Sixth Review of PJM's Variable Resource Requirement Curve

FOR PLANNING YEARS 2028/29 THROUGH 2031/32

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NOTICE

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Executive Summary

We have been commissioned by PJM Interconnection (PJM) to evaluate the parameters and shape of the Variable Resource Requirement (VRR) curve used to procure capacity under the Reliability Pricing Model (RPM), as required periodically under the PJM Tariff.[1] In this Sixth Quadrennial Review, we have conducted several rounds of stakeholder presentations and individual meetings, and reviewed written feedback to incorporate input from stakeholders and the Independent Market Monitor (IMM).[2]

We have conducted this Sixth Quadrennial Review with a focus on priorities identified by stakeholders, PJM staff, and our own assessment of challenges likely to affect the performance of the VRR curve and RPM in the relevant delivery years 2028/29 through 2031/32. The focus areas for this review include:

- **Tight market conditions** that have recently resulted in a substantial contraction in the capacity supply-demand balance, exacerbated by suddenly high load growth, a compressed forward period for upcoming auctions, and a limited development pipeline of gas-fired resources with long lead times and scarcity pricing for new projects;
- **Uncertainty in Net Cost of New Entry (CONE) and reference resources**, considering the ongoing transition in the resource mix, uncertainties in the cost and economic outlook for each technology, differences in consumer and policy requirements across the PJM footprint, and evolving energy market conditions, all making it difficult to set auction parameters that provide stable long-term investment signals despite these uncertainties; and
- **Recent and anticipated RPM market design changes**, including recent updates to reliability modeling and resource accreditation, as well as the potential to transition to a sub-annual capacity market.

We have conducted this Sixth VRR Curve Review in light of these focus areas and the overarching design objectives of the RPM and VRR Curve. The uncertainties affecting the RPM market will be

1. PJM Interconnection, LLC. (2024). PJM Open Access Transmission Tariff. Effective January 1, 2024. ("PJM Tariff"), Attachment DD, Section 5.10.a.iii.
2. See stakeholder materials posted within the PJM Market Implementation Committee, special sessions focused on the Quadrennial Review. Meeting dates: September 27, 2024; October 24, 2024; November 26, 2024; December 17, 2024; February 21, 2025; March 11, 2025; and April 11, 2025. Monitoring Analytics has been the IMM for PJM since 2008. See Monitoring Analytics, Homepage, accessed February 26, 2025.

further affected by the impacts of major US tariffs announced on April 2, 2025 just before the issuance of this report, in ways that are not yet considered in this review. The primary design objective of the RPM is to attract and retain capacity sufficient to meet the region's reliability objectives on a long-run average basis. This means that the RPM should provide accurate accounting of supply and demand and structure the market to produce prices aligned with the underlying fundamentals. Prices should be high enough to attract private investors to bring forward merchant capacity resources and to support demand-side solutions when those resources are needed for reliability; prices should be lower in long market conditions when retirements can be absorbed in an orderly fashion. For state agencies and utilities engaged in regulated planning, RPM price and quantity outcomes can similarly inform cost-effective policy and resource decisions. The downward-sloping VRR curve helps to support price formation, mitigate pricing volatility, and express the incremental value of reliability across reserve margins.

Over nearly two decades since its launch, the RPM has fulfilled these objectives, including managing over 64 GW of capacity de-ratings and retirements, attracting over 74 GW of new generation capacity, and attracting other cost-effective competitive resources such as demand response, uprates, and imports.[3] The role of the RPM to provide accurate and efficient signals for reliability needs will become even more critical in the coming years and decades, as the sector must mobilize to serve rapid demand growth; as states and customers pursue policy and clean energy goals; and as the system becomes increasingly dependent on intermittent resources to support reliability needs. The RPM market design will need to continue to evolve if it is to keep pace with the rate of change in market fundamentals and resource transition. Throughout this evolution, the market design should remain focused on economic principles including the accurate measurement of supply and demand; supporting competitive price outcomes driven by market fundamentals; and enabling new entrants and technology innovation.

Forefront in present conditions is an acutely tight supply conditions in the face of rapid growth in demand. As discussed more extensively in our concurrent report *Brattle 2025 PJM CONE Report* ("Brattle 2025 PJM CONE Report"), the cost and feasibility of building incremental capacity supply is presently constricted by supply chain limits for turbines and other inputs, siting and permitting delays, a compressed forward period in the Base Residual Auctions (BRAs), extended resource development timelines, and a lengthy (although shortening) interconnection queue process.[4] These acute supply challenges may increase the cost or limit the volume or types

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3 Capacity ratings are expressed in ICAP GW. Data on capacity de-ratings, retirements, and new generation capacity is recent as of the 2023/24 Base Residual Auction and does not include changes in installed capacity that have occurred since, see PJM, 2023/2024 RPM Base Residual Auction Results, June 21, 2022, p. 19.

4 See Newell, et. al., Brattle 2025 CONE Report for PJM ("*Brattle 2025 PJM CONE Report*"), April 9, 2025.

of new supply that can be developed into the initial years relevant to this Quadrennial Review, but may moderate by the end of the review period as industry-wide supply increases capability to keep pace with demand growth.[5] Under these conditions, it is possible that one or more BRAs may clear at the VRR Curve price cap, but still remain insufficient to attract new entry until supply-demand conditions resolve.

Further, moderate increases to the price cap would not be an effective means to address this transient and acute supply tightness, considering that the high prices can only be made available under one-year commitments in the RPM and that higher prices do not address the underlying barriers to timely supply entry. A well-functioning capacity market should be structured to limit the frequency of price cap and reliability shortfall events to the extent possible, while incorporating a price cap and/or other mechanisms that manage impacts for both the consumer and the broader market.

Despite these challenges, we continue to take as a premise that the role of the RPM and VRR Curve should be to support short-term decisions on an ongoing basis, and to attract new merchant supply as soon as it becomes available. In other words, the VRR Curve and price cap should be sufficient to support reliability under long-run equilibrium conditions when new entry can be attracted at the long-run marginal cost of supply. This is the same economic concept that we have adopted in all prior VRR Curve reviews, although factors affecting the most relevant Reference Price or Net CONE are more complex than in prior reviews considering that the price and term required to attract supply may be substantially higher in the first year compared to the last year of the upcoming Review Period (see the *Brattle 2025 PJM CONE Report* for a comprehensive discussion of our recommended Reference Price).

To support reliability over the long term and to more meaningfully represent the value of reliability in this shifting landscape, we recommend that the VRR Curve be reshaped to align with the concept of marginal reliability impact (MRI). An MRI-based curve is more meaningfully grounded in the underlying reliability value of capacity, considering that it reflects a constant willingness-to-pay to avoid expected unserved energy (EUE) as a function of procurement volume. The MRI curve will more accurately reflect how marginal reliability value of capacity declines with an increasing reserve margin and can naturally be adapted to a potential future sub-annual capacity market construct. We further recommend returning to the 3-year forward period for the BRAs and transitioning to a sub-annual capacity construct with at least two capacity

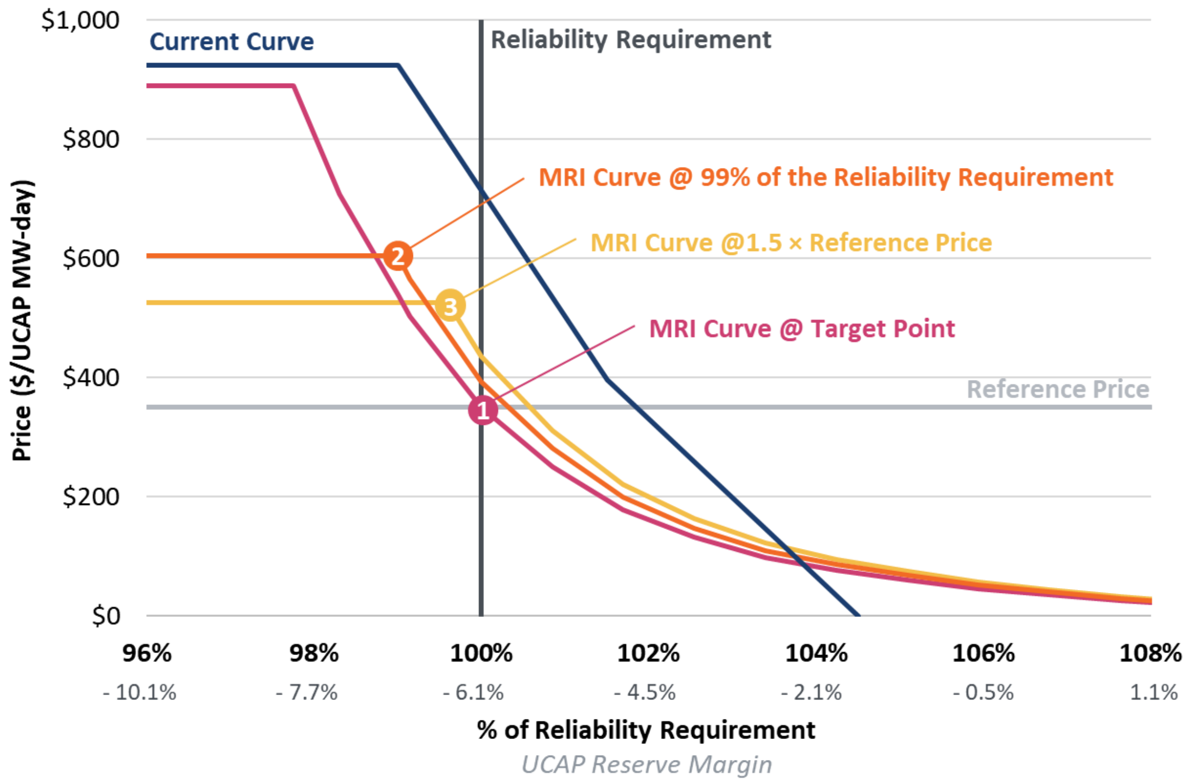
[5] GE Vernova, GE Vernova to invest almost $600 million in U.S. factories and facilities over next two years, January 29, 2025.

seasons as soon as practicable, so the MRI-based VRR Curves can be used to more accurately and economically guide resource investments.

Relevant to initial implementation with the present annual construct, we have examined three variations of MRI-based VRR Curves as illustrated in the following Figure 1. Each of these MRI-based curves is "tuned" to meet the PJM reliability standard of 0.1 loss of load events (LOLE) per year, or one-day-in-ten years (1-in-10) on a long-run average basis. Curves 1, 2 and 3 have respective price caps at 2.5×, 1.7×, and 1.5× the Net CONE or "Reference Price" which is expressed in $/MW-day in Unforced Capacity (UCAP) terms. The three curves present different trade-offs, with Curve 1 having the highest price volatility and customer cost exposure in price cap events and Curve 3 having the greatest quantity uncertainty and reliability risk exposure (i.e. if the price cap is too low). Under relatively stable or long-run equilibrium conditions with typical levels of year-to-year variability in the supply-demand balance and moderate uncertainties in the long-run marginal cost of supply, we would anticipate Curve 2 as one that offers strong performance across competing design objectives. Curve 3 would offer more protection to customers by applying a lower price cap but has the downside of introducing a greater risk of low-reliability and price cap events. These analyses indicate that a price cap in the range of 1.5-1.75 × Reference Price will be sufficient to attract new entry and support reliability under long-run equilibrium conditions.

In Figure 1 and all analyses in this report, the reference prices used to develop the MRI-based VRR curves are derived from our analysis of Net CONE in the *Brattle 2025 PJM CONE Report* as part of this Quadrennial Review.

FIGURE 1: MRI-BASED VRR CANDIDATE CURVES TURNED TO 1-IN-10 LOLE STANDARD



Sources and Notes: Throughout this report we utilize a Reference Price of $350/MW-day. The MRI-based VRR curves are defined by the highlighted anchor point (signified by the numbered dot for each curve) and as described in more detail in Section IV.B below. The Current Curve is developed using the current VRR curve formula and estimates of a dual-fuel combustion turbine (CT) reference resource Net CONE ($528/MW-day UCAP) and Gross CONE ($832/MW-day UCAP) from the Brattle 2025 PJM CONE Report. We note that the Net CONE and Gross CONE values used to generate the Current Curve in our simulation analysis are slightly different from the final numbers in the Brattle 2025 PJM CONE Report; however, this does not materially impact the conclusions of the analyses.

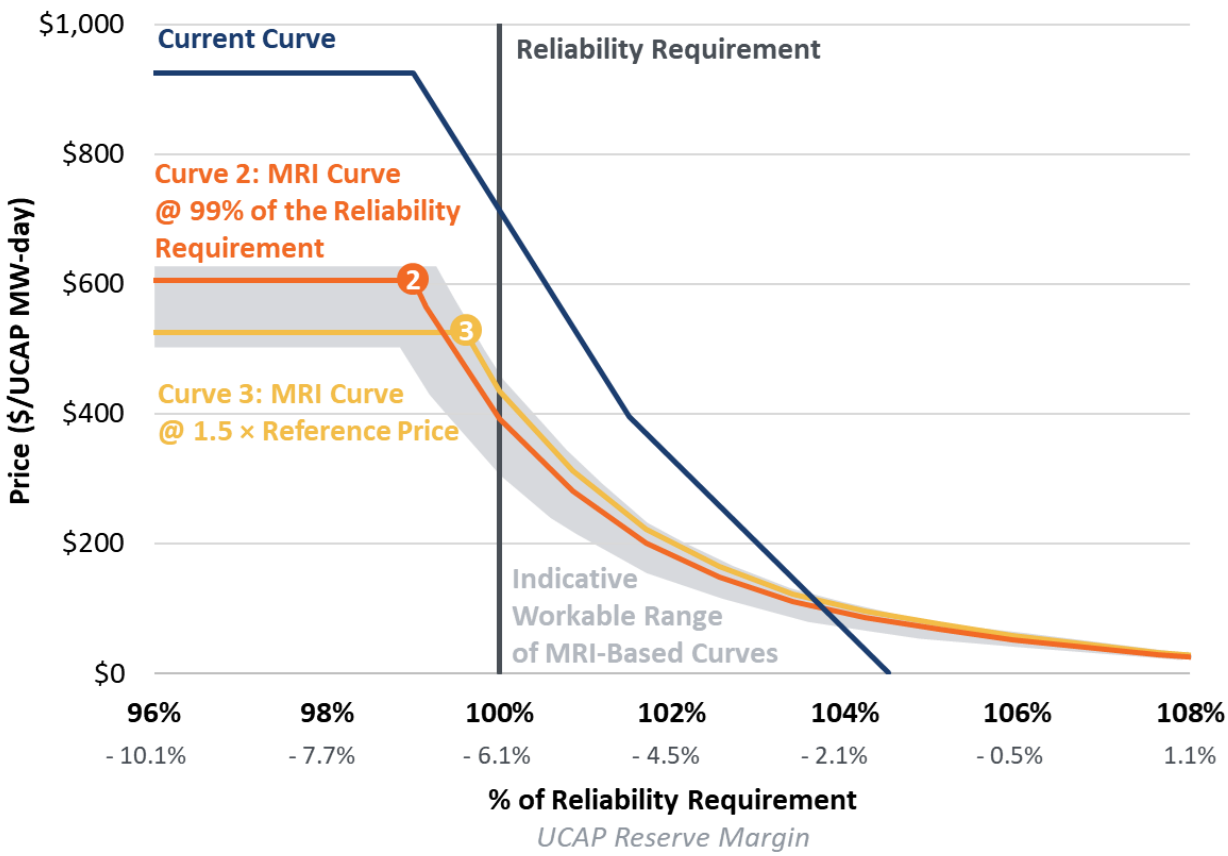
To manage the reliability risks under these acute supply conditions, we do not recommend increasing the price cap above our recommended range of 1.5–1.75 × Reference Price. We instead recommend addressing underlying barriers directly to the extent possible, including by prioritizing ongoing efforts to enable and maximize capacity supply participation, expedite interconnection queue processes, address other barriers to entry, and consider refining risk modeling more fully account for the benefits of interties and non-firm resources that can contribute to meeting demand. In addition, we recommend developing contingency plans for the event that inadequate supply is procured. Such plans could allow some combination of accepting lower reliability temporarily while still aiming to meet reliability criteria on a long-term average basis; and/or enhancing the RPM Reliability Backstop mechanism so that it can be triggered in any locational deliverability area (LDA) and so that it can more quickly and efficiently secure backstop commitments without undermining the primary competitive signals issued through the BRAs.

I. Detailed Recommendations

1. RECOMMENDED SYSTEM VRR CURVE BASED ON MARGINAL RELIABILITY IMPACT

We recommend adopting an MRI-based curve similar to those already adopted by the Independent System Operator of New England (ISO-NE) and the Midcontinent Independent System Operator (MISO) in their respective capacity markets, but that has been adapted to align with PJM's reliability modeling and other RPM design elements. We offer two specific MRI-based VRR curves, Curve 2 and Curve 3 to illustrate the approximate "workable range" of curves (shown approximately as the gray shaded area in Figure 2) which would offer sufficient system reliability but with a different balance of performance trade-offs.

FIGURE 2: RECOMMENDED "WORKABLE RANGE" OF MRI-BASED VRR CURVES



Sources and Notes: MRI-based Curves shown in figure are drawn relative to a Reference Price of $350/MW-day. The Current Curve is developed using the current VRR curve formula, with a Net CONE based on the dual-fuel current combustion turbine (CT) reference resource at an indicative Net CONE of $528/MW-day UCAP and an indicative Gross CONE of $832/MW-day UCAP.

Compared to the Current Curve, we recommend the following changes for transitioning to an MRI-Based Curve:

1.1. **Develop VRR pricing parameters relative to the updated concept of a "Reference Price" parameter,** that is informed by the uncertainty range in Net CONE for multiple potential reference resources (rather than the Net CONE of a specific Reference Resource). We anticipate that transitioning to a Reference Price approach will provide more pricing stability to the VRR curve, while ensuring that the curve is robust to the uncertainties in Net CONE and reference resources. Specific values for recommended RTO-wide and LDA Reference Prices are documented in the *Brattle 2025 PJM CONE Report*, considering the uncertainty range of the cost of developing new supply such as a gas-fired combustion turbine (CT) plants, gas-fired combined cycle (CC) plants, and battery energy storage systems (BESS). For the purposes of this report, we use an RTO Reference Price of \$350/MW-day for the 2028/29 delivery year and have developed our MRI curve recommendations considering that the MRI curve performance outcomes are similar across an uncertainty range of approximately +/- \$100/MW-day in Reference Price.

1.2. **Adopt an RTO-wide price cap in the range of 1.5-1.75 × Reference Price,** and within the range of \$500-\$625/MW-day for the 2028/29 Planning Year. An RTO price cap in this range would manage competing design objectives including being high enough to attract merchant capacity supply entry; aligning with the price caps of neighboring capacity markets that may engage in capacity trade with PJM; and mitigating customers' cost exposure in sustained high pricing. We caveat this recommendation based on our finding that a price cap in this range is not sufficient to manage all reliability risks that may materialize during near-term acute tight supply conditions, and so should be adopted alongside reviewing the reliability backstop mechanism (Recommendation 3.2 below). The specific parameters for the price cap if adopting either MRI-based Curve 2 or Curve 3 would be:

   - *Curve 2:* Price cap at 1.7 × Reference Price and 99.0% of the Reliability Requirement, or
   - *Curve 3*: Price cap at 1.5 × Reference Price and 99.6% of the Reliability Requirement

1.3. **Derive other points on the VRR curve based on a modeled MRI curve.** Transitioning to an MRI-based demand curve will produce a consistent expression of the willingness to pay to avoid involuntary load shedding at each quantity/price point along the curve. The MRI-based curve will provide a more economically meaningful expression of the reliability value to consumers accomplished by procuring more capacity and allow for a more rationalized expression of reliability value at different reserve margins, over time, and on a sub-annual basis (relevant if the RPM transitions to a sub-annual construct). The specific steps conducted each year to derive the MRI-based curve would include:

- Using PJM's annual reliability modeling study to estimate both the Reliability Requirement (as conducted today) and to produce reliability metrics across a range of UCAP MW quantities above and below the Reliability Requirement;
- Calculating the MRI across UCAP MW quantities, in the units of MWh of avoided expected unserved energy (EUE) per 1 MW of UCAP capacity added; and
- Calculating the "Scaling Factor" in $/MWh that aligns with the defined price and quantity at the price cap.

1.4. **Stabilize annual updates to the VRR curve pricing parameters based on the Consumer Price Index (CPI) and fleet-wide UCAP Ratings,** as discussed further in the *Brattle 2025 PJM CONE Report*. To increase stability in the pricing parameters of the VRR curve, we recommend updating the pricing parameters of the VRR curve to reflect broad economic trends as reflected in the CPI and to move away from the present formula based on annual updates to CONE and Net CONE as currently calculated in each delivery year. Specifically:

- *Between Review Periods:* the Reference Price for 2028/29 would be updated using a simplified updating approach for the subsequent delivery years 2029/30, 2030/31 and 2031/32. The two updates to be applied would be: (1) an inflation-based update based on the CPI increase between auction dates;[6] and (2) a UCAP update based on the change in pool-wide accredited UCAP factor considering all resources. By extension, the Price Cap and Scaling Factor relevant for each delivery year would also be updated with CPI and Unforced Capacity (UCAP) ratings;
- *In Future Quadrennial Reviews*: At the time of each future Quadrennial, we recommend more comprehensively reviewing potential updates to the Reference Price, price cap formula, and scaling factor parameters, considering updated estimates of Net CONE for different Reference Technologies and other market evidence that may be available.

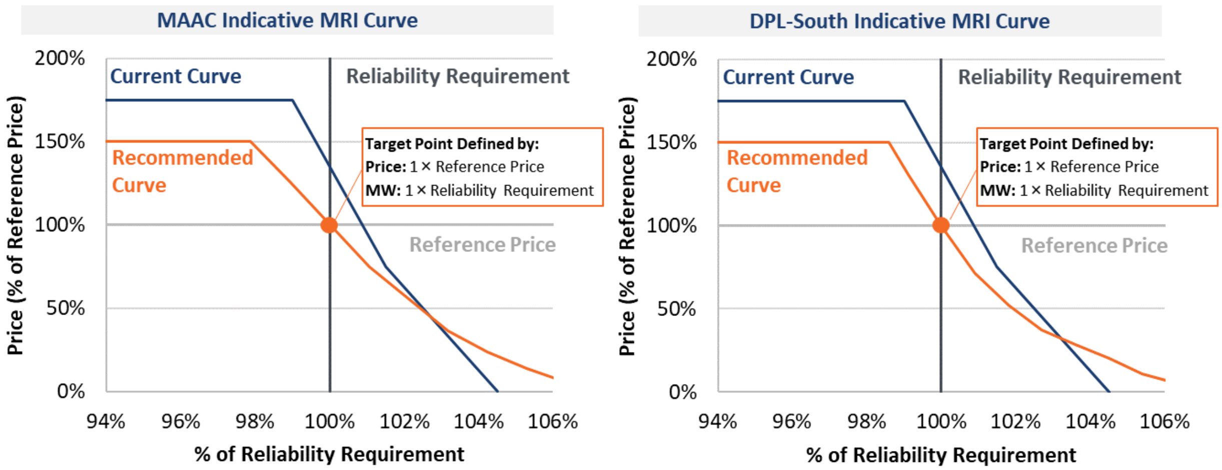
2. RECOMMENDED LDA VRR CURVES BASED ON MARGINAL RELIABILITY IMPACT

Consistent with transitioning to an MRI-based curve on a system-wide basis, we recommend to use location-specific MRI-based VRR curves for each modeled LDA in RPM. Figure 3 provides an

[6] As discussed in the *Brattle 2025 PJM CONE Report,* we propose the "Consumer Price Index for All Urban Consumers (CPI-U) for the U.S. City Average for All Items, 1982-84=100" as reported by the U.S. Bureau of Labor Statistics (BLS), since this is the broadest, most comprehensive CPI. See U.S. BLS, Consumer Price Index for All Urban Consumers (CPI-U).

illustration of LDA MRI curves for a large and small LDA: Mid-Atlantic Area Council (MAAC) and Delmarva Power and Light Company (DPL) South.

FIGURE 3: RECOMMENDED LDA VRR CURVES DERIVED FROM MARGINAL RELIABILITY IMPACT



Sources and Notes: The LDA MRI-based curves would be defined by the target point at 1 × LDA Reference Price and the LDA Reliability Requirement.

Compared to the Current Curve, we recommend the following changes for transitioning to an MRI-Based Curve for each LDA:

2.1. Initial Implementation: Derive LDA VRR curves based on locational MRI, with a different scaling factor derived for each LDA. By applying the MRI concept on a locational basis, each LDA VRR curve will be calculated in a fashion similar to the system-wide MRI-based curve. The resulting MRI-based curves will be flatter with more gradual slopes than the current LDA VRR Curves, meaning they will reduce the potential for price spikes and offer more pricing stability to producers and consumers. Similar to the approach used to calculate the system-wide MRI-based VRR curve, the locational MRI-based VRR curves would be calculated as follows:

- Using PJM's annual reliability modeling analysis to estimate both the LDA Reliability Requirement (as conducted today) and to produce reliability metrics across a range of UCAP MW quantities above and below the LDA Reliability Requirement;
- The LDA MRI curves would be defined by and drawn through the "LDA Target Point", defined by the LDA Reliability Requirement and the LDA Reference Price. LDAs may have the same or higher Reference Price than the RTO, for example if they are affected by specific policy requirements or siting limitations (see *Brattle 2025 PJM CONE Report*);

- Developing a scaling factor specific to each LDA such that the LDA MRI curve is drawn through the "LDA Target Point" defined by the LDA Reliability Requirement and LDA Reference Price; and
- Setting an LDA price cap at the greater of either the 1.5 × LDA Reference Price, the parent LDA price cap, or the RTO price cap. The volume at this price cap would be dictated by the shape of the MRI curve and may be at higher or lower levels depending on the extent to which lower volumes more quickly drive reliability challenges in each LDA (initial PJM modeling results indicate the price cap would be consistent with a volume of 96%–99% of the LDA Reliability Requirement, depending on the LDA).

2.2. Longer Term: Update LDA VRR curves to incorporate a uniform scaling factor across the RTO and all LDAs. The above implementation of the LDA MRI curves allows for immediate implementation without requiring updates to PJM's capacity auction clearing engine. However, it does not allow for a unified approach to reflecting differences in reliability value across different LDAs over the footprint. To allow for more efficient pricing signals that fully reflect these differences in reliability value, we recommend that PJM and stakeholders eventually transition to an LDA MRI curves that incorporate a uniform scaling factor across the RTO footprint and all LDAs. The updated approach would be similar to the ISO-NE approach to locational MRI curves and would require updates to capacity auction clearing in RPM. These updates would naturally align with the implementation of a sub-annual capacity auction, and so we recommend that these changes could be considered at the same time (see Recommendation 3.2 below and more comprehensive discussion of the implications for locational and sub-annual MRI curves in Sections VII.A and VII.B in the body of this report).

3. RECOMMENDATIONS RELATED TO VRR CURVE IMPLEMENTATION

In addition to the specific recommendations to update the VRR curve parameters, we have identified several ways in which the performance of the VRR curve may interact with other aspects of the RPM design. We offer the following recommendations to improve performance of the VRR curve performance in the context of the broader RPM design:

3.1. Avoid delays to future Base Residual Auction (BRA) schedules and restore the RPM to the intended three-year forward period. We recommend following through on the current planned schedule of BRA auctions that will restore the RPM to a full 3-year forward period by 2030/31; this may require delaying or phasing in the implementation of future RPM design changes to later delivery years in order to prioritize maintaining the auction schedule. Restoring the regularized auction schedule will offer customers and producers more time to incorporate new information and proactively consider design changes before they come into effect and will allow more resources to make entry and exit decisions as an outcome of the BRA (rather than in advance of the BRA). We anticipate that the result will be to improve pricing stability, mitigate the potential for large year-over-year price increases such as observed in the 2025/26 BRA, and improve confidence in the market.

3.2. **Enhance the RPM Reliability Backstop Mechanism to Mitigate Potential for Acute Reliability Risks.** We find that the RPM faces the potential for acute reliability challenges over an upcoming period of tight supply conditions due to rapid growth in demand and limited capacity to rapidly deploy new supply resources (see additional discussion in the *Brattle 2025 PJM CONE Report*). Currently, RPM incorporates two levels of reliability backstop mechanisms to: (1) trigger an investigation of the causes and solutions for a shortfall event (if shortfall is experienced in 1 year); or (2) trigger a Reliability Backstop Auction (may procure supply under up to 15-year commitments if shortfall is experienced in 3 consecutive years). To mitigate the potential for acute reliability challenges in the upcoming years, we recommend:

- For the investigative review, update the mechanism so that it can be triggered either on an RTO-wide basis or also on an LDA-specific basis, triggered by a "minimum acceptable" reliability level, defined as: (a) 99% of the Reliability Requirement for the RTO; and (b) volume at the price cap for each LDA (approximately 96%–99% of LDA reliability requirements, consistent with recommended MRI-based curves for each LDA); and
- For Backstop Procurements, consider whether the current mechanism offers sufficient reliability protections or whether enhancements to the mechanism are warranted. We recommend that any adjusted or expanded role for backstop procurements would be developed in close coordination with state regulatory agencies.

3.3. **Transition to a sub-annual capacity construct with at least two seasons (summer and winter).** The transition to a sub-annual capacity market is naturally aligned with the transition to an MRI-based VRR curve as we have recommended, using a seasonal VRR curve approach similar to that already adopted by MISO. Each sub-annual period would be defined by its own VRR curve, and each supply resource would receive UCAP accreditation that reflects its reliability value in that specific season. If the RTO and each LDA were to incorporate the same scaling factor for all VRR curves (system-wide and LDA, and for each sub-annual period) this would offer more granular signals by location and season to guide the market toward the supply investments that offer the greatest reliability value proposition to customers. We find that a sub-annual capacity market will offer a substantially improved basis for which to accurately measure capacity supply and demand in the most accurate and economically meaningful manner; reduce barriers to entry for resources with seasonally distinct reliability value; provide a more stable basis for measuring capacity needs and value over time; and increase economic efficiency.

II. Background and Context

A. Quadrennial Review and Demand Curve Design Objectives

PJM's capacity market, the Reliability Pricing Model (RPM), aims to support long-term grid reliability by procuring the required volume of capacity resources needed to meet predicted electricity demand in the future.[7] The RPM is an auction mechanism that employs a downward sloping demand curve and consists of the Base Residual Auction (BRA) which procures capacity on a forward basis and three Incremental Auctions (IAs), which serve to procure or release capacity closer to the Delivery Year.

To ensure reliability and that the VRR Curve is reasonably updated over time to align with changes in market conditions, PJM is required to undergo this periodic review process. Initially the periodic review took place every three years but has been extended to every four years since 2018.

> *"Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall perform a review of the shape of the Variable Resource Requirement Curve. Such analysis shall be based on simulation of market conditions to quantify the ability of the market to invest in new Capacity Resources and to meet the applicable reliability requirements on a probabilistic basis. Based on the results of such review, PJM shall prepare a recommendation to either modify or retain the existing Variable Resource Requirement Curve shape." -PJM Open Access Transmission Tariff ("OATT"), Attachment DD.5.10, Section (a)(iii).*

This report addresses the VRR Curve shape and the second companion report *Brattle 2025 PJM CONE Report* addresses the Reference Price, Cost of New Entry (CONE), and the Energy and

[7] PJM, [Capacity Market (RPM)](), 2025.

Ancillary Services (E&AS) offset methodology used to calculate Net CONE that will apply for planning years 2028/29 through 2031/32.

The VRR Curve is designed to fulfill the objectives summarized in Table 1. As in all prior reviews, our assessment of the VRR Curve performance and design is grounded by these long-term capacity market design objectives which constitute inherent trade-offs between reliability outcomes, price volatility, and procurement cost.[8] Any workable VRR Curve shape must ensure adequate performance while reasonably balancing these competing objectives. Some objectives are central to RPMs functioning and are codified in the PJM OATT and PJM Manuals such as meeting the 1-in-10 Loss of Load Expectation (LOLE) system-wide reliability standard. The locational reliability standard has recently changed to be defined as maintaining the normalized Expected Unserved Energy (EUE) of no more than 40% of the RTO-wide normalized EUE at criterion.[9] Given increasingly differentiated seasonal risks, the system-wide performance and reliability is being considered in a new light and potentially expanded to include additional metrics such as LOLE, EUE, and Loss of Load Hours (LOLH). Others are our interpretation of RPM's overarching role to support reliability and economic efficiency in a financially sustainable merchant investment context.

8 Spees, Newell, Thompson, and Bartone, Fifth Review of PJM's Variable Resource Requirement Curve For Planning Years Beginning 2026/27, April 19, 2022; Newell, Oates, Pfeifenberger, Spees, Hagerty, Pedtke, Witkin, and Shorin, Fourth Review of PJM's Variable Resource Requirement Curve, April 19, 2018; Pfeifenberger, Newell, Spees, Murray, and Karkatsouli, Third Triennial Review of PJM's Variable Resource Requirement Curve, May 15, 2014; Pfeifenberger, Newell, Spees, Hajos, and Madjarov, Second Performance Assessment of PJM's Reliability Pricing Model, August 26, 2011; and Pfeifenberger, Newell, Earle, Hajos, and Geronimo, Review of PJM's Reliability Pricing Model, June 30, 2008.

9 PJM, PJM Manual 20A. Effective June 27, 2024. Section 1.3.

TABLE 1: VRR CURVE DESIGN OBJECTIVES

	VRR Curve Design Objectives
Reliability	• Maintain 1-in-10 LOLE system-wide planning target on a long-term average basis • For each LDA, normalized EUE no more than 40% above RTO-wide normalized EUE at criterion • Assess curve performance with additional criteria including LOLE, LOLH, and EUE on average and in extremes (ensure robustness across potential market conditions) • Maintain reliability across a range of potential market conditions • Rarely drop below a "minimum acceptable" level when PJM may intervene (<99% of reliability requirement on a system-wide basis, though no specific value is defined for LDAs)
Pricing Efficiency	• Outcomes reflective of economic fundamentals in a well-functioning, competitive market: prices high enough to attract entry when needed for reliability; prices low enough to enable efficient exit and retirements during surplus • Reduce price volatility due to small changes in supply and demand, but allow prices to move sufficiently to reflect changes in market conditions and enable competition • Mitigate susceptibility to exercise of market power • Few outcomes at the administrative cap • Mitigate customers' exposure to price spikes and the costs of over-procurement
Other	• Aim for simplicity, stability, and transparency • Provide a sustainable value proposition to states, members and market participants with diverse customer segments, business interests, policy requirements and regulatory models • Strike a balance among competing objectives

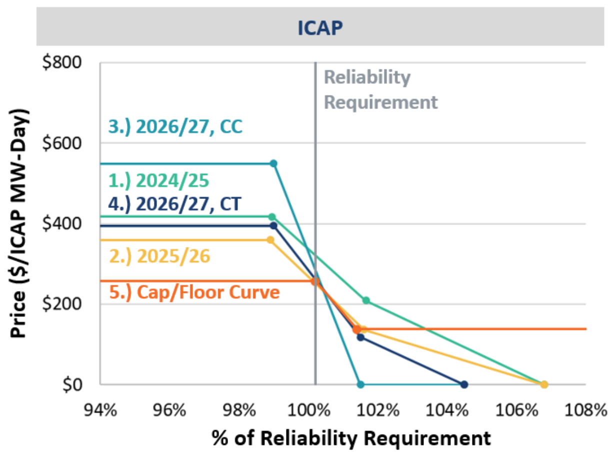
Sources and Notes: For detail on reliability criteria, see PJM, PJM Manual 20A. Effective June 27, 2024. Section 1.3; and Reliability Assurance Agreement, Definitions, Capacity Emergency Transfer Objective (CETO).

B. Recent Changes to the VRR Curve Formula

The VRR curve has undergone a series of changes recently including updates to PJM's reliability modeling, as well as recent fundamentals-driven and rules updates affecting the Reference Technology and Net CONE parameter (where Net CONE = Gross CONE minus E&AS Offset). Figure 4below shows some of the most recent VRR curve shapes in Installed Capacity (ICAP) terms on the left and UCAP price units on the right. Note that the changes on the left chart (in ICAP terms) offer a more valid comparison of the overall financial consequences of recent updates, since the different curves are reflected on common ICAP-based units of measure. On an ICAP basis, prices are lower and more reflective of what generators earn and what customers pay.

The UCAP-based units are more relevant for a different reason, as the units of measure for clearing and settling the RPM market. However, UCAP-based prices are not self-consistent across recent years, considering that market-wide cleared volumes are substantially lower as of the 2025/26 delivery year when the market-wide Forecast Pool Requirement (FPR) dropped from 109% to 93.87% of the annual peak load. Sellers ELCC-adjusted UCAP ratings have dropped by a similar amount from 94.98% to 79.69% of ICAP ratings for the same reason.[10] In other words, UCAP-based prices would need to be 19% higher in 2025/26 than in 2024/25 in order to result in the same revenues to producers on an ICAP basis.[11] Throughout this report, we use the updated UCAP-based accounting where possible, and (other than in this figure) adjust prior years' prices upwards as relevant to compare results on a common basis.

FIGURE 4: COMPARISON OF RECENT CHANGES TO VRR CURVE FORMULA



Sources and Notes: 2024/25 curve from PJM, Planning Period Parameters, 2024, converted from UCAP to ICAP using Fleet Equivalent Forced Outage Rate on demand (EFORd) for 2024/25 auction and Fleet Effective Load Carrying Capacity (ELCC) for the 2025/26 auction; 2026/27, CC values calculated from data provided by PJM; 2026/27 CT curve based on PJM, Affidavit of Walter Graf and Skyler Marzewski on Behalf of PJM Interconnection, L.L.C., Docket No. ER25-682-000; Cap/Floor Curve provided by PJM.

Considering each change individually, the recent changes to the VRR curve shape include:

1. **2024/25 BRA**—VRR Curve in the 2024/25 BRA used the prior curve formula and prior capacity accreditation with a gas-fired CT plant as the Reference Resource. The price cap was set at the maximum of either 1.5 × Net CONE or 1 × CONE as it had been for several previous auctions. The quantity points on the curve ranged across 99% to 106.8% of the Reliability Requirement.
2. **2025/26 BRA**—VRR Curve in the 2025/26 BRA similarly used the prior curve formula with a CT as the Reference Resource. However, PJM adopted a new capacity accreditation method and reliability modeling approach to adjust ICAP to UCAP values and model reliability risk. The combination of the new methods reduced the total procured volumes, Reliability Requirement, and pool-wide UCAP accreditation factor, such that starting in 2025/26 all

[10] See PJM Capacity Market: 2024/25 and 2025/26 Base Residual Auction Planning Parameters.

[11] Example calculation: Consider a $100/MW-day ICAP price. In 2024/25 that price would translate into $100 ÷ 94.08% = $105.28/MW-day UCAP. In 2025/26, the same ICAP-based price would translate into $100 ÷ 79.69% = $125.49/MW-day UCAP (or a 19% increase in prices with no increase in revenues from a generator perspective).

future curves appear 19% more expensive in UCAP terms relative to prior curves based on the prior reliability modeling and accreditation.[12]

3. **2026/27, CC (Overwritten)**—The initially-calculated (but since over-written) VRR curve for the 2026/27 BRA used an updated curve formula where the price cap was determined by the maximum of either 1.75 × Net CONE or 1 × CONE, but with the new capacity accreditation, with a CC as the Reference Resource, a forward-looking approach for estimating the Net E&AS, and additional changes from the prior Quadrennial Review.[13] The updated Curve formula is a steeper shape that crosses fewer quantity points ranging from 99% to 104.5% of the Reliability Requirement. While the auction was scheduled to run with this curve, the auction was delayed due to the impact of these changes and broader economic conditions which resulted in a Net CONE and price cap that were outside of the anticipated ranges the curve was designed for. The Net CONE of the CC reference resource went to zero which caused the price cap to be set by the CONE parameter and resulted in much steeper curve that only consisted of two points.
4. **2026/27, CT (Approved, but Subject to More Recent Filing)**—In December 2024 PJM submitted a 205 filing that was accepted by FERC in February 2025 intended to address the above issues and maintain a CT as the Reference Resource with an updated estimate of CT Net CONE.[14] The updated curve is still steeper than prior curves (considering the smaller quantity range of 99% to 104.5% of Reliability Requirement), but the price cap is lower and more consistent with prior curves.
5. **Cap/Floor Curve (Most Recent Filing, Pending FERC Review)**—Meanwhile the Commonwealth of Pennsylvania filed a 206 filing at FERC protesting the 2025/26 BRA clearing results, and expressing concerns about the VRR Curve and customers' exposure to price cap events if tight supply conditions continue. In response, PJM has most recently filed a 205 filing before FERC as of February 2025. The updated proposed VRR curve would limit the range of

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12 Dependent upon FPR and resource risk modeling, if there is a sizable shift to summer risk, this would not hold true.

13 Spees et. al., Fifth Review of PJM's Variable Resource Requirement Curve, For Planning Years Beginning 2026/27 ("2022 VRR Curve Report"), April 19, 2022; PJM Interconnection, L.L.C., Tariff filing per 35.13(a)(2)(iii: Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters to be effective 12/1/2022 under ER22-2984, filed before the Federal Energy Regulatory Commission, September 30, 2022, Docket No. ER22-2984-000; 182 FERC ¶ 61,073, Order Accepting Proposed Tariff Revisions re PJM Interconnection, L.L.C. under ER22-2984, February 14, reference 2023, Docket Nos. ER22-2984-000 and ER22-2984-001.

14 PJM Interconnection, L.L.C., Revisions to Reliability Pricing Model, Request for a 28-day comment period, i.e., January 6, 2025 comment date, filed before the Federal Energy Regulatory Commission, Docket No. ER25-682-000, December 9, 2024; 190 FERC ¶ 61,088, Order Accepting Tariff Revisions Subject to Condition re PJM Interconnection, L.L.C. under ER25-682, February 14, 2025, Docket No. ER25-682-000.

potential pricing outcomes by applying temporary cap and floor at $325 and $175/MW-day respectively, and is intended to be in place for 2 years for the 2026/27 and 2027/28 auctions.[15]

For the purposes of our analysis in this report, we describe the "Current Curve" as the current VRR curve formula using a CT Reference Resource with the price cap at 1.75 × Net CONE or CONE and updated with 2028/29 values for the CT (the first year in the review period) from our concurrently issued *Brattle 2025 PJM* CONE *Report*.

C. Focus Areas of the Sixth Quadrennial Review

We have conducted this Sixth Quadrennial Review with a focus on priorities identified by stakeholders, PJM staff, and our own assessment of challenges likely to affect the performance of the VRR curve and RPM in the relevant delivery years 2028/29 through 2031/32. The focus areas for this review include:

- **Tight market conditions** that have recently resulted in a substantial contraction in the capacity supply-demand balance, exacerbated by suddenly high load growth, a compressed forward period for upcoming auctions, and a limited development pipeline of gas-fired resources with long lead times and scarcity pricing for new projects;
- **Uncertainty in Net CONE and reference resource**, considering the ongoing transition in the resource mix, uncertainties in the cost and economic outlook for each technology, differences in consumer and policy requirements across the PJM footprint, and evolving energy market conditions, all making it difficult to set auction parameters that provide stable long-term investment signals despite these uncertainties; and
- **Recent and anticipated RPM market design changes**, including recent updates to reliability modeling and resource accreditation, as well as the potential to transition to a sub-annual capacity market.

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[15] Governor Josh Shapiro and The Commonwealth of Pennsylvania v. PJM Interconnection, L.L.C., Complaint of Governor Josh Shapiro and The Commonwealth of Pennsylvania, filed before the Federal Energy Regulatory Commission, Docket No. EL25-46-000, December 30, 2024; Governor Josh Shapiro and The Commonwealth of Pennsylvania v. PJM Interconnection, L.L.C., Stipulation of Satisfaction and Joint Motion to Dismiss Complaint of PJM Interconnection, L.L.C, Governor Josh Shapiro, and the Commonwealth of Pennsylvania, filed before the Federal Energy Regulatory Commission, Docket No. EL25-46-000, February 14, 2025; and PJM Interconnection L.L.C, re PJM Interconnection, L.L.C., Docket No. ER25-1357-000 Proposal for Revised Price Cap and Price Floor for the 2026/2027 and 2027/2028 Delivery Years, and Request for a Waiver of the 60-Days' Notice Requirement to Allow for a March 31, 2025 Effective Date, filed before the Federal Energy Regulatory Commission, Docket No. ER25-1357-000, February 20, 2025.

III. Analysis of Recent Capacity Market Outcomes

A. Historical RPM Procurement Levels and Clearing Prices

Clearing prices and volumes vary depending on market conditions. By design, RPM aims to support long-term reliability by targeting a cleared volume of capacity resources consistent with the reliability requirement, the 1-in-10 reliability standard. Consistent with expected outcomes in a competitive marketplace where supply is attracted by prices sufficient to cover investment costs, a functioning capacity market should be anticipated to produce clearing prices that investors expect will converge on average to the Net CONE in long-term equilibrium conditions.

In reality, no market is ever in a true long-term equilibrium but rather shifts through a series of disequilibrium conditions that depend on unforeseen circumstances or shifts in fundamentals. Times of shortfall will produce periods of high prices, while times of surplus will produce low prices. A large, competitive marketplace such as the RPM should be well-positioned to manage and compensate for these shifts, using price outcomes as the signal of when new supply should come forward and older resources should retire.

The most recent shifts in RPM prices however, require additional focus in this Quadrennial Review, particularly the substantial price increase observed in the 2025/26 BRA that arrived after several years of low prices. As shown in Figure 5, RTO clearing prices ranged between $16/MW-day and $165/MW-day between the 2012/13 Delivery Year and the 2024/25 Delivery Year, prices that were substantially below administrative estimates of Net CONE due to consistent procurement in excess of reliability requirements and long market conditions.[16] Despite prices substantially below Net CONE, over time the RPM has attracted large volumes of new investment (for example 34 GW ICAP of new gas-fired combined cycle resources since the 2014/15 auction).[17]

[16] In several instances, constrained LDAs cleared above the system price driven by transmission constraints and local resource retirements. See PJM BRA results reports available at PJM, Capacity Market (RPM), accessed February 10, 2025 and 2022 VRR Curve Report, Sections II.A and II.B.

[17] New supply provided in ICAP MW. Does not include data from the 2014/15 BRA. Data is recent as of the 2023/24 Base Residual Auction and does not include changes in installed capacity that have occurred since. See PJM, 2023/2024 RPM Base Residual Auction Results, 2022, Table 8.

Following several years of supply entry at moderate prices, the RPM has most recently had a period over 2022/23-24/25 in which prices were relatively low and commensurate with prices that signaled long market conditions and encouraged sellers to exit the market or defer their entry decisions. Low prices were a reflection of long market conditions relative to the supply-demand accounting of the RPM capacity market. However, these prices did not yet account for the challenges that PJM has increasingly observed in accurately measuring system reliability risks as the fleet changes and as winter reliability risks grow. For that reason, the extent and nature of reliability needs were not fully reflected in prices signaled via the RPM over that period.

In the most recent BRA, the 2025/26 BRA system price (RTO) rose to $270/MW-day, which is above the RTO Net CONE estimate of $229/MW-day. Additionally, the Baltimore Gas and Electric (BGE) and Dominion Load Deliverability Areas (LDAs) cleared at their price caps at $466/MW-day and $444/MW-day respectively.[18] The sudden price increases came as a surprise to many stakeholders, regulators, and market participants, and warrant specific analysis in the current quadrennial review to understand the causes of these price changes and understand the implications for the appropriate VRR Curve parameters for the coming years.

As an initial observation on the levels of resulting prices: we note that the absolute level of the clearing prices should be considered in the context of a long-run resource adequacy construct. Prices at or near Net CONE are the level that should be expected over the long term in a market that relies on merchant capacity entry for a portion of supply needs. Further, multi-year periods of prices above or below that level should also be expected as the market predicts and reacts to supply-demand conditions and broader market fundamentals. However, a sudden price increase (and LDA price cap event) of the size observed in the last auction is problematic in particular for customers that have unhedged exposure to capacity market prices. On the supply side, unexpected and unpredictable price increases can also be problematic since some resources that could have been available may have failed to bring their projects forward (but are likely relatively quickly resolved in the next auction or as soon as those resources can mobilize). A final category of drivers for price increases can relate to market design changes and one-time transition effects, most notably the recent changes to more accurately account for reliability risks in setting capacity demand parameters and resource accreditation. In the following sections, we unpack the multiple factors influencing 2025/26 BRA and assess the implications for upcoming auctions.[19]

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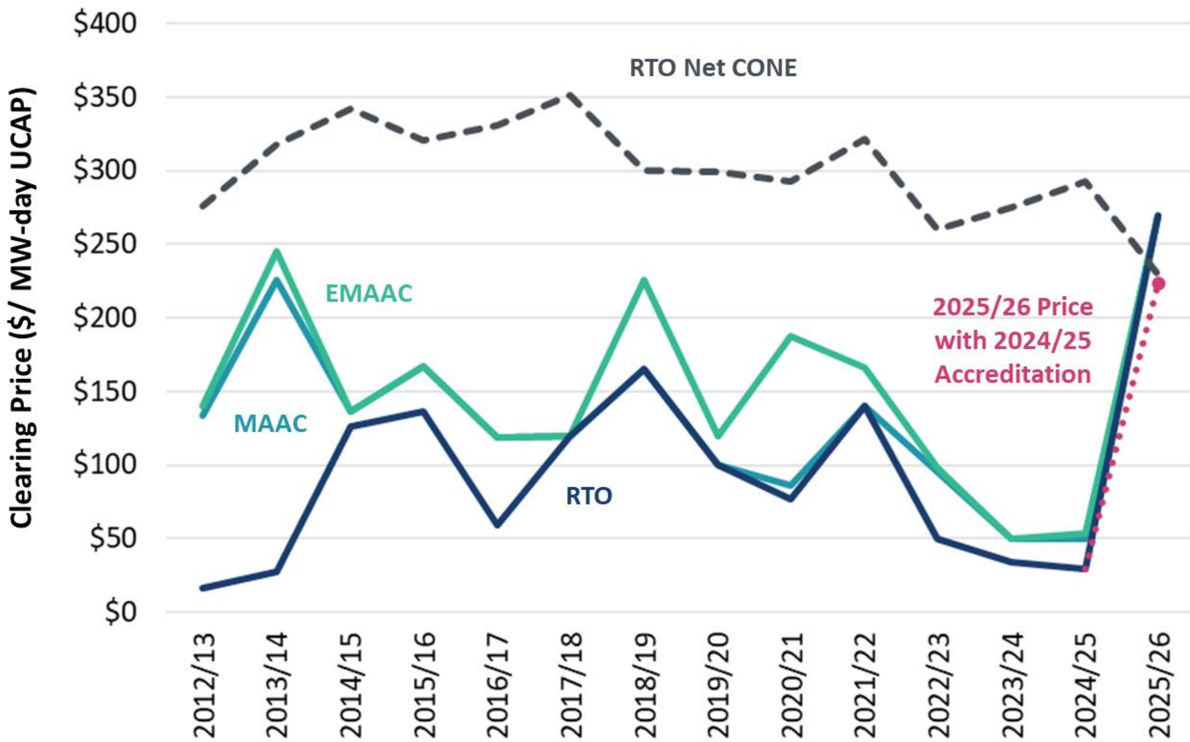
18 PJM, 2025/25 Base Residual Auction Report, July 30, 2024.

19 See PJM, 2025/26 Base Residual Auction Results, August 21, 2024; PJM, 2025/26 Base Residual Auction Report, July 30, 2024.

FIGURE 5: HISTORICAL RPM CLEARING PRICES AND NET CONE



Sources and Notes: Prices in nominal dollars. Data from historical PJM BRA Planning Parameters and Results reports available on the PJM website. See PJM, Capacity Market (RPM), accessed February 4, 2025.

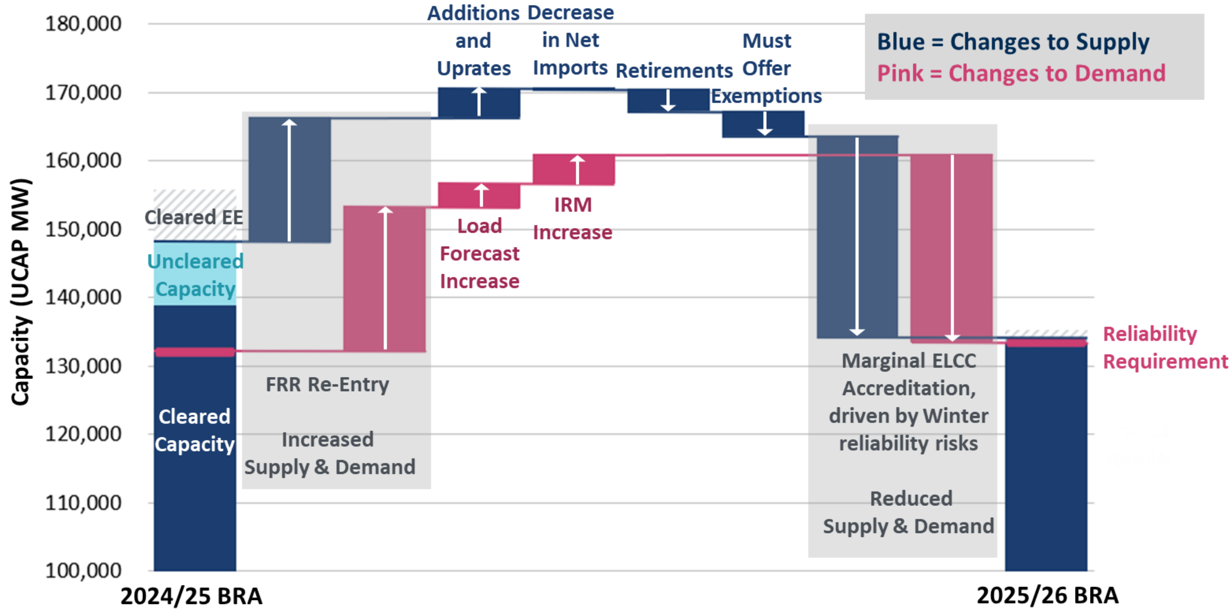
B. Diagnosis of Outcomes from the 2025-26 BRA

The elevated clearing prices in the 2025/26 BRA indicate that PJM is entering into a period of tight supply conditions which signals a need for further investment in capacity resources.[20] In total, there was a 15,500 MW contraction in the market-wide supply demand balance with the 2024/25 auction running with a 16,000 MW surplus in offered supply relative to the Reliability Requirement (a large portion of this surplus did not clear the auction). The level of supply surplus contracted to only a 500 MW in 2025/26 (i.e., nearly all available supply was cleared). As shown in Figure 5, the system-wide clearing price increase from $29/MW-day in 2024/25 to $270/MW-day in 2025/26 was driven by a substantial tightening of the supply-demand balance paired with insufficient forward time for supply to react.[21] These tightening supply conditions were driven by a combination of market fundamentals and one-off events including the market reforms effecting reliability modeling and capacity accreditation approach.

[20] PJM, 2025/25 Base Residual Auction Report, July 30, 2024.

[21] PJM, 2025/2026 Base Residual Auction Report, July 30, 2024, p. 4.

FIGURE 6: DRIVERS OF TIGHTENING SUPPLY CONDITIONS IN BETWEEN THE 2024/25 AND 2025/26 BRAS



Sources and Notes: Data compiled based on supply offer data provided by PJM staff and public reports. Supply offer values only include annual offers (exclude summer-only or winter-only offers). See PJM, 2025/26 Base Residual Auction Results, August 21, 2024; PJM, 2025/26 Base Residual Auction Report, July 30, 2024.

There were many factors that contributed to a tightening supply-demand balance for the 2025/26 BRA. Any one of these factors would likely have proven only to have a modest impact on market outcomes as a stand-alone driver (or if these individual drivers moved in offsetting directions). But the combination of the following factors led to a significant tightening event for the 2025/26 BRA:

- **The re-entry of entities from the FRR alternative** contributed similar size increases in both supply and demand, considering that FRR entities self-supply outside the RPM and tend to affect the market with a modest impact based on their net supply or net demand position (net demand in this case);
- **An increase in the load forecast** used for the 2025/26 BRA relative to the 2024/25 BRA. The 2024/25 BRA used the 2022 load forecast which estimated a summer peak of 150,300 MW and a winter peak of 135,500 MW for the 2024/25 delivery year.[22] The 2025/26 BRA used the more recent 2024 load forecast which projected a summer peak of 153,500 MW and a winter peak of 139,200 MW for the 2025/26 delivery.[23] The increases in load are driven primarily by

[22] PJM, PJM Load Forecast Report: January 2022, January 2022, Tables B-1 and B-2.

[23] *Ibid*.

increasing data center and electrification load. In January, PJM released the 2025 load forecast which projects additional load growth relative to the 2024 load forecast, primarily from data centers. Demand is expected to continue to grow in PJM with the 2025 load forecast projecting approximately 31,600 MW of peak demand growth by 2030.[24]

- **Updated reliability modeling increased the IRM** putting upward pressure on the reliability requirement.[25] The increase in the IRM was driven primarily by modeling enhancements that more accurately capture winter reliability risks.
- **New additions and uprates** increased supply availability by 4,200 MW (a factor that offsets most of the other drivers that decreased the supply-demand balance).
- **A decrease to net imports, retirements of existing resources, and unoffered resources with a must-offer exemption** lowered supply offered by 10,500 MW. PJM filed updated market rules with FERC which were accepted in February 2025 that are meant to remove the must-offer exemption from intermittent resources. The IMM has estimated that approximately 3,745 MW of accredited intermittent and storage resources did not offer in the last BRA under the must-offer exemption.[26]
- **The implementation of new marginal ELCC resource accreditation methodology** decreased supply offers through a decrease in accreditation of existing resources of 29,700 MW.[27] However, the updated resource accreditation methodology also decreased the reliability requirement by a similar volume of 27,500 MW. The two adjustments are large individually, but are associated with the same transitional change to the accreditation reforms and together produced much smaller decrease in net supply of 2,200 MW directly attributable to

[24] PJM forecasts approximately 31,600 MW of RTO summer peak demand growth between 2024 and 2030; and approximately 34,500 MW of RTO winter peak demand growth between the 2023/24 and 2029/30 winter periods. The PJM RTO is predicted to be summer-peaking in 2030. See PJM, 2025 Load Forecast Tables, January 24, 2025, Tables B-1 and B-2.

[25] PJM, 2023 Reserve Requirement Study, October 3, 2023.

[26] Approximately 13,000 UCAP-MW of resources were exempt from the most-offer requirement in the 2025/26 BRA that will now be subject to the must-offer requirement. However, the majority of these resources still offered into the 2025/26 BRA. See Monitoring Analytics, Comments of the Independent Market Monitor for PJM, Docket No. ER25-785-000, January 10, 2025, p. 5.

[27] Based on analysis of supply offers of existing resources that offered into both the 2024/25 and 2025/26 BRAs. Value does not include the accreditation effect of new resources that offered into the 2025/26 BRA but not the 2024/25 BRA.

the resource accreditation changes.[28] Further discussion on PJM's resource accreditation is contained in Section III.D below.

In total, the net supply decreased from 16,000 MW for the 2024/25 BRA to 500 MW for the 2025/26 BRA, of which the majority was due to adjustments to the updated resource accreditation methodology, FRR re-entry, and increased IRM.[29] The market was unable to fully respond because the magnitudes may have come as a surprise to many market participants and the auction occurred with a shorter forward period than usual, resulting in a substantial increase in prices.[30]

Looking forward, tight supply conditions may persist or worsen for several years given outlook for strong load growth, development time needed for sellers, and reforms needed to address barriers to supply entry.

C. Impact of the Compressed Forward Capacity Auction Schedules

The RPM is designed as a three-year forward auction but has operated with a compressed forward period since 2021/22 due to implementation of several market reforms which have delayed auction timelines, both for the most recent four auctions and for the upcoming four auctions. Figure 7 summarizes the forward period of the most recent auctions in addition to the planned schedule for future auctions.[31,32] The current plan is to extend the forward auction

[28] The numbers in the text differ slightly from the numbers presented separately by PJM due to treatment of resources that did not participate in both the 2024/25 and 2025/26 BRAs and the treatment of FRR entities on the demand-side. PJM, 2025/2026 Base Residual Auction Results, Presented at Markets & Reliability Committee meeting, August 21, 2024, slide 22.

[29] PJM, 2025/2026 Base Residual Auction Results, presented at Markets and Reliability Committee, August 21, 2024.

[30] Further discussion on the impacts of the shortened forward period of the 2025/26 BRA can be found in Section III.C.

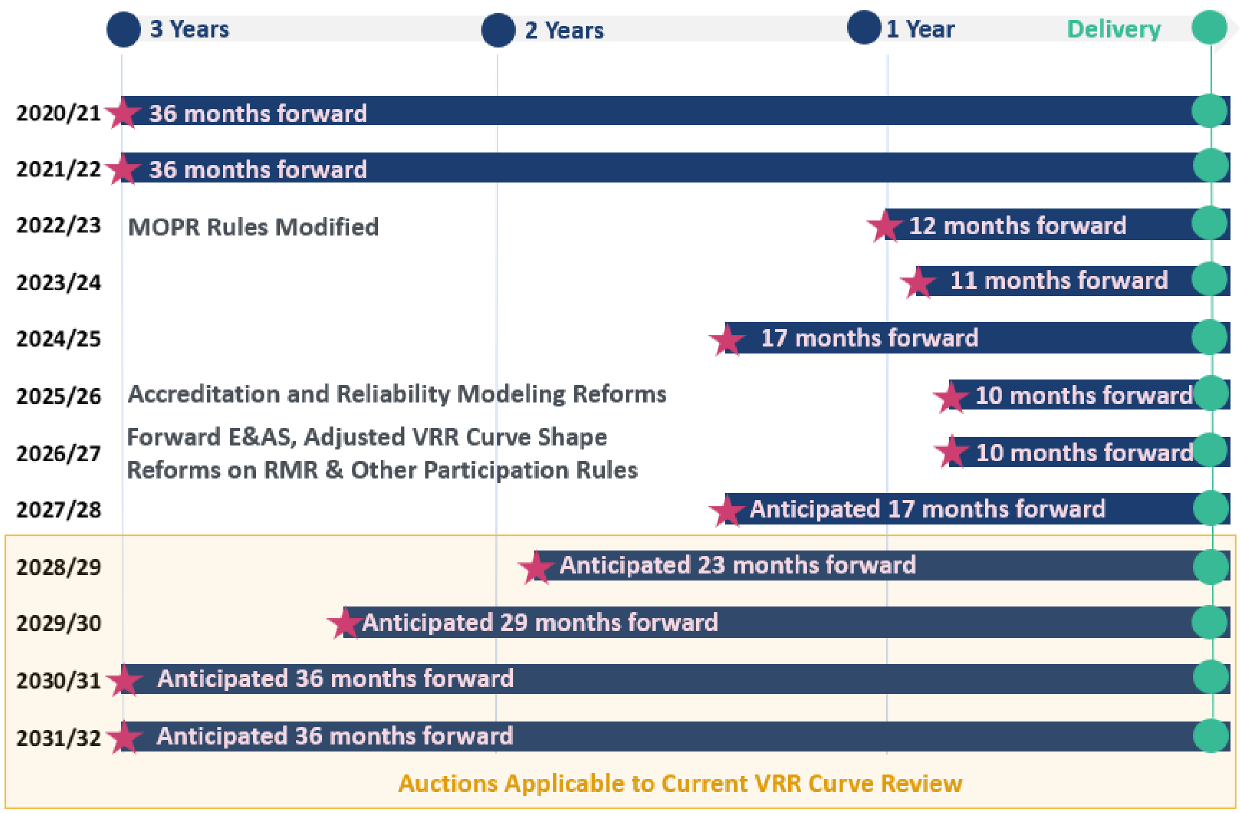
[31] The 2022/23 auction was delayed due to changes to the minimum offer price rule (MOPR), the 2023/24 auction was delayed due to updated minimum office seller cap (MSOC) rules, and the 2025/26 auction was delayed to enable time to implement the new reliability modeling and resource accreditation methodologies. See, Monitoring Analytics, Analysis of the 2022/23 RPM Base Residual Auction: Revised, February 22, 2022, revised January 13, 2023; Monitoring Analytics, Analysis of the 2023/24 RPM Base Residual Auction, October 28, 2022; and PJM, "FERC Sets New Date for PJM 2025/2026 Capacity Auction," February 26, 2024.

[32] The 2026/27 auction has already been delayed until July 2025 to allow time to change the participation rules for Reliability Must Run resources, to maintain a gas-fired combustion turbine (CT) as the reference resource, and to implement a new temporary price cap and floor to the 2026/27 and 2027/28 VRR curves among other rule

Continued on next page

period on a staged basis, reverting to the full three-year forward period by the 2030/31 BRA (and only if there are no further BRA delays to accommodate future design changes). Therefore, we anticipate that any VRR Curve updates resulting from this Review may apply to auctions with a compressed forward period, and so consider the interactions the non-forward period may have with the VRR Curve in the 2028/29 and 2029/20 BRAs.[33]

FIGURE 7: PJM RPM AUCTION FORWARD PERIODS



Sources and Notes: Timelines of historical auctions are based on PJM and IMM reports. Timeline for future auctions based on PJM published auction schedule as of 2024. See Monitoring Analytics, Analysis of the 2022/23 RPM Base Residual Auction: Revised, February 22,2022, Revised January 13, 2023; Monitoring Analytics, Analysis of the 2023/24 RPM Base Residual Auction, October 28, 2022; PJM, Auction Schedule, accessed April 7, 2025.

There are two distinct aspects of forward period that affect capacity market performance:

- **The three-year forward period of the BRA auctions,** which is intended to allow sufficient time for some resources to respond to price signals and make efficient entry and exit

changes. See FERC, Order on Contested Settlement, Docket No. ER22-1539-000, January 26, 2025 and PJM, Proposal for Revised Price Cap and Price Floor for the 2026/27 and 2027/28 Delivery Years, and Request for a Waiver of the 60-Days' Notice Requirement to Allow for a March 31, 2025 Effective Date, Docket No. No. ER25-01357-000, February 20, 2025.

33 See discussion on analysis of VRR curve options in the context of forward periods as opposed to non-forward periods in Section V.C.

decisions. The volume of incremental supply options is greater with a farther-forward period, with a 6-12 month forward period allowing for only limited responsiveness to price (e.g. from demand response and net imports); while a 2-3 year forward period can allow a wider array of supply responses (e.g. including uprates, life-extensions, and BESS investments). Some gas plants may also be able to finalize or accelerate construction timelines to meet a three-year forward period if their projects are sufficiently developed and permitted. Though other longer-lead resources or those that are not at a sufficient stage of development will still not be able to come online within a 3-year forward period, they will at least receive an earlier and clearer signal on when to initiate construction. By comparison, a compressed forward period leaves fewer options for sellers to adjust supply plans before the delivery period.

- **The forward timeframe over which market participants are notified of material rule changes and other information,** so that they can proactively plan for and manage needs as they arise. If new rule changes, capacity ratings updates, load forecast increases, or auction parameters come as a surprise or with limited forward time before the relevant auction, then market participants may not have sufficient time to adjust their plans. If market participants learn of an impending supply shortfall or rule change immediately prior to an auction, they will not be able to adjust or accelerate their plans in time to bring forward more resources to be offered into the auction. However, if rule changes are anticipated and implemented over a multi-year schedule that is communicated in advance, then market participants can be ready to meet new requirements by the time rule changes are in effect (this is true even in a non-forward capacity market). Beyond rule changes, anticipated changes to the load forecast, capacity ratings, transmission parameters, queue completion rates, and other factors that may materially affect supply and demand are critical information for market participants to assess the timing of their own projects.

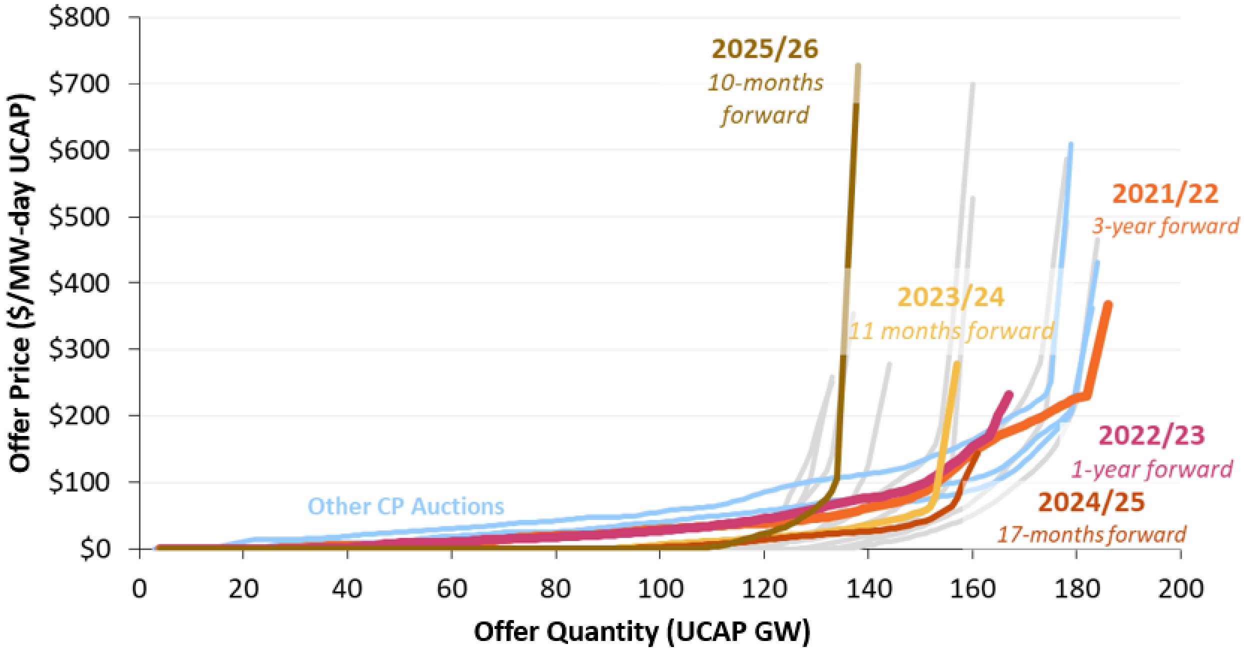
Both of these factors have influenced recent RPM performance and contributed to pricing outcomes in the most recent 2025/26 BRA. The influence of the compressed forward period can be observed empirically in Figure 8 below, which illustrates that the 2025/26 BRA and other auctions with a compressed forward period had much steeper supply curves compared to the 2021/22 BRA and other auctions with the full 3-year forward period. The steeper supply curves are a manifestation of the reality that in a non-forward auction, nearly all supply decisions must be made before the auction based on their expectations of market price: new resources must decide to build or defer, aging resources must decide whether to retire or life-extend. They cannot wait until they know the auction clearing price in order to finalize these decisions. If many sellers inaccurately predict low prices (as they did prior to the 2025/26 auction) some sellers may fail to make an offer, even if their projects would have been in the money. The pre-auction decision-making and steeper supply curves make non-forward capacity auctions somewhat more susceptible to price volatility and exposed to shortage events compared to forward capacity auctions.

In a full three-year forward auction, a much larger scope of potentially marginal resources can make a capacity offer and finalize their go/no-go decisions after the auction. The result is a higher and flatter supply curve, where more resources can be available to meet demand if prices are attractive and others can retire if prices are too low. Over most years since RPM's implementation, the market has attracted a volume of supply offers that was substantially beyond what was needed to meet the Reliability Requirement and, as a consequence, the BRA supply curve intersected with the VRR Curve at low or medium prices. At the same time, RPM has enabled over 58 GW of retirements of existing resources.[34] We view those outcomes as strong indicators that the market was healthy and performing well on the dimensions of attracting supply interest, producing a dynamic and competitive marketplace with robust competition between new and existing resources and amongst multiple technologies.

Considering these observations and the advantages of a farther-forward period, we recommend that PJM should prioritize maintaining its auction schedule and returning to the full three-year forward period. This may mean that some design changes may not be possible to implement until later delivery years, e.g., under a staged transition period. Staged rule changes with planned and Tariff-defined implementation dates can also often offer the additional benefit of providing stakeholders time to more proactively and effectively manage the transition.

34 As of 2023/24 BRA, See Monitoring Analytics, 2024 State of the Market Report for PJM, Section 5: Capacity Markets, Table 5-6.

FIGURE 8: ILLUSTRATIVE SUPPLY CURVES FOR HISTORICAL RPM AUCTIONS



Sources and Notes: Curves shown are illustrative and based on confidential supply offer data provided by PJM staff. More recent Capacity Performance (CP) auctions are shown in light blue while later auctions before CP rules were implemented are shown in gray.

D. Interactions with Capacity Accreditation Reforms

PJM implemented updated marginal ELCC resource accreditation rules effective for the 2025/26 BRA. The updates to the accreditation methodology aim to improve reliability value assessments of all resource types, apply a consistent approach to all resources, and to account for correlated outages for thermal resources driven by extreme weather.[35] Figure 9 below shows the impact of the resource accreditation reforms on the existing resource fleet in PJM. Overall, the fleet-wide average accreditation fell from 95% for the 2024/25 BRA to 80% for the 2025/26 BRA. Much of the reduction in the fleet-wide average was due to reductions in accreditation of dispatchable fossil resources where gas-fired CC accreditation decreased from 97% to 79% and dual-fuel CT accreditation decreased from 95% to 79%. While other resources such as wind and solar also

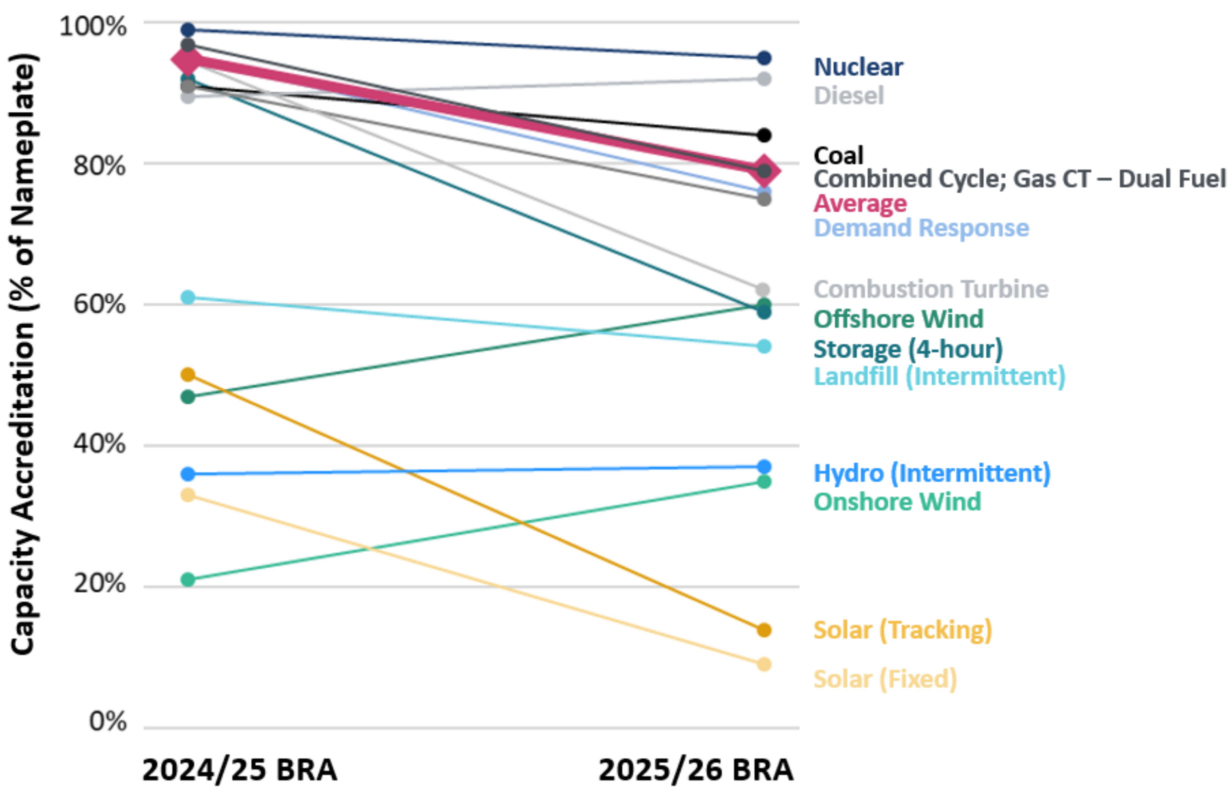
[35] After Winter Storm Elliot in December 2022, it became clear that accreditation levels for existing resources were overvaluing the winter reliability contributions for much of the resource fleet. During Winter Storm Elliot, 47,000 MW of capacity-qualified resources were unable to operate up to expected levels leading to $1.8 billion in performance related penalties. PJM subsequently enacted reforms to better account for system reliability risks and resource performance during extreme weather. See FERC, Order Accepting Tariff Revisions Subject to Conditions, Docket No. ER24-99-000, January 30, 2024; PJM, Winter Storm Elliott: Event Analysis an Recommendation Report, July 17, 2023, pp. 1–2; Howland, "PJM, market participants reach agreement to resolve $1.8B in Winter Storm Elliott fines," September 5, 2023.

experienced decrease in accreditation levels, there is less installed capacity of these resources currently in operation which reduces the impact of their lower accreditation levels.

The substantial changes in resource accreditations will have material implications for the resource mix in PJM, considering that some resources' ELCC values (especially solar, battery, and gas plants) will now earn lower capacity revenues and appear less competitive compared to other resources that retained higher capacity value (such as nuclear, coal, and offshore wind). Resources will also identify opportunities to improve their capacity ratings, such as by improving their access to firm fuel or battery storage duration. These values will also shift further as PJM and stakeholders continue to update and improve both reliability modeling and accreditation approaches.

However, the implications of the accreditation changes to the VRR Curve itself may be relatively more limited (since the VRR Curve is a measure of total demand needs rather than individual suppliers' capabilities). One substantive implication for the VRR curve is that, as noted above, the VRR curve pricing parameters under current UCAP accreditations appear 19% higher than they would under prior UCAP accreditations (see Section II.B above). Another implication is that if fleet-wide resource accreditations differ substantially from year to year, the VRR Curve pricing points may be similarly inflated or deflated in terms of their implications for customers and producers (the magnitude of these shifts will likely be reduced by the transition to a sub-annual construct, as discussed further below). It will take several years of experience with the new construct before it is possible to determine the scale and implications of these year-to-year updates in accreditation ratings. To maintain a more stable alignment between the VRR Curve pricing parameters and total volumes procured and accredited, the Reference Price can be updated alongside the pool-wide UCAP accreditation factor (e.g., such that on a fleet-wide average basis, a 5% increase in ELCC-accredited ratings would correspond to a 5% reduction in VRR Curve pricing parameters—this is similar to how the Net CONE parameter is currently updated based the UCAP of the Reference Technology).

FIGURE 9: IMPACT OF ACCREDITATION REFORMS BY RESOURCE CLASS FROM 2024/25 TO 2025/26



Sources and Notes: "Average" class in the 2024/25 BRA refers to 1—Pool-Wide Average Equivalent Forced Outage Rate on demand (EFORd); "average" class in the 2025/26 BRA refers to the Pool-Wide Accredited UCAP Factor; resource classes units without explicitly-defined capacity accreditation ratings in the 2024/25 BRA are assigned to "average" for this figure; 2024/25 EFORd from PJM, Planning Period Parameters for the 2024/25 Base Residual Auction, 2024; 2025/26 Pool-Wide Accredited UCAP Factor from PJM, Planning Period Parameters for the 2025/26 Base Residual Auction, 2024; 2024/25 ratings for non-dispatchable resources from PJM, ELCC Class Ratings for 2024/2025, 2023; 2024/25 ratings for dispatchable resources from PJM, 2021 PJM Reserve Requirement Study, 2021; 2025/26 ratings provided by PJM.

E. Implications of Seasonally Distinct Reliability Drivers and Resource Capabilities

Historically, PJM has been a summer-peaking system and is expected to remain so into the future.[36] However, through enhanced reliability modeling PJM has determined that more

[36] The 2025 Long-term Load Forecast Report projected the PJM summer peak to be 209,923 MW in 2035 and 228,544 MW in 2045 relative to a forecasted winter peak of 198,175 MW in 2033/35 and 218,760 MW in 2044/45. See PJM, 2025 Long-Term Load Forecast Report, prepared by the PJM Resource Adequacy Planning Department, January 24, 2025.

reliability risk now occurs in the winter season despite its lower peak demand.[37] Higher winter reliability risk is driven by a higher risk of correlated outages in extreme cold weather paired with supply availability from dispatchable and non-dispatchable resources relative to summer output. Additionally winter adequacy risk events tend to be longer, which impacts the ability of duration-limited resources to meet demand, relative to summer adequacy risk events which tend to be shorter and more concentrated into a few hours in July.[38] As electrification of heating increases, peak winter demand will continue to grow and at a pace that may be higher than summer demand increases.[39] Combined, these risk factors result in relatively more reliability risk identified in winter than in summer, though both seasons will continue to present their unique profile of reliability challenges with different underlying risk drivers. In the current annual capacity market construct, the distinct reliability risks and volume of capacity needs presented by each season is reflected on a weighted-average basis as the combined annual Reliability Requirement.

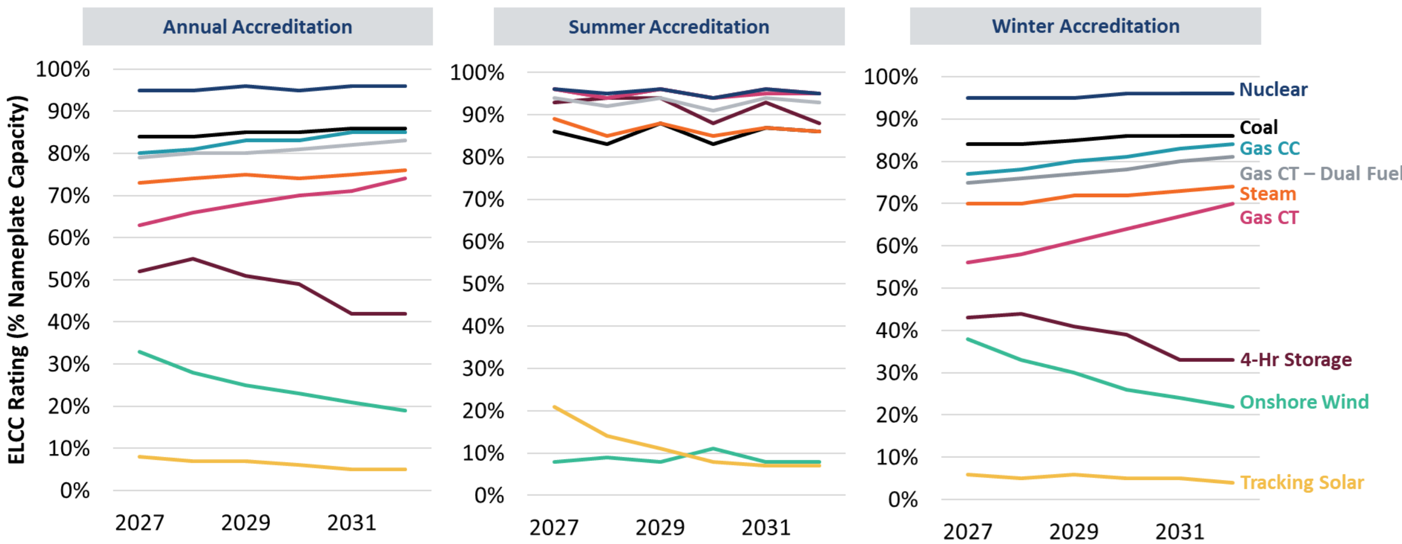
An additional complexity in the annual capacity market construct is that different resource types have substantially different reliability and resource adequacy value between the summer and winter seasons. Figure 10 below shows illustrative projected capacity accreditations by resource type and season compared to an annual accreditation. As shown, the summer accreditation levels are distinct and generally higher across most resource types relative to the winter accreditations. This highlights that more resources are available and able to reliably serve demand at higher levels during summer periods of adequacy risk than during winter periods of risk. The figure also demonstrates that adequacy risk is not static and should be expected to evolve with the changing resource mix and demand profile over time. Under the current annual construct, these resources' distinct reliability value in summer and winter seasons is accredited on a combined annual basis, with the annual capacity value influenced by the share of system-wide risk exposure anticipated across the seasons.

37 PJM, Capacity Market Reform: PJM Proposal, Critical Issue Fast Path-Resource Adequacy ("CIFP-RA"), July 27, 2023, slide 57; and PJM, Energy Transition in PJM: Emerging Characteristics of a Decarbonizing Grid, May 17, 2022.

38 Annual heat maps of Expected Unserved Energy show that winter adequacy risk tends to be spread across more hours and peaks twice daily in the early morning and late evening in January and February, as opposed to summer adequacy risk which is mostly concentrated to three afternoon hours in July. See PJM, Capacity Market Reform: PJM Proposal, Critical Issue Fast Path-Resource Adequacy ("CIFP-RA"), July 27, 2023, slides 63 and 64.

39 See PJM, Energy Transition in PJM: Emerging Characteristics of a Decarbonizing Grid, May 17, 2022 and Celebi et al., Bulk System Reliability for Tomorrow's Grid, The Brattle Group, prepared for the Center for Applied Environmental Law and Policy, December 20, 2023.

FIGURE 10: SEASONAL RESOURCE ACCREDITATION PROJECTIONS FOR PJM



Sources and Notes: Data provided by PJM staff.

Overall, the current approach to reflecting supply and demand on an annual basis is becoming an increasingly imprecise way to measure capacity needs and commitments. While reliability risk is currently greater in the winter months, it is possible that more reliability risk could shift back into the summer season in the future. For example, a shift to more summer reliability risk could occur if, under the annual construct, accreditations that reflect current greater winter risk incentivize more winter-focused resources to the point that summer-focused resources (e.g. solar and demand response) exit the market. Furthermore, there is a possibility that some LDAs in PJM could experience greater summer reliability risks compared to winter, even if RTO-wide risks are greatest in winter.

The annual construct as it is currently structured will eventually measure and track these shifting seasonal risks as they occur, but will tend to do so on a lagging basis that trails (rather than guides) the resource mix. To the extent that PJM's reliability modeling materially mis-estimates the balance of summer vs. winter risks, the result could be that the winter-focused accreditations produce low prices and apparently long market conditions; while at the same time the summer season remains insufficiently protected because summer-focused reliability needs and supply capabilities have not been meaningfully reflected in capacity market prices. Another challenge could occur if estimated seasonal risks shift back and forth frequently or even between each auction; in that scenario, the volumes of demand procured and resources' accreditation could be subject to material instability without being reflective of underlying supply-demand fundamentals. Overall, the performance of an annual construct to accurately measure reliability needs and supply capabilities will become increasingly eroded to the extent that: (1) more than one season is anticipated to present material reliability risks, and (2) a substantial and/or increasing share of the resource mix has substantially different reliability value across these seasons.

Transitioning to a sub-annual or seasonal capacity construct would address these reliability risks and improve overall economic efficiency of capacity market outcomes. A sub-annual capacity construct can better align assessments of seasonally-distinct resource adequacy needs with more effective economic signals to attract investment in a supply mix that is better aligned to meet those needs over the year. Further, the PJM capacity market would be better-positioned to attract season-specific capacity commitments (e.g. from summer demand response) and engage in mutually beneficial seasonal capacity trade with neighboring jurisdictions that have complementary needs (e.g. importing in summer and exporting in winter, or vice versa).

Most other capacity markets have already acknowledged the reliability needs and economic rationale for moving to more accurate and seasonally-distinct capacity needs. For example, Ontario's Independent Electricity System Operator (IESO) conducts a two-season capacity auction with co-optimized auction clearing that sets separate prices in the summer and winter seasons; MISO has moved to a four-season capacity market starting with the 2023/24 delivery year; and ISO-NE is developing its proposal to adopt a seasonal auction for the 2028/29 delivery year.[40] Though the reasons for a seasonal capacity market differ in each of these regions, the common thread is that each region faces a shift in reliability drivers that may produce materially different and distinct costs and capability to manage reliability needs on a seasonal basis.

PJM and the PJM Board have previously recognized the value in a sub-annual construct, and PJM staff have presented a high-level concept for how a sub-annual capacity construct would be structured over stakeholder processes conducted in 2022 and 2023.[41] The outcomes of the most recent auction highlight further the reliability and economic benefits of transitioning to a sub-annual construct, considering the substantially tighter supply-demand conditions and winter-focused reliability challenges revealed by the 2025/26 auction results.

To ensure that a sub-annual construct supports reliability needs and produces efficiency benefits, it should have the following primary components, each of which can be built upon the experience

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[40] ISO-NE is considering a sub-annual capacity auction but it is not yet approved. See Schatzki, Cavicchi, Ross, Capacity Market Alternatives for a Decarbonized Grid: Prompt and Seasonal Markets, January 2024.

[41] PJM, Capacity Market Reforms to Accommodate the Energy Transition While Maintaining Resource Adequacy, October 13, 2023, Docket No. ER24-99-000; PJM, Executive Summary: PJM Seasonal and Annual Proposals, CIFP-RA, August 23, 2023; PJM, Seasonal Demand Curves, CIFP-RA, August 14, 2023; and PJM, Energy Transition in PJM: Emerging Characteristics of a Decarbonizing Grid, May 17, 2022.

of other markets where they have already been tested and implemented. Elements of a sub-annual capacity market would include:

- **Sub-annual reliability requirements reflecting the capacity quantity needed to maintain reliability:** PJM's reliability modeling already incorporates the capability to separately measure reliability risks and needs by season, which can be used to establish seasonally-distinct Reliability Requirements. To first order, these season-specific reliability needs are closely associated with peak demand in each season, after accounting for other factors such as season-specific demand uncertainties, event durations, and seasonal capacity ratings. The seasonal capacity needs would be reflected in the RPM auctions as season-specific capacity demand curves as is done in both MISO and IESO (see additional discussion in Section VII.B below regarding the potential for seasonal MRI-based VRR curves in PJM).
- **Sub-annual resource accreditation, offer quantities, and commitment obligations:** Capacity resources would also have distinct seasonal UCAP ratings, reflecting their seasonal capacity ratings and resource capabilities. These seasonal drivers of resource value are already accounted for in establishing the marginal ELCC accreditation methodology, but the season-specific results would need to be used directly rather than combined into an annual composite value. Sub-annual accreditation has the potential to unlock more supply to participate in the RPM, such as: (a) thermal resources that would likely have higher winter capacity ratings than under the current annual construct, as long as incremental thermal ICAP (including above their annual capacity injection rights (CIR) ratings) can be considered in the accreditation;[42] (b) demand response, batteries, and solar resources that have substantially higher summer capacity accreditations compared to winter; and (c) seasonal net imports.
- **Prices that reflect the marginal costs of meeting demand, as driven by the supply-demand balance in each sub-annual commitment period:** A sub-annual auction construct can more accurately reflect the marginal value of incremental capacity in each season, sending economically rational price signals for investment and aligning market-based payments with sub-annual contributions to reliability by season. To most accurately reflect the costs of supply, resources would be able to reflect the distinct cost profiles if cleared to meet the needs in only one season versus if they are committed across the entire year (where the total revenues received over the year would need to be sufficient to recover total costs). Market prices would also be most accurately set if they are the product of a co-optimized auction clearing that minimizes the total annual cost of supply and ensures that cleared participants recover the avoided costs that occur for clearing in one or both seasons.

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[42] Monitoring Analytics, Analysis of the 2025/2026 RPM Base Residual Auction Part A, September 20, 2024, p. 6.

Together, these components of a sub-annual capacity construct could produce substantial cost savings, particularly under present conditions when supply needs are tight. These cost savings arise due to the ability to unlock additional supply capability in individual seasons in the near term, and over the longer-term by guiding a more economic and right-sized capacity mix to meet reliability needs across seasons. A sub-annual construct would also be more robust to changing reliability risks and able to achieve efficient market outcomes even without perfect foresight into the precise resource mix will be in future years. MRI-based VRR Curves such as we recommend in this Review are also aligned with a transition to a sub-annual construct, as discussed in more detail in Section VII.B below.

IV. Development of System-Wide MRI-Based VRR Curves

A. Comparison to Current VRR Curve and Other Capacity Markets' Curves

Figure 11 illustrates the current PJM VRR curve and an MRI-based VRR curve, in comparison to the downward-sloping capacity demand curves used in other capacity markets including in New York Independent System Operator (NYISO), Midcontinent Independent System Operator (MISO), ISO New England Inc. (ISO New England), and Ontario's Independent Electricity System Operator (IESO).

As in PJM, these other capacity markets' demand curves are designed so that, on average and over the long term, clearing prices can reflect long-run marginal costs and clearing quantities align with reliability needs.[43] While this economic logic is shared across all capacity markets, there are variations in demand curve shape associated with different preferences in the trade-off between lower price volatility (accomplished through a lower price cap and/or flatter demand curve) and certainty over the cleared quantity (accomplished through a higher price cap and steeper demand curve).

Additional variation between curves is tied to other market features, such as the forward period and seasonality of the auction. For example, NYISO's curve is notably flatter than neighboring markets' curves and features a higher price cap, in part due to NYISO's non-forward capacity auction structure, which includes seasonal, monthly and spot auctions. The demand curve is incorporated only into the final spot auction, with the farther forward auctions and bilateral markets serving to support hedging against the spot auction price.[44]

These capacity markets also account for seasonality in distinct ways. The IESO capacity auction is structured relative to two distinct capacity seasons with different volumes of supply and demand

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43 While the terminology varies by market, all capacity markets aim to procure a level of quantity equal to the Reliability Requirement, i.e., the peak load plus a reserve margin, as adjusted to a UCAP or ELCC basis.

44 NYISO's capacity market includes three types of capacity auctions: Strip Auctions for each Capability Period (i.e., twice a year); Monthly Auctions (held every monthly for the remaining months in the Capability Period); and Spot Auctions (held every month for procurement of capacity for use in the upcoming month). For more information, see Mathangi Srinivasan Kumar, "NYISO Administered ICAP Market Auctions," September 26-27, 2024.

and different clearing prices; MISO has supported a four-season capacity market starting in 2023/24. In both of these seasonal capacity markets, the parameters and shape of the demand curves are influenced by the seasonal nature of the constructs (chiefly, because the volumes are a product of peak load in the relevant season). The NYISO market incorporates a mixture of annual, seasonal, and monthly components.[45] The ISO-NE capacity market is currently an annual construct, but the region is in the process of developing a proposal to transition to a two-season construct.[46]

The shape and slope of the other markets' capacity demand curves are also influenced by considerations similar to those that we have previously considered in the VRR Curve reviews, including the relationship of prices to the implied willingness-to-pay for reliability. The relationship of the capacity demand curve to reliability value is strongest in both ISO-NE and MISO, where both markets derive their demand curve shapes directly from their modeling estimates of the marginal reliability impact. ISO-NE was the first region to adopt MRI-based demand curves in 2016, with different MRI curves utilized system-wide as well as for import-constrained and export-constrained regions.[47] MISO will first utilize its MRI-based demand curves in its seasonal auction in the upcoming auction for the 2025/26 delivery year.[48]

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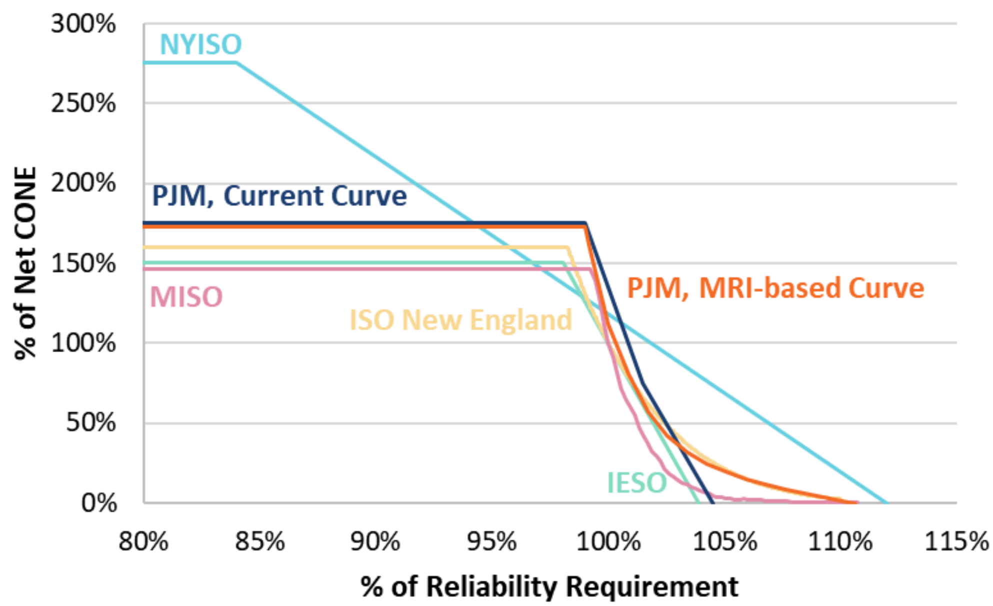
45 Demand parameters are primarily associated with annual peak load, while supply accreditation is mostly related to 6-month seasonal capability. Individual supply commitment periods have a duration of one-month at a time, consistent with the timeframe relevant for the monthly and spot auctions.

46 See ISO-NE, "Capacity Auction Reforms Key Project."

47 155 FERC ¶ 61,319, Order Accepting Filing re ISO New England Inc. and New England Power Pool Participants Committee under ER16-1434, June 28, 2016, Docket No. ER16-1434-000.

48 The MISO reliability-based demand curves are defined on a system-wide basis and across the two large market regions, with separate curves in each of the four capacity seasons (3 distinct geographies × 4 seasons = 12 curves in each auction). 187 FERC ¶ 61,202, Order Accepting Tariff Revisions, re Midcontinent Independent System Operator, Inc. proposed Reliability Based Demand Curves, June 27, 2024, Docket Nos. ER23-2977-000, ER23-2977-001, and ER23-2977-002; see also Written Testimony of Dr. Kathleen Spees, Dr. Samuel A. Newell, and Dr. Linquan Bai, filed before the Federal Energy Regulatory Commission, September 28, 2023, Docket No. ER23-2977-000.

FIGURE 11: DEMAND CURVE COMPARISON OF NEIGHBORING CAPACITY MARKETS



Sources/Notes: "PJM, MRI-based Curve" shown as Curve 2, Price Cap at 99% of the Reliability Requirements, described in detail in Section IV.B, "PJM, Current Curve" constructed using updated Gross CONE and Net CONE estimates for a dual-fuel CT with a June 2028 online date from the Brattle 2025 PJM CONE Report (although the y-axis is shown as a percentage of Net CONE, this information is relevant to determine the price cap) and the current VRR curve formula; PJM, Open Access Transmission Tariff, Attachment DD, Section 5.10, accessed March 3, 2025; NYISO curve based on NYCA Zone summer 2024 curve; NYISO, ICAP/UCAP Translation of Demand Curve, Summer 2024 Capability Period, 2024; NYISO, Annual Update for 2024-2025 ICAP Demand Curves, November 17, 2023; IESO curve from the 2025 capacity auction, this curve includes implied long-term contracted capacity, auction parameters from the 2025 capacity auction; IESO, Annual Planning Outlook, March 2024; IESO, Capacity Auction: Pre-Auction Report, August 16, 2024; MISO curve from Brattle testimony supporting MISO's implementation of Reliability-Based Capacity Demand Curve, The Brattle Group, Written Testimony of Dr. Kathleen Spees, Dr. Samuel A. Newell, and Dr. Linquan Bai, filed before the Federal Energy Regulatory Commission, September 28, 2023, Docket No. ER23-2977-000; ISO-NE curve from Forward Capacity Auction 18 for Capacity Commitment Period 2027/28; ISO-NE, FCA 18 Demand Curves, August 14, 2023.

B. Constructing an MRI-Based VRR Curve

Following the concept demonstrated in both ISO-NE and MISO, we recommend that PJM's VRR Curve should be updated to a shape aligned with the marginal reliability value or MRI. In prior quadrennial reviews we have used the MRI-based curve as a key indicator of the alignment of the VRR Curve with reliability benefits delivered to customers but have not previously recommended to formally adopt the MRI-based approach primarily because PJM was in the midst of enhancing its approaches to more accurately model reliability value of incremental capacity and accredit capacity.[49] Now that these reforms have been implemented, we recommend taking the next step toward more accurate supply-demand accounting with an MRI-based VRR Curve. Adopting an MRI-based curve in PJM can also leverage the experience from ISO-NE and MISO, which have both demonstrated the feasibility and implementation details associated with MRI-based demand curves that can be adapted into the PJM context.

MRI-based curves have the conceptual advantage of reflecting a more uniform and unified representation of the willingness-to-pay for reliability, meaning that market prices are more meaningfully aligned with reliability value delivered to customers. The wider and more gradually declining foot of these curves reflects the diminishing need for and value of capacity when the market is long, while the steeper slope near the cap reflects more acute reliability needs when the market is tight. To the extent that the same $/MWh scaling factor is used to for multiple capacity demand curves, this also offers a more unified signal on the value of capacity by location (like in New England) and by season (like in MISO). The capability of an MRI curve to more accurately and meaningfully reflect differentiated reliability value across seasons will be particularly valuable in the PJM region, considering the other economic and reliability benefits that will be realized if PJM proceeds with implementing a sub-annual construct. For the majority of this report, we describe the MRI curve as it would be implemented in the current annual capacity market construct (consistent with the scope of this Quadrennial Review), and provide an indicative description of the method that would be applied to adapt the curve into a sub-annual or seasonal market (in Section VII.B below). To develop these MRI-based curves, we used reliability modeling results provided by PJM staff from the same modeling platform that is currently used to set the RTO and LDA Reliability Requirements.[50]

The process we used to develop MRI-based VRR Curves in PJM is illustrated at a high-level in Figure 12. The process includes three steps to: (1) develop the MRI curve in units of reliability (ΔEUE MWh /ΔMW UCAP); (2) multiply the MRI value by a "Scaling Factor" in units of $/MWh to translate from units of reliability to units of capacity price; and (3) determine the resulting capacity market demand curve in units of capacity price ($/MW-day UCAP). We describe these steps in more detail below.

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[49] See 2022 VRR Curve Report, Section III.B.

[50] PJM, 2023 Reserve Requirement Study, October 3, 2023.

FIGURE 12: CONCEPTUAL STEPS TO DESIGNING AN MRI-BASED DEMAND CURVE

Step 1: Develop MRI Value

- Y-axis in units of reliability (Δ EUE/Δ MW)
- Derived from reliability modeling
- Can be separately calculated for system, zones, and sub-annual periods

Step 2: Multiply by "Scaling Factor"

- Translates from units of reliability into units of price
- Scaling Factor sized so MRI-based demand curve runs through Anchor Point, which is chosen considering overall curve performance

Step 3: Calculate MRI-Based Demand Curve

- Y-axis in units of price ($/MW-day)
- Reflects consistent willingness-to-pay vs. quantity across full curve
- Subject to designed price cap

In **Step 1,** PJM's reliability modeling is used to determine quantity of capacity at which the system achieves the Reliability Requirement, at 1-in-10 or 0.1 LOLE (this process is already utilized in PJM's current reliability modeling). Next, an additional modeling step is conducted in which perfectly available UCAP MWs of capacity are added or subtracted to determine the incremental reliability value of adding/subtracting capacity. The MRI curve is defined as the MWhs of reduction to Expected Unserved Energy accomplished by adding 1 UCAP MW of incremental supply. The MRI can be calculated relative to the entire system, a specific LDA, or in a sub-annual period, which has the potential to support more accurate pricing signals at specific locations and across seasons. The MRI curves utilized in this report are derived from the Loss of Load Hours (LOLH) metric and is mathematically defined in Equation 1.

Figure 13 shows the resulting PJM RTO-wide MRI curve for the PJM region, which is convex and downward-sloping. When supply is scarce, incremental capacity additions lead to large improvements in system reliability, as reflected by the steep slope of the MRI curve at low quantities. However, when supply is abundant, the gradual slope of the MRI curve reflects the diminishing, but non-zero, reliability impact of incremental capacity additions.

EQUATION 1: CALCULATION OF MARGINAL RELIABILITY IMPACT

MRI = Avoided EUE from Incremental Capacity = LOLH × 1 MW UCAP

WHERE:

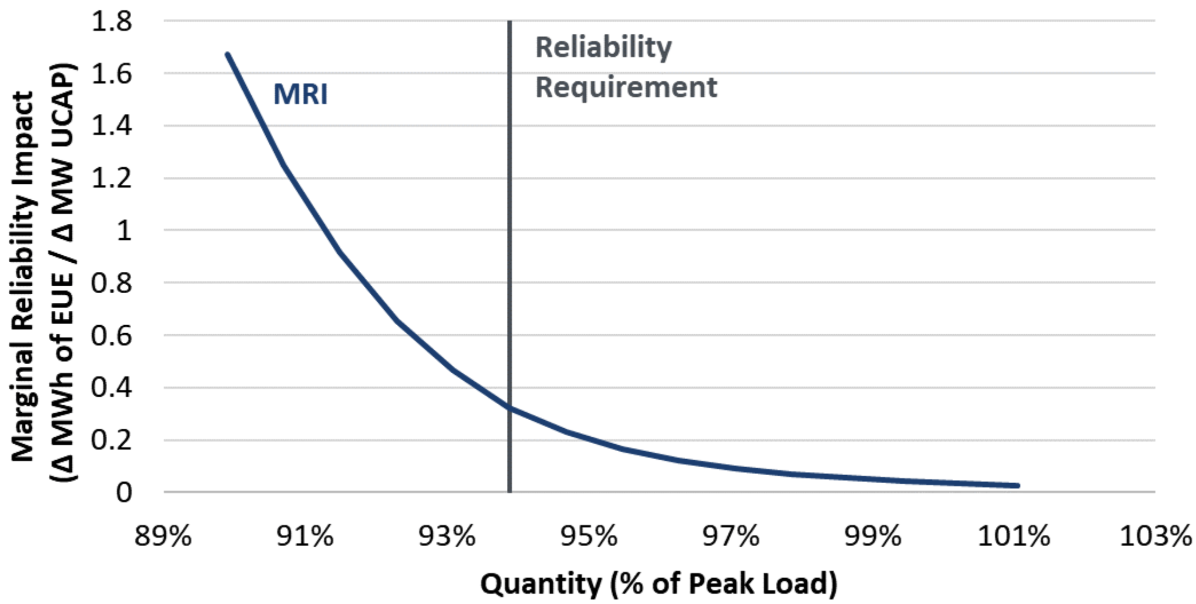
MRI (MWh per 1 UCAP MW): is the incremental reliability value of adding 1 UCAP MW of capacity to the system

Avoided EUE (MWh of avoided EUE per MW UCAP): is the reduction in expected involuntary load shedding caused by adding 1 UCAP MW of incremental capacity

Incremental Capacity (UCAP MW): is the volume of perfectly available capacity added (assumed to be 1 UCAP MW to calculate the marginal impact)

LOLH (hours per year): is the duration of outage hours (which may occur across one or many events) predicted in reliability simulations across the season in question, consistent with a specific quantity of UCAP MW available

FIGURE 13: PJM SYSTEM-WIDE (RTO) ANNUAL MRI CURVE



Sources/Notes: Reliability data provided by PJM reliability modeling staff; UCAP Reserve Margin from the 2025/26 Base Residual Auction, see PJM, [2025/26 Planning Period Parameters](), 2023.

In **Step 2** the "Scaling Factor" is defined which translates the MRI curve from units of reliability (ΔEUE /ΔMW UCAP) into units of price ($/MW-day UCAP). The Scaling Factor is sized so that the resulting MRI-based demand curve runs through an "Anchor Point" which is chosen considering the overall curve's performance. The anchor point itself can be defined in any number of ways, but sets a single price-quantity pair through which the MRI-based VRR curve is drawn. In both ISO-NE and MISO, the anchor point is defined by the Reliability Requirement and Net CONE. For the purposes of this report, we focus on three different curves with differently-defined anchor points as discussed further in the following Section III.C. Equation 2 is the formula for deriving the Scaling Factor from the Anchor Point.

EQUATION 2: CALCULATION OF SCALING FACTOR FOR MRI-BASED VRR CURVE

Scaling Factor = Price @ Anchor Point ÷ MRI @ Anchor Point

WHERE:

System Scaling Factor ($/MWh): is the payment rate at which the system VRR Curve would seek to procure additional supply

Price @ Anchor Point ($/MW-year UCAP): is equal to the price at a defined Anchor Point, through which the MRI-based VRR Curve is drawn

MRI @ Anchor Point (MWh/MW-year UCAP): is the marginal reliability impact of additional capacity, measured at the Anchor Point quantity through which the MRI-based VRR Curve is drawn

Finally, in **Step 3**, the system or locational MRI-based VRR Curve is calculated by multiplying the Scaling Factor by the MRI curve at each quantity point to translate from units of reliability into units of capacity price and willingness to pay. The resulting MRI-based VRR Curve can extend to volumes above and below the Anchor Point, and is subject to a price cap.

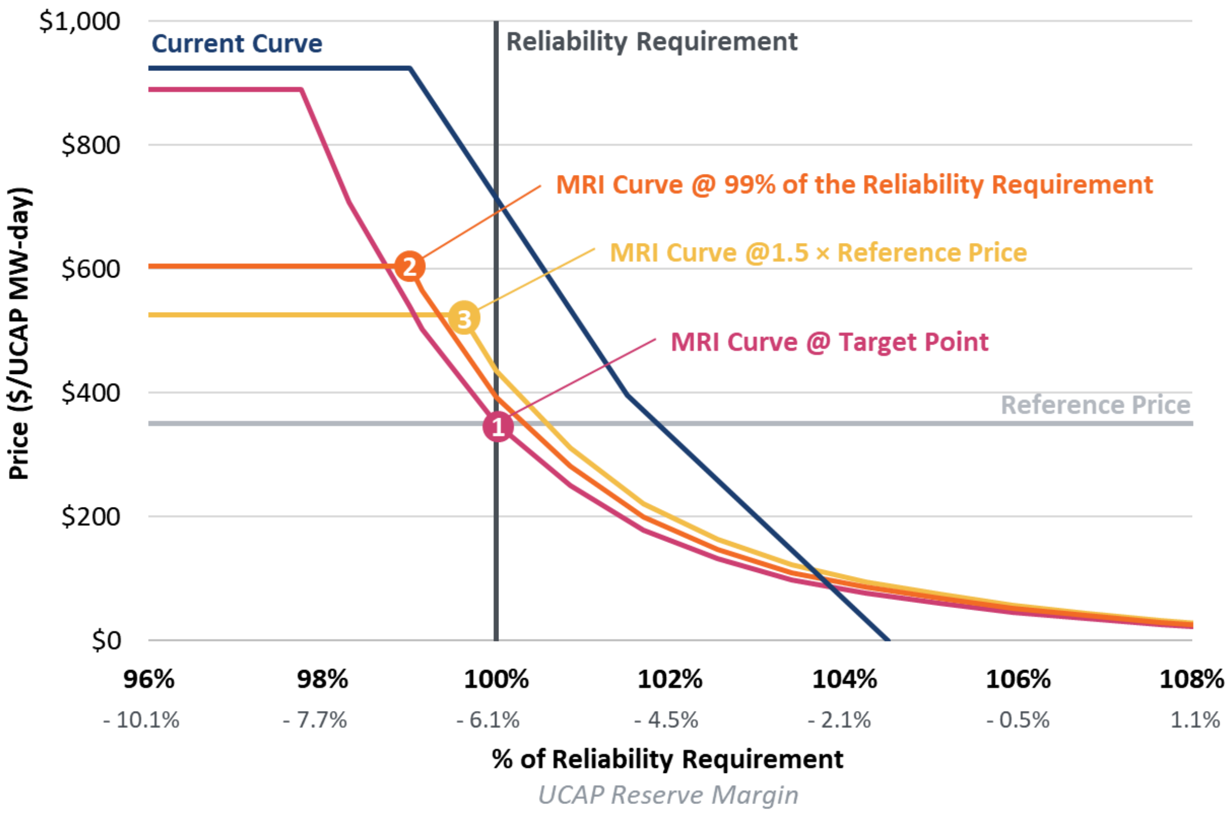
C. MRI Curves Tuned to 1-in-10 Standard

As described in Section IV.B above, MRI curves can be developed based on different scaling factors to pass through unique anchor points. To construct Candidate MRI-based VRR Curves and evaluate their potential performance in the PJM capacity market, we identified three different approaches to defining the MRI-based curves such that the parameters would be "tuned" to the 1-in-10 LOLE reliability standard. In each case, we adjust the price and quantity of the defined Anchor Point, such that in long-term probabilistic modeling the prices and quantities supported by the MRI-based VRR Curve align with 0.1 LOLE at prices that on average are equal to the Reference Price or long-run marginal cost of supply. This simulation modeling is the same approach that we have utilized in prior VRR Curve Reviews, with modeling parameters updated to reflect recent market outcomes and present conditions as described in more detail in the Appendix.

The three Candidate Curves that we examine throughout this report are defined as follows, and are illustrated in Figure 14 below after tuning the Anchor Points to the 1-in-10 standard. The three MRI-based curves we consider are:

- **Curve 1, Anchor Point at the Target:** This Anchor Point is set so that clearing prices are equivalent to the Reference Price at the target point (i.e. the Reliability Requirement). The price cap quantity and price are then adjusted so the curve achieved 1-in-10 LOLE. Under base modeling conditions with the Reference Price at $350/MW-day, Curve 1 has a price cap of $890/MW-day and a price cap quantity at 97.8% of the Reliability Requirement.
- **Curve 2, Anchor Point at 99% of the Reliability Requirement:** This Anchor Point is set so that the price cap quantity is at 99% of the Reliability Requirement, which is the quantity threshold below which auction clearing results could trigger a review of the VRR curve. The price cap price was then adjusted so the curve achieved 1-in-10 LOLE under base modeling conditions. With a Reference Price of $350/MW-day, Curve 2 has a price cap of $605/MW-day and a price cap quantity at 99% of the Reliability Requirement.
- **Curve 3, Anchor Point at 1.5 × Reference Price:** This Anchor Point is set so the price cap price is 1.5 × Reference Price. The quantity at the price cap quantity is then adjusted so that the curve produces reliability at 1-in-10 LOLE under base conditions. With a Reference Price of $350/MW-day, Curve 3 has a price cap of $525/MW-day at a price cap quantity at 99.6% of the Reliability Requirement.

FIGURE 14: MRI-BASED VRR CANDIDATE CURVES TURNED TO 1-IN-10 LOLE STANDARD



Sources and Notes: Curves constructed using a unique scaling factor based on the Anchor Point. See Section C for additional description of Curve 1, Curve 2, and Curve 3 and their Anchor Points (indicated in the figure above by the numbered circles).

To examine the performance of the candidate VRR curves, we conducted probabilistic simulation analyses of potential market outcomes under long-run equilibrium conditions. As described more fully in the Appendix and similar to the approach used in prior Quadrennial Reviews, we conducted a Monte Carlo analysis to simulate the estimated range of price, quantity, and reliability outcomes under each VRR curve. These simulation results indicate curve performance under long-term equilibrium conditions, and accounting for year-to-year variability in supply and demand at the same scale that we have historically observed in RPM. We do not attempt in this exercise to project the near-term price or reliability outcomes that may occur over the next few years.

Table 2 below compares the resulting performance metrics of the three tuned Candidate Curves from our probabilistic Monte Carlo simulation model, in comparison with the Current VRR Curve (defined relative to a dual-fuel CT Reference Resource as updated to 2028/29 parameters). Since all three tuned Candidate Curves are designed to achieve system-wide reliability at the 1-in-10 LOLE standard under baseline long-run equilibrium conditions, average procurement costs are similar for the three MRI-based curves. However, each curve offers trade-offs in price volatility, frequency of clearing results at the price cap, and frequency of clearing results below 99% of the Reliability Requirement.

As shown in the table, Curve 1 results in the highest price volatility with a standard deviation of $178/MW-day across simulation runs. The higher price volatility is due to a higher price cap which leads to a broader range of potential clearing prices. Curve 2 and Curve 3 have somewhat lower levels of price volatility due to their lower price caps. However, these curves result in a higher frequency of clearing outcomes at their price caps, with Curve 2 clearing at the price cap for 12.7% of simulation runs and Curve 3 clearing at the price cap for 19.9% of simulation runs. Curve 2 has the best performance in mitigating low clearing outcomes below 99% of the Reliability Requirement (12.7% of runs) compared to 13.3% for Curve 1 and 15.0% for Curve 3. In conclusion, all three tuned curves perform adequately under the base assumptions. Shape and performance of the tuned MRI curves under alternative reference prices are discussed in Section IV.D below and the factors we investigated for determining an acceptable price cap range are discussed in Section VI.A.

TABLE 2: PERFORMANCE OF "TUNED" MRI CURVES

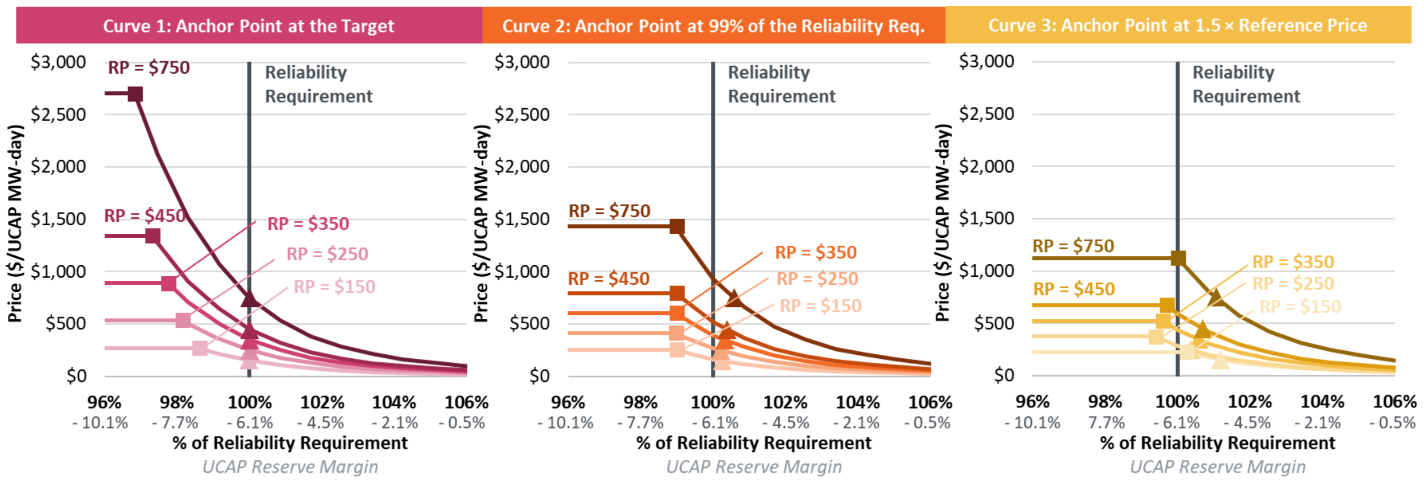
	Price			Reliability							Cost
	Average Clearing Price	Standard Deviation	Frequency at Cap	Average LOLE	Average Excess (Deficit) Above Reliability Requirement	Average Excess (Deficit) Above Target Reserve Margin	Average EUE	Normalized Portfolio EUE (% of Target)	Frequency Below Reliability Requirement	Frequency Below 99% of Reliability Requirement	Average Procurement Cost
	($/MW-d)	*($/MW-d)*	*(%)*	*(events/yr)*	*(MW)*	*(UCAP RR + X %)*	*(MWh)*	*(%)*	*(%)*	*(%)*	*($ mln/yr)*
Current Curve	$350	$183	2.3%	0.053	2,607	1.86%	834	54.9%	6.3%	2.3%	$17,491
Curve 1	$350	$178	3.0%	0.100	366	0.28%	1,615	106.3%	34.7%	13.3%	$17,188
Curve 2	$350	$141	12.7%	0.100	463	0.35%	1,643	108.1%	31.2%	12.7%	$17,189
Curve 3	$350	$122	19.9%	0.100	566	0.43%	1,668	109.7%	29.1%	15.0%	$17,192

Sources and Notes: Simulated curves match curves shown in the figure above.

D. Tuned MRI Curves with Varying Reference Prices

We evaluated these three MRI-based candidate curve constructs with varying Reference Prices to understand the consequent effects on curve shape, price cap placement, and performance. For this evaluation, we utilized Reference Price values of $150, $250, $350, $450, and $750/MW-day UCAP. This analysis aims to test the robustness of the alternative MRI-based curve approaches to a wide range of potential Net CONE values that may be associated with different economic conditions and underlying technology types, as detailed further in the *Brattle 2025 PJM CONE Report*. To properly compare curve performance across different Reference Price values, we adjusted the Anchor Point and price cap in tandem so that each curve achieved reliability at the 1-in-10 LOLE target under base modeling conditions. Detailed results for each curve, as well as their impact on our final decision of the Candidate Curve, are provided below.

FIGURE 15: CURVE 1, CURVE 2, AND CURVE 3, VARYING REFERENCE PRICE VALUES



Sources and Notes: "RP" stands for Reference Price. Squares indicate the maximum quantity at the price cap and triangles indicate the intersection of each VRR curve with its respective reference price.

TABLE 3: PERFORMANCE OF CANDIDATE CURVES, TUNED TO VARYING REFERENCE PRICE VALUES

	Clearing Price			Price Cap @ 1-in-10		Reliability						Cost
	Avg. Clearing Price	Standard Deviation	Frequency at Cap	Price	Multiple of Ref. Price	Avg. LOLE	Avg. Excess (Deficit) Above Reliability Requirement	Avg. Excess (Deficit) Above Target Reserve Margin	Normalized Portfolio EUE (% of Target)	Frequency Below Reliability Requirement	Frequency Below 99% of Reliability Requirement	Avg. Procurement Cost
	($/MW-d)	*($/MW-d)*	*(%)*	*($/MW-d)*	*(%)*	*($/MW-d)*	*(MW)*	*(UCAP RR + X %)*	*(%)*	*(%)*	*(%)*	*($ mln/yr)*
Curve 1: Anchor Point at the Target, Tuned to 1-in-10 LOLE												
Ref. Price = $150	$150	$65	3.7%	$271	181%	0.100	351	0.26%	104.4%	47.6%	16.4%	$7,340
Ref. Price = $250	$250	$104	3.8%	$537	215%	0.100	288	0.22%	104.5%	43.6%	10.7%	$12,264
Ref. Price = $350	$350	$178	3.0%	$890	254%	0.100	366	0.28%	106.3%	34.7%	13.3%	$17,188
Ref. Price = $450	$450	$273	3.3%	$1,345	299%	0.100	470	0.36%	108.4%	33.7%	14.1%	$22,104
Ref. Price = $750	$750	$600	3.8%	$2,703	360%	0.100	741	0.56%	112.6%	30.6%	16.9%	$36,812
Curve 2: Anchor Point at 99% of the Reliability Requirement, Tuned to 1-in-10 LOLE												
Ref. Price = $150	$150	$63	8.5%	$253	168%	0.100	503	0.37%	107.5%	40.5%	8.5%	$7,343
Ref. Price = $250	$250	$90	8.9%	$413	165%	0.100	351	0.27%	105.5%	39.3%	8.9%	$12,263
Ref. Price = $350	$350	$141	12.7%	$605	173%	0.100	463	0.35%	108.1%	31.2%	12.7%	$17,189
Ref. Price = $450	$450	$197	13.4%	$797	177%	0.100	558	0.42%	110.0%	31.8%	13.4%	$22,106
Ref. Price = $750	$750	$402	17.7%	$1,434	191%	0.100	882	0.66%	114.1%	27.3%	17.7%	$36,860
Curve 3: Anchor Point at 1.5 × Reference Price, Tuned to 1-in-10 LOLE												
Ref. Price = $150	$150	$57	19.2%	$225	150%	0.100	1,303	0.94%	121.8%	18.4%	14.2%	$7,374
Ref. Price = $250	$250	$83	13.9%	$375	150%	0.100	411	0.32%	107.3%	33.5%	11.6%	$12,264
Ref. Price = $350	$350	$122	19.9%	$525	150%	0.100	566	0.43%	109.7%	29.1%	15.0%	$17,192
Ref. Price = $450	$450	$166	22.6%	$675	150%	0.100	674	0.51%	111.7%	30.1%	16.0%	$22,111
Ref. Price = $750	$750	$305	28.2%	$1,125	150%	0.100	1,018	0.76%	115.5%	27.7%	18.5%	$36,890

Sources and Notes: The MRI-based VRR curves that produce these results are constructed using administrative Reference Prices of $150/MW-day, $250/MW-day, $350/MW-day, $450/MW-day, and $750/MW-day. These VRR curves are calibrated to achieve 1-in-10 LOLE when the true Reference Price is equal to the administrative Reference Price, as shown in this table.

Curve 1 requires a high price cap to support 1-in-10 reliability under long-run equilibrium conditions, both in absolute terms and as a multiple of Net CONE. The resulting price caps for Curve 1 are between 1.8–3.6 × Reference Price; the price cap exceeds $1,000/MW-day even when the Reference Price is as low as $450/MW-day. These price caps are a substantially higher multiple of Net CONE compared to today and would introduce an escalated risk of high-priced auction clearing outcomes. As discussed further in Section VI.A, price caps at this level would be untenable due to the potential high consumer costs under shortage conditions. Since this curve passes through the Reliability Requirement at the Reference Price, it is left-shifted relative to Curve 2 and Curve 3 (as shown in Figure 14), which requires a higher price cap to support reliability and renders Curve 1 susceptible to low-reliability outcomes. The curve also as a relatively poorer capability to protect against low reliability events, since the curve does not reach the price cap until very low cleared quantities, in the range of 96.8%–98.6% of the Reliability Requirement. This lower quantity at the cap also means that the RPM Backstop provisions (which trigger at 99% of the Requirement) would be triggered more often and before the market has reached the price cap. The outcome of triggering backstop provisions before all in-market opportunities for capacity supply have been exhausted would be misaligned with design objectives of supporting reliability through market signals on a long-run basis. For these two reasons (excess customer exposure to price cap events, and inconsistency of the volume of the cap with backstop provisions), we view Curve 1 as substantially less desirable compared to Curves 2 and 3.

Curve 2 has price cap quantity fixed at 99% of the Reliability Requirement; this curve is right-shifted relative to Curve 1 and left-shifted relative to Curve 3. The price cap required to support 1-in-10 reliability under long-run equilibrium conditions is relatively stable at 1.7–1.9 × Reference Price across all tested Reference Prices; meaning that the price cap multiplier could offer more stability over the long term even as Reference Prices substantially change. Customers' exposure to price volatility and price cap events is much less than in Curve 1, but still near or above the maximum price exposure that would have prevailed for most of RPM history. Curve 2 produces significantly fewer clearings at the price cap (between 9% and 18% of clearings at the cap across all different simulated Reference Prices) compared to Curve 3, which has a lower price cap at 1.5 x Reference Price (between 19% and 28% of clearings at the cap). Further, the shape of Curve 2 is robust to changes in Reference Price, as all curves pass through the relevant Reference Price at an acceptable and stable quantity of 100.2%–100.6% of the Reliability Requirement across all tested Reference Prices.

Curve 3 is the furthest right-shifted of the three candidate MRI-based curves. The right-shifting of the curve is necessary to support 1-in-10 LOLE under long-run equilibrium conditions since the price cap is fixed at 1.5 × Reference Price. The tradeoff is that a lower price cap limits the high end of attainable prices under shortage conditions, such that the population of pricing outcomes must contain more frequent price cap events for prices to equal the Reference Price on average. As expected, Curve 3 frequently clears at the price cap across tested Reference Prices, ranging from 19%–28% of all clearing outcomes. Similarly, Curve 3 produces a higher percentage of years with cleared volumes below 99% of the Reliability Requirement than Curves 1 and 2. This suggests a greater likelihood of PJM needing to take corrective actions to ensure sufficient capacity in the RPM, as this threshold triggers Reliability Backstop provisions. The relatively high potential for outcomes at the price cap would be a substantial drawback of Curve 3, a performance tradeoff against the benefit of achieving lower price volatility and customer exposure to high price events.

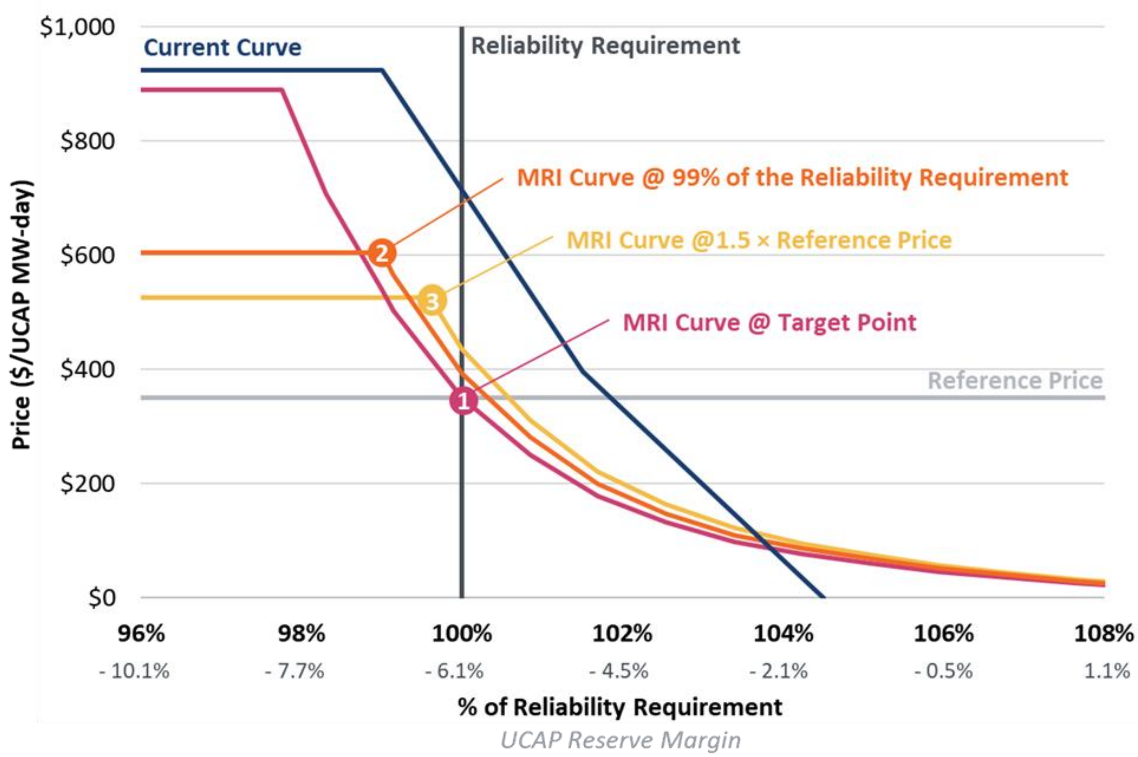
V. Performance of Candidate MRI-Based Curves

A. Current Curve vs MRI-Based Curves (Base Assumptions)

In Figure 16 we show the tuned MRI-based curves, Curve 1 (pink), Curve 2 (orange), and Curve 3 (yellow) in comparison to the Current Curve (blue). Under the current formula, the price cap of the Current Curve is set based on 1.75 × the Net CONE of a CT, which is estimated to be \$528/MW-day UCAP, resulting in a price cap of \$924/MW-day UCAP.[51] Curve 1 is left-shifted relative to the Current Curve but has a similar price cap of \$890/MW-day UCAP. Curve 2 and Curve 3 have lower caps of \$605/MW-day UCAP (or approximately 1.73 × Reference Price of \$350/MW-day UCAP) and \$525/MW-day UCAP (1.5 × Reference Price) respectively.

51 The current formula for the VRR Curve sets the price cap equal to the maximum of 1.75 × Net CONE and 1 × Gross CONE. Gross CONE for a CT is estimated to be \$832/MW-day UCAP, meaning that 1.75 × the CT Net CONE is the binding parameter that sets the price cap. See Brattle 2025 PJM CONE Report.

FIGURE 16: CANDIDATE CURVES VS CURRENT CURVE



Sources and Notes: The MRI-based VRR curves are defined by the highlighted anchor point (signified by the circle containing the number for each curve). The Reference Price is $350/MW-day is based on an estimate of the long-run marginal cost of supply in 2028$. The scaling factor for Curve 1, (MRI Curve @ Target Point) is $394,290/MWh based on a price cap of $890/MW-day. The scaling factor for Curve 2, (MRI Curve @ 99% of the Reliability Requirement) is $442,352/MWh based on a price cap of $605/MW-day. The scaling factor for Curve 3, (MRI Curve @ 1.5 x Reference Price) is $490,523/MWh based on a price cap of $525/MW-day. The Current Curve is developed using the current VRR curve formula, with a Net CONE based on the current CT reference resource with an indicative Net CONE of $528/MW-day UCAP and Gross CONE of $832/MW-day UCAP.

Table 4 and Figure 17 below summarize the baseline simulation results for the Current Curve and all three variations of MRI-based VRR curves. As shown in the table, all MRI-based curves are tuned to achieve 1-in-10 LOLE under baseline conditions where both the true and administrative Reference Price are equal to $350/MW-day UCAP. The Current Curve, however, over-procures capacity relative to the reliability target and produces an average LOLE of 0.053 events per year (1 loss of load event every 19 years). This over-procurement would increase procurement cost under the Current Curve to approximately $300 million per year greater than the procurement cost under each of the three MRI-based curves. Most of the increase in procured volume and cost associated with the Current Curve is caused by the continued use of the CT-based reference price, the Net CONE for which is substantially higher than the $350/MW-day UCAP Reference Price that we adopt as the most accurate estimate of the long-run marginal cost of supply. (We assess the robustness of the MRI-based curves to administrative error in Net CONE estimation in Section V.B below).

TABLE 4: PERFORMANCE OF CURRENT CURVE AND THE MRI-BASED VRR CURVES

	Price			Reliability						Cost
	Average Clearing Price	Standard Deviation	Frequency at Cap	Average LOLE	Average Excess (Deficit) Above Reliability Requirement	Average Excess (Deficit) Above Target Reserve Margin	Normalized Portfolio EUE (% of Target)	Frequency Below Reliability Requirement	Frequency Below 99% of Reliability Requirement	Average Procurement Cost
	($/MW-d)	*($/MW-d)*	*(%)*	*(events/yr)*	*(MW)*	*(UCAP RR + X %)*	*(%)*	*(%)*	*(%)*	*($ mln/yr)*
Current Curve	$350	$183	2.3%	0.053	2,607	1.86%	54.9%	6.3%	2.3%	$17,491
Curve 1	$350	$178	3.0%	0.100	366	0.28%	106.3%	34.7%	13.3%	$17,188
Curve 2	$350	$141	12.7%	0.100	463	0.35%	108.1%	31.2%	12.7%	$17,189
Curve 3	$350	$122	19.9%	0.100	566	0.43%	109.7%	29.1%	15.0%	$17,192

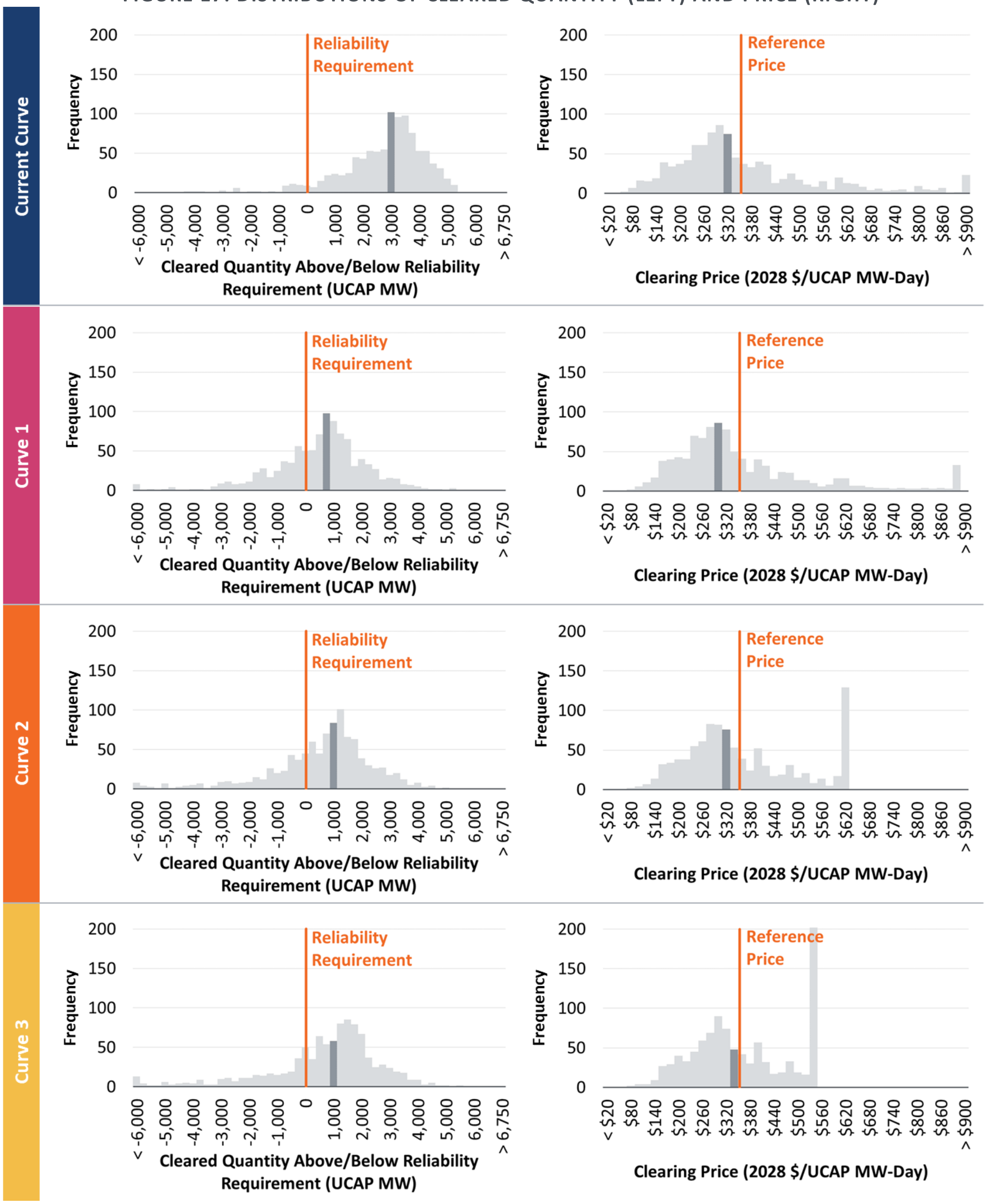
Sources and Notes: Results generated from Base Case model run where the true Reference Price is equal to the administrative Reference Price used to construct the VRR curves ($350/MW-day UCAP). See Section IV.C for additional description of Curve 1, Curve 2, and Curve 3. The Current Curve is developed using the current VRR curve formula, with a Net CONE based on a dual-fuel CT reference resource with an indicative Net CONE of $528/MW-day UCAP and a Gross CONE of $832/MW-day UCAP.

Figure 17 summarizes the distributions of simulated clearing quantities and prices across all model draws of the MRI-based VRR curves and the Current Curve under baseline conditions. The left-hand side of the figure shows the distributions of clearing quantity while the right-hand side of the figure shows the distribution of price outcomes generated by the Current Curve and the three MRI-based VRR curves.

As seen on the left-hand side (Cleared Quantity Above/Below Reliability Requirement) the Current Curve would over-procure by a greater volume and with a greater frequency than the MRI-based VRR curves, leading to higher costs. Median over-procurement under the Current Curve (shown in dark gray in Figure 17) is 2,950 MW, compared to 575 MW under Curve 1, 775 MW under Curve 2, and 1,000 MW under Curve 3.

As can be seen on the right-hand side (Clearing Price), while all curves result in an average clearing price equal to the $350/MW-day Reference Price under the baseline model runs, the distribution of prices differs. The Current Curve has a wider distribution of clearing prices and therefore greater price volatility due to its elevated price cap and steep slope at low volumes of cleared capacity relative to the MRI-based VRR curves. Meanwhile, Curve 3's median clearing price is closest to the Reference Price. Additionally, the rightmost vertical bar in the clearing price histograms indicates the number of clearing events at the price cap, which occurs more frequently for Curve 3 then Curve 2 then Curve 1, which all have lower price caps than the Current Curve. Figure 17 and Table 4 present a subset of inherent performance tradeoffs that must be considered when choosing a VRR curve which we explore in more detail in the following sections.

FIGURE 17: DISTRIBUTIONS OF CLEARED QUANTITY (LEFT) AND PRICE (RIGHT)



Sources and Notes: Median shown in dark gray. Results generated from Base Case model run where the true Reference Price is equal to the Administrative Reference Price ($350/MW-day UCAP). See Section IV.C for additional description of Curve 1, Curve 2, and Curve 3. The Current Curve is developed using the current VRR curve formula, with a Net CONE based on the current dual-fuel CT reference resource with an indicative Net CONE of $528/MW-day UCAP and a Gross CONE of $832/MW-day UCAP.

B. Performance Sensitivity to Net CONE Estimation Error

While the three candidate MRI-based VRR curves all support long-term reliability objectives under (with different performance tradeoffs) base assumptions, we also performed a sensitivity analysis to test reliability and cost outcomes when the estimated Reference Price differs from the true Net CONE faced by resource developers. As discussed in the *Brattle 2025 PJM CONE Report*, Net CONE estimates are subject to a substantial uncertainty range.[52] Net CONE estimates always carry inherent uncertainty, such that the VRR Curve must be capable of offering reasonable outcomes even in the event that Net CONE is over- or under-estimated. Current Net CONE estimates are subject to greater uncertainty than in prior VRR Curve Reviews due to turbine scarcity, constrained supply chains, broader economic conditions, and policy changes that may greatly impact the costs of generation equipment, all while there is expected high demand growth across PJM and neighboring regions. To the extent possible, the VRR curve should be robust to a range of realized Net CONE values that may be faced by developers.

Table 5 below summarizes the estimated performance of the tuned MRI-based VRR curves and the Current Curve when Net CONE is over- and under-estimated. We tested all MRI-based curves in a scenario where the Reference Price is overestimated and the true Net CONE is $200/MW-day, as well as four scenarios where the Reference Price is underestimated and the true Net CONE values are $400/MW-day, $450/MW-day, $500/MW-day, and $550/MW-day. These results are compared to the baseline results when the administrative Reference Price of $350/MW-day is accurate (base conditions or "Accurate Reference Price").

The table illustrates a somewhat different comparison for the Current CT-based VRR Curve, considering that the CT-based pricing parameters would be based on a Net Cone of $528/MW-day (which is substantially higher than the $350/MW-day Reference Price that we assume in the MRI-based curves). As a result, the Current CT-based curve produces higher reliability and higher cost than the MRI-based curves across all scenarios of Net CONE. This indicates that if the Current Curve were to be updated for continued use in the RPM, it should be adjusted to align with the updated estimate of long-run marginal cost of supply consistent with the $350/MW-day Reference Price.

Considering the MRI-based curves only, they show different performance and robustness to administrative uncertainty in Reference Price. As expected, when the true Net CONE is lower

[52] See Brattle 2025 PJM CONE Report.

than the administrative Reference Price, reliability levels exceed the 1-in-10 LOLE standard and each curve results in average procurement beyond the Reliability Requirement with fewer than 1% of clearing results at the price cap for all curves. All three MRI-based curve perform very similarly in the event that the Reference Price is over-estimated, largely do to the feature of the MRI-based curves that produces downward-sloping shapes with converging slope at higher volumes. The most right-shifted variation, Curve 3, is somewhat more susceptible to over-procurement compared to Curves 1 and 2. However, all three MRI-based curves perform very similarly on dimensions of price volatility and reliability.

The reverse situation in which Reference Price is underestimated is more challenging. As true Net CONE is progressively higher than the Reference Price, average procurement costs increase, excess cleared capacity goes down, average reliability results get worse, and frequency of clearing below the reliability requirement and frequency of clearing at the cap increase. We represent this progression in the colored cells of the table where green indicates a better performance for the metric in question, yellow indicates a moderate performance, and red indicates a worse performance.

To evaluate performance of each curve to Reference Price underestimates, we use an approximate threshold of 0.2 LOLE (1-in-5) as the level of reliability risk that is reasonable to accept. Though that level of reliability would not align with reliability objectives over the long run, it is acceptable in the context of RPM considering that periodic Reference Price updates will aim to address any potential under-estimates over the course of each review period. Considering this approximate 0.2 LOLE threshold for eroded reliability performance, Curve 1 offers the strongest robustness to Net CONE under-estimates. Even a large under-estimate of up to $200/MW-day can be absorbed by Curve 1 with moderate reductions to reliability (primarily because of the higher price cap). Curves 2 and 3 offer acceptable reliability performance with a smaller under-estimate of up to $100/MW-day. Performance erodes most quickly with Curve 3 in the event of Reference Price under-estimates, because it has the lowest price cap.

On the high bound of our sensitivity range, when true Net CONE is higher than the Reference Price by $200/MW-day (i.e., true Net CONE is equal to $550/MW-day), costs are higher for all curves and none of the three MRI-based VRR curves achieve the 0.1 LOLE reliability standard. Under this scenario, Curve 1 achieves an average LOLE of 0.180 (1 loss of load event every 5.6 years) compared to 0.312 (1 event every 3.2 years) for Curve 2. Curve 1 and 2 would procure a quantity of capacity less than the Reliability Requirement in greater than 75% of modeled runs. Results are not shown for Curve 3, because its price cap ($525/MW-day UCAP) is lower than the true Net CONE of $550/MW-day in this scenario, therefore prices would clear at the price cap

100% of the time and the model cannot converge to true Net CONE (in other words, the RPM would not be in a position to attract incremental supply since the price cap is below the cost of building new resources). These outcomes highlight the importance of conducting an investigative review of the causes of any price-cap events should they occur, as we discuss further in Section VI below.

TABLE 5: PERFORMANCE OF THE CANDIDATE CURVES IN CONTEXT OF NET CONE UNCERTAINTY

	Price			Reliability						Cost
	Average Clearing Price ($/MW-d)	Standard Deviation ($/MW-d)	Frequency at Cap (%)	Average LOLE (events/yr)	Average Excess (Deficit) Above Reliability Requirement (MW)	Average Excess (Deficit) Above Target Reserve Margin (UCAP RR + X %)	Normalized Portfolio EUE (% of Target) (%)	Frequency Below Reliability Requirement (%)	Frequency Below 99% of Reliability Requirement (%)	Average Procurement Cost ($ mln/yr)
Current Curve: CT-based Net CONE @ $528, Price Cap @ $924										
$328 Overest. (True Ref Price = $200)	$200	$98	0.1%	0.033	3,983	2.81%	34.1%	0.1%	0.1%	$10,101
$178 Overest. (True Ref Price = $350)	$350	$183	2.3%	0.053	2,607	1.86%	54.9%	6.3%	2.3%	$17,491
$128 Overest. (True Ref Price = $400)	$400	$204	4.4%	0.062	2,159	1.54%	64.9%	10.4%	4.5%	$19,912
$78 Overest. (True Ref Price = $450)	$450	$220	7.3%	0.072	1,713	1.23%	76.9%	15.2%	7.3%	$22,310
$28 Overest. (True Ref Price = $500)	$500	$231	10.4%	0.084	1,264	0.92%	91.4%	21.3%	10.6%	$24,690
$23 Underest. (True Ref Price = $550)	$550	$236	15.3%	0.098	793	0.59%	109.4%	28.9%	15.3%	$27,046
Curve 1: Price Cap = $890, Quantity @ Cap = 97.8% × Reliability Requirement										
$150 Overest. (True Ref. Price = $200)	$200	$86	0.1%	0.057	2,278	1.62%	57.6%	4.2%	0.6%	$9,951
Accurate (Ref. Price = $350)	$350	$178	3.0%	0.100	366	0.28%	106.3%	34.7%	13.3%	$17,188
$50 Underest. (True Ref. Price = $400)	$400	$200	5.8%	0.117	(141)	-0.07%	127.8%	46.7%	21.1%	$19,562
$100 Underest. (True Ref. Price = $450)	$450	$216	9.8%	0.136	(617)	-0.40%	152.1%	57.5%	29.7%	$21,915
$150 Underest. (True Ref. Price = $500)	$500	$227	14.2%	0.156	(1,080)	-0.73%	180.7%	66.5%	37.5%	$24,253
$200 Underest. (True Ref. Price = $550)	$550	$232	19.3%	0.180	(1,573)	-1.07%	217.1%	74.6%	45.3%	$26,564
Curve 2: Price Cap = $605, Quantity @ Cap = 99.0% × Reliability Requirement										
$150 Overest. (True Ref. Price = $200)	$200	$84	0.3%	0.051	2,684	1.91%	51.5%	2.5%	0.3%	$9,979
Accurate (Ref. Price = $350)	$350	$141	12.7%	0.100	463	0.35%	108.1%	31.2%	12.7%	$17,189
$50 Underest. (True Ref. Price = $400)	$400	$147	21.0%	0.126	(244)	-0.14%	142.0%	44.3%	21.0%	$19,524
$100 Underest. (True Ref. Price = $450)	$450	$142	33.0%	0.161	(1,041)	-0.70%	192.1%	59.3%	33.0%	$21,814
$150 Underest. (True Ref. Price = $500)	$500	$128	46.6%	0.215	(2,027)	-1.38%	275.7%	74.6%	46.6%	$24,036
$200 Underest. (True Ref. Price = $550)	$550	$101	65.7%	0.312	(3,397)	-2.34%	434.1%	87.7%	65.7%	$26,147
Curve 3: Price Cap = $525, Quantity @ Cap = 99.6% × Reliability Requirement										
$150 Overest. (True Ref. Price = $200)	$200	$82	0.6%	0.046	3,055	2.17%	46.6%	1.6%	0.3%	$10,005
Accurate (Ref. Price = $350)	$350	$122	19.9%	0.100	566	0.43%	109.7%	29.1%	15.0%	$17,192
$50 Underest. (True Ref. Price = $400)	$400	$117	33.5%	0.135	(370)	-0.22%	157.3%	43.7%	26.9%	$19,489
$100 Underest. (True Ref. Price = $450)	$450	$101	52.4%	0.195	(1,599)	-1.08%	247.8%	64.2%	43.3%	$21,701
$150 Underest. (True Ref. Price = $500)	$500	$61	79.6%	0.357	(3,874)	-2.67%	508.4%	86.7%	72.8%	$23,681
$200 Underest. (True Ref. Price = $550)	Model does not converge (Curve 3 Price Cap < True Reference Price)									

Sources and Notes: All MRI curve simulations performed using an Administrative Reference Price of $350/MW-day. The current curve is constructed using an administrative Net CONE estimate based on a dual-fuel CT of $528/MW-day.

C. Performance Sensitivity to Forward Period

We performed an additional sensitivity to evaluate the performance of the three MRI-based VRR curves and the Current Curve considering the potential for changes in the auction forward period, which in turn affects the shape of the supply curves that determine clearing outcomes in the BRA. As explained in Section III.C, shorter forward periods can lead to contractions in the total volume of supply offered in the auction (and at what prices) since new resources may not have sufficient lead-time to respond to price signals. As shown previously in Figure 8, the shape of offered supply curves in auctions with contracted forward periods is steeper than the shape of comparable curves from 3-year forward auctions. This sensitivity is relevant to this Quadrennial Review because both the 2028/29 and 2029/30 Base Residual Auctions are projected to operate under shortened timeframes (23 and 29 months, respectively) as shown in Figure 7. By the end of the review period, the full 3-year forward period should apply.

In this sensitivity, we evaluated the performance of the three MRI-based VRR curves and the Current Curve under base assumptions (a mix of 3-year forward and non-3-year forward period supply curves based on the historical forward periods), in comparison to two sensitivity scenarios: one considering only the flatter 3-year forward supply curves; and the other considering only the steeper non-3-year forward supply curves. Results are shown in Table 6.

We find that the performance of the three candidate MRI-based curves is robust to changes in the supply curve shape. As expected, all three curves perform better in the context of a full 3-year forward auction, in which the flatter supply curves can compensate for supply-demand fluctuations and produce greater stability in both resulting prices and quantity outcomes. With the full three-year forward period, price volatility is lower and reliability is modestly improved. In the non-forward (< 3 years) supply curve sensitivity, all three MRI-based VRR curves perform worse, with higher price volatility and slightly worse reliability than the 0.1 LOLE target (0.11–0.12 loss of load events per year). Overall, the implications for price volatility are substantially greater than the implications for reliability.

Overall, the magnitude of these performance differences are relatively small compared to the other performance sensitivities that we examine. They do suggest that any VRR Curve and RPM will offer better performance under a three-year forward period, particularly in terms of the resulting exposure to price volatility.

TABLE 6: PERFORMANCE OF CANDIDATE CURVES IN FORWARD VERSUS NON-FORWARD AUCTIONS

	Price			Reliability						Cost
	Average Clearing Price	Standard Deviation	Frequency at Cap	Average LOLE	Average Excess (Deficit) Above Reliability Requirement	Average Excess (Deficit) Above Target Reserve Margin	Normalized Portfolio EUE (% of Target)	Frequency Below Reliability Requirement	Frequency Below 99% of Reliability Requirement	Average Procurement Cost
	($/MW-d)	*($/MW-d)*	*(%)*	*(events/yr)*	*(MW)*	*(UCAP RR + X %)*	*(%)*	*(%)*	*(%)*	*($ mln/yr)*
Only 3-Year Forward Supply Curves										
Current Curve	$350	$166	1.9%	0.051	2,588	1.84%	53.0%	5.1%	1.9%	$17,491
Curve 1	$350	$163	2.5%	0.100	299	0.23%	103.5%	36.2%	11.4%	$17,186
Curve 2	$350	$130	9.7%	0.098	448	0.34%	104.3%	29.8%	9.7%	$17,190
Curve 3	$350	$113	16.8%	0.097	591	0.44%	104.5%	26.1%	11.8%	$17,199
All Supply Curves										
Current Curve	$350	$183	2.3%	0.053	2,607	1.86%	54.9%	6.3%	2.3%	$17,491
Curve 1	$350	$178	3.0%	0.100	366	0.28%	106.3%	34.7%	13.3%	$17,188
Curve 2	$350	$141	12.7%	0.100	463	0.35%	108.1%	31.2%	12.7%	$17,189
Curve 3	$350	$122	19.9%	0.100	566	0.43%	109.7%	29.1%	15.0%	$17,192
Only Non-Forward (<3 years) Supply Curves										
Current Curve	$350	$239	6.3%	0.058	2,615	1.87%	62.7%	11.1%	6.3%	$17,471
Curve 1	$350	$227	7.5%	0.106	542	0.42%	118.7%	32.5%	19.4%	$17,176
Curve 2	$350	$171	20.2%	0.112	441	0.35%	127.5%	36.4%	20.2%	$17,157
Curve 3	$350	$145	30.0%	0.116	397	0.32%	134.7%	37.0%	22.9%	$17,143

Sources and Notes: All model runs use true Reference Price and Administrative Reference Price equal to $350/ MW-day UCAP. Auctions prior to the 2022/23 Base Residual Auction were run on a 3-year forward timeframe while all auctions since (including the 2022/23 BRA) have been run on compressed forward schedules. See Section III.C for additional description of the effect of the auction forward period on supply curve shape and Appendix A.4 for additional detail on the processing of supply curves for use in the model.

D. Performance Sensitivity to Higher/Lower Net Supply Variability

The RPM VRR Curve must manage year-to-year variability in net supply in RPM, including the potential for changes to the load forecast, supply entry and exit, FRR participation, and resource accreditations. As discussed further in Appendix A.5, we represent these variations in net supply in the model by calibrating the correlation between supply and demand variability such that the resulting net supply variability matches the historically observed variability in the BRA. Under base assumptions, this net supply variability is equal to 2.8% of the average BRA Reliability Requirement from 2012/13 to 2024/25. However, we also recognize that historically-observed levels of net supply variability may differ in the future. Recognizing the potential for changes in the RPM net supply balance, we performed an additional sensitivity to evaluate the performance of the three MRI-based VRR curves under net supply variability that is 33% larger and 33% smaller than base assumptions. Results are summarized in Table 7.

As expected, reduced net supply variability results in reduced price volatility and improved reliability relative to base assumptions, with the opposite true when net supply variability is increased. In the low net supply variability scenario, all three MRI-based VRR curves achieve reliability better than the 1-in-10 LOLE target, ranging from 0.098 average LOLE for Curve 1, 0.091 for Curve 2, and 0.086 LOLE for Curve 3. In the high net supply variability scenario, reliability is slightly worse than the 1-in-10 target for all three curves, and Curve 1 has average results closest to the 1-in-10 target at 0.108 LOLE, compared to 0.120 for Curve 2, and 0.128 for Curve 3. However, Curve 1 produces the greater price volatility across all scenarios compared to Curve 2 and 3. Similar to the forward/non-forward supply curve sensitivity, these three MRI-based VRR curves limit both over- and under-procurement when net supply variability is out of line with historically observed variability, which indicates robustness to potential future changes in net supply variability.

TABLE 7: PERFORMANCE OF CANDIDATE CURVES WITH DIFFERING NET SUPPLY VARIABILITY

	Price			Reliability						Cost
	Average Clearing Price	Standard Deviation	Frequency at Cap	Average LOLE	Average Excess (Deficit) Above Reliability Requirement	Average Excess (Deficit) Above Target Reserve Margin	Normalized Portfolio EUE (% of Target)	Frequency Below Reliability Requirement	Frequency Below 99% of Reliability Requirement	Average Procurement Cost
	($/MW-d)	*($/MW-d)*	*(%)*	*(events/yr)*	*(MW)*	*(UCAP RR + X %)*	*(%)*	*(%)*	*(%)*	*($ mln/yr)*
Low Variability										
Current Curve	$350	$134	0.5%	0.050	2,577	1.83%	50.9%	2.2%	0.5%	$17,489
Curve 1	$350	$131	1.4%	0.098	243	0.19%	100.1%	38.5%	8.5%	$17,180
Curve 2	$350	$113	5.7%	0.091	523	0.39%	93.0%	27.5%	5.7%	$17,209
Curve 3	$350	$100	11.6%	0.086	762	0.56%	87.8%	21.9%	6.7%	$17,232
Base Variability										
Current Curve	$350	$183	2.3%	0.053	2,607	1.86%	54.9%	6.3%	2.3%	$17,491
Curve 1	$350	$178	3.0%	0.100	366	0.28%	106.3%	34.7%	13.3%	$17,188
Curve 2	$350	$141	12.7%	0.100	463	0.35%	108.1%	31.2%	12.7%	$17,189
Curve 3	$350	$122	19.9%	0.100	566	0.43%	109.7%	29.1%	15.0%	$17,192
High Variability										
Current Curve	$350	$220	5.2%	0.059	2,578	1.84%	64.4%	9.4%	5.2%	$17,468
Curve 1	$350	$212	6.3%	0.108	443	0.35%	121.2%	33.7%	17.2%	$17,172
Curve 2	$350	$160	17.5%	0.120	313	0.26%	140.9%	33.5%	17.5%	$17,141
Curve 3	$350	$136	26.6%	0.128	264	0.23%	155.7%	33.3%	20.9%	$17,124

Sources and Notes: All model runs use true Reference Price and Administrative Reference Price equal to $350/ MW-day UCAP. Net supply variability is set equal to 2.8% in the “Base Variability” scenario, 1.8% in the “Low Variability” scenario and 3.7% in the “High Variability” scenario. For additional description of net supply variability, see Appendix A.5.

E. Summary of MRI-Based Curves' Performance

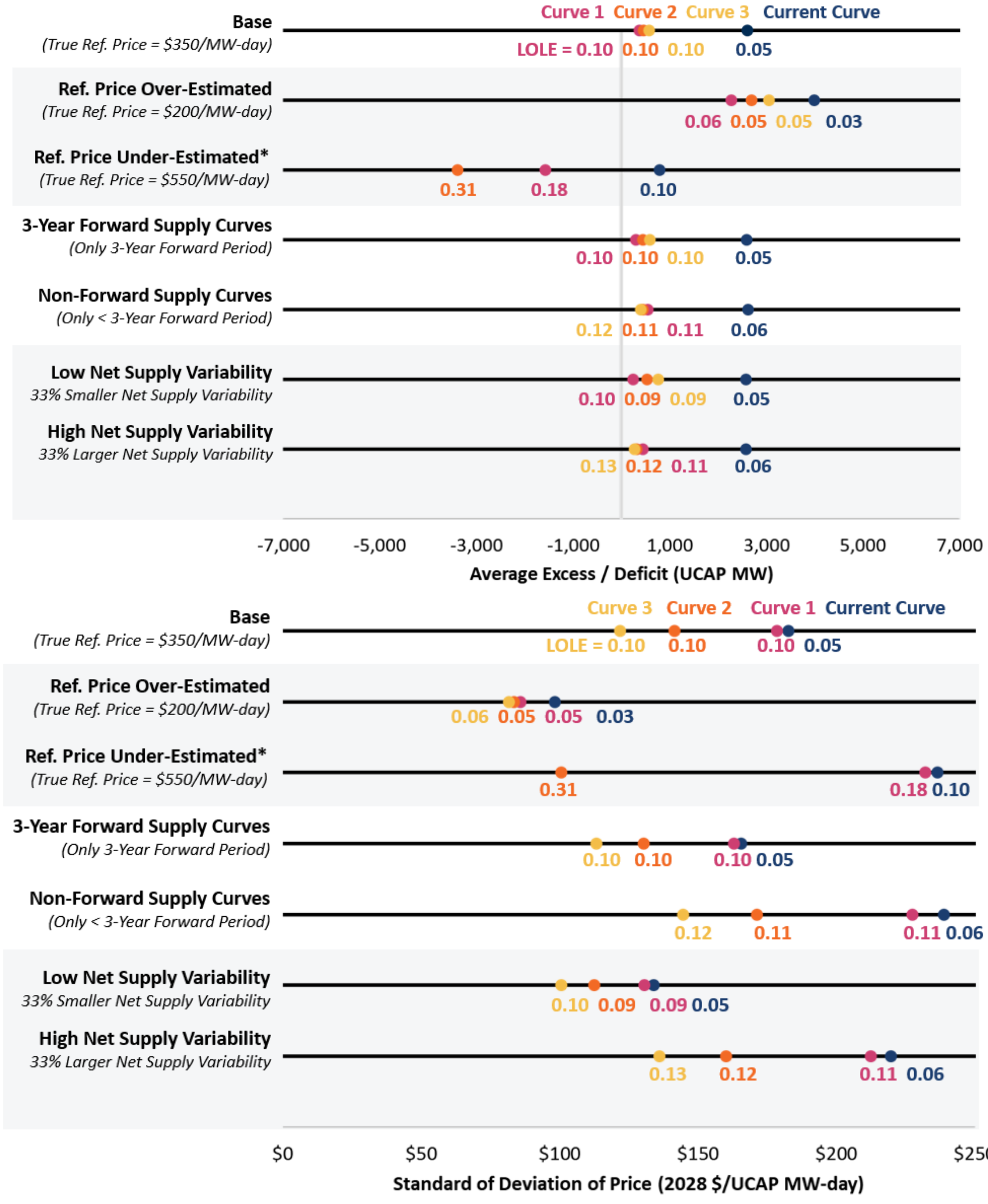
In Figure 18 we summarize the performance of the three MRI-based VRR curves and the Current Curve across base assumptions and sensitivity scenarios. The top panel shows the average excess or deficit cleared quantity for each curve and the bounds of each sensitivity; the bottom panel shows the average price volatility for each curve and the bounds of each sensitivity. We report the LOLE results for each curve in the numbers in the figure with the same colors used for each curve as throughout this report.

The top panel summarizes the scale of quantity procurement, with the Current Curve (blue) over procures relative to the 1-in-10 LOLE target across nearly all scenarios (primarily due to the continued use of a CT-based Net CONE that would be higher than our estimated $350/MW-day reference price). The current curve shows better reliability and higher procurement levels than the other curves for the same reason.

The three MRI-based VRR curves in all produce similar reliability outcomes in most scenario and more frequently procure capacity consistent with the 1-in-10 LOLE target across sensitivities. The most impactful sensitivity is when the Reference Price is under-estimated and the MRI-curves with higher caps procure closer to the 0.1 LOLE (Curve 1, then Curve 2 respectively) and show more robustness to maintain reliability even in the face of under-estimated Reference Price. Curve 3 is the most susceptible to lower reliability outcomes than the other curves, due to the lower price cap.

The bottom panel, we see the implications of each curve's shape and price cap on clearing price volatility. The Current Curve results in the highest price volatility across all sensitivities, while MRI-based curves all offer lower price volatility (with lower price volatility accomplished primarily due to a lower price cap). For that reason Curve 3 performs best, followed by Curve 2 and then Curve 1. This performance sort-order illustrates the direct tradeoff between price stability (accomplished by a lower price cap) and reliability performance, especially in challenging scenarios (accomplished by a higher price cap).

FIGURE 18: COMPARISON OF PERFORMANCE OF CANDIDATE VRR CURVES, AVERAGE EXCESS/DEFICIT (TOP) AND PRICE VOLATILITY (BOTTOM)



Sources and Notes: *Curve 3 results not shown for the scenario where the Reference Price is under estimated by $200/ MW-day UCAP, because the Curve 3 price cap ($525/MW-day UCAP) is lower than the true Net CONE of $550/MW-day in this scenario and the model therefore cannot converge to true Net CONE. Administrative Reference Price = $350/MW-day UCAP for all runs shown above. True Reference Price = $350/MW-day UCAP except for "Reference Price Over-Estimated" and "Reference Price Under-Estimated" sensitivities. Colored numbers show the average LOLE in each run. In base modeling results, both Administrative and True Reference Price = $350/MW-day UCAP; the model uses a mix of 3-year forward and non-3-year forward supply curves, and net supply variability is set to the baseline level of 2.8%.

VI. Managing Acute Tight Supply Conditions

As discussed in the *Brattle 2025 PJM CONE Report*, the PJM region and other power markets are presently facing acute tight supply-demand conditions that may persist into the Planning Years relevant to this Quadrennial Review. In this context, the height of the VRR Curve price cap is a matter of heightened scrutiny and focus, beyond its usual focus as influencing VRR Curve pricing volatility and overall performance. Further, in the event that acute tight supply conditions exceed the scope of conditions that can be productively managed by the price cap, we assess the role of contingency plans to mitigate reliability risks including a possible enhanced PJM Reliability Backstop mechanism.

A. Considerations in Setting the Price Cap

Several factors influence the performance of the VRR Curve and inform the most relevant price cap. The main tradeoff is that a higher price cap provides greater certainty of attracting supply when conditions are tight and reliability needs are most acute; while a lower price cap mitigates customers' exposure to price spikes and exercise of market power.

The price cap in a market that relies on competitive forces to attract new entry needs to be high enough to: manage year-to-year variations in supply and demand conditions; to enable short-term response from resources with higher costs that may enter or exit the market on an annual basis (such as demand response and net imports); and to exceed the long-run marginal cost (i.e., at Net CONE) to support prices at Net CONE in long-run average expectations. As discussed in Section IV, we anticipate that a price cap in the range of 1.5–1.75 × Reference Price is likely sufficient to support RPM reliability objectives on a long-run basis.

Figure 19 summarizes the historical RTO-wide price cap and clearing price, which was set at 1.5 × Net CONE at RPM's inception and has been updated over time. Beginning with the 2017/18 delivery year, the price cap has also been subject to a minimum value at 1 × Gross CONE to prevent the possibility of the VRR curve collapse in the event that the Net CONE parameter would fall to low levels or close to zero. The CONE-based minimum value has only set the RTO price cap once, in the 2025/26 BRA. We note that the need for a CONE-based minimum would be obviated if the Reference Price and price cap are updated in a more simplified fashion based on a single price index, rather than considering the separate components of Gross CONE and E&AS offset of a single Reference Resource that are subject to more year-to-year variability in administrative estimates.

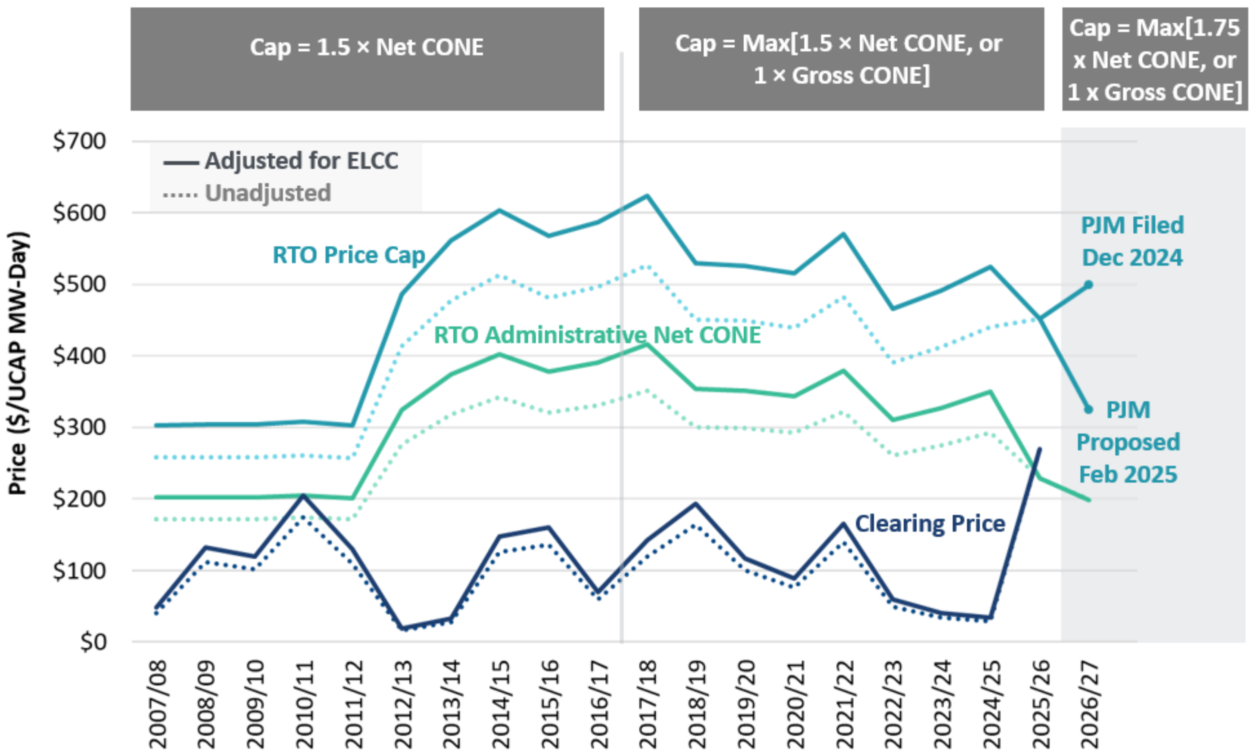
Since the 2012/13 Planning Year, the RTO VRR Curve price cap has been in the range of $450–$625/MW-day in nominal dollars, after adjusting upward by 19% for the years before 2025/26 to account for changes in accreditation affecting the "per-MW" UCAP ratings in the denominator. Over the same period, auction clearing prices have remained far below the caps. In most years, clearing prices have been less than half the administrative estimate of Net CONE, even though the market has attracted approximately 34,000 MW ICAP of new gas combined-cycle units since the 2014/15 auction.[53] These market outcomes have demonstrated the primary role of market forces and competition to keep prices and customer costs low, and the limited role of a price cap in a well-functioning market (i.e., when the price cap is rarely or never binding).

The higher prices observed in the 2025/26 auction and current Net CONE estimates (see the *Brattle 2025 PJM CONE Report*), indicate that market conditions are tighter, the cost of building new supply has increased, and that other barriers to supply could limit entry and result in higher clearing prices in upcoming auctions. These conditions have brought greater focus to the price cap, including through two recent filings by PJM: (1) the FERC-approved filing to retain a CT as the reference resource instead of a CC, thereby lowering the price cap to approximately $500/MW-day but not to change the price cap formula tied to the maximum of 1.75 × Net CONE or 1 × CONE; and (2) a more recent filing (still awaiting FERC response) that would, for a temporary two-year period, further lower the price cap to $325/MW-day alongside raising the price floor from $0 to $175/MW-day.[54] Regardless of whether the second of these filings is eventually approved by the FERC, they both highlight the concern that upcoming auctions are subject to greater risk and have a higher potential to produce prices at the cap than in prior periods since the RPM was implemented.

53 New entry numbers are based on data from 2015/16 to 2023/24 Base Residual Auctions. See PJM, 2023/2024 RPM Base Residual Auction Results, 2022, Table 8.

54 The most recent filing was made in response to a Section 206 complaint filed with the FERC by the Pennsylvania Governor's Office, which expressed concern that prevailing market conditions introduced excess customer risk and cost exposure in the event of a price cap outcome. For change to a CT as the reference resource, see FERC, Order Accepting Tariff Revisions Subject to Condition, Docket No. ER25-682-000, February 14, 2025. For PJM's illustrative estimate of the price cap for the 2026/27 Base Residual Auction using a CT reference resource, see PJM, Affidavit of Walter Graf and Skyler Marzewski on Behalf of PJM Interconnection, L.L.C., Docket No. ER25-682-000. For PJM's proposed cap and floor filing, see PJM, Proposal for Revised Price Cap and Price Floor for the 2026/2027 and 2027/2028 Delivery Years, and Request for a Waiver of the 60-Days' Notice Requirement to Allow for a March 31, 2025 Effective Date, Docket No. No. ER25-1357-000, February 20, 2025.

FIGURE 19: HISTORICAL RPM PRICE CAPS COMPARISON



Sources and Notes: Nominal dollars; Historical price caps from PJM Planning Period Parameters and PJM BRA Results Reports, prices adjusted upward based on difference in Pool-Wide Accredited UCAP Factor between historical year and the 2025/26 BRA; 2026/27 values based on an illustrative 2026/27 RTO VRR Curve with a CT reference resource, from PJM, Affidavit of Walter Graf and Skyler Marzewski on Behalf of PJM Interconnection, L.L.C., Docket No. ER25-682-000. The proposed $325 price cap value comes from PJM's cap and floor filing, see PJM, Proposal for Revised Price Cap and Price Floor for the 2026/2027 and 2027/2028 Delivery Years, and Request for a Waiver of the 60-Days' Notice Requirement to Allow for a March 31, 2025 Effective Date, Docket No. ER25-01357-000, February 20, 2025.

From a consumer perspective, high or increasing prices always pose the potential for imposing an economic burden (even while stimulating demand-side measures), regardless of the underlying reason for those increases. But from an economic and market design perspective, it is important to distinguish price increases associated with market fundamentals from those that may be an artifact of market inefficiencies. In a scenario where prices rise over the coming years due to the underlying economic forces of supply costs and rapid demand growth, then the resulting prices should be interpreted as an economically efficient expression of market conditions. Prices may moderate over time as competitive forces accelerate or the market design evolves, but limiting the price cap at a level that is too low to reflect these economic realities would not be an effective way to avoid cost increases. Instead, it would discourage supply entry and increase exposure to reliability risks.

However, the price cap and high price events should be assessed differently in a scenario where they are the product of barriers to entry relative to need; if they are transitional outcomes associated with rule changes that have not yet been accounted for in suppliers' development plans; or transient shocks to the market. If these factors are driving higher prices or price cap events, then the primary response is to address any identified market barriers. Prevailing market prices may remain high for a period regardless but should revert to lower competitive levels as soon as suppliers have sufficient opportunity to bring their projects forward.

Another consideration is alignment with the price caps in neighboring capacity markets. Other capacity markets' price caps are an indicator of the maximum prices deemed relevant to inform entry and exit decisions in those regions' various regulatory and investment contexts, and indicate the maximum price at which the PJM region may need to compete for capacity imports in the event that multiple regions are tight on capacity. As summarized in Table 8, the price caps employed in other neighboring markets are developed as a multiple of CONE or Net CONE, and range from $524–$631/MW-day (in 2028$ and UCAP terms). The exception is MISO, which has a 4-season market where the maximum price cap can theoretically reach up to 4 × CONE if all four seasons cleared with a shortfall. That is unlikely, however, so the effective cap is closer to 1 × CONE or 2 × CONE on an annualized basis if one or two seasons cleared short, respectively, while the others cleared at a low price).[55] To provide sufficient economic incentives to attract net imports (and avoid net exports) to address any near-term capacity shortfalls, the PJM price cap would need to be in this range.

To the extent that resources' total annual capacity revenues are affected by seasonally higher prices in other markets or differences in UCAP accreditation methods, this would also be accounted for by sellers' assessment of whether to import or export.

[55] The MISO auction is seasonal. The price cap in each season is set at 4 × CONE, meaning that each season would need to clear at the cap to produce an average clearing price equal to 4 × CONE on an annual basis.

TABLE 8: PRICE CAPS IN NEIGHBORING CAPACITY MARKETS
(ESCALATED WITH INFLATION TO 2028$, NOT ADJUSTED FOR UCAP DIFFERENCES)

	Reference Price/ Net CONE *($/MW-Day)*	Gross CONE *($/MW-Day)*	Quantity at Cap *(% of Target)*	Price Cap Formula	Price Cap in 2028$ *($/MW-Day)*
PJM 2025/26 BRA	$246	$486	99%	MAX{Gross CONE, 1.5 × Net CONE}	$486
NYISO	$229	$420	84%	1.5 × Gross CONE	$631
ISO-NE	$328	$513	98%	MAX{Gross CONE, 1.6 × Net CONE}	$524
MISO*	$229	$367	99%	4 × Gross CONE (Applied seasonally)	$1,468
IESO	$353	-	98%	1.5 × Net CONE	$529

Sources and Notes: All prices in 2028$/MW-day UCAP, calculated by adjusting most recent parameter year available for other markets by annual inflation and using neighboring markets' UCAP ratings (which could result in higher UCAP MW quantity ratings than PJM's updated accreditation methodology); PJM Net CONE and CONE from the 2025/26 Planning Year, adjusted to 2028$ using forecast inflation, Gross CONE is the binding parameter that sets the price cap; NYISO Net CONE and CONE values adjusted from $/ICAP kW-Year using published ICAP to UCAP Reference Point Translation Factor and applicable unit conversions; ISO-NE values in raw data assumed in ICAP MW and converted to UCAP MW using ISO-NE average EFORd; *MISO cap is based on 4 × CONE, but applied seasonally (i.e. to produce a 4 × CONE cap on an annual basis, all four seasons would need to clear at the price cap); MISO Net CONE and CONE reflect simple average of the Net CONE and CONE values per LRZ, assumed to be UCAP MW; IESO quantity at price cap includes contracted capacity; PJM, 2025/26 Planning Period Parameters for Base Residual Auction; ISO-NE, FCA 18 Demand Curve Values; ISO-NE, Market Rule 1—Section 13; MISO, MISO CONE and Net CONE Calculation for Planning Year 2025/2026; 187 FERC ¶ 61,202, Order Accepting Tariff Revisions, re Midcontinent Independent System Operator, Inc. proposed Reliability Based Demand Curves, June 27, 2024, Docket Nos. ER23-2977-000, ER23-2977-001, and ER23-2977-002; IESO, Capacity Auction: Pre-Auction Report; IESO, 2024 Annual Planning Outlook Report, Thompson and Spees, IESO Capacity Auction Reference Price and Maximum Auction Clearing Price Updates; Bank of Canada, Annual Exchange Rates; NYISO, Annual Update for 2024-2025 ICAP Demand Curves; NYISO, ICAP Demand Curve; NYISO, ICAP/UCAP Translation of Demand Curve.

Table 9 compares the range of RTO-wide price caps that may be considered based on our long-term simulation modeling, neighboring markets' caps, and relative to a $350/MW-day Reference Price. These indicators suggest a price cap consistent with Curve 2 or Curve 3 would be sufficient to support reliability under long-run equilibrium conditions, when competitive forces can be expected to mobilize entry. However, these indicators provide an incomplete picture on the role and implications of a price cap in the event that of acute tight supply conditions prevent or severely limit the pace at which new entrants can respond to high prices.

TABLE 9: CONSIDERATIONS INFORMING THE PRICE CAP ($/MW-DAY UCAP)

Consideration	Cap Range	Suggests Price Cap:
Historical PJM Price Cap	**$450-$625** (Nominal dollars, adjusted for ELCC)	• Historical price cap range has been sufficient to maintain supply-side interest in new developments (except in most recent 2025/26 BRA, when other factors limited participation)
Proposed Temporary Cap	**$325**	• PJM proposal filed with FERC (pending approval) to temporarily reduce price cap and mitigate customer exposure to price cap events under near-term tight supply conditions. Paired with price floor at $175 to maintain supplier interest
Neighboring Markets' Price Caps	**$524-$631** (2028$)	• Price cap high enough to align with neighboring capacity markets would be needed to compete for net imports when multiple regions are tight
Simulation Modeling	**150% - 191% × Reference Price** @ $350 Reference Price, cap would be $605 for Curve 2, or $525 for Curve 3	• Curve 2: Cap at 168%-191% × Reference Price supports 0.1 LOLE under long-run equilibrium conditions if price cap quantity is at 99% of reliability requirement • Curve 3: Lower cap at 150% × Reference Price would be right-shifted at minimum quantity

Table 10 below illustrates the maximum 1-year cost exposure that customers could face in an RTO-wide price cap event, compared to prices that would be expected on a long-run average basis (at an assumed $350/MW-day Reference Price). The table is a conceptual extreme in that it assumes that no customers are hedged against year-to-year capacity price spikes. Customers in regions with regulated planning are not heavily exposed to these prices, while customers in other states have a partial hedge on capacity prices through a combination of state contracts and standard offer service auctions. However, a subset of customers, particularly in retail choice states, are substantially exposed to these prices. Limiting the extent of customers' potential exposure to price cap outcomes is the primary reason to consider a price cap at the lower end of the potentially workable range.

TABLE 10: MAXIMUM 1-YEAR CUSTOMER COST EXPOSURE IN CAPACITY PRICE CAP EVENTS (ASSUMES NO CUSTOMERS ARE HEDGED AGAINST CAPACITY PRICES)

	Curve Parameters			Customer Costs		
	Price @ Cap	Quantity @ Cap	Quantity @ Cap (for Maximum Cost Exposure)	Expected Avg. Customer Cost @ $350	Maximum Cost Exposure @ Cap	Ratio of Maximum to Average Cost Exposure
	($/MW-day) [1]	*(% of Reliability Req.)* [2]	*(MW)* [3]	*($ mln/yr)* [4]	*($ mln/yr)* [5]: [1] x [3]	*(%)* [6]: [5] / [4]
Current Curve	$924	99.0%	132,228	$17,491	$44,595	255%
Curve 1	$890	97.8%	130,562	$17,188	$42,413	247%
Curve 2	$605	99.0%	132,228	$17,189	$29,199	170%
Curve 3	$525	99.6%	133,069	$17,192	$25,499	148%

Sources and Notes: [1]: Price cap for each curve, expressed in $/MW-day UCAP; [2]: Price cap quantity, expressed as a percent of the Reliability Requirement; [3]: Equal to the baseline simulated Reliability Requirement (133,564 MW) x [2]; [4]: Expected average customer cost under baseline modeling assumptions (i.e., True Reference Price equal to baseline value of $350/MW-day UCAP for all curves); [5]: [1] × [3], with additional unit conversions; [6]: [5] / [4].

B. Implications of Transient Acute Tight Supply Conditions

As discussed more fully in the *Brattle 2025 PJM CONE Report*, the PJM region presently faces a material risk that the RTO or some LDAs could face acute supply tightness over the coming auctions. Near-term accessible new gas-fired capacity may be insufficient to meet the projection of 31,600 MW of demand growth forecast by 2030, plus up to 18,000 MW of potential retirements by 2030 as previously forecasted by PJM.[56] These supply needs can be at least partially met by a combination of near-term competitive response (e.g., uprates, demand response, net capacity imports, and thermal life extensions) and market reforms (e.g., reforms to capacity must offer rules, treatment of reliability must run (RMR) supply, and accelerated interconnections for some resources under the Reliability Resource Initiative (RRI)).[57] However, there remains a substantial risk that demand growth outpaces net increases in supply, considering potential for limited supply of gas turbines (available only at a pricing premium) and

[56] PJM forecasts approximately 31,600 MW of RTO summer peak demand growth between 2024 and 2030. See PJM, 2025 PJM Long-Term Load Forecast Report, January 24, 2025, Table B-1 . The retirement projection shows the projected retirements from 2025 through 2030 (inclusive) and comes from the February 2023 Energy Transition in PJM Report, see PJM, Energy Transition in PJM: Resource Retirements, Replacements & Risks, February 24, 2023, p. 5.

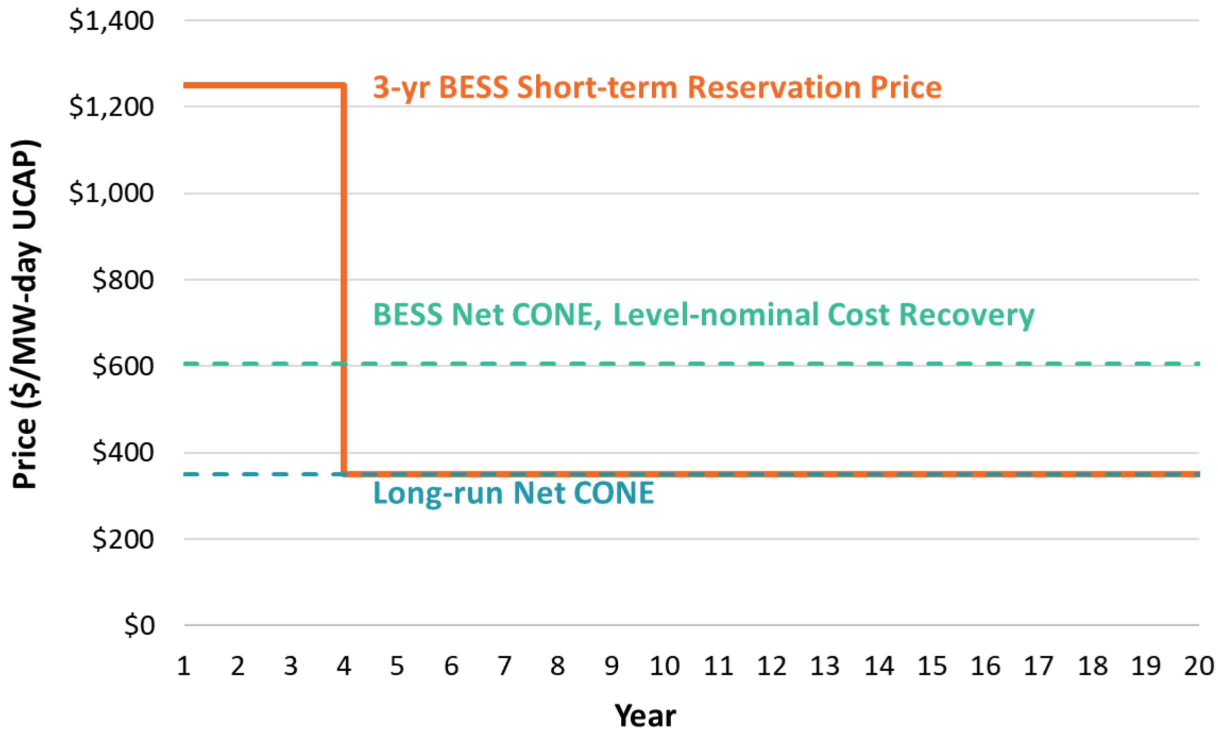
[57] For must-offer requirement, see FERC, Order Accepted Tariff Revisions, Docket No. ER25-785-000, February 20, 2025; For treatment of RMR supply, see PJM, FERC Approves PJM Capacity Market Design Changes To Support Reliability, Affordability, February 20, 2025; For the RRI, see PJM, Reliability Resource Initiative Draws 94 Applications, March 21, 2025 and Howland, PJM fast-track interconnection process draws 26.6 GW in proposals, March 27, 2025.

longer timeframes required for resource interconnection processes and construction than have been required in the past. BESS resources may be possible to develop more quickly than gas plants to meet demand growth, but our analysis suggests they will be available only at a cost premium compared to the long-run Reference Price.

The role of the RPM price cap may be critical in the upcoming years if the market faces acute tight supply conditions. In the most extreme version of an acute tight supply scenario, with absolute barriers to supply entry, new capacity supply would not be possible to build regardless of the capacity market clearing price. In that scenario, the price cap should remain high enough to maximize response from short-term resources (life extensions, uprates, demand response, net imports) and to motivate investment in new resources as soon as barriers are resolved. However, prices above that level would be ineffectual to address near-term reliability shortfalls. If there is no ability for market response to these price signals, then further increases to the price cap would only serve to produce transfer payments from customers to incumbent generators for several years, likely beyond what they could reasonably have expected or counted on when they invested. If the acute tight conditions prevail for multiple consecutive years, then the size of the customer cost exposure and associated transfer payments would be similarly extended.

A slightly moderated and more realistic scenario is one where supply-demand conditions are tight, but there remains at least some capability for the market respond, albeit at prices that may be substantially higher than the long-run marginal cost of supply. The implications for the BRA price cap in this scenario are informed by the conceptual exercise illustrated in the following Figure 20. We examine a scenario in which market participants correctly predict that capacity market prices will be set at $350/MW-day over the long run in line with the expected long-run marginal cost of supply ("Long-run Net CONE"). We further assume that for a short-term period of 3 years, it will not be possible to develop new gas-fired plants, and so capacity prices will be either set at the price cap or must rise high enough to attract BESS that can be built more quickly. The BESS resources would be attracted to enter at a capacity price of $629/MW-day UCAP if they expect to earn that same price over the entire 20-year asset life of the project ("BESS Net CONE, Level-nominal Cost Recovery"). However, the same BESS resource will require a much higher price of $1,329/MW-day UCAP in the first three years ("3-yr BESS Short-term Reservation Price") if future prices will return to the lower long-run price of $350/MW-day UCAP over years 4–20 of the asset life after substantial volumes of new supply is able to come online (and assuming net E&AS offsets remain constant at current forward estimates, in nominal terms).

FIGURE 20: ILLUSTRATION OF SHORT-TERM RESERVATION PRICE NEEDED TO ATTRACT ENTRY FROM HIGHER-COST BESS IF FACED WITH 3 YEARS OF HIGH PRICES FOLLOWED BY LOW PRICES ALIGNED WITH LONG-RUN MARGINAL COST OF SUPPLY ($350/MW-DAY) FOR REMAINING ASSET LIFE



Sources and Notes: *Brattle 2025 PJM CONE Report*.

In other words, a price cap in the range of $1,300/MW-day (and an expectation that prices will remain at the price cap for at least three years running) could be required to attract higher-cost and shorter-lead BESS resources to enter the market if they are only able to secure high prices under one-year commitments and expect that future revenues will be undercut by lower-cost supply entry in the long term. Such a high price cap is outside the bounds of what can be considered a reasonable balance of VRR curve objectives, considering that it would: (a) be many multiples higher than needed to attract supply over the longer-term; and (b) expose customers to the potential for extreme pricing shocks.

If the price cap is maintained in the range of the 1.5–1.75 × Reference Price that we recommend and that is consistent with what is needed to support reliability on a long-run basis, the outcome in this scenario is that prices would clear at the price cap and that the BESS resources would not be developed under the one-year pricing commitments available. The market would then face a shortfall in supply relative to the reliability requirement for a temporary period, unless a backstop mechanism or out-of-market contracts were deployed to address the shortfall. Prices would still be high enough to elicit other short-term response and motivate gas-fired plants to develop as quickly as possible, until reliability would be restored and new entrants would compete prices down to the long-run marginal cost of supply.

These scenarios illustrate a more general point about the role and limitations of a capacity market structured around one-year commitments. Annual capacity auctions reflect near-term market conditions and create opportunities for customers to access competitive pricing. The value proposition for customers is greatest when new, innovative players can enter the market with creative solutions that undercut the cost of incumbents. The biggest drawback of competitive markets that rely on merchant investors for a portion of supply entry is that customers can be exposed to the extremes of market conditions, particularly for any classes of customers that are not at least partially protected by longer-term supply commitments or retail pricing hedges.

C. Contingency Plan for Shortfalls

A well-functioning capacity market ideally produces few clearing results at the price cap and rarely or never relies on a reliability backstop or any out-of-market actions to ensure reliability. However, under expected near-term market conditions, we anticipate a material risk that a price cap aligned with long-term reliability needs may be insufficient meet reliability requirements for a temporary period until supply-demand conditions moderate. Modest increases to the capacity price cap would not be an effective means to fully mitigate this risk, as discussed above.

We therefore recommend that PJM and state agencies jointly review what to do in the event of a substantial shortfall. They may consider a combination of temporarily accepting some degree of lower reliability, other mechanisms to mitigate reliability risks, and/or reviews of the causes and necessary adjustments.

The RPM already incorporates a Reliability Backstop mechanism to address such situations, although it has never been triggered and has been a lesser focus in prior VRR Curve Reviews (other than as an indicator for the appropriate minimum quantity of the VRR Curve). Under the current Reliability Backstop mechanism, if any BRA clears below the reliability backstop threshold (99% of the system Reliability Requirement) on a system-wide basis, this triggers an investigation to review the reasons for the shortfall and to potentially recommend corrective actions to address it (e.g. addressing barriers to entry or increasing VRR curve pricing parameters). If the RPM clears below the 99% threshold on an RTO-wide basis for three consecutive BRAs, this would trigger a Reliability Backstop Auction where seller offers are solicited for a 6-month bid window, sellers compete on price, and they can receive terms of up to 15-years to provide new capacity.[58] Currently the backstop mechanism provisions apply only on an RTO-wide basis; it is not triggered if an individual LDA is short.

The current Reliability Backstop mechanism has the following limitations for addressing anticipated acute supply challenges:

- The backstop is not triggered by shortages that may affect individual LDAs but that do not affect the entire RTO. This leaves a gap in which specific LDAs may be affected by supply barriers or unanticipated high supply costs, and that an immediate investigation or other backstop response may not be automatically triggered to address the problem;
- The Backstop Procurement is not triggered until a shortfall is observed for three consecutive years, meaning that the region would face at least two (and probably more) years of shortfalls before the needed supply would be brought forward under the backstop;
- The compressed forward period of upcoming BRAs, when combined 6-month timeline to solicit bids under the Backstop Procurement Auctions, is long enough that it would be unlikely for any winning resources to be able to reach online status for the relevant delivery period; and
- The procurement and payment structure of the Backstop Procurement is somewhat ambiguously specified and may result in higher-cost procurements that the minimum that might be required to fill the reliability gap under an all-source competitive auction for capacity-only commitments at the lowest possible price and term.[59]

With respect to the first role of the Reliability Backstop of triggering an investigative review, we recommend to expand its applicability to include LDAs. On an LDA-specific basis, the trigger for an investigation would be any price cap event (which may correspond with a volume in the range of 95%-99% of the LDA Reliability Requirement, as discussed further in Section VII.A below). For both RTO-wide and LDA shortage events, it is important to diagnose the causes of the event so that PJM and state agencies can take appropriate actions, which will likely fall into one of the following three categories:

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[58] There are other triggering conditions as well, see PJM, 2022 OATT, Attachment DD, Section 16.

[59] The Tariff description leaves room for interpretation and judgement but implies that the contracts could be awarded under bundled contract structures (inclusive of energy and ancillary revenues) that would make it more challenging to determine the offers with the lowest net cost compared to a capacity-only payment structure. As another ambiguity, the Tariff references a contractual term of up to 15 years (to be specified by the seller) but does not specify how different offer terms would be considered in selecting winning offers.

- **Design flaw or barrier to entry.** If the reason for a price-cap and shortfall event is that there is a market design flaw or a barrier to competitive market entry, then these issues should be addressed directly either through PJM rule changes (or by providing state agencies or other entities the information needed to address permitting or other challenges that may exist outside the scope of PJM markets).
- **VRR curve pricing parameters lower than the incremental cost of supply.** If the reason for a price cap event is that the cost of incremental supply is above the prices supported in the RPM construct, then an accelerated adjustment to increase the price cap or Reference Price is required to attract entry.
- **Shifts to market fundamentals**. In some cases, the cause of a price cap event may have been a large contraction to supply (e.g. a large resource exiting, a large increase to local demand). If that shift is very large compared to LDA size or came as a surprise, then there may simple have been insufficient anticipation by the market to predict high prices and propose alternative projects. In these cases, no rule change or pricing adjustment may be needed to attract supply interest to address the shortfall in subsequent RPM auctions.

With respect to the more impactful aspect of the Reliability Backstop mechanism associated with Backstop Procurements, our recommendations are more limited. Our primary recommendation is that PJM and state agencies should consider whether the current Reliability Backstop mechanism offers sufficient protections in the present market context, considering the possibility that acute supply conditions may affect one or more upcoming auctions and that modest adjustments to the price cap would not be an effective means to limit the associated reliability risks. While a comprehensive redesign of the Reliability Backstop mechanism is out of the scope of the Quadrennial Review process, we offer high-level thoughts on aspects of the mechanism that could be adjusted. These or other adjustments to the backstop should be developed with the understanding that the BRA auctions are the primary means of signalling the need for new capacity entry, such that the trigger of the backstop is understood to indicate the presence of a design deficiency or barrier to entry that should be separately and directly addressed.

Design components of an enhanced Backstop Procurement mechanism that could be considered may include:

- **Reliability Threshold Triggering a Procurement:** We would recommend that any backstop procurement would be applied only at or below the quantity at which the RTO or VRR curves reach the price cap (99% of Requirement system-wide, but a lower 95-99% of Requirement in the LDAs). Setting the Backstop Procurement volume at a lower volume would indicate more tolerance to absorb modest reliability shortfalls, which is likely justified considering that market response or investigative review may be sufficient to address most shortfall events (particularly those that are associated with surprises or short-term market variations).

- **Consecutive Years Requirement:** We recommend that states and PJM review the appropriateness of triggering the Backstop Procurements only after three consecutive years of shortfall if that creates unacceptable reliability exposures. One option would be to trigger a Backstop Procurement in any year the clears short of some defined minimum acceptable reserve margin.
- **Procurement Volume**: If a Backstop Procurement is conducted, we would recommend that it procure only up to the minimum acceptable reliability level, which should be at or below the quantity of the RTO or LDA price cap. This would retain the role of the BRA and VRR curve to reflect the willingness to pay for in-market capacity supply up to the price cap and revert to backstop procurements only in the event that in-market signals are insufficient. The result of the procurement is then to support reliability at a minimum level, without introducing excess volumes that may undermine BRA and VRR-based pricing signals in future years.
- **Product and Term:** If a one-year term at the price cap is insufficient to attract supply, one option would be to procure incremental supply under a 2 to 15-year commitment (with a goal to secure commitments under both the lowest price and shortest term to minimize the total magnitude of financial commitments). To limit the total size of financial commitments produced, the commitments would be structured as capacity-only payments for a specified volume of UCAP supply, leaving the capacity seller to retain risks associated with capacity ratings, energy market risks, and ancillary service market risks.
- **Format of Competitive Procurement**: Structuring any backstop procurement to prioritize both lower price and shorter term could incentivize sellers to offer at the lowest price and term (i.e. a uniform clearing price and term). One way to structure the clearing would be to select resources based on price at any prices up to the cap (normal BRA clearing), or based on the shortest term for incremental resources offering supply at the price cap.
- **Sellers Eligible for Multi-year Commitments**: Eligibility would likely be limited to new resources and existing resources that demonstrate costs commensurate with the offered price and term, subject to expanded monitoring and mitigation to address market power, including the possibility that even new resources may be in a position to exercise market power in very tight market conditions or LDAs with limited supply options. Solutions to address these circumstances may differ from the approaches to reviewing supplier offer costs that are effective in the BRA auctions.
- **Other capacity sellers**: Earn 1-year commitment at the price cap (same as today).

We caveat these options by noting that relying frequently or extensively on backstop procurements would indicate that in-market incentives for new supply entry are inadequate, signalling that there is likely a deficiency in the market design or barrier to entry that should be addressed. The above-market costs associated with any such procurements would ultimately be allocated to consumers of the affected regions over the duration of the commitments (even to customers who have hedged), another reason to limit the size and scale of any such backstops.

VII. Implementation Considerations for MRI-Based VRR Curves

The MRI-based approach to setting VRR Curves on a system-wide basis can be adapted for use in each of the LDAs, as well as in a sub-annual RPM construct. Consistent with the rationale for our recommendation to adopt a system-wide MRI-based VRR curve, applying MRI-based curves in the LDAs and within a sub-annual market construct has the potential to enhance economic efficiency and send price signals that reflect the marginal value of incremental capacity, tailored to specific locations and each sub-annual period.

A. Locational VRR Curves Based on Marginal Reliability Impact

To accompany the system-wide MRI-based VRR curve, we recommend PJM implement MRI-based curves in the LDAs. We recommend implementing MRI-based curves at the LDA level for similar reasons as we recommend MRI-based VRR curves in the system. This will provide consistent price signals to consumers that reflect a rationalized expression of the value of reliability at different reserve margins for different locations on the system. We describe here two options for how to construct MRI-based local curves:

- **Option 1: Additive LDA MRI-based Curves** (Long-Term Recommendation). The first option matches the approach used by ISO-NE, wherein the local clearing prices in each LDA are interpreted as additive to the system price.[60] Additive MRI-based LDA curves employ the same scaling factor for both the system and LDA curves, which ensures a consistent willingness to pay for reliability value of all resources, regardless of their location. This approach as a strong conceptual basis and hence is our recommended approach over the long term for PJM; but would require more time to implement considering that the RPM auction clearing engine would need to be updated.
- **Option 2: Non-additive LDA MRI-based Curves** (Recommended for Initial MRI Curve Implementation). The second approach is non-additive and is more similar to the approach currently used currently in PJM and by MISO in its locational MRI-based curves. Under this methodology, separate MRI-based curves are developed for the LDAs and the system, each

[60] 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.

of which uses its own scaling factor to ensure that the curve passes through a consistent Anchor Point for each LDA.[61] Under this methodology, the local MRI-curve is binding only when import limits bind and cause LDA price separation above the system price (same auction clearing mechanism that PJM uses today).

As we explain further below, we recommend PJM adopt the non-additive approach (Option 2) alongside implementation of a system-wide MRI-based curve in the 2028/29 auction due to its relative ease of implementation. However, over the long term, we recommend PJM consider transitioning to the additive approach (Option 1), alongside the transition to a sub-annual capacity auction.[62]

OPTION 1: ADDITIVE LDA MRI-BASED CURVES (LONG-TERM RECOMMENDATION)

The additive MRI-based curves approach maintains consistent willingness to pay for reliability value across all resources by using a single scaling factor to translate the MRI curves in each location, including the system, from units of reliability into units of price ($/MW-day UCAP). This approach follows the method used by ISO-NE to calculate locational demand curves in their capacity market.[63] While the system-wide MRI curve reflects avoided EUE from reduced system-wide shortfall events, the LDA MRI curves reflect the additional avoided EUE associated with locating capacity in a particular LDA, rather than locating that capacity elsewhere in the unconstrained system. Under this approach, an LDA would clear at a higher price to the extent that there is additional reliability value for a resource being built within a specific import-constrained LDA. The difference in reliability value by location is driven by transmission constraints between LDAs and the system, since local capacity may be able to serve internal demand that a resource outside the LDA would not be able to serve.

Figure 21 illustrates the additive nature of the resulting price formation that would be created by the system-wide MRI curve (reflecting system-wide reliability value), plus the LDA-specific MRI curve (reflecting the additional reliability value created by locating supply within a constrained area).

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[61] MISO, Business Practices Manual No. 011: Resource Adequacy, February 21, 2025, pp. 207–213.

[62] The additive approach is particularly amenable to seasonal capacity markets as one can retain the same willingness to pay for reliability across seasons and locations. Additionally, the auction optimization process is simplified when the willingness to pay is consistent across seasons and locations, which could facilitate the implementation of a seasonal market.

[63] 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.

FIGURE 21: ADDITIVE LDA MRI-BASED CURVE METHODOLOGY (OPTION 1)

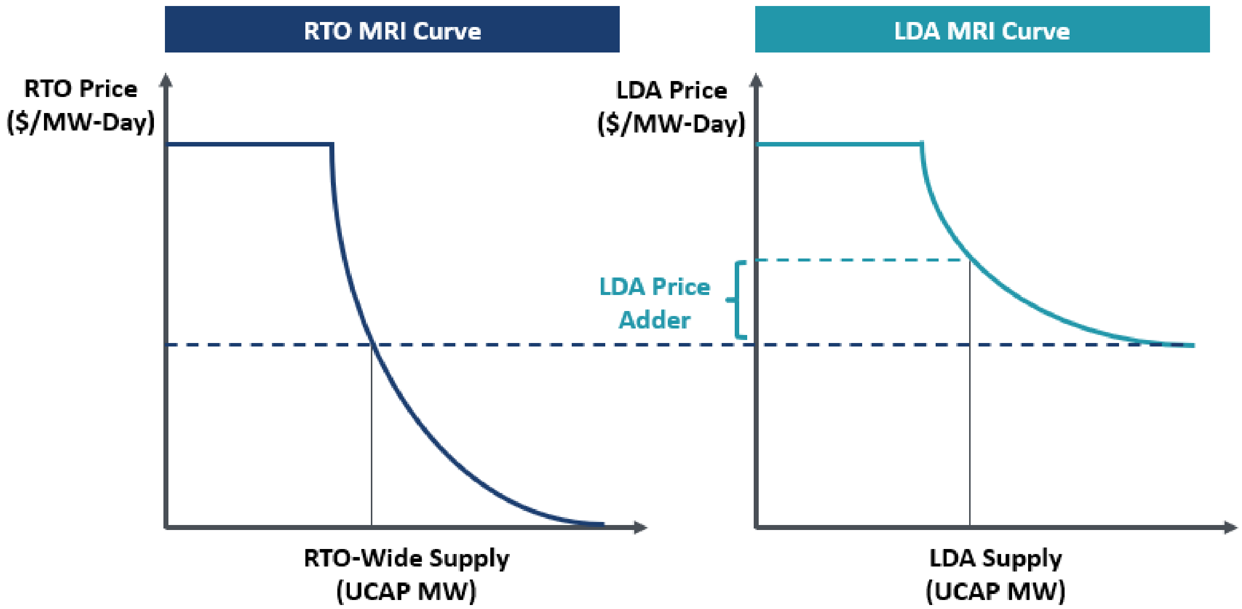


Table 11 provides more detail on the steps used to calculate additive MRI-based curves (adapted somewhat from the ISO-NE approach to align with PJM's current LDA reliability modeling approach).

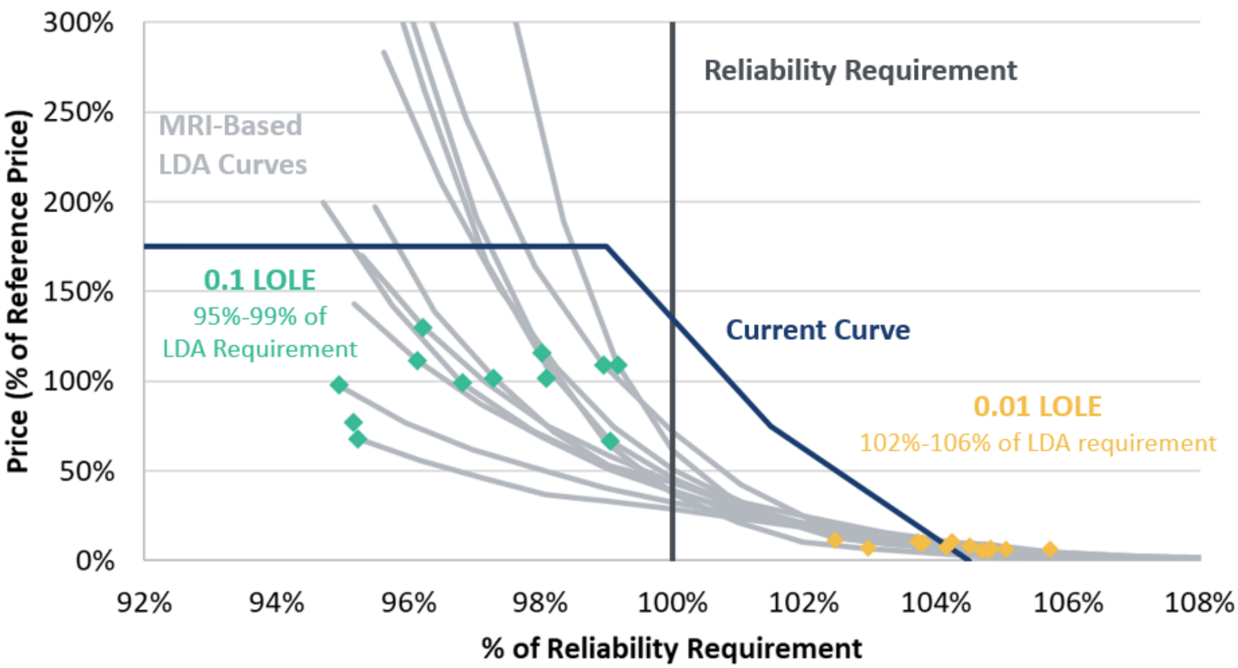
TABLE 11: STEPS TO CALCULATE ADDITIVE LDA MRI CURVES

Step 1: Set the system-wide reliability target using the 0.1 Annual LOLE in each region using the system-wide reliability model, and establish the RTO-wide "scaling factor" for the system-wide MRI-based VRR Curve
Step 2: Establish the RTO-wide "scaling factor" as aligned with the system-wide MRI-based VRR Curve
Step 3: For each LDA, similarly calculate the location-specific MRI curves across varying reserve margins by adding or subtracting capacity from that location. The EUE events considered in the LDA MRI curve should only capture the *additional* reliability value accomplished by locating capacity within the LDA beyond what is achieved by locating the capacity within the parent LDA or broader RTO system[64]
Step 4: Calculate the LDA MRI-based demand curves by multiplying the LDA MRI curve by the system-wide scaling factor

[64] In the versions of the LDA MRI curves presented here, the reliability results have not been adjusted to ensure that only the additional reliability value is reflected. After making this adjustment, the resulting MRI-based curves would produce a somewhat lower price than shown in the following figure.

Following this approach, each LDA would have an MRI curve aligned with local reliability modeling data for that specific LDA, but reflecting a uniform value of reliability across the footprint. Figure 22 provides an illustration of additive MRI curves for each LDA in gray compared to the current VRR curve that may result from this approach. The resulting curves are substantially lower and left-shifted compared to the current VRR Curve, though this comparison does not mean that prices would necessarily be lower in total considering that the local plus parent or RTO curves together would affect the local clearing price. The additive LDA curves approach would produce substantially more stabilized price formation in the LDAs, considering that a modest LDA pricing premium would be realized even if the in-LDA supply is relatively high, and the much flatter slope of the LDA MRI curves would more gradually introduce locational price premiums.

FIGURE 22: ADDITIVE MRI-BASED CURVES FOR PJM LDAS
(OPTION 1, RECOMMENDED FOR LONG-TERM IMPLEMENTATION)



Sources and Notes: Indicative curves constructed based on LDA reliability modeling data provided by PJM staff.

The additive LDA MRI curve approach could offer efficiency benefits by producing a standardized willingness to pay for all units of reliability in the auction, accounting both for system-wide and local reliability value. Moreover, the additive approach will align well with the implementation of a seasonal market as discussed further in Section VII.B.

However, several challenges would be presented with implementing this additive MRI concept on an LDA-specific basis. If PJM were to implement this approach, the consequence would be to transition away from the current concept of a Net CONE-based approach to managing reliability needs in each location (i.e. with the height of LDA VRR Curves tied to the locationally-adjusted long-run marginal cost of supply) and toward a different approach that relies more centrally on placing a uniform value on reliability across the footprint. Since the revised LDA VRR Curves would no longer be tied to a location-specific Net CONE as the primary determinant of pricing parameters, the result would be that locations with a much higher cost of supply may absorb poorer reliability before prices could rise high enough to attract local supply investment.

The RPM clearing approach would also need to be updated to implement an additive MRI curves approach. Hence, we recommend that PJM implement non-additive LDA MRI-based curves for the 2028/29 BRA (which would not require revisions to the clearing approaches) but consider eventually transitioning to the additive approach alongside implementation of a potential sub-annual market.

OPTION 2: NON-ADDITIVE LDA MRI-BASED CURVES (RECOMMENDED FOR INITIAL MRI CURVE IMPLEMENTATION)

To remain more closely aligned with the current LDA VRR Curves and current auction clearing approaches, non-additive LDA MRI curves can be used. Under this approach, locational price separation would continue to occur as they do today (when capacity import limits bind). In considering how to adapt an MRI-based curve concept to the LDAs, we considered three sub-options as illustrated in Figure 23 below. Each of these curve options is constructed using a distinct scaling factor for each LDA.

Variations of the approach that we considered include:

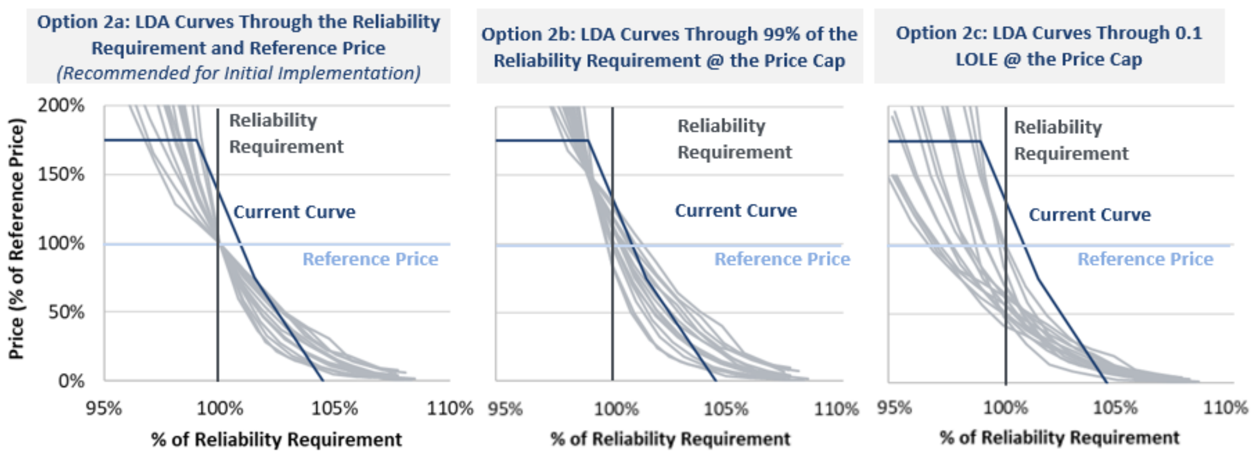
- **Option 2a (Recommended)** is constructed such that the curve passes through the Reliability Requirement at the LDA-Specific Reference Price for each LDA. Option 2a curves (like all MRI-based curves that we considered) are flatter than the current VRR curve, which would tend to reduce price volatility in the LDAs over the long run. Although these curves intersect the price cap at approximately 96%–99% of the local Reliability Requirements, the additive reliability events at the price cap remain fewer than 0.1 LOLE events in each curve. This indicates that a somewhat lower volume of supply can be absorbed in the LDAs before excess reliability risks are introduced, and thus justifies intersecting with the price cap at a lower percentage of the LDA Reliability Requirement. In the low-price and high-quantity region of this curve, the LDA MRI curves are flatter and have a wider foot compared to the Current VRR Curve. However, unlike in the additive MRI curves approach described above, this portion of the LDA curves is unlikely to materially affect auction clearing outcomes (considering that parent LDA and RTO prices would infrequently be low enough that this portion of the LDA demand curve would be relevant in setting prices).

- **Option 2b** was another option that we considered for an LDA MRI-based curve, and is constructed such that each curve intersects the price cap at 99% of each LDA's Reliability Requirement. The logic of this curve would be to align with a concept in which the priority is to align with the LDA Reliability Requirement and rarely fall below 99% of that Requirement (i.e., using 99% as the equivalent of a "minimum acceptable" reliability threshold that should not be violated for economic reasons). Option 2b curves are right-shifted relative to Option 2a, and would be more likely to produce outcomes above the LDA Reliability Requirement. However, these curves are less grounded in economic logic than the system-level version of the curves defined by 99% of Requirement, since the cap tied to 99% of the LDA Reliability Requirement does not necessarily map to similar reliability levels at the price cap for each LDA. On balance, we view Option 2a as a more attractive approach that would allow LDA prices to reach the cap more gradually in most LDAs and at a pace that is more aligned with reliability risks.
- **Option 2c** is set such that each curve intersects the price cap at the quantity corresponding to a 0.1 LOLE.[65] Option 2c curves are similar to Option 2a but are more left-shifted and could absorb a more substantial shortfall compared to the LDA Reliability Requirement. This approach has some conceptual appeal if 0.1 LDA LOLE were treated as a minimum acceptable level of LDA reliability risk. However, the 2c curves are misaligned with the LDA Reliability Requirement, considering that they would produce pricing below the LDA Reference Price at the LDA Reliability Requirement.

Considering the tradeoffs amongst these options, we recommend PJM adopt Option 2a curves in the LDAs for the 2028/29 BRA alongside the system-wide MRI-based curve, and eventually evaluate the potential to transition to additive curves in the future.

65 The price cap value is shown at 1.5 × Reference Price in Figure 23.

FIGURE 23: NON-ADDITIVE LDA MRI CURVE VARIATIONS (OPTIONS 2A, 2B & 2C)

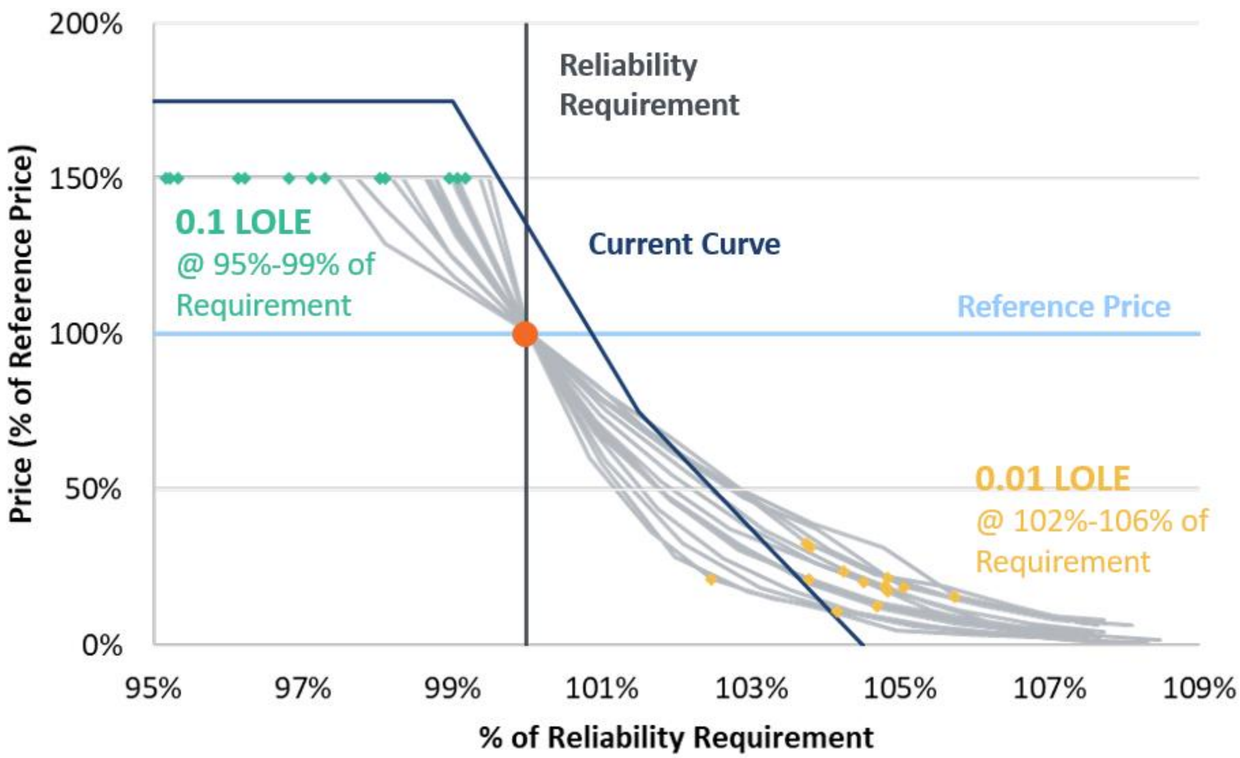


Sources and Notes: For each MRI curve option, all LDAs have distinct scaling factors. For option 2a, the scaling factors are calculated such that the curves go through the Reliability Requirement at the Reference Price. For option 2b, the scaling factors are calculated such that the curves pass through the price cap at 99% of the Reliability Requirement. For option 2c, the scaling factors are calculated such that the curves pass through the price cap at the quantity associated with 0.1 local LOLE. The price cap is assumed to be equal to 1.5 × Reference Price for all LDAs. Reliability modeling data is provided by PJM staff.

All LDAs will have distinct MRI-based VRR Curves using this approach, with differences in shape due to differences in reliability modeling for each LDA. Some LDAs may be able to retain adequate levels of reliability at a level further below their reliability requirement and thus those LDAs will intersect the price cap at a lower reliability level. Figure 24 below illustrates the resulting locational VRR curves across all LDAs, compared against the Current Curve. As shown in the figure, the candidate MRI-based curves are flatter than the Current Curve, would be somewhat left-shifted, and would reach the LDA price caps at a somewhat lower quantity in most LDAs. These more gradual pricing outcomes signaled by the LDA MRI-based curves are more attuned to the reliability risks introduced by variations in LDA supply quantities. Despite the potential for lower volume outcomes when considering the outcomes as a percentage of Reliability Requirement, all MRI-based LDA curves reach the price cap before LDA-specific risks are high (as indicated by the green dots, plotted where LDA reliability events reach 0.1 LOLE).

We recommend that each LDA Reference Price would be set equal to or higher than the parent LDA or system Reference Price, acknowledging the one-way interaction in which LDA VRR curves can only produce higher prices when import constraints are binding (but cannot produce lower prices). For a similar reason, we recommend setting the price cap of the LDA curves equal to the greater of either: (a) the parent LDA/RTO price cap; or else (b) 1.5 × the LDA Reference Price. We recommend the 1.5 × multiplier for LDAs even if a higher multiple is adopted for the RTO-wide MRI curves in order to mitigate exposure to locational price spikes that may be associated with year-to-year variability or unanticipated shifts in supply and demand. However, we reiterate our recommendation (from Section VI.C above) that it would be beneficial to update the Reliability Backstop mechanism to ensure that any LDA price cap event would automatically trigger an investigative review to understand the causes of the outcome. If the event is driven by a surprise such as an unexpected change to the Capacity Emergency Transfer Limit (CETL) parameter, no change to the price cap would be relevant as supply response would be expected for the next auction. However, if the local price cap event is driven by increased supply costs in the LDA, that would indicate expedited increase in pricing parameters. Other price cap events may be associated with barriers to entry or other challenges that would need to be addressed through more targeted solutions as discussed above.

FIGURE 24: INDICATIVE LDA MRI CURVES
(OPTION 2A, RECOMMENDED FOR INITIAL IMPLEMENTATION)



Sources and Notes: Indicative LDA curves are constructed option 1 of the LDA MRI curves shown above in Figure 23. All curves have the same price cap as a percentage of their reference price. The scaling factors is distinct for each LDA and is calculated such that the curve runs through the Reliability Requirement at the Reference Price.

B. Adapting MRI-Based VRR Curve to a Potential Sub-annual Capacity Market Construct

In addition to the economic advantages of an MRI-based demand curve described in Section IV, an MRI-based VRR Curve could also be readily adapted to provide economically rationalized signals should PJM transition to a sub-annual capacity market construct. In 2023, PJM introduced a proposal to transition from an annual auction construct to a sub-annual market with two seasons: winter and summer.[66] In a sub-annual market, both resource accreditation and reliability needs would be season-specific, which would provide more visibility into reliability needs, enable more resources with different seasonal capabilities, and offer economic efficiency benefits as discussed in Section III.E above. Further, co-optimized auction clearing across seasons can ensures that resources are able to recover their going-forward costs over the year and allow an economically-optimized selection of resources that supports seasonal resource needs.

As a starting point approach to developing a seasonal MRI-based curve, we recommend considering the MISO approach. MISO has already demonstrated the development of a four-season MRI-based capacity demand curve, which will be first used in the 2025/26 planning year capacity auction.[67] Though MISO's approach applies across four seasons, the same concept can be adapted to apply to an arbitrary number of sub-annual periods.

The concept in a sub-annual MRI curve, as with the annual MRI curve, is to establish an economically rationalized willingness-to-pay (or "scaling factor") that is uniform across reserve margins and across capacity seasons. The season-specific VRR Curves' horizontal placement are then tied to the season-specific peak load, while the shape and slope are associated with season-specific reliability drivers. However, the $/MWh scaling factor would remain identical across the seasons, meaning that the same value of reliability is expressed across all seasons and capacity volumes. Each season's MRI curve would be subject to a capacity price cap, as would the total annual capacity price.[68]

In RPM auction clearing, sellers' season-specific ELCC UCAP ratings would be accounted for, with individual sellers able to submit offers to sell capacity either for an individual season or for the full annual period. Seasonally co-optimized auction clearing would be utilized to maximize cleared reliability value minus total resource cost across the annual period, with prices set at the

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[66] PJM, Capacity Market Reform: PJM's Proposal, Resource Adequacy Senior Task Force, June 14, 2023.

[67] See 187 FERC ¶ 61,202, Order Accepting Tariff Revisions, re Midcontinent Independent System Operator, Inc. proposed Reliability Based Demand Curves, June 27, 2024, Docket Nos. ER23-2977-000, ER23-2977-001, and ER23-2977-002; and Spees, Newell, Bai. Written Testimony regarding MISO's Reliability-Based Demand Curve, September 28, 2023.

[68] The annual price cap would apply to the average price realized across all seasons, which we would recommend should continue to remain within the traditional range of 1.5-2 × Reference Price that currently applies in PJM and other capacity markets. However, the maximum price in any one season may be appropriate to increase to a higher level, to account for the scenario in which one season is the primary driver of reliability needs (while other seasons have low or zero prices) and so that one season's pricing signals may need to be sufficient to attract new resource investments for a period.

intersection of supply and demand on a season-specific basis.[69] As a result, the seasonal MRI-based VRR Curves will help to balance and guide the resource mix in a fashion that is economically rationalized based on the value of reliability and marginal cost of improving reliability (i.e. against sellers' resource costs).

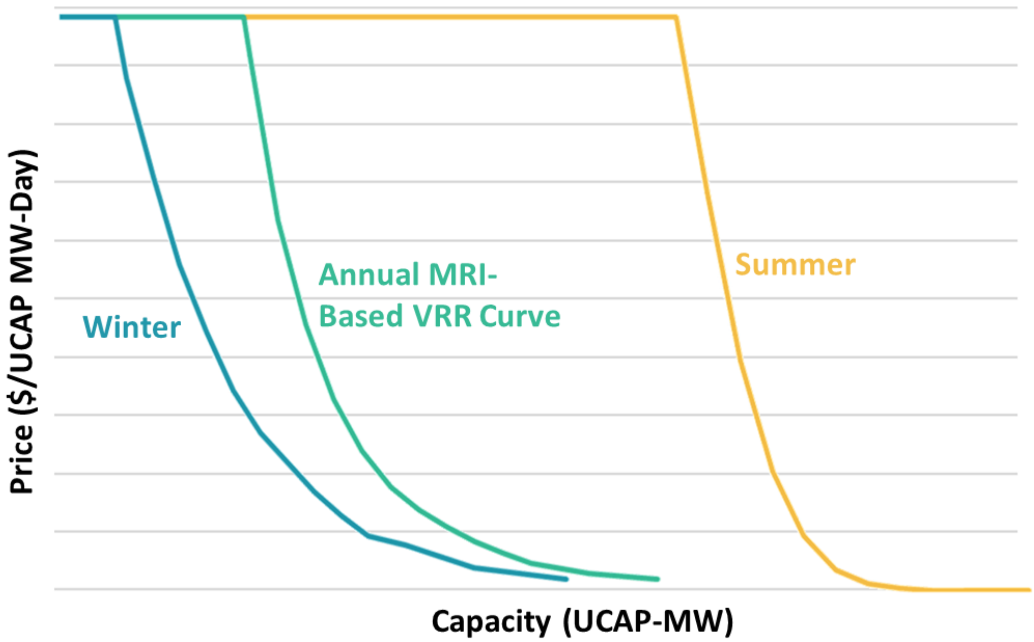
The result will be to incentivize the marketplace to identify the lowest-cost and highest-value resources to improve reliability. If the summer season is tight and reliability needs are acute there, then capacity prices will be higher in the summer than in the winter season and sellers will be incentivized to bring forward more summer-focused capacity resources such as solar; if the winter season is tight, then resources with higher and more firm fuel capabilities will be attracted; if reliability needs in both seasons are balanced, then resources with strong annual ELCC ratings will be prioritized. This in-market signaling would also reduce the current level of criticality placed on accurately predicting the resource mix in PJM's reliability modeling, since the market can be more adaptable to a different balance of summer and winter risks (while offering more visibility a certainty that both seasons' capacity needs will be met). Implementing a co-optimized, sub-annual market would require enhancing the RPM auction clearing engine, and would be aligned with the additive MRI-based VRR curve approach described in Section VII.A above (i.e., Option 1A). The use of a single scaling factor to develop summer and winter MRI-based VRR curves for the system and for all LDAs would allow the market to reflect a consistent willingness to pay for reliability across all sub-annual periods and all locations in the PJM RTO.

Figure 25 provides an indicative representation of summer and winter MRI-based curves that could be used in PJM. Each season's curve is derived from PJM's modeling of season-specific reliability risks, with x-axis quantities adapted to account for season-specific ELCC ratings of the resource mix. Since these curves are curves are developed based on the same willingness to pay for reliability (i.e., the use of the same scaling factor in all seasons), the relative flatness of the winter curves reflects that, at the same sub-annual reserve margin, 1 MW of additional capacity provides greater reliability improvements in the summer rather than the winter. The winter curve is left-shifted compared to the annual curve due to the lower winter peak load and associated supply needs, while the summer curve is right-shifted for the same reason. The two curves are

[69] The surplus-maximizing objective function would maximize the area under the cleared demand curves (system and LDA) minus the cost of cleared supply (allowing sellers to clear under a season-specific or annual offer structure, but without duplicate clearing). Prices would be derived from the shadow price on the supply-demand constraint in each season and LDA (which stipulates that cleared supply ≥ cleared demand). The result would be to produce distinct prices for each capacity season, with LDA-specific price adders also for each season. All sellers would earn a capacity payment equal or greater than the offer price, though for annual offers the sellers would be presumed to be indifferent regarding which season produces higher prices as long as the total annual offer cost is recovered.

tens of GW apart from each other, which illustrates the scale of imprecision that must currently be averaged into the current composite annual RPM construct.

FIGURE 25: INDICATIVE SUB-ANNUAL AND ANNUAL MRI-BASED VRR CURVES



Notes: Indicative calculation, derived from PJM seasonal MRI modeling and seasonal UCAP accreditations.

Whether in an annual or sub-annual market, the implementation of MRI-based VRR curves will promote economic efficiency and enable PJM to meet its reliability needs in a cost-effective manner. Collectively, the recommendations outlined in this report will strengthen the ability of the RPM to attract and retain sufficient capacity to meet reliability objectives on a long-run average basis, while ensuring the market remains resilient to uncertainties, both in the near-term and beyond.

Appendix

In this appendix we provide additional detail on the structure and input assumptions of the Monte Carlo simulation model used to evaluate the VRR curve performance across a range of sensitivities. This methodology allows us to simulate the distribution of clearing outcomes that might be realized over many years, rather than making recommendations about the VRR curve size and shape based solely on near-term forecasts of supply and demand in the PJM market.

A.1 Overview of Model Structure and Assumptions

To evaluate PJM's current VRR Curve and possible alternative curves, we conducted Monte Carlo simulations using an updated and enhanced version of the model used in the 2022 Quadrennial Review. This methodology provides us with distributions of price, quantity, and reliability outcomes for each evaluated VRR curve, which we then analyze in light of the performance objectives of the RPM and the VRR curve. This model exclusively simulates outcomes in the three-year-forward BRA and does not analyze the supply and demand changes that result from the short-term Incremental Auctions held between the BRA and the beginning of the Planning Year.

The Monte Carlo simulation model we employ in this analysis evaluates capacity market outcomes probabilistically, given realistic variability in supply and demand. The model operates under the long-run equilibrium assumption that merchant generation will enter and/or exit the market until clearing prices equal Net CONE on average. Due to unavoidable variability in supply-demand conditions, it is not possible to ensure that procured capacity will land exactly at the Reliability Requirement in every year. For each model run, we therefore simulate 10,000 capacity market outcomes (or "draws"). The supply-demand balance varies in each draw due to the application of randomized supply and demand variability tuned to historical levels. To simulate rational economic entry and exit, infra-marginal supply is added or subtracted from the market in each draw to facilitate model convergence to a long-run average clearing price equal to the Reference Price across the final 1,000 market simulations. Using these results in equilibrium, we assess the performance of the demand curve.

Every input parameter utilized in the model is derived directly from auction parameters, historical market data, and historical offer prices.[70] By ensuring that all model inputs and parameters are derived directly from observable data, we aim to accurately capture the range of outcomes that may be reflected in the upcoming review period relevant for VRR curve implementation. Reliability results (i.e., LOLE, LOLH, and EUE calculations) are tabulated based on cleared quantity values and reliability modeling provided by PJM. See Table 12 summarizes primary inputs used in the Monte Carlo simulation model under base modeling assumptions.

TABLE 12: MODEL INPUTS UNDER BASE CASE ASSUMPTIONS

Parameter	Unit	Value
PJM System Parameters		
Peak Load	(MW)	142,286
Forecast Pool Requirement	(UCAP %)	93.9%
UCAP Reserve Margin	(UCAP %)	-6.1%
Reliability Requirement	(UCAP MW)	133,564
Supply and Demand Variability		
BRA Total Supply	(Std. Dev as % of BRA Total Supply)	4.4%
BRA Reliability Requirement	(Std. Dev as % of BRA Reliability Requirement)	3.7%
BRA Net Supply	(Std. Dev as % of BRA Reliability Requirement)	2.8%

Sources and Notes: Peak Load and Reliability Requirement do not include demand from FRR entities. System parameters match the values used in the 2025/26 Base Residual Auction, from PJM, 2025/26 Planning Period Parameters, 2023. See Sections A.2, A.3, and A.4 for explanation of the derivation of total supply variability, reliability requirement variability, and net supply variability.

We set the Reliability Requirement and the initial volume of total supply offers consistent with historical market data from the 2025/26 BRA. These values are updated in each model draw based on the supply and demand variability parameters, which are based on the observed variability in BRA supply and demand from the 2015/16 to 2024/25 Planning Years.

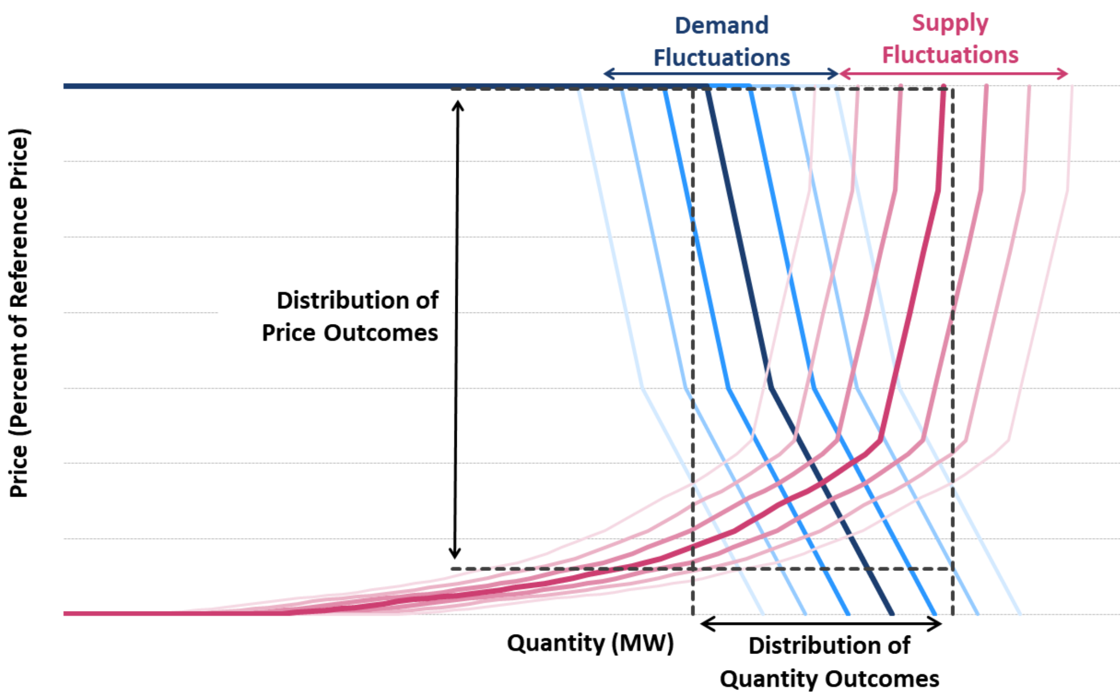
In each draw, the model selects a single capacity market supply curve. Each supply curve having the same shape as a historical BRA supply curve, but with offer prices adjusted for inflation and with price-quantity blocks that have been smoothed. The model cycles through 17 supply curves, derived from the historical supply curves used from the 2009/10 to 2025/26 Base Residual Auctions. Each block in the supply curve is sized as a percent of total supply offers, which is subject to variability in each draw. On the demand side, the quantity points on the VRR Curve are

70 For additional detail on the derivation of the $350/MW-day UCAP base Reference Price, see the Brattle 2025 PJM CONE Report.

calculated relative to the Reliability Requirement, which is also subject to variability in each model draw. Figure 26 shows a stylized depiction of how the model estimates a distribution of price and quantity distributions driven by supply and demand variability.

The intersection of supply and demand determines the clearing price, quantity, and reliability in each draw. These clearing results are tabulated across the final 1,000 draws, once the model has reached equilibrium market conditions, and these draws provide the estimated distribution of market clearing results. The shape of the VRR curve under consideration will affect the price and quantity distributions compared to other tested curves.

FIGURE 26: SUPPLY AND DEMAND VARIABILITY

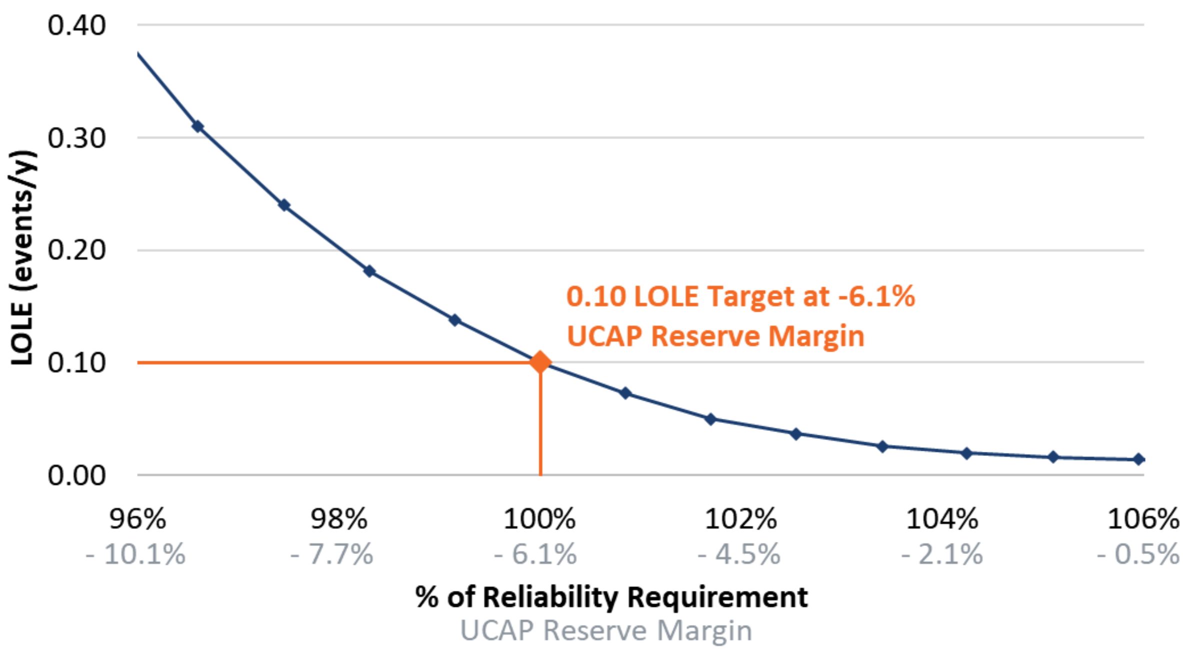


Sources and Notes: Illustrative variations are not intended to reflect the exact variation magnitudes used in our simulations.

A.2 Reliability

We model reliability outcomes based on the cleared UCAP reserve margin in each draw and reliability modeling data provided by PJM that captures the LOLE, LOLH, and EUE values at a range of different UCAP reserve margins. Linear interpolation is used to calculate reliability when the cleared UCAP reserve margin falls between two data points provided by PJM. The relationship between UCAP reserve margin and the various reliability metrics is asymmetrical. For simplicity, the following paragraph describes LOLE, but the relationship is the same for LOLH and EUE. Below the Reliability Requirement, LOLE increases more steeply (indicating worsening reliability outcomes), but at reserve margins above the Reliability Requirement, LOLE decreases more gradually (meaning improving reliability). An implication of this asymmetry is that a demand curve that results in a distribution of clearing outcomes centered on the Target Point (i.e. the Reliability Requirement) with equal variance above and below the target will fall short of the 0.1 LOLE target on an average basis.

FIGURE 27: LOSS OF LOAD EVENTS VS UCAP RESERVE MARGIN

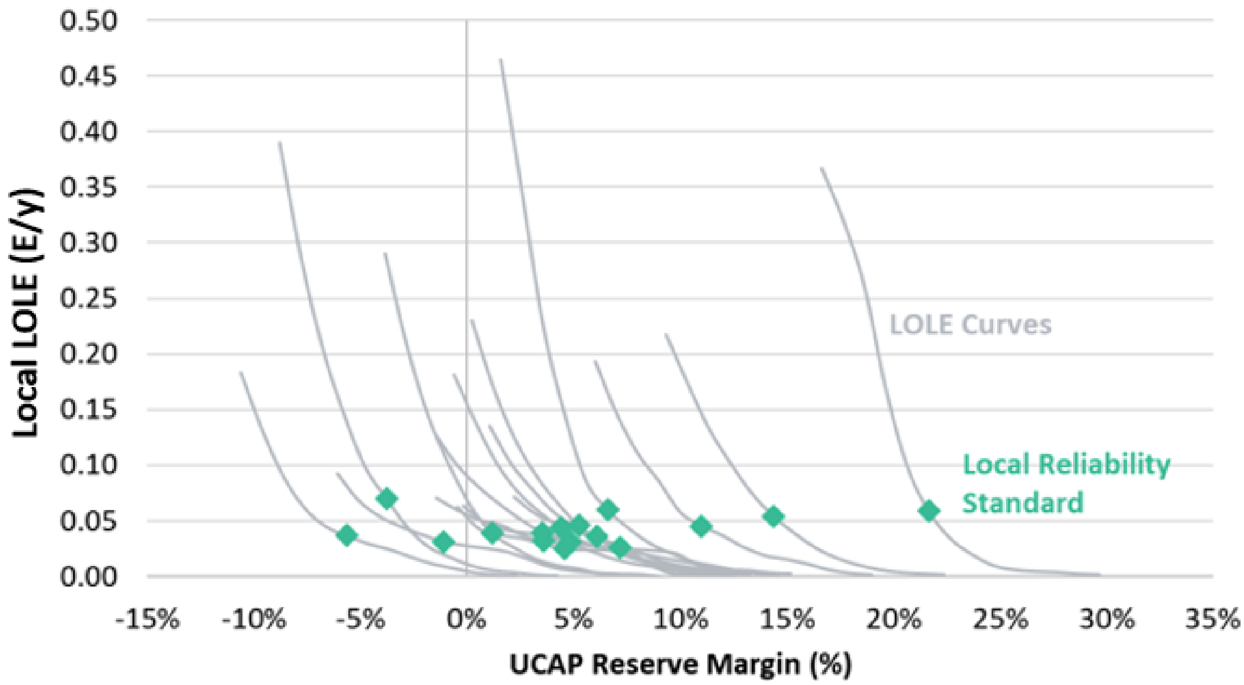


Sources and Notes: Reliability data provided by PJM reliability modeling staff; PJM is a summer-peaking region, but most reliability risks occur in the winter due to infrastructure complications primarily associated with gas generation, which leads to a negative summer reserve margin at the 1-in-10 LOLE target.

We did not model the reliability results for individual LDAs as part of this Quadrennial Review. However, in any given LDA, the relationship between the local reserve margin (calculated based on local supply and imports) and local reliability mirrors that of the overall system. In both the LDAs and the system as a whole, there is a convex, downward-sloping relationship between UCAP reserve margin and reliability, which reflects the diminishing marginal reliability impact of capacity as reserve margins increase.

Unlike the system-wide LDA curves, the Reliability Requirement of individual LDAs is not calculated by adding/subtracting perfect capacity around the 1-in-10 LOLE target. Instead, local reliability curves are calculated in relation to the locational reliability standard in each LDA, defined as 40% of the RTO-wide load-normalized EUE.[71] As a result of this calculation, the local reliability standard for each LDA falls at slightly different reserve margins, as shown in Figure 28.

FIGURE 28: LDA LOLE CURVES



Sources and Notes: Reliability data provided by PJM reliability modeling staff; Local reliability standard calculated using data provided by PJM and following the logic from PJM, Manual 20A, Effective Date June 27, 2024.

A.3 Demand

In the model, the base value for the Reliability Requirement is set to match the Reliability Requirement from the 2025/26 BRA at 133,564 MW. In each model draw, this Reliability Requirement is updated by applying normally-distributed randomized variability. The magnitude of this variability parameter is tuned to the historical variation in the RTO Reliability Requirement relative to a linear trend, consistent with the methodology used in the prior Quadrennial Review.

Table 13 shows the historical Reliability Requirement values, as well as the linear prediction and the deviation from the trend, which sets the BRA Reliability Requirement variability parameter.

[71] The LDA-specific Local Reliability Standard is set at 40% × RTO-wide load-normalized EUE. Load-normalized EUE is the (very small) percentage of annual energy demand that cannot be served due to resource adequacy events, defined as the estimated MWh of EUE, divided by the forecasted annual net energy consumption (MWh EUE/MWh Load). Since the LDA-specific EUE measures only shortages in the LDA, but not the shortages that may coincide with system-wide events, LDA-specific normalized EUE is a measure that is partly (but not entirely) additive to system-wide normalized EUE. See: PJM, Manual 20A, Effective Date June 27, 2024.

The average historical deviation from the trend is 5,540 UCAP MW, or 3.7% of the average BRA Reliability Requirement from 2015/16 to 2024/25.

TABLE 13: HISTORICAL VARIABILITY IN BRA RELIABILITY REQUIREMENT

Year	Historical BRA Reliability Requirement [A] *(UCAP MW)*	Linearized BRA Reliability Requirement [B] *(UCAP MW)*	Residual Above (Below) Linear Trend [C] *(UCAP MW)*
2015	162,777	170,766	(7,989)
2016	166,128	166,491	(363)
2017	165,007	162,215	2,792
2018	160,607	157,939	2,668
2019	157,092	153,664	3,429
2020	154,355	149,388	4,967
2021	153,161	145,113	8,048
2022	132,257	140,837	(8,580)
2023	131,820	136,561	(4,741)
2024	132,056	132,286	(230)
Average BRA Reliability Requirement		[1]: Average [A]	151,526
Standard Deviation of Residuals		[2]: Std. Dev. [C]	5,540
BRA Reliability Requirement Variability		[3]: [2]/[1]	3.7%

Sources and Notes: All quantities in UCAP MW; [A]: From PJM, 2015/26 to 2024/25 Base Residual Auction Planning Parameters; [B]: Expected value of [A] based on linear trend; [C]: [A] – [B]

A.4 Supply

Unlike the demand curve, the capacity market supply curve is not administratively determined and under the control of PJM. Instead, the supply curve consists of price-quantity pair supply offers by market participants. For our modeling, we use supply curve shapes derived from historical RPM offers from the 2009/10 to 2025/26 Planning Years. These supply curves reflect a wide range of capacity resources offered into the market and account for participant offer levels in response to changing market conditions, rule changes, supply-side constraints, and resource accreditations over time. To prepare these curves for our model, we construct smoothed and normalized supply curves from the 2009/10 to 2025/26 Base Residual Auction offer data. For all supply curves, we smooth price-quantity pairs into 1,000-MW standard blocks, adjust prices for inflation so that all prices are in 2028$, and normalize MW quantity bids so that the final supply curves quantities are represented as a percentage of BRA Total Supply for each year. The model employs a cyclical process to select one normalized, smoothed supply curve for use in each model draw. This supply curve is then adjusted to account for the model convergence parameter (represented by the quantity of infra-marginal supply), as well as total supply variability, which is tuned to historically observed levels. The resulting supply curves are shown in Figure 8 above.

By using a range of supply curves, the model captures a substantial range of different possible market conditions that could be faced in RPM, including that may be affected by different market conditions, retirement cost drivers, and other market conditions. In addition to capturing these historical changes via the shape of the supply curves, we adjust the total supply quantity in each draw by adding normally-distributed randomized variability. Similar to the demand variability, the magnitude of this variability parameter is based on historical variability in totally supply offers in the BRA relative to a linear trend. The average historical deviation from the trend is 7,792 UCAP MW, or 4.4% of the average BRA Total Supply from 2015/16 to 2024/25, as summarized in Table 14.

TABLE 14: HISTORICAL VARIABILITY IN BRA TOTAL SUPPLY

Year	Historical BRA Total Supply [A] *(UCAP MW)*	Linearized BRA Total Supply [B] *(UCAP MW)*	Residual Above (Below) Linear Trend [C] *(UCAP MW)*
2015	178,588	186,823	(8,235)
2016	184,380	184,488	(108)
2017	178,839	182,153	(3,315)
2018	179,891	179,818	73
2019	185,540	177,483	8,056
2020	183,352	175,149	8,203
2021	186,505	172,814	13,691
2022	167,698	170,479	(2,781)
2023	157,281	168,144	(10,863)
2024	161,088	165,809	(4,722)
Average BRA Total Supply		[1]: Average [A]	176,316
Standard Deviation of Residuals		[2]: Std. Dev. [C]	7,792
BRA Total Supply Variability		[3]: [2]/[1]	4.4%

Sources and Notes: All quantities in UCAP MW; [A]: From auction data provided by PJM; [B]: Expected value of [A] based on linear trend; [C]: [A] – [B]

A.5 Net Supply Variability

In addition to calibrating the supply and demand variability to the historically observed levels, we tune the net supply variability (i.e., the correlation between supply and demand) to historically observed levels. In the RPM, there is a partial correlation between supply and demand. This correlation in supply and demand is associated with market participants' individual efforts to align their decision-making with anticipated market conditions (i.e., plan ahead to offer more supply when conditions are tight, or defer/retire supply when the market is long). Similarly FRR entities tend to enter and exit the market with a relatively balanced volume of supply and demand. Separately estimating supply and demand variability without accounting for this correlation would overstate the resulting variability in net supply (i.e. total supply minus Reliability Requirement) that produces the effect of market price volatility.

Due to this relationship, we apply a correlation factor between the supply and demand variability to ensure that modeled net supply variability matches the historically observed net supply variability. We estimate the deviation of Net Supply from a linear trend in the same manner as with the other variability calculations, using data from the 2012/13 to 2024/25 Base Residual Auctions to capture a wide range of observed Net Supply values. The historical deviation of Net Supply from the linear trend is 4,145 UCAP MW, as shown in Table 13. This value is equivalent to 2.8% of the average BRA Reliability Requirement from 2012/13 to 2024/25, which sets the BRA Net Supply variability size as implemented in our model.

TABLE 15: HISTORICAL VARIABILITY IN BRA NET SUPPLY (SUPPLY LESS RELIABILITY REQUIREMENT)

Year	Historical BRA Reliability Requirement [A] *(UCAP MW)*	Historical BRA Total Supply [B] *(UCAP MW)*	Historical BRA Net Supply [C] *(UCAP MW)*	Linearized BRA Net Supply [D] *(UCAP MW)*	Residual Above (Below) Linear Trend [E] *(UCAP MW)*
2012	133,732	145,373	11,641	9,907	1,734
2013	149,989	160,898	10,909	11,879	(970)
2014	148,323	160,486	12,163	13,851	(1,688)
2015	162,777	178,588	15,810	15,823	(13)
2016	166,128	184,380	18,253	17,795	457
2017	165,007	178,839	13,831	19,767	(5,936)
2018	160,607	179,891	19,284	21,739	(2,456)
2019	157,092	185,540	28,447	23,712	4,736
2020	154,355	183,352	28,996	25,684	3,313
2021	153,161	186,505	33,344	27,656	5,688
2022	132,257	167,698	35,442	29,628	5,814
2023	131,820	157,281	25,461	31,600	(6,139)
2024	132,056	161,088	29,032	33,572	(4,540)
Average BRA Reliability Requirement				[1]: Average [A]	149,793
Standard Deviation of Residuals				[2]: Std. Dev. [E]	4,145
BRA Net Supply Variability				[3]: [2]/[1]	2.8%

Sources and Notes: All quantities in UCAP MW; [A]: From PJM, 2012/13 to 2024/25 Base Residual Auction Planning Parameters; [B]: From auction data provided by PJM; [C]: [B] – [A]; [D]: Expected value of [C] based on linear trend; [E]: [C] – [D]

List of Acronyms

BESS	Battery Energy Storage Systems
BGE	Baltimore Gas and Electric Company
BRA	Base Residual Auction
CC	Combined Cycle
CETL	Capacity Emergency Transfer Limit
CETO	Capacity Emergency Transfer Objective
CIFP-RA	Critical Issue Fast Path-Resource Adequacy
COD	Commercial Online Date
CONE	Cost of New Entry
CPI	Consumer Price Index
CT	Combustion Turbine
DPL	Delmarva Power and Light Company
E&AS	Energy and Ancillary Services
ELCC	Effective Load Carrying Capability
EMAAC	Eastern Mid-Atlantic Area Council
EUE	Expected Unserved Energy
FRR	Fixed Resource Requirement
GW	Gigawatt
IA	Incremental Auction
ICAP	Installed Capacity
IESO	Ontario's Independent Electricity System Operator
IMM	Independent Market Monitor
IRM	Installed Reserve Margin
ISO-NE	Independent System Operator of New England
LDA	Locational Deliverability Area
LOLE	Loss of Load Events
LOLH	Loss of Load Hours
MAAC	Mid-Atlantic Area Council
MISO	Midcontinent Independent System Operator

MOPR	Minimum Offer Price Rule
MRI	Marginal Reliability Impact
MSOC	Minimum Office Seller Cap
MW	Megawatt
MWh	Megawatt Hour
NYISO	New York Independent System Operator
PJM	PJM Interconnection
RPM	Reliability Pricing Model
RTO	Regional Transmission Organization
UCAP	Unforced Capacity
VRR	Variable Resource Requirement

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