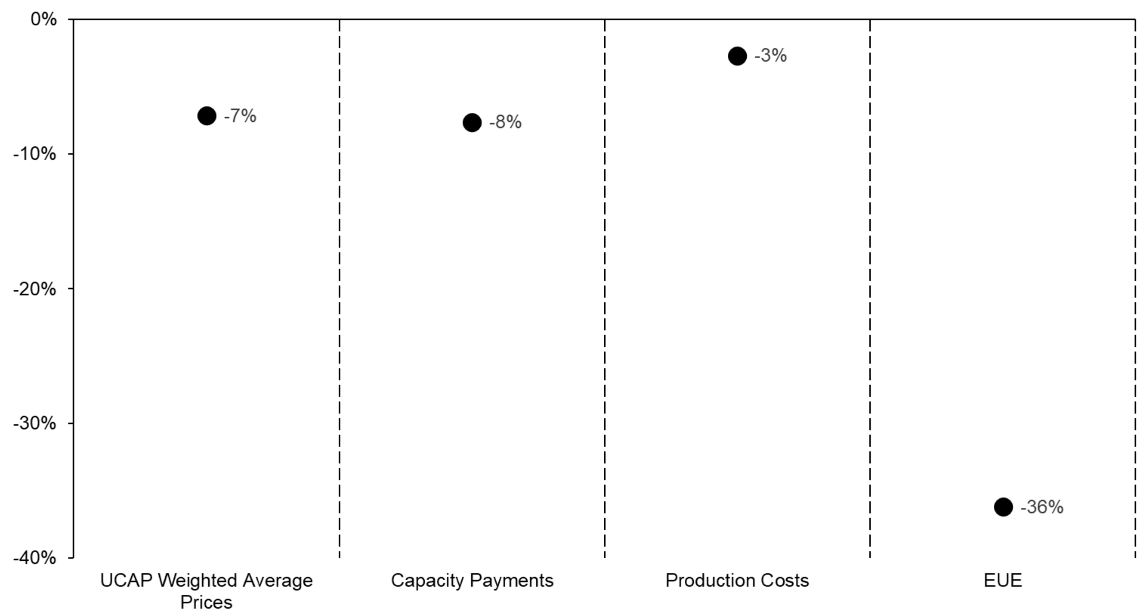
LDA	Clearing Price ($/MW-Day)	Cleared UCAP (MW)	Uncleared UCAP (MW)	Capacity Payments ($M)	Production Costs ($M)	EUE (MWh)
Annual						
RTO	$204.62	153,092	0	$12,162	$1,224	1,561
Dominion	$277.92	21,778	0	$ 2,215	$ 81	
MAAC	$204.62	53,067	0	$ 4,087	$ 587	
EMAAC	$204.62	24,585	0	$ 1,841	$ 240	
SWMAAC	$250.33	6,735	0	$ 617	$ 98	
UCAP-Weighted Average Price	$217.06					
Seasonal						
Summer						
RTO	$ 88.47	175,681	1,617	$ 4,995	$ 516	142
Dominion	$119.04	25,185	144	$ 552	$ 30	
MAAC	$261.10	62,757	0	$ 3,015	$ 267	
EMAAC	$261.10	29,333	0	$ 1,409	$ 97	
SWMAAC	$261.10	7,805	0	$ 375	$ 48	
UCAP-Weighted Average Price	$154.52					
Winter						
RTO	$223.65	153,295	0	$ 6,240	$ 675	854
Dominion	$223.65	21,909	0	$ 892	$ 47	
MAAC	$223.65	52,859	0	$ 2,152	$ 320	
EMAAC	$223.65	24,524	0	$ 998	$ 143	
SWMAAC	$223.65	6,823	0	$ 278	$ 50	
UCAP-Weighted Average Price	$223.65					
Seasonal Total						
Annual UCAP-Weighted Average	$201.52	152,316	**Total**	$11,234	$1,191	996

Total capacity payments are $12,162 million in the annual market, which is greater than the $11,234 million in total capacity payments in the seasonal market ($4,995 million in summer and $6,240 million in the winter), an 8% difference.

In the annual market, total production costs are $1,224 million compared with $1,191 million in the seasonal ($516 million in summer and $675 million in the winter). The difference in production costs reflects differences in the capacity clearing and receiving a full annual capacity commitment between the annual and seasonal markets where all capacity offered clears in the annual market, but some capacity clears in winter but not summer in the seasonal market.

Total EUE is 1,561 MWh in the annual market, relative to 996 MWh in the seasonal market (142 MWh summer and 854 MWh winter), a 36% difference. As noted above, this change in EUE reflects measured performance, not actual performance.

Figure VII-18: Summary of Current Market Scenario Differences Annual v. Sub-Annual, MRI Demand Curve



*   *   *

In sum, as anticipated, prices are higher under the Current Market Scenario relative to the Base Scenario, reflecting the tighter supply conditions. Under these conditions, the seasonal market leads to larger reductions in prices and total payments, with substantially larger reductions with a VRR demand curve compared to an MRI demand curve.

3. Disaggregation of Results by Sub-Annual Features

The quantitative analysis accounts for several features of a potential sub-annual market, specifically:

[A] Sub-annual market features

   i. Sub-annual demand and value of capacity – *i.e.*, seasonal demand curves

   ii. Sub-annual resource supply quantity – *i.e.*, seasonal accreditation and ELCC/UCAP

   iii. Sub-annual resource supply prices – *i.e.*, seasonal going forward costs

[B] Accounting for seasonal transmission system performance (*i.e.*, higher winter CETL values)

[C] Accounting for seasonal (winter) resource performance for thermal resources (*i.e.*, Winter ICAP for certain thermal resources greater than Annual/Summer ICAP)

Table VII-10 below summarizes the impact on the Base Scenario outcomes that can be attributed to [A], [B] and [C] in the list above, and **Table VII-11** shows the same for the Current Market Scenario. This breakdown allows for the isolation of impacts of each of the features accounted for above. Full results are shown in **Appendix B.3.**

Table VII-10: Base Scenario Results, Sub-Annual Market Only, Winter CETL and Winter ICAP

	UCAP-Weighted Average Price			Capacity Payments			Production Costs			EUE		
	Annual ($M)	Seasonal ($M)	Diff. (%)	Annual ($M)	Seasonal ($M)	Diff. (%)	Annual ($M)	Seasonal ($M)	Diff. (%)	Annual (MWh)	Seasonal (MWh)	Diff. (%)
VRR												
Base Scenario = [A] + [B] + [C]	*$112.4*	*$114.3*	*1.6%*	*$6,232*	*$6,285*	*0.9%*	*$1,144*	*$1,098*	*- 4.0%*	*727*	*358*	*-50.8%*
[A] Sub-Annual Market Only	*$112.4*	*$146.2*	*30.0%*	$6,232	$8,071	29.5%	$1,144	$1,126	- 1.6%	727	518	-28.7%
[B] = [A] + Adjusted Winter CETLs	*$112.4*	*$143.9*	*28.0%*	$6,232	$7,947	27.5%	$1,144	$1,126	- 1.6%	727	518	-28.7%
[C] = [A] + Adjusted Winter ICAP	*$112.4*	*$115.4*	*2.6%*	$6,232	$6,346	1.8%	$1,144	$1,098	- 4.0%	727	358	-50.8%
MRI												
Base Scenario = [D] + [E] + [F]	*$109.7*	*$107.9*	*-1.6%*	*$6,058*	*$5,882*	*- 2.9%*	*$1,122*	*$1,040*	*- 7.3%*	*825*	*505*	*-38.8%*
[D] Sub-Annual Market Only	*$109.7*	*$120.9*	*10.2%*	$6,058	$6,625	9.4%	$1,122	$1,078	- 3.9%	825	621	-24.7%
[E] = [D] + Adjusted Winter CETLs	*$109.7*	*$120.9*	*10.2%*	$6,058	$6,625	9.4%	$1,122	$1,078	- 3.9%	825	621	-24.7%
[F] = [D] + Adjusted Winter ICAP	*$109.7*	*$107.9*	*-1.6%*	$6,058	$5,882	- 2.9%	$1,122	$1,040	- 7.3%	825	505	-38.8%

Table VII-11: Current Market Scenario Results, Sub-Annual Market Only, Winter CETL and Winter ICAP

	UCAP-Weighted Average Price			Capacity Payments			Production Costs			EUE		
	Annual ($M)	Seasonal ($M)	Diff. (%)	Annual ($M)	Seasonal ($M)	Diff. (%)	Annual ($M)	Seasonal ($M)	Diff. (%)	Annual (MWh)	Seasonal (MWh)	Diff. (%)
VRR												
Current Market Scenario = [A] + [B] + [C]	*$356.9*	*$240.5*	*-32.6%*	*$19,998*	*$13,474*	*-32.6%*	*$1,224*	*$1,224*	*0.0%*	*1,561*	*912*	*-41.6%*
[A] Sub-Annual Market Only	*$356.9*	*$347.3*	*-2.7%*	$19,998	$19,458	- 2.7%	$1,224	$1,224	0.0%	1,561	1,561	0.0%
[B] = [A] + Adjusted Winter CETLs	*$356.9*	*$332.2*	*-6.9%*	$19,998	$18,615	- 6.9%	$1,224	$1,224	0.0%	1,561	1,561	0.0%
[C] = [A] + Adjusted Winter ICAP	*$356.9*	*$248.6*	*-30.4%*	$19,998	$13,927	-30.4%	$1,224	$1,224	0.0%	1,561	912	-41.6%
MRI												
Current Market Scenario = [A] + [B] + [C]	*$217.1*	*$201.5*	*-7.2%*	*$12,162*	*$11,234*	*- 7.6%*	*$1,224*	*$1,191*	*- 2.7%*	*1,561*	*996*	*-36.2%*
[A] Sub-Annual Market Only	*$217.1*	*$278.1*	*28.1%*	$12,162	$15,506	27.5%	$1,224	$1,191	- 2.7%	1,561	1,645	5.4%
[B] = [A] + Adjusted Winter CETLs	*$217.1*	*$271.4*	*25.0%*	$12,162	$15,128	24.4%	$1,224	$1,191	- 2.7%	1,561	1,645	5.4%
[C] = [A] + Adjusted Winter ICAP	*$217.1*	*$202.6*	*-6.7%*	$12,162	$11,295	- 7.1%	$1,224	$1,191	- 2.7%	1,561	996	-36.2%

a. Accounting for sub-annual features

Accounting for sub-annual features only (model run [A] above) allows for the market to properly value seasonal differences in the supply of and demand for capacity. In the Base Scenario, for both VRR and MRI demand curves, prices and payments increase when accounting for sub-annual features only in the seasonal market relative to the annual market (*see* **Table B-14***,* **Table B-15**). In the Current Market Scenario, for the VRR demand curves, prices and payments are lower in the seasonal market relative to the annual market, but for the MRI demand curves, prices and payments are higher in the seasonal market relative to the annual market (*see* **Table B-16**, **Table B-17**).

With a sub-annual market, production costs are reduced or are unchanged when comparing annual to seasonal by 0% to 3.9%. While this reduction may not necessarily be the efficient outcome, the results illustrate how a sub-annual structure provides a signal to the market about differential values of capacity by season relative to the annual.

In addition, in the Base Scenario, accounting for sub-annual features only results in a reduction in EUE in the seasonal relative to the annual (28.7% reduction for VRR demand curves and 24.7% for MRI demand curves). This reduction in EUE in the sub-annual relative to the annual is achieved with lower production costs, albeit with higher payments. The improvements in reliability are not driven by the higher accreditation of thermal resources, but instead a result of the differences in market-clearing in the sub-annual market as compared to the annual market. Thus, while the seasonal market clears at higher prices and payments, this is producing improved reliability.

The results indicate that the impact of a sub-annual market on pricing can be sensitive to particular market conditions and extent which a sub-annual market increases the extent of pricing under shortage conditions (which is the case in several of our scenarios) or decreases the extent of pricing under shortage conditions (which is not the case in any of our scenarios, but is a possibility).

b. Accounting for transmission performance

Accounting for improved winter transmission performance, [B] above, can reduce clearing prices and payments. This reduction in the model is driven by an elimination of the transmission constraint in Dominion in the winter. For example, for the Base Scenario with VRR demand curves, sub-annual market only (**Table B-14**), Dominion is constrained without the increased winter CETL, resulting in a clearing price of $216/MW-day, which is above the RTO clearing price of $184.25. However, the modest increase in the winter CETL by 5% eliminates the constraint, meaning that Dominion clears at the RTO price (*see* **Table B-18**). The result is a reduction in total payments from $8,071 million to $7,947 million, where all of this reduction is driven by a reduction in payments to resources in Dominion. For the Base Scenario with MRI demand curves, sub-annual market only (*see* **Table B-15**), none of the LDAs are import constrained in the winter. Thus, accounting for improved winter transmission performance has no effect in this case (*see* **Table B-19**). The reduction in payments for the Current Market Scenario, relative to accounting for the sub-annual market only, with VRR or MRI demand curves, is similarly driven by eliminating the import constraint for Dominion (*see* **Table B-20**, **Table B-21**).

It is possible that, due to constraints not driven by ambient conditions, a winter CETL in some LDAs could be lower than the current summer-based CETL. In this scenario, a summer-based CETL is too high relative to its true winter value, and an LDA could be modeled as unconstrained when in fact it may be constrained in reality in the winter. In this situation, a lower winter-based CETL would increase prices and payments, but the lower CETL properly provides an incentive, via price adder, for new entry within the LDA or qualifying transmission upgrade to relieve the constraint for that season in that LDA, where such an incentive would not have existed prior. Thus, the increase in payments and prices would be efficient in this circumstance.

c. Accounting for winter thermal performance

Accounting for winter thermal performance, [C] above, reduces prices, payments, production costs and EUE, with impacts driven by changes in winter market outcomes. Because the changes in accreditation only affect winter performance, the incremental impact of this sensitivity compared to [A], which reflects only sub-annual market design changes, reflects only changes in winter market outcomes. For example, for the Base Scenario, VRR demand curve, with the additional winter capacity, RTO winter clearing prices are reduced from $184.25/MW-day (**Table B-14**) to $122.43 (**Table B-22**), which in turn reduces total seasonal market payments. Accounting for improve winter performance also results in additional uncleared capacity and a reduction in production costs. Finally, accounting for winter thermal performance is what accounts for roughly half of the measured reduction in EUE in the Base Scenario, and all of the reduced EUE in the Current Market Scenario, relative to the annual market. As noted above, this change in EUE reflects measured performance, not actual performance. Similar results occur in the Base Scenario with an MRI demand curve (**Table B-23**) and in the Current Market Scenario with both the VRR or MRI demand curve (**Table B-24**, **Table B-25**).

4. Sensitivities and Other Issues

In this section, we present results of several sensitivities to the main results discussed above and discuss certain other issues in sub-annual market design and impact. Sensitivities are undertaken to both evaluate certain aspects of market design and test sensitivity of outcomes to input assumptions. Each sensitivity is designed to test how the results may change under reasonable alternative market conditions that are not reflected in the Base and Current Market Scenarios. Each sensitivity will alter one of the inputs in the Base and Current Market Scenarios (which we refer to as "core assumptions"). These sensitivities include:

1. **Tighter LDA transmission constraints ("Reduced CETLs")**, reflecting a sensitivity where additional LDAs are import constrained, represented by lower CETL values. CETL values in each LDA are reduced by 10% relative to the Base Scenario in the annual market and in each season of the seasonal market.
2. **Collar on seasonal LOLE risk allocation ("Collar on Seasonal Risk")**, reflecting an alternative for how to allocate the LOLE risk across seasons while maintaining the annual 1-in-10 requirement. In the RA analysis by PJM for the 2027/28 BRA, at the 0.1 annual RTO LOLE requirement, 0.076 LOLE is in the winter and 0.024 LOLE in the summer. In certain LDAs, more than 99% of the annual LOLE risk is in a single season at the annual LDA reliability requirement. This sensitivity anchors the demand curves such that at least 30% of the annual LOLE risk is in each season – *i.e.*, for RTO, 0.07 LOLE in the winter and 0.03 LOLE in the summer. This alternative alters the VRR and MRI seasonal reliability requirements for RTO and the LDAs.
3. **Tighter Supply/Increased Demand ("Tighter Supply")**, reflecting conditions where the market is even shorter than in the Current Market Scenario. Since the Current Market Scenario already reflects this sensitivity relative to the Base Scenario, this sensitivity is only applied to the Current Market Scenario. We represent tighter supply/increased demand by increasing the reliability requirement in the Current Market Scenario by 1 GW annual UCAP.
4. **No price caps ("Relaxed Summer Price Cap")**, in order to reflect a situation with price discovery. This sensitivity only affects the summer market in the Current Market Scenario with a VRR demand curve, as the price caps do not constrict prices in the winter or annual markets, with MRI demand curves, or in the Base Scenario.
5. **Alternative slopes for VRR demand curves ("Alternative Seasonal Slopes")**, reflecting a consistent willingness to pay per avoided MWh of EUE across seasons. This alternative makes the seasonal VRR demand curve slopes more consistent with the MRI demand curve slopes. The price caps and "B" point on the VRR curves are unchanged in this sensitivity.

a. Base Scenario

Table VII-12 summarizes the difference in clearing price, payments, production costs, and EUE between annual and seasonal markets, respectively, for the Base Scenario as well as each sensitivity. Full results for each sensitivity are shown in **Appendix B.1**. The Base Scenario includes two sensitivities for both VRR and MRI demand curves: reduced CETLs and a collar on seasonally allocated risk. An additional sensitivity for VRR demand curves only uses alternative slopes.

Table VII-12: Base Scenario Sensitivities

	UCAP-Weighted Average Price			Capacity Payments			Production Costs			EUE		
	Annual ($/MW-Day)	Seasonal ($/MW-Day)	Diff. (%)	Annual ($M)	Seasonal ($M)	Diff. (%)	Annual ($M)	Seasonal ($M)	Diff. (%)	Annual (MWh)	Seasonal (MWh)	Diff. (%)
VRR												
Base Scenario	$112.43	$114.26	2%	$6,232	$6,285	1%	$1,144	$1,098	- 4%	727	358	-51%
Reduced CETLs	$138.89	$121.81	-12%	$7,702	$6,700	-13%	$1,148	$1,100	- 4%	716	358	-50%
Collar on Seasonal Risk	$112.43	$112.48	0%	$6,232	$6,186	- 1%	$1,144	$1,099	- 4%	727	355	-51%
Alternative Seasonal Slopes	$112.43	$105.17	- 6%	$6,232	$5,726	- 8%	$1,144	$1,032	-10%	727	597	-18%
MRI												
Base Scenario	$109.69	$107.92	- 2%	$6,058	$5,882	- 3%	$1,122	$1,040	- 7%	825	505	-39%
Reduced CETLs	$118.47	$112.04	- 5%	$6,545	$6,105	- 7%	$1,124	$1,040	- 7%	816	505	-38%
Collar on Seasonal Risk	$109.69	$109.43	0%	$6,058	$5,976	- 1%	$1,122	$1,054	- 6%	825	455	-45%

Across the three sensitivities for the Base Scenario, capacity payments, production costs, and EUE are each lower in the seasonal market than the annual market, with the difference between annual and sub-annual markets on capacity payments ranging between 1% and 13%, between production costs ranging from 4% to 10%, and on EUE ranging from 51% to 18%. Generally, the differences between annual and sub-annual markets in these sensitivities are larger than the Base Scenario. Directionally, the difference is the same for production costs and EUEs, and for payments and prices for the MRI. For the VRR, in contrast to the Base Scenario, clearing prices and payments are lower in the sub-annual market than the annual market.

b. Current Market Scenario

Table VII-13 summarizes the difference in clearing price, payments, production costs, and EUE between annual and seasonal, respectively, for the Current Market Scenario as well as each sensitivity. Full results for each sensitivity are shown in **Appendix B.2**. The Current Market Scenario includes four sensitivities: reduced CETLs, a collar on seasonally allocated LOLE risk, tighter supply, and a relaxed summer price cap. An additional sensitivity for VRR demand curves only uses alternative slopes.

Table VII-13: Current Market Scenario Sensitivities

	UCAP-Weighted Average Price			Capacity Payments			Production Costs			EUE		
	Annual ($/MW-Day)	Seasonal ($/MW-Day)	Diff. (%)	Annual ($M)	Seasonal ($M)	Diff. (%)	Annual ($M)	Seasonal ($M)	Diff. (%)	Annual (MWh)	Seasonal (MWh)	Diff. (%)
VRR												
Current Market Scenario	$356.90	$240.48	-33%	$19,998	$13,474	-33%	$1,224	$1,224	0%	1,561	912	-42%
Reduced CETLs	$366.77	$296.33	-19%	$20,550	$16,604	-19%	$1,224	$1,224	0%	1,561	912	-42%
Collar on Seasonal Risk	$356.90	$254.40	-29%	$19,998	$14,254	-29%	$1,224	$1,224	0%	1,561	912	-42%
Tighter Supply	$441.22	$285.13	-35%	$24,722	$15,977	-35%	$1,224	$1,224	0%	1,961	1,171	-40%
Relaxed Summer Price Cap	$356.90	$259.31	-27%	$19,998	$14,530	-27%	$1,224	$1,224	0%	1,561	912	-42%
Alternative Seasonal Slopes	$356.90	$217.36	-39%	$19,998	$12,127	-39%	$1,224	$1,224	0%	1,561	912	-42%
MRI												
Current Market Scenario	$217.06	$201.52	- 7%	$12,162	$11,234	- 8%	$1,224	$1,191	-3%	1,561	996	-36%
Reduced CETLs	$271.68	$224.91	-17%	$15,223	$12,543	-18%	$1,224	$1,194	-2%	1,561	986	-37%
Collar on Seasonal Risk	$217.06	$209.19	- 4%	$12,162	$11,672	- 4%	$1,224	$1,195	-2%	1,561	976	-37%
Tighter Supply	$290.53	$241.14	-17%	$16,279	$13,482	-17%	$1,224	$1,209	-1%	1,961	1,221	-38%
Relaxed Summer Price Cap	$217.06	$201.52	- 7%	$12,162	$11,234	- 8%	$1,224	$1,191	-3%	1,561	996	-36%

Across the sensitivities for the Current Market Scenario, capacity payments, production costs, and EUE are each lower in the seasonal than annual, with the difference between annual and sub-annual on capacity payments ranges between 4% and 35%, between production costs ranges from 0% to 3%, and on EUE ranges from 36% to 42%. These values are in line with the differences for the Current Market Scenario results.

c. Discussion of sensitivities analysis and other issues

i. Tighter LDA transmission constraints

We simulate market conditions in which each LDA faces tighter transmission constraints, as reflected by lower CETL values, which increases the risk that the LDA is import constrained with higher clearing prices. The tighter transmission constraint sensitivity demonstrates how a seasonal market can allow LDA import constraints and the associated prices to vary by season. We see this in the Base Scenario and Current Market Scenario with both the VRR and MRI-based demand curves (**Table VII-6** to **Table VII-9**). We also observe this in the sensitivity (*see* **Table B-1**, **Table B-4, Table B-6**, **Table B-11**).

For example, in the annual market for the Base Scenario, MRI demand curve scenario (*see* **Table B-4)**, three LDAs are import constrained and clear above the RTO price. In the seasonal market, four LDAs are import constrained and clear above the RTO price in the summer market, but none are import constrained in the winter market. Thus, the seasonal market can allow for higher prices in import constrained LDAs *in only the season with the constraint*, rather than imposing it for the entire year. The result is that payments are 7% lower in the seasonal market than in the annual market.

The sensitivity also shows the LDA outcomes under the seasonal market are sensitive to the CETL values. With lower deliverability (*i.e.*, lower CETL), LDA prices increase relative to the corresponding Base or Current Market Scenarios. In addition, in some scenarios, there is no price separation between the RTO and LDA when there is higher deliverability but price separation emerges as deliverability decreases.

ii. Collar on seasonal risk

We simulate a case in which seasonal LOLE risk is constrained through a collar on the range of LOLE values. In our core assumptions, LOLE risk is 0.024 and 0.076 for summer and winter, respectively. In the sensitivity, we impose a 70/30 collar, which results in anchoring each season's demand curve at a separate LOLE target: 0.03 in summer and 0.07 in winter, which satisfies the annual 0.1 LOLE requirement. We similarly limit the seasonal share of LOLE risk in each LDA. The annual market is unaffected by this change.

The change in seasonal risk allocation results in four changes to demand curve parameters. First, the seasonal reliability requirement changes. Relative to the Base Scenario assumptions, this seasonal LOLE target increases the RTO reliability requirement in the winter (since the winter LOLE target is now lower) and decreases the RTO reliability requirement in the summer (since the summer LOLE target is now higher). Second, the seasonal allocation of Net CONE recovery changes with the allocation of risk. Relative to the Base Scenario assumptions, more of the recovery is assigned to the summer and less to the winter. Third, the change in seasonal Net CONE allocation results in different price caps. Relative to the Base Scenario, price caps are higher in the summer and lower in the winter.

The risk collar shifts assumed risk from winter to summer. Under the Base Scenario, the risk collars have little effect on outcomes. With the Current Market Scenario, impacts are larger, with summer and winter prices and payments increase, although changes are modest in both cases. (*see* **Table B-2, Table B-5, Table B-9**, **Table B-13**). Differences in production costs and EUE relative to the Base and Current Market Scenarios are minimal.

iii. Tighter supply in Current Market Scenario

As a sensitivity, we increase demand in the Current Market Scenario by 1 GW to illustrate even tighter supply conditions. Recent auctions have cleared at the existing price caps, suggesting that supply is tight in the market. With uncertain demand growth in PJM, as discussed in **Section III.A**, it is possible that increased demand will result in tighter supply than illustrated in the Current Market Scenario. This scenario thus considers how outcomes differ between an annual and sub-annual market under even tighter market conditions.

As expected, tighter supply increases prices and payments in both the annual and sub-annual markets. Production costs and EUE also increase when all resources were not already clearing. (*See* **Table B-7** and **Table B-12)**. The impact of a sub-annual market is generally smaller, with the reduction associated with more frequent annual market clearing at LDA price caps, which limits the increase in payments in the annual market from tighter supply. In the seasonal market, RTO and some of the LDAs clear at the price caps in the summer market, but prices clear in the winter market below all price caps, meaning that the increase in payments in the seasonal market from tighter supply is limited by the price caps in the summer, but not the winter.

iv. No price caps

We test a case with no price caps to evaluate impacts, particularly in the Current Market Scenario given the risk of over-recovery of costs. In the Current Market scenario, with VRR demand curves, the market clears at the price caps for RTO and Dominion in the summer season, but below price caps in the annual market and winter season. Removing the price caps results in the average seasonal clearing price increasing from $240.48 to $259.31 (**Table VII-13**). The increase in the average seasonal clearing price is due to increases in prices that were previously constrained by price caps. Specifically, the RTO summer clearing price increases from $126.27 to $145.00 and the Dominion summer clearing price increases from $126.27 to $286.75 (*see* **Table B-8**). Total payments for the seasonal market increase, but are still below the payments in the annual market.

With MRI-based curves in the Current Market Scenario, the market clears below price caps in the annual, winter, and summer markets. Thus, removing the price caps does not change the results.

v. Alternative seasonal VRR demand curve slopes

We simulate the Base and Current Market Scenarios with an alternative construction of the seasonal VRR Demand Curve slopes. In the Base and Current Market Scenarios, we construct the seasonal VRR curves such that the slopes of the curves preserve the scalar, in $ per MW-day, as the annual curve. This construction is one, but not the only, way in which the seasonal VRR curves could be specified.[283] In the alternative specification, the slopes on the seasonal VRR curves are adjusted to reflect differences in each season's contribution to avoided annual EUE. The alternative slopes are more consistent with an MRI-like framework. Compared to our core assumptions, the winter VRR curve is steeper and the summer VRR curve is flatter and the VRR curve price caps and anchor points are unchanged. The annual market is unaffected by this change.

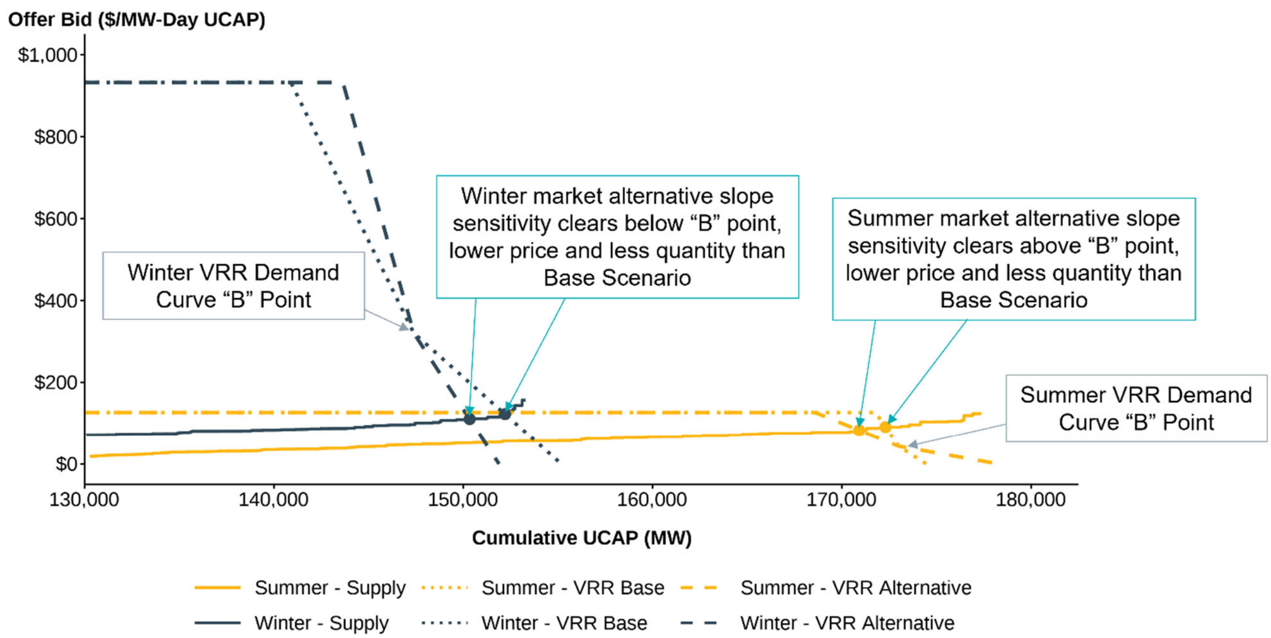
The alternative slopes for the VRR curves result in lower prices and payments in the seasonal market, as shown in **Table VII-12** and **Table VII-13** with full results in **Table B-3** and **Table B-10**. **Figure VII-19** illustrates the seasonal market clearing with the demand curves for the Base Scenario and the alternative slopes sensitivity. In the summer market, the supply curve intersects the upper portion of the VRR demand curves (*i.e.*, the line from the price cap to the kink in the VRR curve meet) and thus less quantity is cleared at a lower price. In the winter market, the supply curve intersects the lower portion of the demand curves (*i.e.*, the line from the kink to the x-axis) and the winter market clears at a lower price and with less quantity than in the Base Scenario. Thus, in both seasons, less quantity clears the seasonal market under this alternative VRR compared to the Base Scenario, which reduced production costs and EUE.

The results of this scenario are not generalizable but reflect specific the market circumstances modeled. For example, suppose that instead the winter supply curve intersected the winter demand curves at the upper portion of the demand curve (above the kink) and the summer supply curve intersected demand curves below the kink. Then, the results would be the inverse of this sensitivity: quantity cleared and prices in each season would be higher with the alternative slopes demand curves than the Base Scenario demand curves.

---

[283] As discussed in **Section VI.B.2**, if VRR demand curves are used with a sub-annual market, PJM would need to develop methodologies to determine the appropriate VRR curves for each sub-period.

Figure VII-19: Seasonal Market Clearing with Alternative VRR Slopes



vi. Resources partially clearing

As discussed in **Section VI.A.2.b**, independent sub-annual auctions may result in partial resource clearing, in which a resource clears in some but not all periods. A potential efficiency concern when this occurs is that compensation to partially cleared resources may be insufficient to cover the resource’s annual costs. In this section of the report, we evaluate partial clearing in our market simulations. Our analysis evaluates only the Base Scenario because there is no partial clearing in the Current Market Scenario.

Table VII-14 summarizes the frequency of partial resource clearing, in which a resource clears in only one season but not the other, for the Base Scenario cases and sensitivities. The results show that the large majority of resources clear in both seasons: 1.8% to 3.8% of capacity clear in a single season, while 96.2% to 98.2% of capacity that clear in both seasons (by annual ICAP). The resources that clear in only one season account for 1.0% to 2.3% of the total payments. The majority of resources that clear in only one season clear in the winter but not the summer, ranging from 3,222 MW to 6,944 MW of annual ICAP. By comparison, 0 to 1,906 MW of annual ICAP clears in the summer but not the winter.

Table VII-14: Summary of Resources Clearing in One Season, Base Scenario Cases and Sensitivities

	ICAP (MW)			Seasonal Payments ($M)			Cleared in Summer Only		Cleared in Winter Only	
	Cleared in Both Seasons	Cleared in One Season	Percent of Total Cleared in One Season	Cleared in Both Seasons	Cleared in One Season	Percent of Total Cleared in One Season	ICAP (MW)	Payments ($M)	ICAP (MW)	Payments ($M)
VRR										
Base Scenario	191,142	3,493	1.8%	$6,149	$ 65	1.0%	271	$ 6	3,222	$ 60
Sub-Annual Market Only	*191,539*	*4,057*	*2.1%*	*$7,857*	*$114*	*1.4%*	*0*	*$ 0*	*4,057*	*$114*
Increased Winter CETLs	*191,539*	*4,057*	*2.1%*	*$7,738*	*$112*	*1.4%*	*0*	*$ 0*	*4,057*	*$112*
Increased Winter Ratings	*190,834*	*3,899*	*2.0%*	*$6,195*	*$ 75*	*1.2%*	*523*	*$11*	*3,376*	*$ 64*
Reduced CETLs	191,172	6,638	3.5%	$6,555	$127	1.9%	1,391	$31	5,248	$ 96
Collar on Seasonal Risk	191,060	5,431	2.8%	$6,044	$103	1.7%	836	$18	4,595	$ 85
Alternative Seasonal VRR Slopes	189,551	6,923	3.7%	$5,606	$118	2.1%	1,906	$34	5,017	$ 84
MRI										
Base Scenario	187,594	6,930	3.7%	$5,685	$124	2.1%	705	$13	6,224	$111
Sub-Annual Market Only	*188,965*	*6,944*	*3.7%*	*$6,403*	*$153*	*2.3%*	*0*	*$ 0*	*6,944*	*$153*
Increased Winter CETLs	*188,965*	*6,944*	*3.7%*	*$6,403*	*$153*	*2.3%*	*0*	*$ 0*	*6,944*	*$153*
Increased Winter Ratings	*187,594*	*6,930*	*3.7%*	*$5,685*	*$124*	*2.1%*	*705*	*$13*	*6,224*	*$111*
Reduced CETLs	188,045	6,606	3.5%	$5,913	$122	2.0%	1,270	$27	5,336	$ 95
Collar on Seasonal Risk	188,911	7,243	3.8%	$5,803	$132	2.2%	1,018	$21	6,224	$111

Note: Reported ICAP values exclude fractionally clearing resources.

In the model, seasonal offer prices reflect an "average, all-in" cost. The resources clearing in a single season, on average, recover the majority of these costs in the season that they do clear. **Table VII-15** shows that, on average across the Base Scenario cases and sensitivities, 57% to 85% of these resources' annual costs are recovered in a single season, with individual resources recovering between 50% and 110%.

Table VII-15 calculates cost recovery under two assumptions. Under one approach, we assume all costs are fixed annual costs ("Annual Costs" panel). In this case, a resource avoids no costs during the season when it does not clear. When we assume none of the resource costs are avoidable on a seasonal basis, uncovered costs range from $24 to $90 million across the resources clearing in a single season. These uncovered costs are small compared with $8,071 million and $5,726 million in total payments, respectively (**Table VII-10**, **Table VII-12**), representing 0.3% to 1.6% of total payments in the seasonal market. In principle, resources with uncovered costs could be made "whole" through uplift payments. Uplift would address under-compensation and thus resource retention decisions, but would not address productive inefficiencies due to selection of a less-efficient mix of resources.

In a second approach, we assume that some of a resource's costs are avoidable if it were to not receive a capacity commitment in a season (see "Adjusted Annual Costs" panel). In this alternative, we estimate uncovered costs assuming that a resource can avoid half of its seasonal gross ACR, which results in a 25% reduction in annual gross ACR when clearing in only a single season. In addition, we also assume no net EAS offset for the season without a capacity commitment. Under this adjusted annual costs assumption, the ICAP-weighted average recovery of annual costs, summarized in **Table VII-15**, ranges from 71% to 109% across the Base Scenario cases and associated sensitivities. The total potential uplift payments range from $4 to $50 million, or 0.1% to 0.9% of total payments.

Table VII-15: Cost Recovery, Base Scenario Cases and Sensitivities

	Cleared in One Season		Annual Costs			Adjusted Annual Costs		
	ICAP (MW)	Payments ($M)	ICAP-Weighted Average Recovery (%)	Range of Recovery (%)	Under-Recovery ($M)	ICAP-Weighted Average Recovery (%)	Range of Recovery (%)	Under-Recovery ($M)
VRR								
Base Scenario	3,493	$ 65	59%	54%-73%	$46	75%	71%-86%	$22
Sub-Annual Market Only	*4,057*	*$114*	*85%*	*56%-110%*	*$24*	*109%*	*74%-132%*	*$ 4*
Increased Winter CETLs	*4,057*	*$112*	*83%*	*56%-110%*	*$27*	*106%*	*74%-129%*	*$ 5*
Increased Winter Ratings	*3,899*	*$ 75*	*60%*	*51%-73%*	*$51*	*76%*	*68%-86%*	*$24*
Reduced CETLs	6,638	$127	62%	51%-75%	$84	77%	67%-87%	$39
Collar on Seasonal Risk	5,431	$103	58%	52%-73%	$75	74%	68%-86%	$36
Alternative Seasonal VRR Slopes	6,923	$118	57%	50%-68%	$90	71%	65%-78%	$50
MRI								
Base Scenario	6,930	$124	63%	53%-80%	$76	77%	68%-89%	$38
Sub-Annual Market Only	*6,944*	*$153*	*76%*	*51%-99%*	*$54*	*94%*	*67%-110%*	*$16*
Increased Winter CETLs	*6,944*	*$153*	*76%*	*51%-99%*	*$54*	*94%*	*67%-110%*	*$16*
Increased Winter Ratings	*6,930*	*$124*	*63%*	*53%-80%*	*$76*	*77%*	*68%-89%*	*$38*
Reduced CETLs	6,606	$122	64%	52%-80%	$74	79%	68%-89%	$35
Collar on Seasonal Risk	7,243	$132	64%	50%-80%	$81	78%	65%-89%	$39

Note: Reported ICAP values exclude fractionally clearing resources.

In the Current Market Scenario, an even larger share of resources clear in both seasons relative to the Base Scenario. As shown in **Table VII-16,** across the Current Market Scenario cases and sensitivities, less than 1% of capacity, by annual ICAP, clears in a single season. The resources that clear in one season account for 0% to 0.6% of the total payments. The resources that clear in a single season clear in the winter but not the summer, ranging from 0 MW (*i.e.*, all resources clear in both seasons) to 1,710 MW of annual ICAP. No resources clear in the summer but not the winter.

Table VII-16: Summary of Resources Clearing in One Season, Current Market Scenario Cases and Sensitivities

	ICAP (MW)			Seasonal Payments ($M)			Cleared in Summer Only		Cleared in Winter Only	
	Cleared in Both Seasons	**Cleared in One Season**	**Percent of Total Cleared in One Season**	**Cleared in Both Seasons**	**Cleared in One Season**	**Percent of Total Cleared in One Season**	**ICAP (MW)**	**Payments ($M)**	**ICAP (MW)**	**Payments ($M)**
VRR										
Current Market Scenario	198,378	0	0.0%	$13,474	$ 0	0.0%	0	$ 0	0	$ 0
Sub-Annual Market Only	*198,378*	*0*	*0.0%*	*$19,458*	*$ 0*	*0.0%*	*0*	*$ 0*	*0*	*$ 0*
Increased Winter CETLs	*198,378*	*0*	*0.0%*	*$18,615*	*$ 0*	*0.0%*	*0*	*$ 0*	*0*	*$ 0*
Increased Winter Ratings	*198,378*	*0*	*0.0%*	*$13,927*	*$ 0*	*0.0%*	*0*	*$ 0*	*0*	*$ 0*
Reduced CETLs	198,378	0	0.0%	$16,604	$ 0	0.0%	0	$ 0	0	$ 0
Tighter Supply	198,378	0	0.0%	$15,977	$ 0	0.0%	0	$ 0	0	$ 0
Relaxed Summer Price Cap	198,378	0	0.0%	$14,530	$ 0	0.0%	0	$ 0	0	$ 0
Collar on Seasonal Risk	198,378	0	0.0%	$14,254	$ 0	0.0%	0	$ 0	0	$ 0
Alternative Seasonal VRR Slopes	196,814	955	0.5%	$12,067	$ 36	0.3%	0	$ 0	955	$36
MRI										
Current Market Scenario	196,514	1,565	0.8%	$11,171	$ 53	0.5%	0	$ 0	1,565	$53
Sub-Annual Market Only	*196,514*	*1,565*	*0.8%*	*$15,399*	*$ 90*	*0.6%*	*0*	*$ 0*	*1,565*	*$90*
Increased Winter CETLs	*196,514*	*1,565*	*0.8%*	*$15,023*	*$ 88*	*0.6%*	*0*	*$ 0*	*1,565*	*$88*
Increased Winter Ratings	*196,514*	*1,565*	*0.8%*	*$11,231*	*$ 53*	*0.5%*	*0*	*$ 0*	*1,565*	*$53*
Reduced CETLs	196,668	1,710	0.9%	$12,485	$ 58	0.5%	0	$ 0	1,710	$58
Tighter Supply	197,578	800	0.4%	$13,450	$ 32	0.2%	0	$ 0	800	$32
Relaxed Summer Price Cap	196,514	1,565	0.8%	$11,171	$ 53	0.5%	0	$ 0	1,565	$53
Collar on Seasonal Risk	196,814	955	0.5%	$11,615	$ 34	0.3%	0	$ 0	955	$34

Note: Reported ICAP values exclude fractionally clearing resources.

As shown in **Table VII-17**, virtually all resources that clear in a single season in the Current Market Scenario cases and sensitivities recover their full annual costs, with the ICAP-weighted average recovery of annual costs ranging from 101% to 170%, with individual resources recovering between 83% and 180%. Given that not all resources clearing in one season will require uplift, total uplift payments are small compared to total payments, ranging from $0 to $1.5 million, 0.01% of total payments. Under the alternative adjusted annual costs assumption, all resources in the Current Market Scenario cases and sensitivities recover their annual costs in the one season they clear, resulting in $0 of potential uplift.

Some stakeholders have expressed concerns that resources may not recover their full annual costs when only clearing in one season in the independent sub-annual auctions. The results of our modeling show that this concern would likely affect a small share of resources in the market. Moreover, these resources generally recover a large share of their overall annual costs in the season they do clear, and in some scenarios recover their full annual costs in a single season. The analysis above shows that the unrecovered costs, when not recovered fully in a single season, are small relative to overall capacity market payments. Concerns about unrecovered costs can potentially be mitigated with modest uplift payments that would range from 0% to 1.6% of overall payments. Thus, the results of our modeling suggest that, while valid, these concerns should not be a major impediment to pursuing an independent sub-annual design.

Table VII-17: Cost Recovery, Current Market Scenario Cases and Sensitivities

	Cleared in One Season		Annual Costs			Adjusted Annual Costs		
	ICAP (MW)	Payments ($M)	ICAP-Weighted Average Recovery (%)	Range of Recovery (%)	Under-Recovery ($M)	ICAP-Weighted Average Recovery (%)	Range of Recovery (%)	Under-Recovery ($M)
VRR								
Current Market Scenario	0	$ 0	0%	N/A	N/A	0%	N/A	N/A
Sub-Annual Market Only	*0*	*$ 0*	*0%*	*N/A*	*N/A*	*0%*	*N/A*	*N/A*
Increased Winter CETLs	*0*	*$ 0*	*0%*	*N/A*	*N/A*	*0%*	*N/A*	*N/A*
Increased Winter Ratings	*0*	*$ 0*	*0%*	*N/A*	*N/A*	*0%*	*N/A*	*N/A*
Reduced CETLs	0	$ 0	0%	N/A	N/A	0%	N/A	N/A
Tighter Supply	0	$ 0	0%	N/A	N/A	0%	N/A	N/A
Relaxed Summer Price Cap	0	$ 0	0%	N/A	N/A	0%	N/A	N/A
Collar on Seasonal Risk	0	$ 0	0%	N/A	N/A	0%	N/A	N/A
Alternative Seasonal VRR Slopes	955	$ 36	107%	92%-110%	$0.5	141%	124%-145%	$0
MRI								
Current Market Scenario	1,565	$ 53	101%	83%-109%	$1.5	131%	110%-138%	$0
Sub-Annual Market Only	*1,565*	*$ 90*	*170%*	*163%-180%*	*$0*	*221%*	*214%-228%*	*$0*
Increased Winter CETLs	*1,565*	*$ 88*	*167%*	*137%-180%*	*$0*	*216%*	*181%-228%*	*$0*
Increased Winter Ratings	*1,565*	*$ 53*	*101%*	*83%-109%*	*$1.5*	*131%*	*110%-138%*	*$0*
Reduced CETLs	1,710	$ 58	107%	99%-122%	$0.3	136%	130%-149%	$0
Tighter Supply	800	$ 32	118%	118%-118%	$0	155%	155%-155%	$0
Relaxed Summer Price Cap	1,565	$ 53	101%	83%-109%	$1.5	131%	110%-138%	$0
Collar on Seasonal Risk	955	$ 34	101%	87%-104%	$0.9	133%	116%-137%	$0

Note: Reported ICAP values exclude fractionally clearing resources.

Appendices

A. Stakeholder Survey Responses

1. *September Survey*[284]

Topic and Feedback	Analysis Group Response
Q11 - Sub-Annual Periods	
start with a summer and winter period	*See* **Section VI.A.3**
Please include a slice-of-day scenario (ala CAISO), in addition to a standard seasonal construct	*See* Analysis Group, “Evaluation of Sub-Annual Designs for PJM’s RPM – Education on California Slice of Day,” October 29, 2025, available at https://www.pjm.com/-/media/DotCom/committees-groups/task-forces/sacmstf/2025/20251029/20251029-item-02---analysis-group-education-on-caiso-resource-adequacy-construct---presentation.pdf. **Section VI.A.3** also discusses the hourly construct.
There should be two seasons (summer and winter) May 1 - Oct 31 and Nov 1 - April 30	*See* **Section VI.A.3**
When will each period begin? Will each be six-months in duration or will there be more than two periods annually? If so, what is the duration of each period? Will each period have shoulder months? If a resource receives a capacity obligation or commitment for one period but another, could this accelerate retirement of resources needed for reliability?	*See* **Section VI.A**
Feasibility of the current annual construct and difficulty of transition to various sub-annual options (*i.e.* summer/winter, summer/fall/winter/spring, hourly). For RTOs/ISOs that transitioned to a seasonal model, what were some of the lessons learned and/or some of the unanticipated challenges? Is there analysis available that shows what their auction results would have been and how that compared to the new construct?	*See* **Section IV** and **VI**
Capacity requirements should be set using a planning model with hourly granularity on an adjusted ICAP.	*See* **Section VI.A.3**

[284] PJM, SACMSTF Stakeholder Survey - September, available at https://www.pjm.com/-/media/DotCom/committees-groups/task-forces/sacmstf/postings/survey-results-september.pdf.

Evaluation should explicitly quantify the potential end-use customer value that could be realized from the implementation of a Sub-Annual market design under the present tight/short capacity market conditions, which are likely to last into the 2030s. Quantification should consider end-use customer cost and improvement to Resource Adequacy reliability. Will the implementation of a Sub-Annual Capacity market resolve or improve Resource Adequacy issue immediately or in the near term?	*See* **Section V** and **Section VII**
Q12 - Auction Structure (*e.g.*, co-optimized vs. sequential) and Timing	
co-optimized	*See* **Section VI.A.1**
Auctions should be sequential and based on the New York model with 6-month strip, rest of period monthly and spot. Compulsory spot/prompt auction held several days prior to the start of each month Voluntary auction clears bilateral offers to buy and sell capacity Six-month seasonal capability periods affect demand curves and supply offers: summer (May to October) and winter (November to April)	*See* **Section VI.A.1**
Will the auction include sealed bids or a descending clock structure?	Details of the auction design will depend on other auction design details to revisit when undertaking modifications.
How effective would a prompt auction be in an RTO like PJM as compared to other RTOs/ISOs such as MISO, which has a majority of vertically integrated states? Are some types of resources differently advantaged in a prompt auction vs a forward auction? Is there a way to have a forward looking price signal while also having a prompt auction?	Trade-offs of pursuing prompt versus forward markets are outside of the Scope of the Issue Charge. However, **Section VI.A** discusses prompt versus forward constructs in the context of sub-annual markets.
Longer-term and multi-year commitments of resources may be needed to procure needed supply resources. Consider if, and assess how, a sub-annual capacity market design can be integrated into a longer-term capacity procurement design. Auction structure should optimize risk distribution between seasons while maintaining overall annual ‘1 event in 10 years’ LOLE to achieve lowest annual customer cost. Capacity market design and timing should consider impact on end-use customers. Customers should be provided with ample time to adjust operations if needed to respond to capacity market costs. Capacity Auctions should largely be completed such that customers have an accurate assessment of capacity charge rate in time that such knowledge is actionable.	*See* **Section VI.A and Section VI.B**
Q13 - Demand Curve	
perhaps a unique demand curve per sub season?	*See* **Section VI.B**

Sloped demand curves for two capability periods (winter, summer)	
Will a separate demand curve be used for each period? Will the Net-CONE unit/reference resource be the same for each period or will a different unit be chosen for each? Will a different Installed Capacity Requirement (ICR) be applied for each period (presumably lower in winter at least at first)? If resources will be accredited differently for each period, will the demand curve be adjusted accordingly. If accreditation results in different supply stacks for each period will the demand curve be adjusted accordingly?	
What would the impacts be if you have large, firm load customers that vacillate between participating in DR season-to-season (*i.e*. a data center that agrees to curtailment in the summer, but not the winter, and vice versa)?	With the adoption of a sub-annual market, market mitigation rules should be reviewed to ensure that they continue to mitigate offers, when appropriate given market power concerns. Further assessment is required to evaluate market power risks associated with particular resources.
Sub-annual curves should reflect seasonal Reliability Requirements.	*See* **Section VI.B**
Q14 - Sell Offer Structure	
status quo	*See* **Section VI.A**
As NYISO. Monthly offers reflect avoidable cost and net EAS offset	
If you clear only one of the seasons, will your costs be recovered in only that one season or would it be recovered throughout the year? How to structure offers when the clearing outcome is unknown (preventing over recovery or under recovery). How a market seller is able to reflect its risk season to season (moving to a seasonal model implies that the risk changes by season so how each resource could accurately reflect its risk). As per question in 13, could large DR customers exercise market power season-to-season?	
Needs to reflect that capacity market revenue should largely be addressing the 'missing money' not provided by other markets to meet annual going forward costs. Must offer requirement should apply to all sub-annual periods.	*See* **Section VI.A.2** and **Section V.C.2**
Q15 - Resource Qualifications and Accreditation	
status quo - for summer; replicate for winter	*See* **Section V.C**
We view the Winter Peak Load (WPL) as a suboptimal baseline from which to measure winter curtailment. WPL has an assumption that the peak load corresponds to the peak curtailment, which is not often the case. Alternate baselines provide a more accurate accounting of the quantity and duration of curtailment. Given that PJM is calculating these values from customer meter data, rather than the values provided by distribution utilities, use of other baselines are reasonable and preferable.	While relevant to seasonal considerations, this particular issue is outside the scope of work.
Seasonal MRI-based accreditation	*See* **Section VI.C**

Will resources be accredited differently for different periods? For example, some resources may have lower availability in one season vs. another, in this case will the accreditation reflect those differences? Will changes currently under discussion at PJM regarding accreditation be fully implemented prior to the implementation of a sub-annual period?	*See* **Section VI.C** The exact timing of the implementation of sub-annual elements will be the result of an evaluation process between stakeholders and PJM.
How do you prevent homogenization of resource types within and across seasons in the future as renewable penetration increases? How do you ensure year-round resources can adequately reflect their value in a seasonal construct that does not fall neatly into "summer" or "winter" costs of operations, for instance, especially if there is risk they may clear in one season and not the other if they are the marginal resource in a given season. Would the must-offer requirement be expanded to include all resources eligible to take on a capacity obligation and eliminate any remaining categorical exceptions?	*See* **Section VI.A.2** and **Section VI.C.2.**
Continue to base accreditation on performance during the market period. Resources that perform well and have desired characteristics should have more value than resources that do not perform as well.	*See* **Section VI.C**
Q16 - CETL Values	
CETL values and analysis should be consistent with market period. Any sub-annual seasonal assessment should reflect expected ambient generation output and ambient facility limits.	*See* **Section V.B.4**
Q17 - Capacity Cost Allocation	
Allocates capacity obligations to LSEs based on their share of forecasted seasonal peak load, adjusted for locational capacity requirements. ICAP is translated to UCAP for summer and winter capability periods	
If costs will not be allocated using the same methodology as today, just across more than one period), the consultant is requested to explain why a different methodology is needed and provide examples of alternatives.	
Can you clear by season then "smooth out" the allocation across all 12 months of a DY? If the cost allocation is done by season, would it drive changes to the default service procurement process used by EDCs?	
Cost Allocation must remain consistent with beneficiary pays principles. LSE's with balanced portfolios should not be saddled with excess costs from improper leaning on the Capacity Market.	**Section VI.D** provides a high-level discussion of cost allocation. A more detailed assessment would be required in future stakeholder processes.

Any proposed change to cost allocation should go beyond just assessing allocation at the LSE level but should delve further into the allocation at the end-use customer level. Provide benefits and implications of allocating costs to end-use customers based on annual peak vs. seasonal peak vs. usage only during periods of potential system resource inadequacy.	
Q18 - Corresponding Changes to E&AS Must-Offer Obligations and Performance Assessments	
status quo adjusted for sub season structure	*See* **Section VI.C.2**
Why would E&AS Must-Offer Obligations and Performance Assessments need to change under a sub annual capacity market structure? If they must, the consultant is requested to explain why and provide examples of alternatives.	
Would PJM tether the performance assessment to the season based on the corresponding risk profile?	
Must offer obligation should apply to all sub-annual periods. Performance Assessments should be based on sub-annual period accreditation.	
Q19 - Corresponding Changes to the FRR Alternative	
Why would changes to the FRR alternative need to change under a sub annual capacity market structure? If they must, the consultant is requested to explain why and provide examples of alternatives.	The FRR alternative will need to be revised to align with a sub-annual market design. The current FRR framework provides a suitable foundation for the adoption of a sub-annual FRR. An entity that elects the FRR will have sub-annual capacity obligations defined using the approach that PJM adopts for its sub-annual market design. FRR sub-annual load obligations can be defined similarly to how annual load obligations are used now for FRRs. FRR capacity plans can be aligned with sub-annual periods to ensure that FRR entities have sufficient resources for sub-annual periods. The FRR framework can be readily modified to align with a sub-annual market design.
Would the FRR need to demonstrate sufficient supply by season per the sub-annual construct?	
Q20 - Transition Mechanisms	
How would a sub-annual market interact with the 3-year forward auction? Is that still an appropriate model for a sub-annual market?	*See* **Section VI.A.1** A detailed assessment of a prompt versus forward market is outside of the scope of this report.
Transition mechanisms should include realistic time frames for implementation in recognition of potentially significant work that will need to occur at PJM and among market participants.	Specific timeframes will depend on the sub-annual design options pursued.

How do you implement this without further delaying the auction schedule – from a timing perspective this will be going into place (in theory) right as we are getting back on track. Could you run "dummy" or "shadow" auctions to sus out unforeseen consequences?	
Sub-Annual construct would not be implemented in any delivery year in which any capacity market auction has already occurred, and should not be implemented for any Delivery Year for which market participants have less than 6 months of preparation from the time of a final, non-appealable FERC order approving the tariff changes necessary to implement a sub-annual construct.	A sub-annual construct should not be implemented for any Delivery Year where an annual BRA or incremental auction has already occurred.
Q21 - Other	
We have no specific concerns. As a winter peaking demand resource provider, we see this sub-annual capacity as an opportunity to bring more resource to the market.	
Please ensure to include cost estimates for each of your analyses. In particular, it is important to know whether seasonal resources are likely to increase their bids, and if so, whether a seasonal market will increase costs to consumers. In the most recent MISO auction, the summer price spiked but the price for the rest of the year was relatively low. Are there examples of RTOs that have included a price smoothing mechanism to help ratepayers manage sudden price spikes?	*See* **Section VII.C, VII.D** Volatility in the prices borne by ratepayers is affected by two components: (a) volatility in the auction clearing prices, and (b) cost allocation mechanisms. Greater stability in the auction clearing prices can be introduced through price caps and floors, discussed in **Section VI.B.3**. As discussed in **Section VI.D**, regulators can introduce greater stability in the price that is passed on to ratepayers.
Would the GROSS and NET CONE need to be seasonalized if moving to a sub-annual model? Would the "quad review" need to be performed more frequency than every 4 years? How would any sub-annual model impact the cost to load?	*See* **Section VI.B**

2. *October Survey*[285]

Topic and Feedback	Analysis Group Response
Sub-Annual Periods	
summer, winter	*See* **Section VI.A.3**
Auction Structure (*e.g.*, co-optimized vs. sequential) and Timing	
co-optimized	*See* **Section VI.A.1**
Demand Curve	

[285] PJM, SACMSTF Stakeholder Survey - October, available at https://www.pjm.com/-/media/DotCom/committees-groups/task-forces/sacmstf/postings/survey-results-october.pdf.

adjusted for sub annual periods	*See* **Section VI.B**
Sell Offer Structure	
mw price block pairs	*See* **Section VI.A.2**
Resource Qualifications and Accreditation	
seems we have elcc method in place	*See* **Section VI.C.1**
CETL Values	
N/A	
Capacity Cost Allocation	
to comport with sub-annual structure	*See* **Section VI.D**
Corresponding Changes to E&AS Must-Offer Obligations and Performance Assessments	
to match sub annual periods	*See* **Section VI.C.2**
Corresponding Changes to the FRR Alternative	
N/A	
Transition Mechanisms	
N/A	
Please provide questions or comments on any other topic	
N/A	

3. *November Survey*[286]

Topic and Feedback	Analysis Group Response
Sub-Annual Periods	
During the November 19th meeting, The Analysis Group stated that they were not planning to perform any indicative analysis that may provide some level of validation that the two-season summer and winter design is the appropriate number of sub-annual periods – *i.e.*, that it would be extended to produce superior results to a menu of alternatives across a range of conditions. In explaining why they believe the two-season construct is appropriate, they described PJM as a system where most of the risk occurs in either the summer or winter seasons. We are concerned that designing a sub-annual market construct based on current system risks presents significant challenges if and when the timing of those reliability risks shift. PJM currently is in the throes of navigating significant changes to its load profile due to large load additions. This process should produce a durable solution that can handle current and future risks without having to overhaul the design when conditions change in the future. Just a few years ago no one could have predicted the current level of winter risk, never mind the impact that datacenter development would have on the system. It is naïve to construct a market design that is not durable enough to handle an uncertain future. Again we ask that The Analysis Group provide an appropriate level of analysis and evidence that supports the recommendation for a two-season construct. Without a comparative analysis of a two-season construct versus a more granular sub-period design, stakeholders do not have adequate information to judge whether or not a two-season construct is durable or appropriate for PJM's needs. As noted, seasonal delineations can be arbitrary and, in theory, a design could include an unlimited number of seasons, which ends with a logical endpoint of a more granular/hourly design. Additionally, more granular sub-annual periods such as CAISO's quasi-hourly design can translate well into PJM's current structure and better resolve hourly constraints.	*See* **Section VI.A.3**
Auction Structure (*e.g.*, co-optimized vs. sequential) and Timing	
N/A	
Demand Curve	

[286] PJM, SACMSTF Stakeholder Survey - November, available at https://www.pjm.com/-/media/DotCom/committees-groups/task-forces/sacmstf/postings/survey-results-november.pdf.

N/A	
Sell Offer Structure	
N/A	
Resource Qualifications and Accreditation	
N/A	
CETL Values	
N/A	
Capacity Cost Allocation	
N/A	
Corresponding Changes to E&AS Must-Offer Obligations and Performance Assessments	
N/A	
Corresponding Changes to the FRR Alternative	
N/A	
Transition Mechanisms	
N/A	
Please provide questions or comments on any other topic	
N/A	

B. Additional Results from Quantitative Analysis

1. Base Scenario Sensitivities

a. VRR demand curve

Table B-1: Base Scenario – Tighter LDA Transmission Constraints – VRR Demand Curve

LDA	Clearing Price ($/MW-Day)	Cleared UCAP (MW)	Uncleared UCAP (MW)	Capacity Payments ($M)	Production Costs ($M)	EUE (MWh)
Annual						
RTO	$109.69	151,506	1,586	$ 7,702	$ 1,148	716
Dominion	$301.25	21,778	0	$ 2,401	$ 81	
MAAC	$109.69	52,145	922	$ 2,186	$ 540	
EMAAC	$112.43	23,734	851	$ 977	$ 196	
SWMAAC	$137.50	6,735	0	$ 339	$ 98	
UCAP-Weighted Average Price	$138.89					
Seasonal						
Summer						
RTO	$ 75.28	172,531	4,766	$ 3,016	$ 452	31
Dominion	$126.02	25,185	144	$ 584	$ 30	
MAAC	$ 95.25	61,206	1,551	$ 1,239	$ 235	
EMAAC	$126.00	29,333	0	$ 680	$ 97	
SWMAAC	$ 95.25	7,805	0	$ 137	$ 48	
UCAP-Weighted Average Price	$ 95.00					
Winter						
RTO	$122.43	152,205	1,089	$ 3,684	$ 648	327
Dominion	$195.75	21,909	0	$ 781	$ 47	
MAAC	$122.43	51,770	1,089	$ 1,154	$ 293	
EMAAC	$122.43	23,435	1,089	$ 522	$ 115	
SWMAAC	$122.43	6,823	0	$ 152	$ 50	
UCAP-Weighted Average Price	$132.98					
Seasonal Total						
Annual-UCAP Weighted Average	$121.81	150,275	**Total**	$ 6,700	$ 1,100	358

Table B-2: Base Scenario – Collar on Seasonal Risk – VRR Demand Curve

LDA	Clearing Price ($/MW-Day)	Cleared UCAP (MW)	Uncleared UCAP (MW)	Capacity Payments ($M)	Production Costs ($M)	EUE (MWh)
Annual						
RTO	$112.43	151,437	1,655	$ 6,232	$ 1,144	727
Dominion	$112.43	21,641	138	$ 891	$ 74	
MAAC	$112.43	52,214	853	$ 2,149	$ 543	
EMAAC	$112.43	23,732	853	$ 977	$ 196	
SWMAAC	$112.43	6,735	0	$ 277	$ 98	
UCAP-Weighted Average Price	$112.43					
Seasonal						
Summer						
RTO	$ 77.24	172,460	4,838	$ 2,794	$ 451	32
Dominion	$ 77.24	24,422	907	$ 347	$ 17	
MAAC	$ 93.75	60,962	1,795	$ 1,209	$ 229	
EMAAC	$123.22	29,089	244	$ 659	$ 92	
SWMAAC	$ 93.75	7,805	0	$ 135	$ 48	
UCAP-Weighted Average Price	$ 88.05					
Winter						
RTO	$122.43	152,247	1,048	$ 3,392	$ 648	323
Dominion	$122.43	21,773	136	$ 485	$ 44	
MAAC	$122.43	51,947	912	$ 1,157	$ 297	
EMAAC	$122.43	23,612	912	$ 526	$ 119	
SWMAAC	$122.43	6,823	0	$ 152	$ 50	
UCAP-Weighted Average Price	$122.43					
Seasonal Total						
Annual-UCAP Weighted Average	$112.48	150,267	**Total**	$ 6,186	$ 1,099	355

Table B-3: Base Scenario – Alternative Seasonal Demand Curve Slopes – VRR Demand Curve

LDA	Clearing Price ($/MW-Day)	Cleared UCAP (MW)	Uncleared UCAP (MW)	Capacity Payments ($M)	Production Costs ($M)	EUE (MWh)
Annual						
RTO	$112.43	151,437	1,655	$ 6,232	$ 1,144	727
Dominion	$112.43	21,641	138	$ 891	$ 74	
MAAC	$112.43	52,214	853	$ 2,149	$ 543	
EMAAC	$112.43	23,732	853	$ 977	$ 196	
SWMAAC	$112.43	6,735	0	$ 277	$ 98	
UCAP-Weighted Average Price	$112.43					
Seasonal						
Summer						
RTO	$ 76.50	171,238	6,059	$ 2,709	$ 425	66
Dominion	$ 76.50	24,422	907	$ 344	$ 17	
MAAC	$103.40	60,423	2,334	$ 1,150	$ 217	
EMAAC	$103.40	28,511	822	$ 542	$ 79	
SWMAAC	$103.40	7,805	0	$ 149	$ 48	
UCAP-Weighted Average Price	$ 85.99					
Winter						
RTO	$110.25	150,339	2,956	$ 3,017	$ 607	530
Dominion	$110.25	21,773	136	$ 437	$ 44	
MAAC	$110.25	50,704	2,156	$ 1,017	$ 270	
EMAAC	$110.25	22,368	2,156	$ 449	$ 92	
SWMAAC	$110.25	6,823	0	$ 137	$ 50	
UCAP-Weighted Average Price	$110.25					
Seasonal Total						
Annual-UCAP Weighted Average	$105.17	148,755	**Total**	$ 5,726	$ 1,032	597

b. MRI demand curve

Table B-4: Base Scenario – Tighter LDA Transmission Constraints – MRI Demand Curve

LDA	Clearing Price ($/MW-Day)	Cleared UCAP (MW)	Uncleared UCAP (MW)	Capacity Payments ($M)	Production Costs ($M)	EUE (MWh)
Annual						
RTO	$108.59	150,955	2,136	$ 6,545	$1,124	816
Dominion	$136.44	21,778	0	$ 1,088	$ 81	
MAAC	$108.59	51,595	1,472	$ 2,374	$ 516	
EMAAC	$139.28	23,920	665	$ 1,219	$ 204	
SWMAAC	$130.85	6,735	0	$ 323	$ 98	
UCAP-Weighted Average Price	$118.47					
Seasonal						
Summer						
RTO	$ 70.47	170,373	6,925	$ 2,804	$ 409	107
Dominion	$ 95.95	24,821	508	$ 438	$ 23	
MAAC	$103.60	61,301	1,455	$ 1,274	$ 236	
EMAAC	$123.22	29,117	216	$ 660	$ 92	
SWMAAC	$103.60	7,805	0	$ 149	$ 48	
UCAP-Weighted Average Price	$ 89.45					
Winter						
RTO	$119.76	151,453	1,842	$ 3,301	$ 631	398
Dominion	$119.76	21,773	136	$ 475	$ 44	
MAAC	$119.76	51,154	1,705	$ 1,115	$ 279	
EMAAC	$119.76	22,819	1,705	$ 497	$ 102	
SWMAAC	$119.76	6,823	0	$ 149	$ 50	
UCAP-Weighted Average Price	$119.76					
Seasonal Total						
Annual UCAP-Weighted Average	$112.04	148,889	**Total**	$ 6,105	$1,040	505

Table B-5: Base Scenario – Collar on Seasonal Risk – MRI Demand Curve

LDA	Clearing Price ($/MW-Day)	Cleared UCAP (MW)	Uncleared UCAP (MW)	Capacity Payments ($M)	Production Costs ($M)	EUE (MWh)
Annual						
RTO	$109.69	150,910	2,182	$ 6,058	$1,122	825
Dominion	$109.69	21,641	138	$ 869	$ 74	
MAAC	$109.69	51,687	1,380	$ 2,075	$ 521	
EMAAC	$109.69	23,342	1,243	$ 937	$ 180	
SWMAAC	$109.69	6,735	0	$ 270	$ 98	
UCAP-Weighted Average Price	$109.69					
Seasonal						
Summer						
RTO	$ 70.63	170,753	6,544	$ 2,670	$ 418	82
Dominion	$ 70.63	24,412	917	$ 317	$ 17	
MAAC	$103.60	61,042	1,715	$ 1,244	$ 230	
EMAAC	$118.74	28,857	476	$ 630	$ 87	
SWMAAC	$103.60	7,805	0	$ 149	$ 48	
UCAP-Weighted Average Price	$ 84.97					
Winter						
RTO	$119.76	151,711	1,584	$ 3,307	$ 636	374
Dominion	$119.76	21,773	136	$ 475	$ 44	
MAAC	$119.76	51,412	1,448	$ 1,121	$ 285	
EMAAC	$119.76	23,076	1,448	$ 503	$ 107	
SWMAAC	$119.76	6,823	0	$ 149	$ 50	
UCAP-Weighted Average Price	$119.76					
Seasonal Total						
Annual UCAP-Weighted Average	$109.43	149,219	**Total**	$ 5,976	$1,054	455

2. *Current Market Scenario Sensitivities*

a. VRR demand curve

Table B-6: Current Market Scenario – Tighter LDA Transmission Constraints – VRR Demand Curve

LDA	Clearing Price ($/MW-Day)	Cleared UCAP (MW)	Uncleared UCAP (MW)	Capacity Payments ($M)	Production Costs ($M)	EUE (MWh)
Annual						
RTO	$327.50	153,092	0	$20,550	$ 1,224	1,561
Dominion	$542.83	21,778	0	$ 4,327	$ 81	
MAAC	$327.50	53,067	0	$ 6,845	$ 587	
EMAAC	$327.50	24,585	0	$ 2,947	$ 240	
SWMAAC	$523.74	6,735	0	$ 1,291	$ 98	
UCAP-Weighted Average Price	$366.77					
Seasonal						
Summer						
RTO	$126.27	177,298	0	$ 7,000	$ 549	58
Dominion	$126.27	25,329	0	$ 588	$ 33	
MAAC	$299.50	62,757	0	$ 4,339	$ 267	
EMAAC	$378.25	29,333	0	$ 2,041	$ 97	
SWMAAC	$616.50	7,805	0	$ 885	$ 48	
UCAP-Weighted Average Price	$214.57					
Winter						
RTO	$279.75	153,295	0	$ 9,604	$ 675	854
Dominion	$569.50	21,909	0	$ 2,271	$ 47	
MAAC	$279.75	52,859	0	$ 3,335	$ 320	
EMAAC	$279.75	24,524	0	$ 1,249	$ 143	
SWMAAC	$798.25	6,823	0	$ 991	$ 50	
UCAP-Weighted Average Price	$344.24					
Seasonal Total						
Annual UCAP-Weighted Average	$296.33	153,092	**Total**	$16,604	$ 1,224	912

Table B-7: Current Market Scenario – Tighter Supply – VRR Demand Curve

LDA	Clearing Price ($/MW-Day)	Cleared UCAP (MW)	Uncleared UCAP (MW)	Capacity Payments ($M)	Production Costs ($M)	EUE (MWh)
Annual						
RTO	$419.00	153,092	0	$24,722	$ 1,224	1,961
Dominion	$542.83	21,778	0	$ 4,327	$ 81	
MAAC	$419.00	53,067	0	$ 8,396	$ 587	
EMAAC	$419.00	24,585	0	$ 3,770	$ 240	
SWMAAC	$523.74	6,735	0	$ 1,291	$ 98	
UCAP-Weighted Average Price	$441.22					
Seasonal						
Summer						
RTO	$126.27	177,298	0	$ 7,048	$ 549	109
Dominion	$126.27	25,329	0	$ 588	$ 33	
MAAC	$368.75	62,757	0	$ 4,387	$ 267	
EMAAC	$368.75	29,333	0	$ 1,990	$ 97	
SWMAAC	$458.25	7,805	0	$ 658	$ 48	
UCAP-Weighted Average Price	$216.04					
Winter						
RTO	$320.03	153,295	0	$ 8,929	$ 675	1,062
Dominion	$320.03	21,909	0	$ 1,276	$ 47	
MAAC	$320.03	52,859	0	$ 3,079	$ 320	
EMAAC	$320.03	24,524	0	$ 1,428	$ 143	
SWMAAC	$320.03	6,823	0	$ 397	$ 50	
UCAP-Weighted Average Price	$320.03					
Seasonal Total						
Annual UCAP-Weighted Average	$285.13	153,092	**Total**	$15,977	$ 1,224	1,171

Table B-8: Current Market Scenario – No Price Caps – VRR Demand Curve

LDA	Clearing Price ($/MW-Day)	Cleared UCAP (MW)	Uncleared UCAP (MW)	Capacity Payments ($M)	Production Costs ($M)	EUE (MWh)
Annual						
RTO	$327.75	153,092	0	$19,998	$ 1,224	1,561
Dominion	$496.00	21,778	0	$ 3,954	$ 81	
MAAC	$327.75	53,067	0	$ 6,658	$ 587	
EMAAC	$327.75	24,585	0	$ 2,949	$ 240	
SWMAAC	$446.25	6,735	0	$ 1,100	$ 98	
UCAP-Weighted Average Price	$356.90					
Seasonal						
Summer						
RTO	$145.00	177,298	0	$ 6,725	$ 549	58
Dominion	$286.75	25,329	0	$ 1,336	$ 33	
MAAC	$260.50	62,757	0	$ 3,008	$ 267	
EMAAC	$260.50	29,333	0	$ 1,406	$ 97	
SWMAAC	$260.50	7,805	0	$ 374	$ 48	
UCAP-Weighted Average Price	$206.13					
Winter						
RTO	$279.75	153,295	0	$ 7,805	$ 675	854
Dominion	$279.75	21,909	0	$ 1,115	$ 47	
MAAC	$279.75	52,859	0	$ 2,691	$ 320	
EMAAC	$279.75	24,524	0	$ 1,249	$ 143	
SWMAAC	$279.75	6,823	0	$ 347	$ 50	
UCAP-Weighted Average Price	$279.75					
Seasonal Total						
Annual UCAP-Weighted Average	$259.31	153,092	**Total**	$14,530	$ 1,224	912

Table B-9: Current Market Scenario – Collar on Seasonal Risk – VRR Demand Curve

LDA	Clearing Price ($/MW-Day)	Cleared UCAP (MW)	Uncleared UCAP (MW)	Capacity Payments ($M)	Production Costs ($M)	EUE (MWh)
Annual						
RTO	$327.75	153,092	0	$19,998	$ 1,224	1,561
Dominion	$496.00	21,778	0	$ 3,954	$ 81	
MAAC	$327.75	53,067	0	$ 6,658	$ 587	
EMAAC	$327.75	24,585	0	$ 2,949	$ 240	
SWMAAC	$446.25	6,735	0	$ 1,100	$ 98	
UCAP-Weighted Average Price	$356.90					
Seasonal						
Summer						
RTO	$142.00	177,298	0	$ 6,334	$ 549	58
Dominion	$142.00	25,329	0	$ 662	$ 33	
MAAC	$260.50	62,757	0	$ 3,341	$ 267	
EMAAC	$322.25	29,333	0	$ 1,739	$ 97	
SWMAAC	$260.50	7,805	0	$ 374	$ 48	
UCAP-Weighted Average Price	$194.16					
Winter						
RTO	$281.50	153,295	0	$ 7,920	$ 675	854
Dominion	$298.00	21,909	0	$ 1,188	$ 47	
MAAC	$281.50	52,859	0	$ 2,709	$ 320	
EMAAC	$281.50	24,524	0	$ 1,256	$ 143	
SWMAAC	$282.00	6,823	0	$ 350	$ 50	
UCAP-Weighted Average Price	$283.88					
Seasonal Total						
Annual UCAP-Weighted Average	$254.40	153,092	**Total**	$14,254	$ 1,224	912

Table B-10: Current Market Scenario – Alternative Seasonal Demand Curve Slopes – VRR Demand Curve

LDA	Clearing Price ($/MW-Day)	Cleared UCAP (MW)	Uncleared UCAP (MW)	Capacity Payments ($M)	Production Costs ($M)	EUE (MWh)
Annual						
RTO	$327.75	153,092	0	$19,998	$ 1,224	1,561
Dominion	$496.00	21,778	0	$ 3,954	$ 81	
MAAC	$327.75	53,067	0	$ 6,658	$ 587	
EMAAC	$327.75	24,585	0	$ 2,949	$ 240	
SWMAAC	$446.25	6,735	0	$ 1,100	$ 98	
UCAP-Weighted Average Price	$356.90					
Seasonal						
Summer						
RTO	$ 97.16	175,936	1,362	$ 5,152	$ 520	124
Dominion	$126.27	25,185	144	$ 585	$ 30	
MAAC	$259.25	62,757	0	$ 2,994	$ 267	
EMAAC	$259.25	29,333	0	$ 1,399	$ 97	
SWMAAC	$259.25	7,805	0	$ 372	$ 48	
UCAP-Weighted Average Price	$159.15					
Winter						
RTO	$250.00	153,295	0	$ 6,975	$ 675	854
Dominion	$250.00	21,909	0	$ 997	$ 47	
MAAC	$250.00	52,859	0	$ 2,405	$ 320	
EMAAC	$250.00	24,524	0	$ 1,116	$ 143	
SWMAAC	$250.00	6,823	0	$ 310	$ 50	
UCAP-Weighted Average Price	$250.00					
Seasonal Total						
Annual UCAP-Weighted Average	$217.36	152,438	**Total**	$12,127	$ 1,195	977

b. MRI demand curve

Table B-11: Current Market Scenario – Tighter LDA Transmission Constraints – MRI Demand Curve

LDA	Clearing Price ($/MW-Day)	Cleared UCAP (MW)	Uncleared UCAP (MW)	Capacity Payments ($M)	Production Costs ($M)	EUE (MWh)
Annual						
RTO	$204.62	153,092	0	$15,223	$1,224	1,561
Dominion	$542.83	21,778	0	$ 4,327	$ 81	
MAAC	$220.84	53,067	0	$ 5,036	$ 587	
EMAAC	$220.84	24,585	0	$ 1,987	$ 240	
SWMAAC	$523.74	6,735	0	$ 1,291	$ 98	
UCAP-Weighted Average Price	$271.68					
Seasonal						
Summer						
RTO	$ 83.70	175,810	1,488	$ 5,362	$ 519	133
Dominion	$126.27	25,329	0	$ 588	$ 33	
MAAC	$287.82	62,757	0	$ 3,423	$ 267	
EMAAC	$290.21	29,333	0	$ 1,566	$ 97	
SWMAAC	$347.85	7,805	0	$ 500	$ 48	
UCAP-Weighted Average Price	$165.76					
Winter						
RTO	$223.66	153,295	0	$ 7,181	$ 675	854
Dominion	$352.63	21,909	0	$ 1,406	$ 47	
MAAC	$223.66	52,859	0	$ 2,578	$ 320	
EMAAC	$223.66	24,524	0	$ 998	$ 143	
SWMAAC	$567.20	6,823	0	$ 704	$ 50	
UCAP-Weighted Average Price	$257.38					
Seasonal Total						
Annual UCAP-Weighted Average	$224.91	152,378	**Total**	$12,543	$1,194	986

Table B-12: Current Market Scenario – Tighter Supply – MRI Demand Curve

LDA	Clearing Price ($/MW-Day)	Cleared UCAP (MW)	Uncleared UCAP (MW)	Capacity Payments ($M)	Production Costs ($M)	EUE (MWh)
Annual						
RTO	$266.05	153,092	0	$16,279	$1,224	1,961
Dominion	$405.27	21,778	0	$ 3,230	$ 81	
MAAC	$266.48	53,067	0	$ 5,429	$ 587	
EMAAC	$266.48	24,585	0	$ 2,398	$ 240	
SWMAAC	$369.46	6,735	0	$ 911	$ 98	
UCAP-Weighted Average Price	$290.53					
Seasonal						
Summer						
RTO	$ 97.28	176,602	696	$ 6,035	$ 534	159
Dominion	$126.27	25,329	0	$ 588	$ 33	
MAAC	$334.45	62,757	0	$ 3,862	$ 267	
EMAAC	$334.45	29,333	0	$ 1,805	$ 97	
SWMAAC	$334.45	7,805	0	$ 480	$ 48	
UCAP-Weighted Average Price	$185.72					
Winter						
RTO	$266.93	153,295	0	$ 7,447	$ 675	1,062
Dominion	$266.93	21,909	0	$ 1,064	$ 47	
MAAC	$266.93	52,859	0	$ 2,568	$ 320	
EMAAC	$266.93	24,524	0	$ 1,191	$ 143	
SWMAAC	$266.93	6,823	0	$ 331	$ 50	
UCAP-Weighted Average Price	$266.93					
Seasonal Total						
Annual UCAP-Weighted Average	$241.14	152,758	**Total**	$13,482	$1,209	1,221

Table B-13: Current Market Scenario – Collar on Seasonal Risk – MRI Demand Curve

LDA	Clearing Price ($/MW-Day)	Cleared UCAP (MW)	Uncleared UCAP (MW)	Capacity Payments ($M)	Production Costs ($M)	EUE (MWh)
Annual						
RTO	$204.62	153,092	0	$12,162	$1,224	1,561
Dominion	$277.92	21,778	0	$ 2,215	$ 81	
MAAC	$204.62	53,067	0	$ 4,087	$ 587	
EMAAC	$204.62	24,585	0	$ 1,841	$ 240	
SWMAAC	$250.33	6,735	0	$ 617	$ 98	
UCAP-Weighted Average Price	$217.06					
Seasonal						
Summer						
RTO	$ 97.16	175,951	1,346	$ 5,096	$ 520	122
Dominion	$ 97.16	25,185	144	$ 450	$ 30	
MAAC	$261.21	62,757	0	$ 3,072	$ 267	
EMAAC	$271.57	29,333	0	$ 1,466	$ 97	
SWMAAC	$261.21	7,805	0	$ 375	$ 48	
UCAP-Weighted Average Price	$157.40					
Winter						
RTO	$235.69	153,295	0	$ 6,576	$ 675	854
Dominion	$235.69	21,909	0	$ 940	$ 47	
MAAC	$235.69	52,859	0	$ 2,267	$ 320	
EMAAC	$235.69	24,524	0	$ 1,052	$ 143	
SWMAAC	$235.69	6,823	0	$ 293	$ 50	
UCAP-Weighted Average Price	$235.69					
Seasonal Total						
Annual UCAP-Weighted Average	$209.19	152,446	**Total**	$11,672	$1,195	976

3. Disaggregation of Results by Sub-Annual Features

a. Sub-annual market only

Table B-14: Base Scenario – Sub-Annual Market Only – VRR Demand Curve

LDA	Clearing Price ($/MW-Day)	Cleared UCAP (MW)	Uncleared UCAP (MW)	Capacity Payments ($M)	Production Costs ($M)	EUE (MWh)
Annual						
RTO	$112.43	151,437	1,655	$ 6,232	$ 1,144	727
Dominion	$112.43	21,641	138	$ 891	$ 74	
MAAC	$112.43	52,214	853	$ 2,149	$ 543	
EMAAC	$112.43	23,732	853	$ 977	$ 196	
SWMAAC	$112.43	6,735	0	$ 277	$ 98	
UCAP-Weighted Average Price	$112.43					
Seasonal						
Summer						
RTO	$ 77.24	172,506	4,792	$ 2,894	$ 451	31
Dominion	$ 92.10	24,600	728	$ 417	$ 20	
MAAC	$103.60	60,863	1,894	$ 1,240	$ 226	
EMAAC	$118.74	28,564	769	$ 624	$ 80	
SWMAAC	$103.60	7,805	0	$ 149	$ 48	
UCAP-Weighted Average Price	$ 91.17					
Winter						
RTO	$184.25	150,698	0	$ 5,177	$ 675	487
Dominion	$216.00	21,419	0	$ 842	$ 47	
MAAC	$184.25	52,038	0	$ 1,745	$ 320	
EMAAC	$184.25	24,065	0	$ 807	$ 143	
SWMAAC	$184.25	6,624	0	$ 222	$ 50	
UCAP-Weighted Average Price	$188.76					
Seasonal Total						
Annual-UCAP Weighted Average	$146.19	150,842	**Total**	$ 8,071	$ 1,126	518

Table B-15: Base Scenario – Sub-Annual Market Only – MRI Demand Curve

LDA	Clearing Price ($/MW-Day)	Cleared UCAP (MW)	Uncleared UCAP (MW)	Capacity Payments ($M)	Production Costs ($M)	EUE (MWh)
Annual						
RTO	$109.69	150,910	2,182	$ 6,058	$1,122	825
Dominion	$109.69	21,641	138	$ 869	$ 74	
MAAC	$109.69	51,687	1,380	$ 2,075	$ 521	
EMAAC	$109.69	23,342	1,243	$ 937	$ 180	
SWMAAC	$109.69	6,735	0	$ 270	$ 98	
UCAP-Weighted Average Price	$109.69					
Seasonal						
Summer						
RTO	$ 70.47	170,373	6,925	$ 2,581	$ 410	107
Dominion	$ 70.47	24,412	917	$ 317	$ 17	
MAAC	$103.60	61,042	1,715	$ 1,164	$ 230	
EMAAC	$103.60	28,511	822	$ 543	$ 79	
SWMAAC	$103.60	7,805	0	$ 149	$ 48	
UCAP-Weighted Average Price	$ 82.34					
Winter						
RTO	$147.66	150,480	218	$ 4,044	$ 669	513
Dominion	$147.66	21,419	0	$ 576	$ 47	
MAAC	$147.66	51,820	218	$ 1,393	$ 314	
EMAAC	$147.66	23,847	218	$ 641	$ 136	
SWMAAC	$147.66	6,624	0	$ 178	$ 50	
UCAP-Weighted Average Price	$147.66					
Seasonal Total						
Annual UCAP-Weighted Average	$120.88	149,740	**Total**	$ 6,625	$1,078	621

Table B-16: Current Market Scenario – Sub-Annual Market Only – VRR Demand Curve

LDA	Clearing Price ($/MW-Day)	Cleared UCAP (MW)	Uncleared UCAP (MW)	Capacity Payments ($M)	Production Costs ($M)	EUE (MWh)
Annual						
RTO	$327.75	153,092	0	$19,998	$ 1,224	1,561
Dominion	$496.00	21,778	0	$ 3,954	$ 81	
MAAC	$327.75	53,067	0	$ 6,658	$ 587	
EMAAC	$327.75	24,585	0	$ 2,949	$ 240	
SWMAAC	$446.25	6,735	0	$ 1,100	$ 98	
UCAP-Weighted Average Price	$356.90					
Seasonal						
Summer						
RTO	$126.27	177,298	0	$ 5,669	$ 549	58
Dominion	$126.27	25,329	0	$ 588	$ 33	
MAAC	$260.50	62,757	0	$ 3,008	$ 267	
EMAAC	$260.50	29,333	0	$ 1,406	$ 97	
SWMAAC	$260.50	7,805	0	$ 374	$ 48	
UCAP-Weighted Average Price	$173.78					
Winter						
RTO	$472.00	150,698	0	$13,788	$ 675	1,503
Dominion	$644.00	21,419	0	$ 2,511	$ 47	
MAAC	$472.00	52,038	0	$ 4,643	$ 320	
EMAAC	$472.00	24,065	0	$ 2,067	$ 143	
SWMAAC	$615.00	6,624	0	$ 741	$ 50	
UCAP-Weighted Average Price	$502.73					
Seasonal Total						
Annual UCAP-Weighted Average	$347.26	153,092	**Total**	$19,458	$ 1,224	1,561

Table B-17: Current Market Scenario – Sub-Annual Market Only – MRI Demand Curve

LDA	Clearing Price ($/MW-Day)	Cleared UCAP (MW)	Uncleared UCAP (MW)	Capacity Payments ($M)	Production Costs ($M)	EUE (MWh)
Annual						
RTO	$204.62	153,092	0	$12,162	$1,224	1,561
Dominion	$277.92	21,778	0	$ 2,215	$ 81	
MAAC	$204.62	53,067	0	$ 4,087	$ 587	
EMAAC	$204.62	24,585	0	$ 1,841	$ 240	
SWMAAC	$250.33	6,735	0	$ 617	$ 98	
UCAP-Weighted Average Price	$217.06					
Seasonal						
Summer						
RTO	$ 88.47	175,681	1,617	$ 4,995	$ 516	142
Dominion	$119.04	25,185	144	$ 552	$ 30	
MAAC	$261.10	62,757	0	$ 3,015	$ 267	
EMAAC	$261.10	29,333	0	$ 1,409	$ 97	
SWMAAC	$261.10	7,805	0	$ 375	$ 48	
UCAP-Weighted Average Price	$154.52					
Winter						
RTO	$369.45	150,698	0	$10,511	$ 675	1,503
Dominion	$455.05	21,419	0	$ 1,774	$ 47	
MAAC	$369.45	52,038	0	$ 3,544	$ 320	
EMAAC	$369.45	24,065	0	$ 1,618	$ 143	
SWMAAC	$406.49	6,624	0	$ 490	$ 50	
UCAP-Weighted Average Price	$383.24					
Seasonal Total						
Annual UCAP-Weighted Average	$278.15	152,316	**Total**	$15,506	$1,191	1,645

b. Adjusted winter CETL values

Table B-18: Base Scenario – Adjusted Winter CETL Values – VRR Demand Curve

LDA	Clearing Price ($/MW-Day)	Cleared UCAP (MW)	Uncleared UCAP (MW)	Capacity Payments ($M)	Production Costs ($M)	EUE (MWh)
Annual						
RTO	$112.43	151,437	1,655	$ 6,232	$ 1,144	727
Dominion	$112.43	21,641	138	$ 891	$ 74	
MAAC	$112.43	52,214	853	$ 2,149	$ 543	
EMAAC	$112.43	23,732	853	$ 977	$ 196	
SWMAAC	$112.43	6,735	0	$ 277	$ 98	
UCAP-Weighted Average Price	$112.43					
Seasonal						
Summer						
RTO	$ 77.24	172,506	4,792	$ 2,894	$ 451	31
Dominion	$ 92.10	24,600	728	$ 417	$ 20	
MAAC	$103.60	60,863	1,894	$ 1,240	$ 226	
EMAAC	$118.74	28,564	769	$ 624	$ 80	
SWMAAC	$103.60	7,805	0	$ 149	$ 48	
UCAP-Weighted Average Price	$ 91.17					
Winter						
RTO	$184.25	150,698	0	$ 5,053	$ 675	487
Dominion	$184.25	21,419	0	$ 718	$ 47	
MAAC	$184.25	52,038	0	$ 1,745	$ 320	
EMAAC	$184.25	24,065	0	$ 807	$ 143	
SWMAAC	$184.25	6,624	0	$ 222	$ 50	
UCAP-Weighted Average Price	$184.25					
Seasonal Total						
Annual-UCAP Weighted Average	$143.95	150,842	**Total**	$ 7,947	$ 1,126	518

Table B-19: Base Scenario – Adjusted Winter CETL Values – MRI Demand Curve

LDA	Clearing Price ($/MW-Day)	Cleared UCAP (MW)	Uncleared UCAP (MW)	Capacity Payments ($M)	Production Costs ($M)	EUE (MWh)
Annual						
RTO	$109.69	150,910	2,182	$ 6,058	$1,122	825
Dominion	$109.69	21,641	138	$ 869	$ 74	
MAAC	$109.69	51,687	1,380	$ 2,075	$ 521	
EMAAC	$109.69	23,342	1,243	$ 937	$ 180	
SWMAAC	$109.69	6,735	0	$ 270	$ 98	
UCAP-Weighted Average Price	$109.69					
Seasonal						
Summer						
RTO	$ 70.47	170,373	6,925	$ 2,581	$ 410	107
Dominion	$ 70.47	24,412	917	$ 317	$ 17	
MAAC	$103.60	61,042	1,715	$ 1,164	$ 230	
EMAAC	$103.60	28,511	822	$ 543	$ 79	
SWMAAC	$103.60	7,805	0	$ 149	$ 48	
UCAP-Weighted Average Price	$ 82.34					
Winter						
RTO	$147.66	150,480	218	$ 4,044	$ 669	513
Dominion	$147.66	21,419	0	$ 576	$ 47	
MAAC	$147.66	51,820	218	$ 1,393	$ 314	
EMAAC	$147.66	23,847	218	$ 641	$ 136	
SWMAAC	$147.66	6,624	0	$ 178	$ 50	
UCAP-Weighted Average Price	$147.66					
Seasonal Total						
Annual UCAP-Weighted Average	$120.88	149,740	**Total**	$ 6,625	$1,078	621

Table B-20: Current Market Scenario – Adjusted Winter CETL Values – VRR Demand Curve

LDA	Clearing Price ($/MW-Day)	Cleared UCAP (MW)	Uncleared UCAP (MW)	Capacity Payments ($M)	Production Costs ($M)	EUE (MWh)
Annual						
RTO	$327.75	153,092	0	$19,998	$ 1,224	1,561
Dominion	$496.00	21,778	0	$ 3,954	$ 81	
MAAC	$327.75	53,067	0	$ 6,658	$ 587	
EMAAC	$327.75	24,585	0	$ 2,949	$ 240	
SWMAAC	$446.25	6,735	0	$ 1,100	$ 98	
UCAP-Weighted Average Price	$356.90					
Seasonal						
Summer						
RTO	$126.27	177,298	0	$ 5,669	$ 549	58
Dominion	$126.27	25,329	0	$ 588	$ 33	
MAAC	$260.50	62,757	0	$ 3,008	$ 267	
EMAAC	$260.50	29,333	0	$ 1,406	$ 97	
SWMAAC	$260.50	7,805	0	$ 374	$ 48	
UCAP-Weighted Average Price	$173.78					
Winter						
RTO	$472.00	150,698	0	$12,946	$ 675	1,503
Dominion	$472.00	21,419	0	$ 1,840	$ 47	
MAAC	$472.00	52,038	0	$ 4,470	$ 320	
EMAAC	$472.00	24,065	0	$ 2,067	$ 143	
SWMAAC	$472.00	6,624	0	$ 569	$ 50	
UCAP-Weighted Average Price	$472.00					
Seasonal Total						
Annual UCAP-Weighted Average	$332.22	153,092	**Total**	$18,615	$ 1,224	1,561

Table B-21: Current Market Scenario – Adjusted Winter CETL Values – MRI Demand Curve

LDA	Clearing Price ($/MW-Day)	Cleared UCAP (MW)	Uncleared UCAP (MW)	Capacity Payments ($M)	Production Costs ($M)	EUE (MWh)
Annual						
RTO	$204.62	153,092	0	$12,162	$1,224	1,561
Dominion	$277.92	21,778	0	$ 2,215	$ 81	
MAAC	$204.62	53,067	0	$ 4,087	$ 587	
EMAAC	$204.62	24,585	0	$ 1,841	$ 240	
SWMAAC	$250.33	6,735	0	$ 617	$ 98	
UCAP-Weighted Average Price	$217.06					
Seasonal						
Summer						
RTO	$ 88.47	175,681	1,617	$ 4,995	$ 516	142
Dominion	$119.04	25,185	144	$ 552	$ 30	
MAAC	$261.10	62,757	0	$ 3,015	$ 267	
EMAAC	$261.10	29,333	0	$ 1,409	$ 97	
SWMAAC	$261.10	7,805	0	$ 375	$ 48	
UCAP-Weighted Average Price	$154.52					
Winter						
RTO	$369.45	150,698	0	$10,133	$ 675	1,503
Dominion	$369.45	21,419	0	$ 1,440	$ 47	
MAAC	$369.45	52,038	0	$ 3,499	$ 320	
EMAAC	$369.45	24,065	0	$ 1,618	$ 143	
SWMAAC	$369.45	6,624	0	$ 445	$ 50	
UCAP-Weighted Average Price	$369.45					
Seasonal Total						
Annual UCAP-Weighted Average	$271.36	152,316	**Total**	$15,128	$1,191	1,645

c. Adjusted winter ICAP

Table B-22: Base Scenario – Adjusted Winter ICAP – VRR Demand Curve

LDA	Clearing Price ($/MW-Day)	Cleared UCAP (MW)	Uncleared UCAP (MW)	Capacity Payments ($M)	Production Costs ($M)	EUE (MWh)
Annual						
RTO	$112.43	151,437	1,655	$ 6,232	$ 1,144	727
Dominion	$112.43	21,641	138	$ 891	$ 74	
MAAC	$112.43	52,214	853	$ 2,149	$ 543	
EMAAC	$112.43	23,732	853	$ 977	$ 196	
SWMAAC	$112.43	6,735	0	$ 277	$ 98	
UCAP-Weighted Average Price	$112.43					
Seasonal						
Summer						
RTO	$ 77.24	172,506	4,792	$ 2,894	$ 451	31
Dominion	$ 92.10	24,600	728	$ 417	$ 20	
MAAC	$103.60	60,863	1,894	$ 1,240	$ 226	
EMAAC	$118.74	28,564	769	$ 624	$ 80	
SWMAAC	$103.60	7,805	0	$ 149	$ 48	
UCAP-Weighted Average Price	$ 91.17					
Winter						
RTO	$122.43	152,205	1,089	$ 3,452	$ 648	327
Dominion	$137.75	21,909	0	$ 549	$ 47	
MAAC	$122.43	51,770	1,089	$ 1,154	$ 293	
EMAAC	$122.43	23,435	1,089	$ 522	$ 115	
SWMAAC	$122.43	6,823	0	$ 152	$ 50	
UCAP-Weighted Average Price	$124.63					
Seasonal Total						
Annual-UCAP Weighted Average	$115.37	150,293	**Total**	$ 6,346	$ 1,098	358

Table B-23: Base Scenario – Adjusted Winter ICAP – MRI Demand Curve

LDA	Clearing Price ($/MW-Day)	Cleared UCAP (MW)	Uncleared UCAP (MW)	Capacity Payments ($M)	Production Costs ($M)	EUE (MWh)
Annual						
RTO	$109.69	150,910	2,182	$ 6,058	$1,122	825
Dominion	$109.69	21,641	138	$ 869	$ 74	
MAAC	$109.69	51,687	1,380	$ 2,075	$ 521	
EMAAC	$109.69	23,342	1,243	$ 937	$ 180	
SWMAAC	$109.69	6,735	0	$ 270	$ 98	
UCAP-Weighted Average Price	$109.69					
Seasonal						
Summer						
RTO	$ 70.47	170,373	6,925	$ 2,581	$ 410	107
Dominion	$ 70.47	24,412	917	$ 317	$ 17	
MAAC	$103.60	61,042	1,715	$ 1,164	$ 230	
EMAAC	$103.60	28,511	822	$ 543	$ 79	
SWMAAC	$103.60	7,805	0	$ 149	$ 48	
UCAP-Weighted Average Price	$ 82.34					
Winter						
RTO	$119.76	151,453	1,842	$ 3,301	$ 631	398
Dominion	$119.76	21,773	136	$ 475	$ 44	
MAAC	$119.76	51,154	1,705	$ 1,115	$ 279	
EMAAC	$119.76	22,819	1,705	$ 497	$ 102	
SWMAAC	$119.76	6,823	0	$ 149	$ 50	
UCAP-Weighted Average Price	$119.76					
Seasonal Total						
Annual UCAP-Weighted Average	$107.92	148,921	**Total**	$ 5,882	$1,040	505

Table B-24: Current Market Scenario – Adjusted Winter ICAP – VRR Demand Curve

LDA	Clearing Price ($/MW-Day)	Cleared UCAP (MW)	Uncleared UCAP (MW)	Capacity Payments ($M)	Production Costs ($M)	EUE (MWh)
Annual						
RTO	$327.75	153,092	0	$19,998	$ 1,224	1,561
Dominion	$496.00	21,778	0	$ 3,954	$ 81	
MAAC	$327.75	53,067	0	$ 6,658	$ 587	
EMAAC	$327.75	24,585	0	$ 2,949	$ 240	
SWMAAC	$446.25	6,735	0	$ 1,100	$ 98	
UCAP-Weighted Average Price	$356.90					
Seasonal						
Summer						
RTO	$126.27	177,298	0	$ 5,669	$ 549	58
Dominion	$126.27	25,329	0	$ 588	$ 33	
MAAC	$260.50	62,757	0	$ 3,008	$ 267	
EMAAC	$260.50	29,333	0	$ 1,406	$ 97	
SWMAAC	$260.50	7,805	0	$ 374	$ 48	
UCAP-Weighted Average Price	$173.78					
Winter						
RTO	$279.75	153,295	0	$ 8,258	$ 675	854
Dominion	$356.25	21,909	0	$ 1,421	$ 47	
MAAC	$279.75	52,859	0	$ 2,839	$ 320	
EMAAC	$279.75	24,524	0	$ 1,249	$ 143	
SWMAAC	$398.75	6,823	0	$ 495	$ 50	
UCAP-Weighted Average Price	$295.98					
Seasonal Total						
Annual UCAP-Weighted Average	$248.56	153,092	**Total**	$13,927	$ 1,224	912

Table B-25: Current Market Scenario – Adjusted Winter ICAP – MRI Demand Curve

LDA	Clearing Price ($/MW-Day)	Cleared UCAP (MW)	Uncleared UCAP (MW)	Capacity Payments ($M)	Production Costs ($M)	EUE (MWh)
Annual						
RTO	$204.62	153,092	0	$12,162	$1,224	1,561
Dominion	$277.92	21,778	0	$ 2,215	$ 81	
MAAC	$204.62	53,067	0	$ 4,087	$ 587	
EMAAC	$204.62	24,585	0	$ 1,841	$ 240	
SWMAAC	$250.33	6,735	0	$ 617	$ 98	
UCAP-Weighted Average Price	$217.06					
Seasonal						
Summer						
RTO	$ 88.47	175,681	1,617	$ 4,995	$ 516	142
Dominion	$119.04	25,185	144	$ 552	$ 30	
MAAC	$261.10	62,757	0	$ 3,015	$ 267	
EMAAC	$261.10	29,333	0	$ 1,409	$ 97	
SWMAAC	$261.10	7,805	0	$ 375	$ 48	
UCAP-Weighted Average Price	$154.52					
Winter						
RTO	$223.66	153,295	0	$ 6,300	$ 675	854
Dominion	$223.66	21,909	0	$ 892	$ 47	
MAAC	$223.66	52,859	0	$ 2,212	$ 320	
EMAAC	$223.66	24,524	0	$ 998	$ 143	
SWMAAC	$272.08	6,823	0	$ 338	$ 50	
UCAP-Weighted Average Price	$225.82					
Seasonal Total						
Annual UCAP-Weighted Average	$202.61	152,316	**Total**	$11,295	$1,191	996