UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	Docket No. ER25-1357-000
Governor Josh Shapiro and the Commonwealth of Pennsylvania	)	Docket No. EL25-46-000
v.	)	
PJM Interconnection, L.L.C.	)	(not consolidated)

COMMENTS OF THE INDEPENDENT MARKET MONITOR FOR PJM

Pursuant to Rule 211 of the Commission's Rules and Regulations[1] Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor ("Market Monitor") for PJM Interconnection, L.L.C. ("PJM"),[2] submits these comments responding to the filing submitted by PJM Interconnection, L.L.C. ("PJM") on February 20, 2025 ("February 20th Filing"). The February 20th Filing proposes revisions to the OATT that would establish the maximum price point on the Variable Resource Requirement ("VRR") curve equal to "approximately" $325/MW-day in unforced capacity ("UCAP") with a new MW point that is inconsistent with the tariff definition, a new minimum price point on the VRR curve of "approximately" $175/MW-day (UCAP) for an unlimited number of MW that

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1 18 CFR § 385.211 (2024).

2 Capitalized terms used herein and not otherwise defined have the meaning used in the PJM Open Access Transmission Tariff ("OATT"), the PJM Operating Agreement ("OA") or the PJM Reliability Assurance Agreement ("RAA").

is inconsistent with the tariff, and a VRR curve shape not consistent with the tariff definition, for all Reliability Pricing Model ("RPM") Auctions, including Base Residual Auctions and Incremental Auctions, for the 2026/2027 and 2027/2028 Delivery Years.

The February 20th Filing is submitted to resolve a complaint against PJM submitted by the Commonwealth of Pennsylvania ("Complaint").[3] The Complaint requested (at 26) that PJM "be directed to reduce the price cap by lowering its multiplier to 1.5 times Net CONE." PJM did not answer the Complaint. PJM and Governor Josh Shapiro and the Commonwealth of Pennsylvania filed a stipulation of satisfaction and joint motion to dismiss complaint in Docket No. EL25-46. PJM states (at 1) that it has submitted the February 20th Filing in order to "fully resolve that separate Complaint." The February 20th Filing effectively concedes the Complaint's argument that the current maximum price of the greater of Gross Cost of New Entry ("CONE") or 1.75 times Net CONE is too high, and that relief comparable to that proposed in the Complaint is just and reasonable. The February 20th Filing is not limited to what would be necessary to resolve the Complaint.

The VRR curve has always had a maximum price. The VRR curve has always had a minimum price equal to zero. The proposal would set the maximum price level at somewhat higher than 1.5 times Net CONE. The Market Monitor's position is that the maximum price should be equal to the lesser of 1.5 times Net CONE or Gross CONE. The maximum price that had been proposed by PJM of $499.32/MW-day for the Rest of the RTO was clearly excessive.[4] The maximum price of $325/MW-day in UCAP terms requested in

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3 *See Governor Josh Shapiro and the Commonwealth of Pa. 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, Docket No. EL25-46-000 (February 14, 2025) ("Complaint").

4 PJM's initial proposal was to use Gross CONE for a CC to define the maximum price. PJM changed the reference resource to a CT, with a Gross CONE of $499.32 in the Rest of RTO.

the Complaint is higher than 1.5 times Net CONE for the RTO. A maximum price equal to 1.5 times Net CONE would be the correct price.

There is no support in the record or in economic logic for converting the $325/MW-day maximum price into ICAP terms and then back into UCAP terms, as PJM proposes. The result is to arbitrarily increase the maximum price when the reference resource accredited UCAP factor ("ELCC value") decreases, as it already has. The actual maximum price based on PJM's latest reference resource accredited UCAP factor for a CT is $329.17/MW-day rather than $325/MW-day. It could be higher if the reference resource's ELCC value decreases further.

There is no support in the record or in economic logic for a minimum price greater than zero. The inclusion of a minimum price greater than zero is a radical break from the definition of the VRR curve since its introduction and does nothing to resolve the Complaint. The proposed minimum price introduces an unjust and unreasonable element to the determination of the VRR curve.

There is no support in the record or in economic logic for the distorted VRR curve shape proposed by PJM. PJM should simply have established $325/MW-day as the maximum price on the VRR curve and then followed the tariff rules governing the shape of the VRR curve, including the definition of Points A, B and C.

The approximately $325/MW-day (UCAP) maximum VRR price proposed in the February 20th Filing with the proposed conversion into ICAP and back to UCAP, and the minimum price level should be rejected. The proposed maximum price of approximately $325/MW-Day is $25.56/MW-day, or 8.5 percent, higher than 1.5 times Net CONE value for the RTO. Net CONE for the RTO is $199.63/MW-day and 1.5 times Net CONE for the RTO is $299.45/MW-day.[5]

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[5] See Attachment D, FERC Docket No. ER25-682-000, Revisions to PJM Capacity Market (December 9, 2024). Forward E&AS revenues are provided by PJM.

The Market Monitor supports the Commonwealth of Pennsylvania's Complaint and its proposed use of a maximum price based on the history and logic of the VRR curve and the capacity market.

The Market Monitor does not support the additional elements that PJM added to the maximum price and the VRR curve in the February 20th Filing.

The details of the February 20th Filing are unsupported and should be rejected because they have not been shown to be just and reasonable. In particular, there is no basis for approving a minimum price greater than zero dollars. Action should be taken to revise the maximum price because the current maximum price is excessive. Because the February 20th Filing is submitted in conjunction with the Complaint in Docket No. EL25-46, by granting the Complaint under Section 206 of the Federal Power Act,[6] the Commission can adopt just and reasonable reforms to the PJM market rules while rejecting unsupported, unjust and unreasonable related proposals.[7]

I. COMMENTS

A. A Maximum VRR Curve Price of 1.5 Times Net CONE Should Be Determined in these Proceedings.

The initial VRR curve, introduced in 2007, had a maximum price equal to 1.5 times the Net Cost of New Entry ("Net CONE"). The use of Net CONE was based on the logic of the capacity market, to ensure that between the energy and capacity markets the cost of entry was covered. Net CONE was the missing money that needed to be recoverable in the

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6 16 U.S.C. § 824e.

7 *See NRG Power Mktg., LLC v. FERC*, 862 F.3d 108, 114 (2017) (An order on a Section 205 cannot be conditioned on the adoption of an "entirely different rate design," even if the utility agrees, but "FERC has some authority to propose modifications to a utility's proposal if the utility consents to the modifications"). *NRG* does not limit the authority of the Commission to determine the appropriate relief under Section 206. PJM should not be permitted to unduly restrict the Commission's ability to determine appropriate relief in response to a Complaint by converting the Complaint into a Section 205 proceeding.

capacity market. Net CONE was the equilibrating factor between the capacity market and energy market. The use of Gross CONE is inconsistent with that basic capacity market logic. Gross CONE was introduced by PJM and The Brattle Group, Inc. ("Brattle") as the maximum price based on the unsupported concerns, almost 14 years ago, that Net CONE would be too low for the CT reference unit.[8] The market dynamics of concern that were referenced by Brattle at that time never occurred. In general, the excessive maximum price did not significantly affect clearing prices until the 2025/2026 Base Residual Auction ("BRA"). The maximum point on the VRR curve for the 2025/2026 BRA was the higher of Gross CONE or 1.5 times Net CONE, and Gross CONE was actually used.

If the logic of the markets implies a low Net CONE, that is the right answer. There is nothing inherently wrong with a low Net CONE that requires abandoning the basic capacity market logic. Gross CONE was an intervention designed to increase capacity market prices based on a judgment about what prices should be and what net revenues might be despite the fact that the basic economic logic did not support that increase. If there is an issue with the calculation of Net CONE, it should be addressed directly rather than by ignoring its central role in the design of the capacity market. As Gross CONE numbers are reasonably well defined, much more focus on the accurate calculation of the net revenues used in the forward auctions is required in order to ensure that market participants have confidence in the Net CONE values used in the auctions.

PJM's original proposal which prompted the referenced Complaint would have resulted in a maximum VRR curve price of $499.32/MW-day for the rest of RTO. PJM's proposal would have resulted in total capacity market revenues of about $24.8 billion under a defined set of assumptions (Scenario 63 from Part E).[9]

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8 The Brattle Group, Second Performance Assessment of PJM's Reliability Pricing Model, August 26, 2011.

9 Attachment E, "Analysis of the 2025/2026 RPM Base Residual Auction Part E," (January 31, 2025).

B. A High Minimum VRR Curve Price Is Unnecessary and Has Not Been Shown to be Just and Reasonable.

PJM's argument for a high minimum VRR curve price largely rests on an unsupported assertion that a maximum price should be matched by a minimum price greater than zero. The superficial appeal to symmetry is not relevant. The asserted symmetry is not defined or supported. The proposed minimum value of approximately $175/MW-day is not supported. The rationale is flawed and should be rejected. The record fails to support that the inclusion of a minimum price is just and reasonable. The VRR curve has always had a defined maximum price and a minimum price of zero. The maximum price defines shortage pricing in the capacity market and also protects against the exercise of market power when the market is short. There is no economic argument for a minimum price greater than zero.

The market design necessarily relies on the VRR Curve to determine customer participation in RPM Auctions. Customer participation is mandatory under the rules. Customers have no choice about the price customers are willing to pay in the capacity market.

Sellers, on the other hand, have a responsibility to submit competitive offers in RPM Auctions. Capacity resources are subject to must offer rules, but can propose to deactivate resources and exit the markets.

The proposed minimum price of approximately $175/MW-day would be higher than the average of all historical capacity market weighted average BRA clearing prices prior to the 2025/2026 Delivery Year, which is $116.30/MW-day.[10] [11]

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10 See 2024 Quarterly State of the Market Report for PJM: January through September, Section 5: Capacity Market, Table 5-19.

11 Some price separated LDAs have had higher prices. In the 2015/2016 BRA, ATSI LDA cleared at $357.00 per MW-day. In the 2024/2025 BRA, DPL South LDA cleared at $426.17 per MW-day as a result of a mistake by PJM. In the 2024/2025 First IA, PSEG North LDA cleared at $410.95 per MW-

C. PJM Abandons, without Justification, the Basic Logic for Implementing the VRR Curve.

PJM makes two mistakes in its implementation approach to creating a new VRR curve and to the definition of the maximum price.

The first mistake is that PJM does not propose to create a new VRR curve with a consistently defined new Point A, Point B and Point C. Rather, PJM simply uses the existing VRR curve based on a maximum price of Gross CONE and draws a horizontal line at the new proposed maximum price from the Y axis until it intersects the existing VRR curve. PJM also draws another horizontal line at the proposed minimum price from the Y axis until it intersects the existing VRR curve. This approach is not consistent with defining a new maximum price at approximately $325/MW-day and creating a new, internally consistent VRR curve. (See Figure 1)

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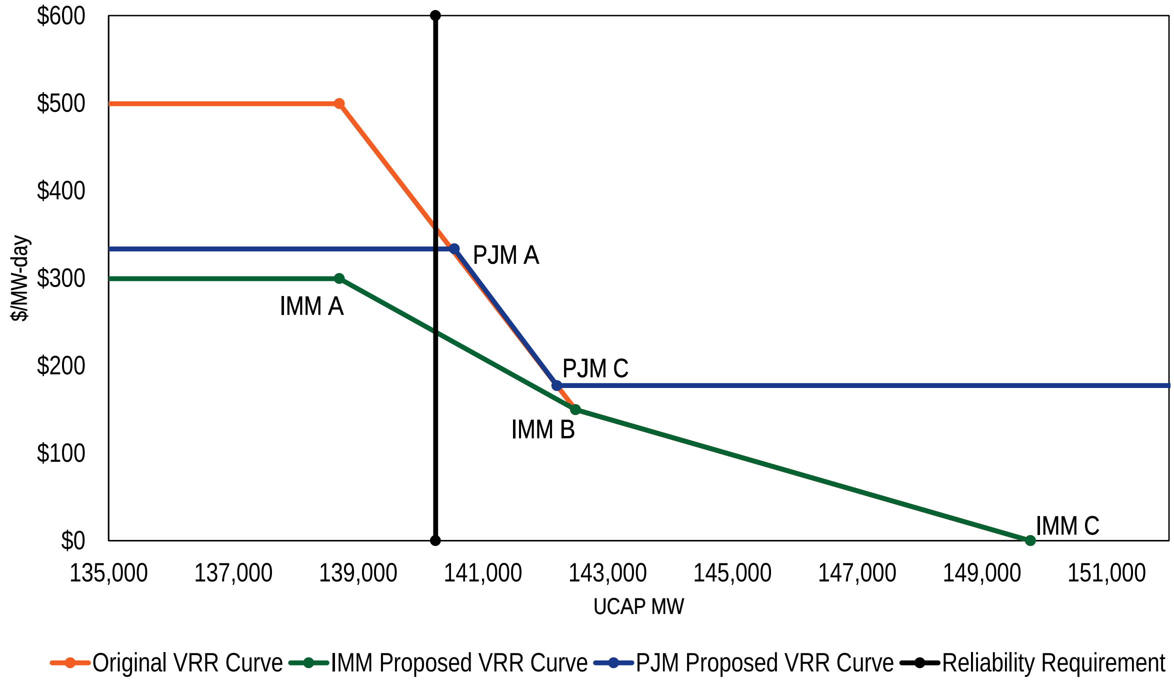
day. In the 2024/2025 Second IA, PSEG North LDA cleared at $310.00 per MW-day. In the 2024/2025 Third IA, PSEG North LDA cleared at $256.76 per MW-day.

Figure 1 Comparison of VRR curves for the RTO



The result of PJM's approach is that Point A (PJM A) on the proposed VRR curve is no longer defined by the (proposed) maximum price and 99.0 percent of the reliability requirement MW. PJM's equivalent of Point A (PJM A), the first inflection point on the VRR curve, now occurs at a MW point that is greater than the reliability requirement and greater than the correctly defined Point A (IMM A and Original VRR Curve Point A). PJM's approach increases the MW that will clear at the maximum price compared to the VRR curve definition (PJM A MW > IMM A MW).

The second mistake is that PJM does not propose to implement the maximum price of approximately $325/MW-Day from the Agreement. Rather, PJM proposes to modify the maximum price based on the ELCC value for the reference resource, a dual fuel CT. PJM's approach is to convert the maximum price of $325/MW-day in UCAP terms to a maximum price of $256.75/MW-day in ICAP terms, using a dual fuel CT accredited UCAP factor of .79. PJM proposes to make the ICAP price the defined price and change the UCAP price to match it if the reference resource accredited UCAP factor changes. Under PJM's approach, if the reference resource accredited UCAP factor increases, the maximum price would decrease. Under PJM's approach, if the reference resource accredited UCAP factor decreases, the maximum price would increase. PJM's approach could result in a significant increase in the clearing price and in total customer payments. In fact, the reference resource ELCC value has already decreased from .79 to .78, for the 2026/2027 RPM Base Residual Auction, with the result that, in PJM's approach, the maximum price has increased from approximately $325/MW-day to approximately $329.17/MW-day and the proposed minimum price has increased from approximately $175/MW-day to approximately $177.24/MW-day.[12]

If the reference resource ELCC value were further reduced from 0.78 to 0.73, the maximum price would increase from $325/MW-day to more than $350/MW-day ($352/MW-day). If the RTO cleared at the $350/MW-day maximum price (Scenario 83 from Part F), this would result in an increase of $1,240,735,375 in annual capacity market revenues compared to using a $325/MW-day maximum price (Scenario 79 from Part F).

PJM's proposal is inconsistent with a maximum price of $325/MW-day. The maximum price is a price in UCAP terms. The maximum price is a fixed value in UCAP terms and should be implemented as a fixed value. PJM's reversed proposal would convert the maximum price to an ICAP price and make the ICAP price the fixed value. The PJM capacity market price is defined in UCAP terms. The maximum price is defined in UCAP terms. PJM's proposal is that if the reference resource ELCC value changes the ICAP price calculated at an accredited UCAP factor of .79 would remain the same and the actual maximum market price must change. There is no reason to introduce this calculation, this change in the maximum price or the associated confusion. If the reference resource ELCC value changes, the maximum price remains the same and the calculated ICAP price would

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12 *ELCC Class Ratings for 2026/2027 Base Residual Auction*, PJM Interconnection L.L.C. (February 28, 2025) <https://www.pjm.com/planning/resource-adequacy-planning/effective-load-carrying-capability>.

change. Given the volatility of PJM's ELCC values, PJM's ability to change ELCC results by switching forecasts, the lack of transparency of PJM's ELCC values and the multiple issues with PJM's calculations of ELCC values, especially for thermal resources like CTs, there is no reason to make the maximum price a function of the ELCC value. The PJM proposal to make the maximum price a function of the reference resource ELCC value is inconsistent with creating certainty for market participants.

The tariff definition of the price at Point B on the VRR curve is .75 times Net CONE. The February 20th Filing does not define Point B because the tariff defined Point B falls below PJM's proposed minimum price for the Rest of RTO. The Market Monitor's proposed VRR curve defines the price at Point B, consistent with the tariff, as .75 times Net CONE. The price at Point C on the Market Monitor's proposed VRR curve is the tariff defined $0/MW-day.

Under the defined VRR curve for the 2025/2026 BRA, the corresponding MW quantities are set at 98.9 percent of the reliability requirement for Point A, 101.6 percent of the reliability requirement for Point B and 106.8 percent of the reliability requirement for Point C.[13] [14] Although the February 20th Filing does not define the MW points, the Market Monitor recommends that the MW points remain as defined in the tariff definition of the VRR curve.

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13 OATT Attachment DD § 5.10(a)(i).

14 For the 2026/2027 and subsequent delivery years, the corresponding MW quantities are set at 99.0 percent of the reliability requirement for Point A, 101.5 percent of the reliability requirement for Point B and 104.5 percent of the reliability requirement for Point C.

D. No Economic Logic Supports the Proposed Minimum VRR Curve Price, and Significant Negative Unintended Consequences Could Result from Including It.

The inclusion of a minimum VRR Curve price is inconsistent with the fundamental capacity market design and risks substantial distortion to the capacity market results, including significant price suppression.

PJM's proposed VRR curve shape would require PJM to purchase an unlimited level of capacity at a price of approximately $175/MW-day. There is no limit to the MW of capacity that PJM would be required to purchase if offered at approximately $175/MW-day or below. This is inconsistent with the shape of the VRR curve since its inception, as defined in the tariff, and is not supported by economic logic. The VRR curve has always had a price of zero at a defined MW point (Point C on the VRR curve). While the supply of actual generation resources is limited, especially for the next auction, the same is not true for demand side resources. Curtailment service providers ("CSPs") are allowed to offer an unlimited amount of capacity into a BRA with no demonstration that actual demand response customers or contracts to provide demand response exist. CSPs are allowed to offer a marketing plan as capacity into the BRA. The potential result with PJM's VRR curve shape and minimum price is that CSPs could offer enough demand side resources to drive the price down to the minimum price of approximately $175/MW-day. The proposed shape of the VRR curve provides a guarantee to CSPs that they can sell as much demand response as they want if offered at approximately $175/MW-day or below, and at a price that is more than 50 percent higher than the average of all historical capacity market weighted average BRA clearing prices prior to the 2025/2026 Delivery Year. This incentive would not exist with the normal Point C at a zero price. The price suppression that could result from PJM's proposal would not be a just and reasonable outcome. Demand side resources are not actually a substitute for physical capacity resources. Demand side resources are inferior to physical generating capacity.[15] This result would also undermine reliability by substituting demand side resources for generating resources. The February 20th Filing's creation of a strong incentive for this outcome is not just and reasonable.

E. PJM Has Not Addressed LDA Clearing with PJM's Proposed Approximately $175/MW-Day Minimum Price

The clearing process for BRAs is complex, given that there are 23 LDAs, of which 16 have been modeled LDAs and all 16 LDAs can price separate, given the CETO/CETL details and LDA modeling rules, given the other rules governing the clearing process, and given all the offers from all the suppliers. PJM has failed to address the problem of how to solve the BRA with a minimum price and no maximum MW purchase. Under PJM's nested VRR structure, the uncleared remaining portion of the VRR curve from the child LDA is transferred to its immediate parent LDA. The uncleared remaining portion from the parent LDA is transferred further to its immediate parent LDA until all of the uncleared remaining segments of the VRR curves from all child LDAs are accounted for in the Rest of RTO. The starting uncleared remaining portion for each child LDA is defined as the difference between the maximum UCAP MW (Point C) and the cleared UCAP MW. Under PJM's proposed VRR curve, there would not be a maximum UCAP MW for any LDA.[16] PJM did not address how the uncleared portion for each child LDA would be determined without a finite maximum UCAP MW or how PJM would define a unique market clearing solution. The market must be cleared in a simultaneous optimization including all the interactions between child and parent LDAs.

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15 See the *2024 Annual State of the Market Report for PJM* (March 13, 2025). <https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2024.shtml>

16 See "Consultation: Capacity Market Demand Curve Adjustments Pursuant to Proposed Settlement," Special Members Committee, Price Cap/Price Floor (February 2025), <https://www.pjm.com/-/media/DotCom/committees-groups/committees/mc/2025/20250207-special/item-01a---1-capacity-market-demand-curve-adjustments-pursuant-to-proposed-settlement.pdf>

F. PJM Fails to Propose a Consistent and Transparent Market Design.

PJM omits key points about the historical maximum price points on the capacity market demand curve (VRR curve). PJM simply assumes that the maximum price of $499.32/MW-day that PJM proposed prior to the agreement with the Commonwealth of Pennsylvania was reasonable. It was not.

PJM incorrectly describes current market conditions in the PJM capacity market. PJM overlooks the fact that capacity market prices already increased dramatically in the last BRA for the 2025/2026 Delivery Year.[17] PJM prices for the Rest of RTO rose by 833.3 percent in the 2025/2026 BRA and capacity market revenues increased by 522 percent, from $2.3 billion in 2024/2025 to $14.7 billion.[18]

The capacity market is getting tighter. The result will be higher capacity market prices. In a well designed market, capacity market prices reflect the underlying supply and demand fundamentals. The results of the 2025/2026 BRA illustrate the amplified impact of not getting the details of the market design right when the market is tight. The Market Monitor analysis shows that while a significant increase in capacity market payments in the 2025/2026 BRA was based on the fundamentals, market design and market power issues resulted in actual capacity market payments that were approximately twice as high as needed in the 2025/2026 BRA. Without significant changes to key details of the market design, prices in the 2026/2027 BRA will be significantly higher than in the 2025/2026 BRA and also not consistent with market fundamentals.[19] The use of Gross CONE as the

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17 See Attachment A; "Analysis of the 2025/2026 RPM Base Residual Auction Part A," (Sept. 20, 2024).

18 In the 2024/2025 BRA, Dominion chose the FRR option. In the 2025/2026 BRA, Dominion was included in the BRA.

19 *See* reports analyzing the 2025/2026 RPM Base Residual Auction, including: Analysis of the 2025/2026 RPM Base Residual Auction–Part A (September 20, 2024), Analysis of the 2025/2026 RPM Base Residual Auction–Part B (October 15, 2024), Analysis of the 2025/2026 RPM Base Residual Auction–Part C (November 6, 2024), Analysis of the 2025/2026 RPM Base Residual Auction–Part D (December 6, 2024), Analysis of the 2025/2026 RPM Base Residual Auction–Part E (January 31,

maximum price is an example of a PJM market design choice and a PJM parameter choice that were not well supported and that result in market outcomes not consistent with market fundamentals.

The market design details that had a significant impact on the results of the 2025/2026 BRA were: the shift from the EFORd availability metric to the ELCC availability metric; the impact of withholding by categorically exempt resources; the impact of using summer ratings rather than winter ratings for combined cycle ("CC") and combustion turbine ("CT") resources; the impact of the exclusion of two reliability must run ("RMR") plants from the capacity market supply curve; and the use of Gross CONE rather than 1.5 times Net CONE as the maximum price in the market.

An increase in demand will further tighten the market, and prices in the next capacity auction will reflect both that increase and the market design issues. The Market Monitor analysis shows that with a 5.0 percent increase in the load forecast over the load forecast used in the 2025/2026 BRA and Gross CONE as the maximum price, total payments would increase by $10,434,929,287, or 71 percent over the actual 2025/2026 BRA payments, to $25,121,976,644, even if a CT is used as a reference resource and RMR capacity is fully included in the supply curve (Scenario 64).[20] That level of increase is in significant part the result of using Gross CONE rather than 1.5 times Net CONE as the maximum price on the capacity market demand curve (VRR curve).

Recent changes, or proposed changes, to the capacity market rules, consistent with Market Monitor recommendations but some of them only temporary, will improve the

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2024), Analysis of the 2025/2026 RPM Base Residual Auction–Part F (February 4, 2025). These reports can be accessed at: <*https://www.monitoringanalytics.com/reports/Reports/2024.shtml*> and <*https://www.monitoringanalytics.com/reports/Reports/2025.shtml*>. For convenience, the reports are included as Attachment A–F to this pleading.

20 *Analysis of the 2025/2026 RPM Base Residual Auction – Part E* at 19, Monitoring Analytics, LLC, (January 31, 2025) <https://www.monitoringanalytics.com/reports/Reports/2025.shtml>.

results of the 2026/2027 Base Residual Auction, while other recent changes will have the opposite effect. The must offer exemption for categorically exempt resources has been eliminated for all except demand side resources. The current RMR resources will be included in the capacity market supply curve. The undervaluation of thermal resources in the winter will not be addressed. The underlying issues with PJM's ELCC model will not be addressed.

Capacity accreditation should recognize the winter capability of thermal resources rather than limiting such resources to summer ratings. Most of the risk recognized in the ELCC model is winter risk but the ELCC accreditation values for thermal resources are capped at the summer ratings. That inappropriately reduces capacity payments to these resources, and reduces the capacity value of these resources, which artificially reduces the supply of capacity. From the market perspective, that unnecessarily limits supply and changes the ELCC values for all other resources which reduces the system accredited unforced capacity, changes the maximum level of load that can be served by the existing resources and therefore changes the reliability requirement. There is no reason that excess winter capacity interconnection rights ("CIRs") cannot be assigned to these resources immediately.

An increase in demand will further tighten the market, and prices in the next capacity auction will reflect both that increase and the modified market design. The Market Monitor analysis shows that with a 5.0 percent increase in the load forecast over the load forecast used in the 2025/2026 BRA, with the RMR resources included in supply, with the end of the categorical must offer exemption and with the maximum price equal to 1.5 times net CONE, total payments would increase by about $1.8 billion over the revenues in the

2025/2026 BRA, or 12.2 percent (Scenario 81*, Table 1).[21] This is significantly lower than the $10.4 billion, or 71.0 percent, increase that would result with PJM's preferred maximum price of Gross CONE or $499.32/MW-day (Scenario 63 from Part E).[22]

A goal of market design should be to be consistent and predictable and transparent. A consistent, predictable and transparent design would provide a stable investment environment for generators and a stable price environment for customers who both consume and invest. New supply requires competitive incentives and a stable investment environment. The objective of the market design should be markets that work, markets that work for generators and markets that work for customers. The objective of the market design should also be markets that are transparent and understandable to market participants and to regulators. The capacity market design should be as simple as possible to meet its objectives. The current capacity market design does not meet these standards.

Table 1 shows the impact on RPM revenues for Scenario 81*.[23] Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If, in addition to Scenario 79 from Part F, the MW capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, if the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual

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21 These calculations are based on the offers in the 2025/2026 BRA. The results of the simulations are not forecasts. If the increase in the load forecast were 3.5 percent, the increase in total payments would be about $0.9 billion, or 6.4 percent.

22 Scenario 63 does not include the price reducing effects of including RMR resources and eliminating the must offer obligation.

23 Scenario 81* was calculated for this filing and did not yet appear in a Market Monitor report. Scenario 81* is a variation of Scenario 81.

Auction would have been $16,484,604,500.0, an increase of 1,797,557,142.5, or 12.2 percent, compared to the actual results.

The expected impact in the 2026/2027 BRA, based on the offers in the 2025/2026 BRA, is an increase of $1.8 billion in customer payments for capacity. This increase of $1.8 billion is in addition to the $14.7 billion actual increase in the 2025/2026 BRA over the results of the 2024/2025 BRA.

This $1.8 billion increase is significantly less than what would have resulted from the use of PJM's maximum price of the higher of Gross CONE and 1.5 times Net CONE (Scenario 64 from Part E).

Table 1 Scenario summary for 2025/2026 RPM Base Residual Auction: VRR Curve Capped at $325 per MW-day; 5.0 Percent Higher Forecasted Peak Load

				Percent Change	
Scenario	Scenario Description	RPM Revenue ($ per Delivery Year)	RPM Revenue Change ($ per Delivery Year)	Scenario to Actual	Actual to Scenario
0	Actual results	14,687,047,357.5	NA	NA	NA
81*	Forecasted Peak Load: 5.0 percent higher, Status quo VRR curve based on $325 per UCAP MW-Day, Categorically exempt offers and RMR resources	16,484,604,500.0	(1,797,557,142.5)	(10.9%)	12.2%

II. CONCLUSION

The Market Monitor respectfully requests that the Commission afford due consideration to this pleading as the Commission resolves the issues raised in these proceedings.

Respectfully submitted,

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Dated: March 17, 2025

ATTACHMENT A

Monitoring Analytics

Analysis of the 2025/2026 RPM Base Residual Auction Part A

The Independent Market Monitor for PJM

September 20, 2024

Introduction

This report, Part A of what will be a comprehensive report, prepared by the Independent Market Monitor for PJM (IMM or MMU), presents a first set of sensitivity analyses of the nineteenth Reliability Pricing Model (RPM) Base Residual Auction (BRA) for the 2025/2026 Delivery Year which was held from July 17 to 23, 2024, and responds to questions raised by PJM members and market observers about that auction. The MMU prepares a comprehensive report for each RPM Base Residual Auction. In this case, rather than waiting until all sensitivities are completed, the MMU will present the results of sensitivities as they are completed in order to provide information to stakeholders that is relevant to decision making about the 2026/2027 BRA, currently scheduled for December 4 to 10, 2024. The IMM will provide a comprehensive report later.

This Part A report addresses, explains and quantifies the impact of specific critical market design choices in the 2025/2026 BRA. This report addresses and quantifies the impact on market outcomes of: the shift from the EFORd availability metric to the ELCC availability metric; the impact of withholding by categorically exempt resources; the impact of using summer ratings rather than winter ratings for combined cycle (CC) and combustion turbine (CT) resources; and the impact of the exclusion of two reliability must run (RMR) plants from the capacity market supply curve.[1]

Recognizing that the quantitative results are estimates, based on explicitly stated assumptions, the results show the direction and magnitude of the impacts of the identified factors in the PJM capacity market design. The results of the scenarios are not strictly additive. The MMU will provide future scenario analysis in order to evaluate the combined impact of multiple design elements.

In summary, holding everything else constant, use of the ELCC approach rather than the prior, EFORd approach, resulted in a 49.1 percent increase in RPM revenues, $4,436,433,748, for the 2025/2026 RPM Base Residual Auction compared to what RPM revenues would have been had PJM cleared the auction without locational constraints and using the prior, EFORd approach.

In summary, holding everything else constant, the failure to offer of some capacity that was categorically exempt from the RPM must offer requirement resulted in a 39.3 percent increase in RPM revenues, $4,139,820,375, for the 2025/2026 RPM Base Residual Auction

[1] The values stated in this report for the RTO and LDAs refer to the aggregate level including all nested LDAs unless otherwise specified. For example, RTO values include the entire PJM market and all LDAs. Rest of RTO values are RTO values net of nested LDA values.

compared to what RPM revenues would have been had the categorically exempt resources been subject to the RPM must offer requirement.

In summary, holding everything else constant, the use of summer ratings rather than winter ratings for CC and CT resources in the marginal ELCC based accreditation resulted, depending on the impact on the reserve margin, in from a 22.7 percent to a 118.1 percent increase in RPM revenues, $2,721,494,123 to $7,953,702,391, for the 2025/2026 RPM Base Residual Auction.

In summary, holding everything else constant, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day resulted in a 41.2 percent increase in RPM revenues, $4,287,256,309, for the 2025/2026 RPM Base Residual Auction compared to what RPM revenues would have been had the capacity of those RMR resources been included in the supply curve at $0 per MW-day.

The capacity market exists to make the energy market work, by providing the additional net revenues required for the incentive to invest in new units and to maintain old units. The definition of capacity is not the ability to provide energy during one peak hour or five peak hours, as implied by the methods used by PJM and LSEs to allocate the costs of capacity to load. The obligations of capacity resources include the requirement to offer their full ICAP in the energy and reserves markets every day. The need for the energy from capacity is not limited to one peak hour or five peak hours. Customers require energy from capacity resources all 8,760 hours per year. Rather than develop a complicated seasonal capacity market based on an arbitrary definition of seasons, the hourly value of the energy from capacity should be explicitly recognized in the capacity market.[2] Under that approach, products with different characteristics at different times of the year (so called seasonal products) would not need to be matched with peak period products.

The MMU recognizes that implementation of the recommendations in this report would require rule changes in some cases.

Conclusions

The capacity market is, by design, always tight in the sense that total supply is generally only slightly larger than demand. The PJM Capacity Market is a locational market and local markets frequently have different supply demand balances than the aggregate

2 See "Executive Summary of IMM Capacity market design proposal: Sustainable Capacity Market (SCM)," IMM presentation to the PJM Board of Managers, (August 23, 2023) <https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_RASTF-CIFP_SCM_Executive_Summary_20230816.pdf>.

market. While the market may be long at times, that is not the equilibrium state. Capacity in excess of demand is not sold and, if it does not earn or does not expect to earn adequate revenues from the full set of PJM markets, or does not have value as a hedge, may be expected to retire, provided the market sets appropriate price signals to reflect the availability of excess supply. Capacity in excess of demand means capacity in excess of the demand as defined by the capacity demand curve, called the Variable Resource Requirement (VRR) curve. PJM rules require load to pay for the level of capacity defined by the VRR curve. But, correctly defined, excess capacity means capacity in excess of the peak load forecast plus the reserve margin, the level of capacity PJM is required to purchase in order to maintain reliability.

The demand for capacity in the capacity market is almost entirely inelastic because the market rules require loads to purchase their share of the system capacity requirement. The downward sloping portion of the VRR curve is everywhere inelastic. The result is that any supplier that owns more capacity than the typically small difference between total supply and the VRR defined demand is individually pivotal and therefore has structural market power. Any supplier that, jointly with two other suppliers, owns more capacity than the difference between supply and the VRR defined demand either in aggregate or for a local market is jointly pivotal and therefore has structural market power.

The market design for capacity leads, almost unavoidably, to structural market power in the capacity market. The capacity market is unlikely ever to approach a competitive market structure in the absence of a substantial and unlikely structural change that results in much greater diversity of ownership. Market power is and will remain endemic to the structure of the PJM Capacity Market. Nonetheless a competitive outcome can be assured by appropriate market power mitigation rules. Detailed market power mitigation rules are included in the PJM Open Access Transmission Tariff (OATT or Tariff). Reliance on the RPM design for competitive outcomes means reliance on the market power mitigation rules. Attenuation of those rules means that market participants are not able to rely on the competitiveness of the market outcomes.

There are currently two important gaps in the market power rules for the PJM Capacity Market. Unlike all other generation capacity resources, Intermittent Resources, Capacity Storage Resources, and Hybrid Resources consisting exclusively of components that in isolation would be Intermittent Resources or Capacity Storage Resources are categorically exempt from the RPM must offer requirement. Capacity Storage Resources include hydroelectric, flywheel and battery storage. Intermittent Resources include wind, solar, landfill gas, run of river hydroelectric, and other renewable resources. As a result, a significant level of such resources withhold their capacity. The result is to increase the clearing prices above the competitive level. This can benefit the owners of capacity portfolios that include such resources as well as resources with an RPM must offer requirement. The MMU recommends that all capacity resources have a must offer obligation. Demand resources (DR) have always been treated more favorably than generation capacity resources. Demand resources also do not have an RPM must offer requirement. Demand resources, unlike all other capacity resources, are not subject to market seller offer caps to protect against the exercise of market power. When demand resources are pivotal, as they were for the 2025/2026 BRA, they have structural market power and can and do exercise market power. The result is to increase the clearing prices above the competitive level. This can benefit the owners of capacity portfolios that include such resources as well as resources with an RPM must offer requirement. The MMU recommends that demand resources have defined and enforced market seller offer caps, like all other capacity resources.

In the capacity market, as in other markets, market power is the ability of a market participant to increase the market price above the competitive level or to decrease the market price below the competitive level. In order to evaluate whether actual prices reflect the exercise of market power, it is necessary to evaluate whether market offers are consistent with competitive offers. The market seller offer cap defines a competitive offer in the capacity market, regardless of whether the concern is efforts to increase the market price above the competitive level or to reduce the market price below the competitive level. As in all other markets, the competitive offer in the capacity market is the marginal cost of capacity. A competitive offer in the capacity market is equal to net ACR.[3]

All participants to which the three pivotal supplier (TPS) test was applied (in the RTO, BGE, and DOM RPM markets) failed the three pivotal supplier test. The result was that offer caps were applied to all sell offers for Existing Generation Capacity Resources when the capacity market seller did not pass the test, the submitted sell offer exceeded the tariff defined offer cap, and the submitted sell offer, absent mitigation, would have resulted in a higher market clearing price.[4] [5]

Based on the data and this review, the MMU concludes that the results of the 2025/2026 RPM Base Residual Auction were significantly affected by flawed market design decisions

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3 174 FERC ¶ 61,212 ("March 18th Order") at 65.

4 Prior to November 1, 2009, existing DR and EE were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 (2009) at P 30.

5 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation, and treating a proposed increase in the capability of a Generation Capacity Resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).

including PJM's ELCC approach and by the exercise of market power through the withholding of categorically exempt resources and high offers from demand resources. The BRA prices do not solely reflect supply and demand fundamentals but also reflect, in significant part, PJM decisions about the definition of supply and demand. The auction results were not solely the result of the introduction of the ELCC approach and do in part reflect the tightening of supply and demand conditions in the PJM Capacity Market. PJM's ELCC filing that created many of these issues was approved by FERC.[6]

Recommendations

The recommendations in this Part A report are related primarily to the results of the sensitivity analyses presented in this Part A report.

The MMU recommends that the must offer rule in the capacity market apply to all capacity resources.[7] Prior to the implementation of the capacity performance design, all existing capacity resources, except DR, were subject to the RPM must offer requirement. There is no reason to exempt intermittent and capacity storage resources, including hydro, from the RPM must offer requirement. The same rules should apply to all capacity resources. The purpose of the RPM must offer rule, which has been in place since the beginning of the capacity market in 1999, is to ensure that the capacity market works based on the inclusion of all demand and all supply, and to prevent the exercise of market power via withholding of supply. The purpose of the RPM must offer requirement is also to ensure equal access to the transmission system through capacity interconnection rights (CIRs). If a resource has CIRs but fails to use them by not offering in the capacity market, the resource is withholding and is also denying the opportunity to offer to other resources that would use the CIRs. For these reasons, existing resources are required to return CIRs to the market within one year after retirement. The same logic should be applied to intermittent and capacity storage resources. The failure to apply the RPM must offer requirement will create increasingly significant market design issues and market power issues in the capacity market as the level of capacity from intermittent and capacity storage resources increases. The failure to apply the RPM must offer requirement consistently could also result in very significant changes in supply from auction to auction which would create price volatility and uncertainty in the capacity market and put PJM's reliability margin at risk. The capacity market was designed on the basis of a must buy

6 186 FERC ¶ 61,080 (January 30, 2024).

7 See "Executive Summary of IMM Capacity market design proposal: Sustainable Capacity Market (SCM)," IMM presentation to the PJM Board of Managers, (August 23, 2023) <https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_RASTF-CIFP_SCM_Executive_Summary_20230816.pdf>.

requirement for load and a corresponding must offer requirement for capacity resources. The capacity market can work only if both are enforced.

The reasons for the exemption of intermittents and storage to date were based on the seasonality of the resources and on PJM's imposition of performance assessment interval (PAI) penalties for nonperformance when performance was not physically possible, e.g. PAI penalties to solar for not producing at night. Neither applies to all the exempt resources and neither is a good reason to exempt these resources. As the role of intermittents and storage grows it is essential to reestablish the must offer obligation for all resources. The inclusion of a must offer obligation for intermittent and capacity storage resources should be coupled with the removal of PAI penalty liability for such resources when it is not physically possible to perform. The capacity market has included balanced must buy and must sell obligations from its inception. These rules can and should be changed.

The MMU recommends that the ELCC be significantly refined to include hourly data that would permit unit specific ELCC ratings, to weight summer and winter risk in a more balanced manner, to eliminate PAI risks, and to pay for actual hourly performance rather than based on relatively inflexible class capacity accreditation ratings derived from a small number of hours of poor performance. Specifically, in the short run the MMU recommends that capacity accreditation recognize the winter capability of thermal resources rather than limiting such resources to summer ratings. Most of the risk recognized in the ELCC model is winter risk but the ELCC accreditation values for thermal resources are capped at the summer ratings. That unnecessarily limits supply and changes the ELCC values for all other resources and changes the system accredited unforced capacity and therefore AUCAP, the maximum level of load that can be served by the existing resources and therefore the reliability requirement. The CIRs of such resources are currently limited by the summer ratings but those rules can and should be changed given the use of the ELCC approach. There is no reason that excess winter CIRs cannot be assigned to these resources immediately.

The MMU recommends that PJM treat the inclusion of RMR resources in the capacity market consistently. PJM currently includes RMR units in the reliability analysis for RPM auctions but does not include the RMR units in the supply curves. This approach is internally inconsistent. It would be internally consistent to leave the RMR units out of the CETO/CETL analysis. It would also be internally consistent to include the RMR units in the supply of capacity and in the CETO/CETL analysis. Including RMR resources in the capacity supply curve does not mean forcing unit owners to offer or to take on PAI risk, for example. It simply means that PJM would recognize the fact that PJM treats RMR resources as a source of reliability. The goal is to ensure that the underlying supply and demand fundamentals are included in the capacity market prices. These two options have very different implications for capacity market prices. There are times when a price signal for the entry of generation is appropriate, e.g. when the goal is to allow generation to compete to replace the transmission option, in whole or in part. There are times when a price signal for the entry of generation is not needed or appropriate, e.g. when PJM has committed to the construction of new transmission that will eliminate the price signal when complete. The relevant rules can and should be changed.

Summary of Results

Cleared generation and DR for the entire RTO of 134,224.2 MW resulted in a reserve margin of 18.6 percent and a net excess of 870.9 MW over the reliability requirement adjusted for FRR and PRD of 133,353.3 MW.[8] [9] Net excess decreased 7,215.9 MW from the net excess of 8,086.8 MW in the 2024/2025 RPM Base Residual Auction. The intersection of the supply curve and the downward sloping VRR demand curve resulted in a clearing price for Capacity Performance Resources of $269.92 per MW-day for the rest of RTO.

Table 1, Table 2 and Table 3 show the summary of the revenue impact of the scenarios analyzed. The results of the scenarios are not strictly additive. The quantitative results are estimates. The report makes explicit when the quantitative results depend on assumptions. Even in those cases, the quantitative results are correct as to direction and order of magnitude. The RPM Revenue column shows the revenues that resulted from the specific scenario only. The Scenario Impact RPM Revenue Change column shows the difference between the actual RPM total revenues and the total RPM revenues that resulted from the specific scenario. A positive number means that the specific scenario resulted in a reduction in RPM revenues. A negative number means that the specific scenario resulted in an increase in RPM revenues. The Percent columns show the percent change in RPM revenues for the specific scenario from two perspectives. The Scenario to Actual Percent column, shows the difference between the revenues under the defined scenario and the defined baseline as a percent of the revenues under the defined scenario. The Actual to Scenario Percent column shows the difference between the revenues under the defined scenario and the defined baseline as a percent of the revenues under the defined baseline.

The 2025/2026 RPM Base Residual Auction was the first BRA held under the new ELCC rules that substantially changed the approach used in the PJM's Reserve Requirement Study (RRS) to establish the reserve margin and the way PJM accredits resources offered

[8] The 18.6 percent reserve margin does not include EE on the supply side or the EE addback on the demand side. The EE for this calculation includes annual EE and summer EE. The reserve margin calculation also does not include any MW of uplift. This is how PJM calculates the reserve margin.

[9] These reserve margin calculations do not consider Fixed Resource Requirement (FRR) load.

in capacity auctions by implementing PJM's ELCC approach. The MMU analyzed the impact of these changes on the auction results for the 2025/2026 RPM Base Residual Auction. PJM calculated the reserve margin that would have been used to derive the reliability requirement of the RTO under the prior, EFORd approach.[10] However, PJM did not publish the Capacity Emergency Transfer Objective (CETO) values that would have been used to derive the reliability requirement of the modeled locational deliverability areas (LDAs) under the prior, EFORd approach. To isolate the impact of these rule changes without making any assumptions about the possible CETO values, the MMU sensitivity analysis first calculated the impact of locational constraints. The result was the BRA revenues under the ELCC approach if there had been no locational constraints. The MMU then calculated the impact of the change from the EFORd approach to the ELCC approach without locational constraints and therefore no modeled LDAs and, as a result, with a single clearing RTO price.

Table 1 shows the impact of these changes on RPM revenues for the auction. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If PJM did not model locational constraints in the 2025/2026 RPM Base Residual Auction and everything else had remained the same, the total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $13,468,655,753, a decrease of $1,218,391,605, or 8.3 percent, compared to the actual results. From another perspective, locational constraints resulted in a 9.0 percent increase in RPM revenues for the 2025/2026 RPM Base Residual Auction compared to what RPM revenues would have been had PJM cleared the auction without locational constraints (Scenario 1A).

If PJM used the EFORd approach rather than ELCC based accreditation in the 2025/2026 RPM Base Residual Auction without locational constraints and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $9,032,222,005, a decrease of $4,436,433,748 or 32.9 percent, compared to the results of RPM Base Residual Auction without locational constraints, using the ELCC approach. From another perspective, use of the ELCC approach rather than the prior, EFORd approach resulted in a 49.1 percent increase in RPM revenues for the 2025/2026 RPM Base Residual Auction compared to what RPM revenues would have been had PJM cleared the auction without locational constraints and using the prior, EFORd approach (Scenario 1B).

10 See *2023 PJM Reserve Requirement Study*, PJM Resource Adequacy Planning (October 3, 2023), <https://www.pjm.com/-/media/committees-groups/committees/mc/2023/20231115/20231115-consent-agenda-b---2-2023-pjm-reserve-requirement-study-report-final.ashx?>

The MMU analyzed the impact of capacity that was categorically exempt from the RPM must offer obligation and that did not offer into the 2025/2026 RPM Base Residual Auction. Capacity resources that were categorically exempt from the RPM must offer requirement and did not offer in the 2025/2026 RPM Base Residual Auction had a significant impact on the auction results. In this scenario, all categorically exempt resources were added to the supply curve at $0 per MW-day.

Table 2 shows the impact on RPM revenues for the auction. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If the capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $10,547,226,983, a decrease of $4,139,820,375, or 28.2 percent, compared to the actual results. From another perspective, the failure to offer capacity that was categorically exempt from the RPM must offer requirement resulted in a 39.3 percent increase in RPM revenues for the 2025/2026 RPM Base Residual Auction compared to what RPM revenues would have been had the categorically exempt resources been subject to the RPM must offer requirement (Scenario 2).

The MMU analyzed the impact of PJM's rules related to the role of RMR resources in capacity auctions. If the RMR resource does not offer into the capacity auction, the resource's capacity is not included in the capacity auction while the capacity is included in PJM's CETO/CETL reliability analysis. Specifically, the RMR resources in the BGE LDA did not offer their capacity in the 2025/2026 RPM Base Residual Auction and that capacity was not included in supply offers when clearing the auction. This scenario (Scenario 3) is the case where all RMR resources in the BGE LDA were added to the supply curve at $0 per MW-day.

Table 2 shows the impact on RPM revenues for the auction. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If the capacity of the RMR resources in the BGE LDA been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $10,399,791,048, a decrease of $4,287,256,309, or 29.2 percent, compared to the actual results. From another perspective, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day resulted in a 41.2 percent increase in RPM revenues for the 2025/2026 RPM Base Residual Auction compared to what RPM revenues would have been had the capacity of the RMR resources been included in the supply curve at $0 per MW-day (Scenario 3).

The MMU analyzed the impact of limiting generation capacity from combined cycle (CC) and combustion turbine (CT) resources to their summer rating rather than their higher winter ratings. The MMU estimated that, on average, the ELCC resource performance adjusted accreditation of each of these resources would have been 8.8 percent higher and the resultant pool wide accredited UCAP factor (AUCAP) would have increased from 79.69 percent to 82.53 percent if the higher winter ratings had been used. The average ELCC class ratings for CC resources in the 2025/2026 RPM Base Residual Auction was 79 percent and the average ELCC class accreditation factor for CT resources was 62 percent.[11]

The MMU recognizes that using higher winter ratings for CCs and CTs affects the ELCC values of other resource types and also affects the peak load that the capacity can serve (solved load). For this preliminary sensitivity analysis, the MMU has assumed a range of peak loads that capacity can serve (solved load) and the related changes in the reserve requirement. The installed reserve margin (IRM) and reliability requirement would be lower if the higher generation capacity of these resources during the winter months were recognized. PJM could recalculate the ELCC ratings for all classes based on the winter ratings for CCs and CTs and calculate the associated reliability requirement (a revised PJM Reserve Requirement Study). In the absence of a comprehensive recalculation, the MMU's sensitivity analysis includes three scenarios with a range of lower IRMs. In the 2023 Reserve Requirement Study, PJM determined that the solved load needed to meet a 1 in 10 Loss of Load Expectation (LOLE) criterion is 160,624 MW, resulting in an associated IRM of 17.8 percent for the 2025/2026 BRA. In Scenario 4A, the MMU assumed the higher winter generation capacity would not result in any change to the solved load and the associated IRM. In Scenario 4B, the MMU assumed the higher winter generation capacity would increase the solved load to 162,500 MW and reduce the IRM to 16.4 percent. In Scenario 4C, the MMU assumed the higher winter generation capacity would increase the solved load to 165,000 MW and reduce the IRM to 14.6 percent. The MMU analysis assumes that under all three scenarios, there would not be any change in the Capacity Emergency Transfer Objective values of modeled LDAs.

Table 3 shows the impact on RPM revenues for the auction. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $11,965,553,235, a decrease of $2,721,494,123, or 18.5 percent, compared to the actual results. From another perspective, the use of summer ratings rather than winter

11 PJM. ELCC Class Ratings for the 2025/2026 Base Residual Auction, Study Results. <https://www.pjm.com/-/media/planning/res-adeq/elcc/2025-26-bra-elcc-class-ratings.ashx>

ratings for CC and CT resources in the marginal ELCC based accreditation resulted in a 22.7 percent increase in RPM revenues for the 2025/2026 RPM Base Residual Auction (Scenario 4A).

Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, the IRM decreased to 16.4 percent, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $8,229,935,414, a decrease of $6,457,111,944, or 44.0 percent, compared to the actual results. From another perspective, the use of summer ratings rather than winter ratings for CC and CT resources in the marginal ELCC based accreditation with an associated change in the IRM to 16.4 percent resulted in a 78.5 percent increase in RPM revenues for the 2025/2026 RPM Base Residual Auction (Scenario 4B).

Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, the IRM decreased to 14.6 percent and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $6,733,344,966, a decrease of $7,953,702,391, or 54.2 percent, compared to the actual results. From another perspective, the use of summer ratings rather than winter ratings for CC and CT resources in the marginal ELCC based accreditation with an associated change in the IRM to 14.6 percent resulted in a 118.1 percent increase in RPM revenues for the 2025/2026 RPM Base Residual Auction (Scenario 4C).

Summary Results Tables

Table 1 Scenario summary for 2025/2026 RPM Base Residual Auction: Impact on RPM revenue due to ELCC related changes[12]

			Scenario Impact		
				Percent Change	
Scenario	Scenario Description	RPM Revenue ($ per Delivery Year)	RPM Revenue Change ($ per Delivery Year)	Scenario to Actual	Actual to Scenario
0	Actual results	$14,687,047,358	NA	NA	NA
1A	Locational constraints	$13,468,655,753	$1,218,391,605	9.0%	(8.3%)
1B	Marginal ELCC based accreditation	$9,032,222,005	$4,436,433,748	49.1%	(32.9%)

12 Scenario to Actual represents the impact of moving from the scenario to the actual BRA results and the percent change is *(Actual RPM Revenue less Scenario RPM Revenue) / (Scenario RPM*

Table 2 Scenario summary for 2025/2026 RPM Base Residual Auction: Impacts on RPM Revenue due to market behavior of categorically exempt resources and RMR resources

			Scenario Impact		
				Percent Change	
		RPM Revenue	RPM Revenue Change	Scenario to	Actual to
Scenario	Scenario Description	($ per Delivery Year)	($ per Delivery Year)	Actual	Scenario
0	Actual results	$14,687,047,358	NA	NA	NA
2	All categorically exempt offers	$10,547,226,983	$4,139,820,375	39.3%	(28.2%)
3	RMR resources	$10,399,791,048	$4,287,256,309	41.2%	(29.2%)

Table 3 Scenario summary for 2025/2026 RPM Base Residual Auction: Impact on RPM Revenue due to winter ratings

			Scenario Impact		
				Percent Change	
		RPM Revenue	RPM Revenue Change	Scenario to	Actual to
Scenario	Scenario Description	($ per Delivery Year)	($ per Delivery Year)	Actual	Scenario
0	Actual results	$14,687,047,358	NA	NA	NA
4A	Winter ratings and IRM at 17.8 percent (same as BRA)	$11,965,553,235	$2,721,494,123	22.7%	(18.5%)
4B	Winter ratings and IRM at 16.4 percent	$8,229,935,414	$6,457,111,944	78.5%	(44.0%)
4C	Winter ratings and IRM at 14.6 percent	$6,733,344,966	$7,953,702,391	118.1%	(54.2%)

Table 4, Table 5 and Table 6 show the summary of the cleared UCAP MW impact of all the scenarios analyzed. The Cleared UCAP column shows the cleared MW that resulted from the specific scenario only. The Scenario Impact Cleared UCAP Change column shows the difference between the actual RPM cleared UCAP MW and the total RPM cleared UCAP MW that resulted from the specific scenario. A positive number means that the specific scenario resulted in a reduction in cleared MW. A negative number means that the specific scenario resulted in an increase in cleared MW. The Scenario Impact Cleared UCAP column shows the difference between the actual RPM cleared MW and the total RPM cleared MW that resulted from the specific scenario. A positive number means that the specific scenario resulted in a reduction in RPM cleared MW. A negative number means that the specific scenario resulted in an increase in RPM cleared MW. The percent columns show the percent change in RPM cleared MW for the specific scenario from two perspectives. The Scenario to Actual Percent column shows the difference between the MW under the defined scenario and the defined baseline as a percent of the MW under the defined scenario. The Actual to Scenario Percent column shows the difference between the MW under the defined scenario and the defined baseline as a percent of the MW under the defined baseline.

Table 4 shows the impact of these changes on the cleared UCAP MW as defined under each approach. If PJM used the ELCC based approach without locational constraints in

Revenue). The Actual to Scenario column represents the alternative perspective of the impact from moving from the actual BRA results to the scenario results and the percent change is *(Scenario RPM Revenue less Actual RPM Revenue) / (Actual RPM Revenue)*.

the 2025/2026 RPM Base Residual Auction, 135,697.9 ELCC UCAP MW would clear. If PJM used the EFORd based approach without locational constraints in the 2025/2026 RPM Base Residual Auction, 163,971.1 EFORd UCAP MW would clear.

Table 5 shows the impact on the cleared UCAP MW for the auction. In both scenarios, additional supply would have resulted in increasing the total cleared UCAP MW compared to the actual results. If the capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction and everything else had remained the same, total cleared UCAP MW in the 2025/2026 RPM Base Residual Auction would have been 137,128.3 UCAP MW, an increase of 1,444.3 UCAP MW, or 1.1 percent, compared to the actual results. If the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction and everything else had remained the same, total cleared UCAP MW for the 2025/2026 RPM Base Residual Auction would have been 134,125.6 UCAP MW, an increase of 1,440.6 UCAP MW, or 1.1 percent, compared to the actual results.

Table 6 shows the impact on the cleared UCAP MW for the auction. The use of winter ratings rather than summer ratings for CC and CT resources would result in increasing the available supply and cleared UCAP MW. If marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction and everything else had remained the same, total cleared UCAP MW for the 2025/2026 RPM Base Residual Auction would have been 141,077.3, an increase of 5,393.3 UCAP MW, or 4.0 percent, compared to the actual results. If marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, the reserve margin decreased to 16.4 percent, and everything else had remained the same, total cleared UCAP MW for the 2025/2026 RPM Base Residual Auction would have been 140,891.7, an increase of 5,207.7 UCAP MW or 3.8 percent, compared to the actual results. If marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, the reserve margin decreased to 14.6 percent, and everything else had remained the same, total cleared UCAP MW for the 2025/2026 RPM Base Residual Auction would have been 140,126.0, an increase of 4,442.0 UCAP MW or 3.3 percent, compared to the actual results. Since the reliability requirement is set proportionately to the IRM, more UCAP MW would clear under 17.8 percent IRM (Scenario 4A) compared to 16.4 percent IRM (Scenario 4B). Similarly, more UCAP MW would clear under 16.4 percent IRM (Scenario 4B) compared to 14.6 percent IRM (Scenario 4C).

Table 4 Scenario summary for 2025/2026 RPM Base Residual Auction: Impacts on RPM cleared UCAP MW due to ELCC related changes[13]

			Scenario Impact		
				Percent Change	
Scenario	Scenario Description	Cleared UCAP (MW)	Cleared UCAP Change (MW)	Scenario to Actual	Actual to Scenario
0	Actual results	135,684.0	NA	NA	NA
1A	Locational constraints	135,697.9	(13.9)	(0.0%)	0.0%
1B	Marginal ELCC based accreditation	163,971.1	(28,273.1)	(17.2%)	20.8%

Table 5 Scenario summary for 2025/2026 RPM Base Residual Auction: Impacts on RPM cleared UCAP MW due to market behavior of categorically exempt resources and RMR resources

			Scenario Impact		
				Percent Change	
Scenario	Scenario Description	Cleared UCAP (MW)	Cleared UCAP Change (MW)	Scenario to Actual	Actual to Scenario
0	Actual results	135,684.0	NA	NA	NA
2	All categorically exempt offers	137,128.3	(1,444.3)	(1.1%)	1.1%
3	RMR resources	137,124.6	(1,440.6)	(1.1%)	1.1%

Table 6 Scenario summary for 2025/2026 RPM Base Residual Auction: Impact on RPM cleared UCAP due to winter ratings

			Scenario Impact		
				Percent Change	
Scenario	Scenario Description	Cleared UCAP (MW)	Cleared UCAP Change (MW)	Scenario to Actual	Actual to Scenario
0	Actual results	135,684.0	NA	NA	NA
4A	Winter ratings and IRM at 17.8 percent (same as BRA)	141,077.3	(5,393.3)	(3.8%)	4.0%
4B	Winter ratings and IRM at 16.4 percent	140,891.7	(5,207.7)	(3.7%)	3.8%
4C	Winter ratings and IRM at 14.6 percent	140,126.0	(4,442.0)	(3.2%)	3.3%

13 Scenario to Actual represents the impact of moving from the scenario to the actual BRA results and the percent change is *(Actual Cleared UCAP less Scenario Cleared UCAP) / (Scenario Cleared UCAP)*. The Actual to Scenario column represents the alternative perspective of the impact from moving from the actual BRA results to the scenario results and the percent change is *(Scenario Cleared UCAP less Actual Cleared UCAP) / (Actual Cleared UCAP)*.

ATTACHMENT B

Analysis of the 2025/2026 RPM Base Residual Auction Part B

The Independent Market Monitor for PJM

October 15, 2024

Introduction

This report, Part B of what will be a comprehensive report, prepared by the Independent Market Monitor for PJM (IMM or MMU), presents a second set of sensitivity analyses of the nineteenth Reliability Pricing Model (RPM) Base Residual Auction (BRA) for the 2025/2026 Delivery Year which was held from July 17 to 23, 2024. The MMU prepares a comprehensive report for each RPM Base Residual Auction. In this case, rather than waiting until all sensitivities are completed, the MMU will present the results of sensitivities as they are completed in order to provide information to stakeholders that is relevant to decision making about the 2026/2027 BRA, previously scheduled for December 4 to 10, 2024, and now delayed for approximately six months. The IMM will provide a comprehensive report later.

This Part B report addresses, explains and quantifies the combined impact of specific critical market design choices in the 2025/2026 BRA that were identified in the Analysis of the 2025/2026 RPM Base Residual Auction Part A ("Part A"). This report addresses and quantifies the combined impact on market outcomes of: the impact of withholding by categorically exempt resources; the impact of the exclusion of two reliability must run (RMR) plants from the capacity market supply curve; and the impact of using summer ratings rather than winter ratings for combined cycle (CC) and combustion turbine (CT) resources.[1] This report does not combine the results of Scenario 1 with Scenarios 2, 3 and 4. The joint analysis of Scenario 1 which compared the results under the prior EFORd approach to the results under the ELCC approach and Scenarios 2, 3 and 4, would have required that PJM do an internally consistent EFORd analysis include CETO and CETL. Scenarios 2, 3 and 4 all assume the basic parameters of PJM's ELCC approach. The estimate of the combined impact of Scenarios 2, 3 and 4, is therefore conservatively low, although the estimated difference is not known.

Recognizing that the quantitative results are estimates, based on explicitly stated assumptions, the results show the direction and magnitude of the combined impacts of the identified factors in the PJM capacity market design. As a result of the fact that the results of the individual scenarios in Part A are not strictly additive, this Part B presents the results of making the identified changes simultaneously. Part B provides scenario analysis that evaluates the combined impact of multiple design elements.

In summary, holding everything else constant, the failure to offer of some capacity that was categorically exempt from the RPM must offer requirement (Scenario 2) together with

[1] The values stated in this report for the RTO and LDAs refer to the aggregate level including all nested LDAs unless otherwise specified. For example, RTO values include the entire PJM market and all LDAs. Rest of RTO values are RTO values net of nested LDA values.

the exclusion of the RMR resources in the BGE LDA from the supply curve (Scenario 3), resulted in a 53.9 percent increase in RPM revenues, $5,142,994,604, for the 2025/2026 RPM Base Residual Auction compared to what RPM revenues would have been had the categorically exempt resources been subject to the RPM must offer requirement and had the RMR resources been included in the supply curve. (Scenario 5)

In summary, holding everything else constant, the exclusion of the RMR resources in the BGE LDA from the supply curve (Scenario 3), together with the use of summer ratings rather than winter ratings for CC and CT resources in the marginal ELCC based accreditation (Scenario 4A), resulted in a 77.6 percent increase in RPM revenues, $6,418,370,722, for the 2025/2026 RPM Base Residual Auction compared to what RPM revenues would have been had the RMR resources been included in the supply curve and had winter ratings been used for CC and CT resources. (Scenario 6)

In summary, holding everything else constant, the failure to offer of some capacity that was categorically exempt from the RPM must offer requirement (Scenario 2) together with the exclusion of the RMR resources in the BGE LDA from the supply curve (Scenario 3), and the use of summer ratings rather than winter ratings for CC and CT resources in the marginal ELCC based accreditation (Scenario 4A) resulted in a 108.1 percent increase in RPM revenues, $7,630,166,235, for the 2025/2026 RPM Base Residual Auction compared to what RPM revenues would have been had the categorically exempt resources been subject to the RPM must offer requirement, had the RMR resources been included in the supply curve, and had had winter ratings been used for CC and CT resources. (Scenario 7)

The capacity market exists to make the energy market work, by providing the additional net revenues required for the incentive to invest in new units and to maintain old units. The definition of capacity is not the ability to provide energy during one peak hour or five peak hours, as implied by the methods used by PJM and LSEs to allocate the costs of capacity to load. The obligations of capacity resources include the requirement to offer their full ICAP in the energy and reserves markets every day. The need for the energy from capacity is not limited to one peak hour or five peak hours. Customers require energy from capacity resources all 8,760 hours per year. Rather than develop a complicated seasonal capacity market based on an arbitrary definition of seasons, the hourly value of the energy from capacity should be explicitly recognized in the capacity market.[2] Under that approach, products with different characteristics at different times of

2 See "Executive Summary of IMM Capacity market design proposal: Sustainable Capacity Market (SCM)," IMM presentation to the PJM Board of Managers, (August 23, 2023) <https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_RASTF-CIFP_SCM_Executive_Summary_20230816.pdf>.

the year (so called seasonal products) would not need to be matched with peak period products.

The MMU recognizes that implementation of the recommendations in this report would require rule changes in some cases.

Conclusions

The capacity market is, by design, always tight in the sense that total supply is generally only slightly larger than demand. The PJM Capacity Market is a locational market and local markets frequently have different supply demand balances than the aggregate market.[3] While the market may be long at times, that is not the equilibrium state. Capacity in excess of demand is not sold and, if it does not earn or does not expect to earn adequate revenues from the full set of PJM markets, or does not have value as a hedge, may be expected to retire, provided the market sets appropriate price signals to reflect the availability of excess supply. Capacity in excess of demand means capacity in excess of the demand as defined by the capacity demand curve, called the Variable Resource Requirement (VRR) curve. PJM rules require load to pay for the level of capacity defined by the VRR curve. Correctly defined, excess capacity means capacity in excess of the peak load forecast plus the reserve margin, the level of capacity PJM is required to purchase in order to maintain reliability, measured in UCAP.

The demand for capacity in the capacity market is almost entirely inelastic because the market rules require loads to purchase their share of the system capacity requirement. The downward sloping portion of the VRR curve is everywhere inelastic. The result is that any supplier that owns more capacity than the typically small difference between total supply and the VRR defined demand is individually pivotal and therefore has structural market power. Any supplier that, jointly with two other suppliers, owns more capacity than the difference between supply and the VRR defined demand either in aggregate or for a local market is jointly pivotal and therefore has structural market power.

The market design for capacity leads, almost unavoidably, to structural market power in the capacity market. The capacity market is unlikely ever to approach a competitive market structure in the absence of a substantial and unlikely structural change that results in much greater diversity of ownership. Market power is and will remain endemic to the structure of the PJM Capacity Market. Nonetheless a competitive outcome can be assured by appropriate market power mitigation rules. Detailed market power mitigation rules

[3] The locational element of the PJM Capacity Market is limited to the recognition of different LDAs which were initially defined by transmission zones but now also include subzones. However the PJM Capacity Market is not fully locational because it treats all capacity within an LDA as equivalent rather than recognizing the impacts of internal transmission constraints.

are included in the PJM Open Access Transmission Tariff (OATT or Tariff). Reliance on the RPM design for competitive outcomes means reliance on the market power mitigation rules. Attenuation of those rules means that market participants are not able to rely on the competitiveness of the market outcomes.

There are currently two important gaps in the market power rules for the PJM Capacity Market. Unlike all other generation capacity resources, Intermittent Resources, Capacity Storage Resources, and Hybrid Resources consisting exclusively of components that in isolation would be Intermittent Resources or Capacity Storage Resources are categorically exempt from the RPM must offer requirement. Capacity Storage Resources include hydroelectric, flywheel and battery storage. Intermittent Resources include wind, solar, landfill gas, run of river hydroelectric, and other renewable resources. As a result, a significant level of such resources withhold their capacity. The result is to increase the clearing prices above the competitive level. This can benefit the owners of capacity portfolios that include such resources as well as resources with an RPM must offer requirement. The MMU recommends that all capacity resources have a must offer obligation. Demand resources (DR) have always been treated more favorably than generation capacity resources. Demand resources also do not have an RPM must offer requirement. Demand resources, unlike all other capacity resources, are not subject to market seller offer caps to protect against the exercise of market power. When demand resources are pivotal, as they were for the 2025/2026 BRA, they have structural market power and can and do exercise market power. The result is to increase the clearing prices above the competitive level. This can benefit the owners of capacity portfolios that include such resources as well as resources with an RPM must offer requirement. The MMU recommends that demand resources have defined and enforced market seller offer caps, like all other capacity resources.

In the capacity market, as in other markets, market power is the ability of a market participant to increase the market price above the competitive level or to decrease the market price below the competitive level. In order to evaluate whether actual prices reflect the exercise of market power, it is necessary to evaluate whether market offers are consistent with competitive offers. The market seller offer cap defines a competitive offer in the capacity market, regardless of whether the concern is efforts to increase the market price above the competitive level or to reduce the market price below the competitive level. As in all other markets, the competitive offer in the capacity market is the marginal cost of capacity. A competitive offer in the capacity market is equal to net ACR.[4]

[4] 174 FERC ¶ 61,212 ("March 18th Order") at 65.

All participants to which the three pivotal supplier (TPS) test was applied (in the RTO, BGE, and DOM RPM markets) failed the three pivotal supplier test. The result was that offer caps were applied to all sell offers for Existing Generation Capacity Resources when the capacity market seller did not pass the test, the submitted sell offer exceeded the tariff defined offer cap, and the submitted sell offer, absent mitigation, would have resulted in a higher market clearing price.[5] [6]

Based on the data and this review in Part A and Part B, the MMU concludes that the results of the 2025/2026 RPM Base Residual Auction were significantly affected by flawed market design decisions including PJM's ELCC approach, by the exercise of market power through the withholding of categorically exempt resources and high offers from demand resources, and by the exclusion from supply of the defined RMR resources. The BRA prices do not solely reflect supply and demand fundamentals but also reflect, in significant part, PJM decisions about the definition of supply and demand. The auction results were not solely the result of the introduction of the ELCC approach and do in part reflect the tightening of supply and demand conditions in the PJM Capacity Market. PJM's ELCC filing that created many of these issues was approved by FERC.[7]

Recommendations

The recommendations in Part A and Part B are related primarily to the results of the sensitivity analyses presented in both Part A and Part B of this report.

The MMU recommends that the must offer rule in the capacity market apply to all capacity resources.[8] Prior to the implementation of the capacity performance design, all

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5 Prior to November 1, 2009, existing DR and EE were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 (2009) at P 30.

6 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation, and treating a proposed increase in the capability of a Generation Capacity Resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).

7 186 FERC ¶ 61,080 (January 30, 2024).

8 See "Executive Summary of IMM Capacity market design proposal: Sustainable Capacity Market (SCM)," IMM presentation to the PJM Board of Managers, (August 23, 2023) <https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_RASTF-CIFP_SCM_Executive_Summary_20230816.pdf>.

existing capacity resources, except DR, were subject to the RPM must offer requirement. There is no reason to exempt intermittent and capacity storage resources, including hydro, from the RPM must offer requirement. The same rules should apply to all capacity resources. The purpose of the RPM must offer rule, which has been in place since the beginning of the capacity market in 1999, is to ensure that the capacity market works based on the inclusion of all demand and all supply, and to prevent the exercise of market power via withholding of supply. The purpose of the RPM must offer requirement is also to ensure equal access to the transmission system through capacity interconnection rights (CIRs). If a resource has CIRs but fails to use them by not offering in the capacity market, the resource is withholding and is also denying the opportunity to offer to other resources that would use the CIRs. For these reasons, existing resources are required to return CIRs to the market within one year after retirement.[9] The same logic should be applied to categorically exempt intermittent and storage capacity resources. The failure to apply the RPM must offer requirement will create increasingly significant market design issues, artificially high capacity prices, and market power issues in the capacity market as the level of capacity from intermittent and capacity storage resources increases. The failure to apply the RPM must offer requirement consistently could also result in very significant changes in supply from auction to auction that would create price volatility and uncertainty in the capacity market and put PJM's reliability margin at risk. The capacity market was designed on the basis of a must buy requirement for load and a corresponding must offer requirement for capacity resources. Holding aside the market power issue, the capacity market can work only if both are enforced.

The reasons for the categorical exemption of intermittent resources and storage to date were based on the seasonality of the resources and on PJM's imposition of performance assessment interval (PAI) penalties for nonperformance when performance was not physically possible, e.g. PAI penalties to solar for not producing at night. Neither applies to all the exempt resources and neither is a good reason to exempt these resources. As the role of categorically exempt intermittents and storage grows it is essential to reestablish the must offer obligation for all resources. The inclusion of a must offer obligation for categorically exempt intermittent and capacity storage resources should be coupled with the removal of PAI penalty liability for such resources when it is not physically possible to perform. The capacity market has included balanced must buy and must sell obligations from its inception. The current rules can and should be changed to restore that balance.

The MMU recommends that PJM treat the inclusion of RMR resources in the capacity market consistently. PJM currently includes RMR units in the reliability analysis for RPM

9 The MMU's position is that CIRs should be returned to the pool of available transmission at the time of a resource's retirement and not held for one year.

auctions but does not include the RMR units in the supply curves. This approach is internally inconsistent. It would be internally consistent to leave the RMR units out of the CETO/CETL analysis. It would also be internally consistent to include the RMR units in the supply of capacity and in the CETO/CETL analysis. Including RMR resources in the capacity supply curve does not mean forcing unit owners to offer or to take on PAI risk, for example. It simply means that PJM would recognize the fact that PJM does treat RMR resources as a source of reliability. The goal is to ensure that the underlying supply and demand fundamentals are included in the capacity market prices. These two options have very different implications for capacity market prices. There are times when a price signal for the entry of generation is appropriate, e.g. when the goal is to allow generation to compete to replace the transmission option, in whole or in part. There are times when a price signal for the entry of generation is not needed or appropriate, e.g. when PJM has committed to the construction of new transmission that will eliminate the price signal when complete. The relevant rules can and should be changed.

The MMU recommends that the ELCC be significantly refined to include hourly data that would permit unit specific ELCC ratings, to weight summer and winter risk in a more balanced manner, to eliminate PAI risks, and to pay for actual hourly performance rather than based on relatively inflexible class capacity accreditation ratings derived from a small number of hours of poor performance. Specifically, in the short run the MMU recommends that capacity accreditation recognize the winter capability of thermal resources rather than limiting such resources to summer ratings. Most of the risk recognized in the ELCC model is winter risk but the ELCC accreditation values for thermal resources are capped at the summer ratings. That unnecessarily limits supply and changes the ELCC values for all other resources and changes the system accredited unforced capacity and therefore AUCAP, the maximum level of load that can be served by the existing resources and therefore the reliability requirement. The CIRs of such resources are currently limited by the summer ratings but those rules can and should be changed given the use of the ELCC approach. There is no reason that excess winter CIRs cannot be assigned to these resources immediately.

Summary of Results

Cleared generation and DR for the entire RTO of 134,224.2 MW resulted in a reserve margin of 18.6 percent and a net excess of 870.9 MW over the reliability requirement adjusted for FRR and PRD of 133,353.3 MW.[10] Net excess is defined as cleared MW of capacity and DR minus the reliability requirement, adjusted for FRR and PRD.

The net excess unforced capacity in the 2025/2026 RPM Base Residual Auction is based on the ELCC approach and the net excess unforced capacity in the 2024/2025 RPM Base

10 These reserve margin calculations do not consider Fixed Resource Requirement (FRR) load.

Residual Auction is based on the prior EFORd approach. Net excess is significantly affected by the method used to define UCAP. Under the ELCC approach, UCAP is the derated ICAP based on the ELCC Accredited UCAP Factor for the resource (ICAP * AUCAP Factor). Under the EFORd approach, UCAP is ICAP adjusted by the unit forced outage rate (ICAP * (1 – EFORd)). The supply and demand balance in the PJM system will appear much tighter using the ELCC approach than the EFORd approach for exactly the same resources.

Net excess decreased 7,215.9 MW from the net excess of 8,086.8 MW in the 2024/2025 RPM Base Residual Auction. This comparison overstates the reduction in net excess because the net excess for the 2024/2025 BRA was in EFORd terms while the net excess for the 2025/2026 BRA was in ELCC terms.

The intersection of the supply curve and the downward sloping VRR demand curve resulted in a clearing price for Capacity Performance Resources of $269.92 per MW-day for the rest of RTO.

Table 1 shows the summary of the revenue impacts of the scenarios analyzed. The results of the scenarios presented in the Analysis of the 2025/2026 RPM Base Residual Auction Part A ("Part A") are not strictly additive. The scenarios in Part B are combinations of scenarios from Part A and show the combined impact of each identified combination of scenarios from Part A. The quantitative results are estimates. The report makes explicit when the quantitative results depend on assumptions. Even in those cases, the quantitative results are correct as to direction and order of magnitude. The RPM Revenue column shows the revenues that resulted from the defined scenario only. The RPM Revenue Change column shows the difference between the actual RPM total revenues and the total RPM revenues that resulted from the defined scenario. A positive number means that the existing market design elements in the defined scenario resulted in an increase in RPM revenues compared to the MMU recommendation. A negative number means that the existing market design elements in the defined scenario resulted in a decrease in RPM revenues compared to the MMU recommendation. The Percent Change columns show the percent change in RPM revenues for the defined scenario from two perspectives. The Scenario to Actual Percent column shows the difference between the revenues under the defined scenario and the actual auction results as a percent of the revenues under the defined scenario. The Actual to Scenario Percent column shows the difference between the revenues under the defined scenario and the actual auction results as a percent of the revenues under the actual auction results.

In Scenario 5, the MMU analyzed the combined impact of capacity that was categorically exempt from the RPM must offer obligation and that did not offer into the 2025/2026 RPM Base Residual Auction (Scenario 2 from Part A) and the impact of PJM's rules related to the role of RMR resources in capacity auctions (Scenario 3 from Part A). In Scenario 5, all categorically exempt resources were added to the supply curve at $0 per MW-day and all RMR resources in the BGE LDA were added to the BGE supply curve at $0 per MW-day.

Table 1 shows the combined impact on RPM revenues for the auction for Scenario 5. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If the capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction and if the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $9,544,052,754, a decrease of $5,142,994,604 from the actual results. The failure to offer capacity that was categorically exempt from the RPM must offer requirement and the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day resulted in a 53.9 percent increase in RPM revenues for the 2025/2026 RPM Base Residual Auction (Scenario 5). From another perspective, if the capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction and if the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been reduced by 35.0 percent compared to the actual auction results.

In Scenario 6, the MMU analyzed the combined impact of limiting generation capacity from combined cycle (CC) and combustion turbine (CT) resources to their summer rating rather than their higher winter ratings (Scenario 4A from Part A) and the impact of PJM's rules related to the role of RMR resources in capacity auctions (Scenario 3 from Part A). In Part A, the MMU assumed a range of peak loads that capacity can serve (solved load) resulting from higher winter ratings for CCs and CTs and the related changes in the reserve requirement. For the combined impact, the MMU assumed the higher winter generation capacity would not result in any change to the solved load and the associated IRM (Scenario 4A). In Scenario 6 the UCAP of CCs and CTs were based on higher winter generation capacity without any change to the solved load and the associated IRM, and the identified RMR resources in the BGE LDA were added to the BGE supply curve at $0 per MW-day.

Table 1 shows the combined impact on RPM revenues for the auction for Scenario 6. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction and if the capacity of the RMR resources in the BGE LDA had been included in the BGE supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $8,268,676,635, a decrease of $6,418,370,722 from the actual results. The use of summer ratings rather than winter ratings for CC and CT resources in the marginal ELCC based accreditation and the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day resulted in a 77.6 percent increase in RPM revenues for the 2025/2026 RPM Base Residual Auction (Scenario 6). From another perspective, if winter ratings rather than summer ratings had been used for CC and CT resources and RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been reduced by 43.7 percent compared to the actual auction results.

In Scenario 7, the MMU analyzed the combined impact of capacity that was categorically exempt from the RPM must offer obligation and that did not offer into the 2025/2026 RPM Base Residual Auction (Scenario 2), PJM’s rules related to the role of RMR resources in capacity auctions (Scenario 3), and limiting generation capacity from combined cycle (CC) and combustion turbine (CT) resources to their summer rating rather than their higher winter ratings (Scenario 4A). In Scenario 7, all categorically exempt resources were added to the supply curve at $0 per MW-day, the identified RMR resources in the BGE LDA were added to the supply curve at $0 per MW-day, and the UCAP of CCs and CTs were based on higher winter generation capacity without any change to the solved load and the associated IRM.

Table 1 shows the combined impact on RPM revenues for the auction for Scenario 7. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If the capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, if the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, and if marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $7,056,881,123, a decrease of $7,630,166,235 compared to the actual results. The failure to offer capacity that was categorically exempt from the RPM must offer requirement combined with the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day and the use of summer ratings rather than winter ratings for CC and CT resources in the marginal ELCC based accreditation resulted in a 108.1 percent increase in RPM revenues for the 2025/2026 RPM Base Residual Auction (Scenario 7). From another perspective, if the capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, if the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, and if marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been reduced by 52.0 percent compared to the actual auction results.

Summary Results Tables

Table 1 Scenario summary for 2025/2026 RPM Base Residual Auction

Scenario	Scenario Description	RPM Revenue ($ per Delivery Year)	RPM Revenue Change ($ per Delivery Year)	Percent Change Scenario to Actual	Percent Change Actual to Scenario
0	Actual results	$14,687,047,358	NA	NA	NA
5	All categorically exempt offers and RMR resources	$9,544,052,754	$5,142,994,604	53.9%	(35.0%)
6	Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$8,268,676,635	$6,418,370,722	77.6%	(43.7%)
7	All categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$7,056,881,123	$7,630,166,235	108.1%	(52.0%)

Table 2 shows the summary of the cleared UCAP MW impact of all the scenarios analyzed. The Cleared UCAP column shows the cleared MW that resulted from the specific scenario only. The Scenario Impact Cleared UCAP Change column shows the difference between the actual RPM cleared UCAP MW and the total RPM cleared UCAP MW that resulted from the specific scenario. A positive number means that the specific scenario resulted in a reduction in cleared MW. A negative number means that the specific scenario resulted in an increase in cleared MW. The Scenario Impact Cleared UCAP column shows the difference between the actual RPM cleared MW and the total RPM cleared MW that resulted from the specific scenario. A positive number means that the specific scenario resulted in a reduction in RPM cleared MW. A negative number means that the specific scenario resulted in an increase in RPM cleared MW. The percent columns show the percent change in RPM cleared MW for the specific scenario from two perspectives. The Scenario to Actual Percent column shows the difference between the MW under the defined scenario and the defined baseline as a percent of the MW under the defined scenario. The Actual to Scenario Percent column shows the difference between the MW under the defined scenario and the defined baseline as a percent of the MW under the defined baseline.

Table 2 shows the impact on the cleared UCAP MW for the auction for each combined scenario from Table 1. The Cleared UCAP column shows the cleared MW that resulted from the defined scenario only. The Cleared UCAP Change column shows the difference between the actual RPM cleared UCAP and the total RPM cleared UCAP MW that resulted from the defined scenario. A positive number means that the existing market design elements in the defined scenario resulted in an increase in RPM cleared UCAP MW compared to the MMU recommendation. A negative number means that the existing market design elements in the defined scenario resulted in a decrease in RPM cleared UCAP MW compared to the MMU recommendation. The Percent Change columns show the percent change in RPM cleared UCAP MW for the defined scenario from two perspectives. The Scenario to Actual Percent column shows the difference between the cleared UCAP under the defined scenario and the actual auction results as a percent of the cleared UCAP under the defined scenario. The Actual to Scenario Percent column shows the difference between the cleared UCAP MW under the defined scenario and the actual auction results as a percent of the cleared UCAP MW under the actual auction results.

If the capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, and the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction and everything else had remained the same, total cleared UCAP MW in the 2025/2026 RPM Base Residual Auction would have been 138,023.9 UCAP MW, an increase of 2,339.9 UCAP MW, or 1.7 percent, compared to the actual results (Scenario 5).

If marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction and everything else had remained the same, total cleared UCAP MW for the 2025/2026 RPM Base Residual Auction would have been 142,527.3 UCAP MW, an increase of 6,843.3 UCAP MW, or 5.0 percent, compared to the actual results (Scenario 6).

If the capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction and everything else had remained the same, total cleared UCAP MW for the 2025/2026 RPM Base Residual Auction would have been 143,397.8 UCAP MW, an increase of 7,713.8 UCAP MW, or 5.7 percent, compared to the actual results (Scenario 7).

Table 2 Scenario summary for 2025/2026 RPM Base Residual Auction

		Scenario Impact			
				Percent Change	
Scenario	Scenario Description	Cleared UCAP (MW)	Cleared UCAP Change (MW)	Scenario to Actual	Actual to Scenario
0	Actual results	135,684.0	NA	NA	NA
5	All categorically exempt offers and RMR resources	138,023.9	(2,339.9)	(1.7%)	1.7%
6	Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	142,527.3	(6,843.3)	(4.8%)	5.0%
7	All categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	143,397.8	(7,713.8)	(5.4%)	5.7%

ATTACHMENT C

Analysis of the 2025/2026 RPM Base Residual Auction Part C

The Independent Market Monitor for PJM

November 6, 2024

Introduction

This report, Part C of what will be a comprehensive report, prepared by the Independent Market Monitor for PJM (IMM or MMU), presents a third set of sensitivity analyses of the nineteenth Reliability Pricing Model (RPM) Base Residual Auction (BRA) for the 2025/2026 Delivery Year which was held from July 17 to 23, 2024. The MMU prepares a comprehensive report for each RPM Base Residual Auction. In this case, rather than waiting until all sensitivities are completed, the MMU will present the results of sensitivities as they are completed in order to provide information to stakeholders that is relevant to decision making about the 2026/2027 BRA, previously scheduled for December 4 to 10, 2024, and now delayed for approximately six months. The MMU will provide a comprehensive report later.

The results of the scenarios presented in the Analysis of the 2025/2026 RPM Base Residual Auction Part A ("Part A") and Part B ("Part B") are based on VRR curves that were used in the 2025/2026 BRA but will not be used in the 2026/2027 RPM BRA. This Part C report addresses the impacts of PJM's posted VRR curve parameters for the 2026/2027 BRA based on the actual data from the 2025/2026 BRA, the scenarios from Part A and Part B, use of a CT as the reference resource, and load growth scenarios. The reported sensitivity results are not predictions or forecasts of the outcome of the 2026/2027 BRA. The sensitivity results show the direction and magnitude of the impacts on capacity market revenues of the proposed market design changes if they had been implemented in the 2025/2026 BRA. Actual conditions could change for the 2026/2027 BRA including changes in supply, in demand and in offer behavior.

This Part C report addresses, explains and quantifies the combined impact of specific critical market design choices in the 2025/2026 BRA that were identified in Part A and further analyzed in Part B, and market design choices for the 2026/2027 BRA. This Part C report is focused on the potential impacts of market design choices for the 2026/2027 BRA, currently expected to be run in June 2025. This report addresses the impact of using a combined cycle resource (CC) as the reference resource and of using a combustion turbine resource (CT) as the reference resource. The CT scenarios include net CONE multipliers of 1.0 and 1.75, combined with the separate and combined impacts on market outcomes of: the impact of the exclusion of two reliability must run (RMR) plants from the capacity market supply curve; the impact of using summer ratings rather than winter ratings for

CC and CT resources; and the impact of withholding by categorically exempt resources.[1] In addition, this report addresses the impact of potential increases in forecast demand.

The preliminary RTO wide peak load forecast for the 2025/2026 BRA was 153,883.04 MW. The posted preliminary RTO wide peak load forecast for the 2026/2027 BRA was 157,196.98 MW, 3,313.94 MW or 2.2 percent higher than the peak load forecast for 2025/2026 BRA. The MMU analyzed two peak load forecast scenarios. The MMU scenarios include an increase in the peak load forecast to 157,730.10 MW, an increase of 3,847.08 MW or 2.5 percent, over the preliminary peak load forecast for 2025/2026 BRA and an increase in the peak load forecast to 161,577.2 MW, an increase of 7,694.15 MW or 5.0 percent, over the preliminary peak load forecast for the 2025/2026 BRA.

Recognizing that the quantitative results are estimates, based on explicitly stated assumptions, the results show the direction and magnitude of the combined impacts of the identified factors in the PJM capacity market design.

The results reported in Part C can be used to evaluate potential market design changes for the 2026/2027 BRA.[2] Assuming that everything else is held constant from the 2025/2026 BRA, the proposal to use a CT as the reference resource and to recognize Brandon Shores and Wagner RMR resources as part of the supply of capacity would reduce RPM revenues from $14,687,047,358 to $10,995,403,198 (Scenario 14). Adopting the other two MMU proposals would reduce the RPM revenues to $6,923,416,413 (Scenario 16). However, if the peak load forecast increases by 2.5 percent over the peak load forecast used in the 2025/2026 BRA, PJM's proposal would increase RPM revenues by $9,151,890,481 (Scenario 28). If the peak load forecast increases by 5.0 percent over the peak load forecast used in the 2025/2026 BRA, PJM's proposal would increase RPM revenues by $12,414,052,425 (Scenario 32). Adopting the other two MMU proposals would reduce RPM revenues to $13,473,937,677 with a 2.5 percent increase in the peak load forecast (Scenario 30) and increase RPM revenues to $28,514,872,062 with a 5.0 percent increase in the peak load forecast (Scenario 34).

In summary, holding everything else constant, if the 2025/2026 RPM BRA had been cleared using a VRR curve based on updated calculations of gross and net CONE for a CC

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1 The values stated in this report for the RTO and LDAs refer to the aggregate level including all nested LDAs unless otherwise specified. For example, RTO values include the entire PJM market and all LDAs. Rest of RTO values are RTO values net of nested LDA values.

2 See "Consultation With Members Regarding Future 205 Filing on Capacity Market," Special Markets and Reliability Committee, November 7, 2024 <https://www.pjm.com/-/media/committees-groups/committees/mrc/2024/20241107-special/item-02---capacity-market-adjustments---presentation.ashx>.

as the reference resource, a 1.75 multiplier for net CONE and a forward net revenue offset, total RPM market revenues for the 2025/2026 RPM BRA would have been $15,689,595,599, an increase of $1,002,548,242, or 6.8 percent, compared to the actual results (Scenario 8).

In summary, holding everything else constant, if the 2025/2026 RPM BRA had been cleared using a VRR curve based on updated calculations of gross and net CONE for a CC as the reference resource, a 1.75 multiplier for net CONE and a forward net revenue offset, and the peak load forecast was 5.0 percent higher than the peak load forecast used in the 2025/2026 BRA, total RPM market revenues for the 2025/2026 RPM BRA would have been $34,413,395,926, an increase of $19,726,348,569, or 134.3 percent, compared to the actual results (Scenario 26).

In summary, holding everything else constant, if the 2025/2026 RPM BRA had been cleared using a VRR curve based on updated calculations of gross and net CONE for a CT as the reference resource, a 1.75 multiplier for net CONE and a forward net revenue offset, total RPM market revenues for the 2025/2026 RPM BRA would have been $16,671,256,307, an increase of $1,984,208,950, or 13.5 percent, compared to the actual results (Scenario 9).

In summary, holding everything else constant, if the 2025/2026 RPM BRA had been cleared using a VRR curve based on updated calculations of gross and net CONE for a CT as the reference resource, a 1.75 multiplier for net CONE and a forward net revenue offset, and the peak load forecast was 5.0 percent higher than the peak load forecast used in the 2025/2026 BRA, total RPM market revenues for the 2025/2026 RPM BRA would have been $26,772,578,885, an increase of $12,085,531,528, or 82.3 percent, compared to the actual results (Scenario 31).

In summary, holding everything else constant, if the 2025/2026 RPM BRA had been cleared using a VRR curve based on updated calculations of gross and net CONE for a CT as the reference resource, a 1.75 multiplier for net CONE and a forward net revenue offset, the MW capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, the marginal ELCC based accreditation had included higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $6,923,416,413, a decrease of $7,763,630,945, or 52.9 percent, compared to the actual results.

The capacity market exists to make the energy market work, by providing the additional net revenues required for the incentive to invest in new units and to maintain old units. The definition of capacity is not the ability to provide energy during one peak hour or five peak hours, as implied by the methods used by PJM and LSEs to allocate the costs of capacity to load. The obligations of capacity resources include the requirement to offer their full ICAP in the energy and reserves markets every day. The need for the energy from capacity is not limited to one peak hour or five peak hours. Customers require energy from capacity resources all 8,760 hours per year. Rather than develop a complicated seasonal capacity market based on an arbitrary definition of seasons, the hourly value of the energy from capacity should be explicitly recognized in the capacity market.[3] Under the hourly approach, products with different characteristics at different times of the year (so called seasonal products) would not need to be matched with peak period products.

The MMU recognizes that implementation of the recommendations in this report would require rule changes in some cases.

Conclusions

The capacity market is, by design, always tight in the sense that total supply is generally only slightly larger than demand. The PJM Capacity Market is a locational market and local markets frequently have different supply demand balances than the aggregate market.[4] While the market may be long at times, that is not the equilibrium state. Capacity in excess of demand is not sold and, if it does not earn or does not expect to earn adequate revenues from the full set of PJM markets, or does not have value as a hedge, may be expected to retire, provided the market sets appropriate price signals to reflect the availability of excess supply. Capacity in excess of demand means capacity in excess of the demand as defined by the capacity demand curve, called the Variable Resource Requirement (VRR) curve. PJM rules require load to pay for the level of capacity defined by the VRR curve. Correctly defined, excess capacity means capacity in excess of the peak load forecast plus the reserve margin, the level of capacity PJM is required to purchase in order to maintain reliability, measured in UCAP.

The demand for capacity in the capacity market is almost entirely inelastic because the market rules require loads to purchase their share of the system capacity requirement. The downward sloping portion of the VRR curve is everywhere inelastic. The result is that any supplier that owns more capacity than the typically small difference between total supply

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3 See "Executive Summary of IMM Capacity market design proposal: Sustainable Capacity Market (SCM)," IMM presentation to the PJM Board of Managers, (August 23, 2023) <https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_RASTF-CIFP_SCM_Executive_Summary_20230816.pdf>.

4 The locational element of the PJM Capacity Market is limited to the recognition of different LDAs which were initially defined by transmission zones but now also include subzones. However the PJM Capacity Market is not fully locational because it treats all capacity within an LDA as equivalent rather than recognizing the impacts of internal transmission constraints.

and the VRR defined demand is individually pivotal and therefore has structural market power. Any supplier that, jointly with two other suppliers, owns more capacity than the difference between supply and the VRR defined demand either in aggregate or for a local market is jointly pivotal and therefore has structural market power.

The market design for capacity leads, almost unavoidably, to structural market power in the capacity market. The capacity market is unlikely ever to approach a competitive market structure in the absence of a substantial and unlikely structural change that results in much greater diversity of ownership. Market power is and will remain endemic to the structure of the PJM Capacity Market. Nonetheless a competitive outcome can be assured by appropriate market power mitigation rules. Detailed market power mitigation rules are included in the PJM Open Access Transmission Tariff (OATT or Tariff). Reliance on the RPM design for competitive outcomes means reliance on the market power mitigation rules. Attenuation of those rules means that market participants are not able to rely on the competitiveness of the market outcomes.

There are currently two important gaps in the market power rules for the PJM Capacity Market. Unlike all other generation capacity resources, Intermittent Resources, Capacity Storage Resources, and Hybrid Resources consisting exclusively of components that in isolation would be Intermittent Resources or Capacity Storage Resources, are categorically exempt from the RPM must offer requirement. Capacity Storage Resources include pumped storage hydroelectric, impoundment hydroelectric, flywheel, and battery. Intermittent Resources include wind, solar, landfill gas, run of river hydroelectric, and other renewable resources. As a result, a significant level of such resources withhold their capacity. The result is to increase the clearing prices above the competitive level. This can benefit the owners of capacity portfolios that include such resources as well as resources with an RPM must offer requirement. The MMU recommends that all capacity resources have a must offer obligation. The MMU also recommends that performance penalties not be applied to solar and wind resources when they are not capable of performing based on ambient conditions. For example, solar resources should be subject to performance penalties if they fail to perform when the sun is shining but should not be subject to performance penalties in the middle of the night. This would be a rational application of the PAI penalties that recognizes the physical capabilities of resources and is therefore not discriminatory. Demand resources (DR) have always been treated more favorably than generation capacity resources. Demand resources also do not have an RPM must offer requirement. Demand resources, unlike all other capacity resources, are not subject to market seller offer caps to protect against the exercise of market power. When demand resources are pivotal, as they were for the 2025/2026 BRA, they have structural market power and can and do exercise market power. The result is to increase the clearing prices above the competitive level. If the resources clear, it benefits the resources directly. Even if the resources do not clear, higher prices can benefit the owners of capacity portfolios that include such resources as well as resources with an RPM must offer requirement. The MMU recommends that demand resources have defined and enforced market seller offer caps, like all other capacity resources.

In the capacity market, as in other markets, market power is the ability of a market participant to increase the market price above the competitive level or to decrease the market price below the competitive level. In order to evaluate whether actual prices reflect the exercise of market power, it is necessary to evaluate whether market offers are consistent with competitive offers. The market seller offer cap defines a competitive offer in the capacity market, regardless of whether the concern is efforts to increase the market price above the competitive level or to reduce the market price below the competitive level. As in all other markets, the competitive offer in the capacity market is the marginal cost of capacity. A competitive offer in the capacity market is equal to net ACR.[5]

All participants to which the three pivotal supplier (TPS) test was applied (in the RTO, BGE, and DOM RPM markets) failed the three pivotal supplier test. The result was that offer caps were applied to all sell offers for Existing Generation Capacity Resources when the capacity market seller did not pass the test, the submitted sell offer exceeded the tariff defined offer cap, and the submitted sell offer, absent mitigation, would have resulted in a higher market clearing price.[6] [7]

Based on the data and this analysis in Part A, Part B and Part C, the MMU concludes that the results of the 2025/2026 RPM Base Residual Auction were significantly affected by flawed market design decisions including PJM's ELCC approach, by the failure to offer categorically exempt resources including, in some cases, the exercise of market power through the withholding of categorically exempt resources, and the exercise of market power through high offers from demand resources, and by the exclusion from supply of the defined RMR resources. The BRA prices do not solely reflect supply and demand fundamentals but also reflect, in significant part, PJM decisions about the definition of supply and demand. The auction results were not solely the result of the introduction of

5 174 FERC ¶ 61,212 ("March 18th Order") at 65.

6 Prior to November 1, 2009, existing DR and EE were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 (2009) at P 30.

7 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation, and treating a proposed increase in the capability of a Generation Capacity Resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).

the ELCC approach and do in part reflect the tightening of supply and demand conditions in the PJM Capacity Market. PJM's ELCC filing that created many of these issues was approved by FERC.[8]

Based on the data and this analysis in Part C, the MMU concludes that there is a significant risk of much higher capacity market prices in the 2026/2027 BRA than in the 2025/2026 BRA if the forecast peak load is from to 2.5 to 5.0 percent higher than the forecast peak load used in the 2025/2026 BRA.

Recommendations

The recommendations in Part A and Part B are related primarily to the results of the sensitivity analyses presented in both Part A and Part B. The recommendations in Part C include the recommendations in Part A and Part B and add additional recommendations.

The MMU recommends that the must offer rule in the capacity market apply to all capacity resources.[9] Prior to the implementation of the capacity performance design, all existing capacity resources, except DR, were subject to the RPM must offer requirement. There is no reason to exempt intermittent and capacity storage resources, including hydro, from the RPM must offer requirement. The same rules should apply to all capacity resources. The purpose of the RPM must offer rule, which has been in place since the beginning of the capacity market in 1999, is to ensure that the capacity market works based on the inclusion of all demand and all supply, and to prevent the exercise of market power via withholding of supply. The purpose of the RPM must offer requirement is also to ensure equal access to the transmission system through capacity interconnection rights (CIRs). If a resource has CIRs but fails to use them by not offering in the capacity market, the resource is withholding and is also denying the opportunity to offer to other resources that would use the CIRs. For these reasons, existing resources are required to return CIRs to the market within one year after retirement.[10] The same logic should be applied to categorically exempt intermittent and storage capacity resources. The failure to apply the RPM must offer requirement will create increasingly significant market design issues, artificially high capacity prices, and market power issues in the capacity market as the

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8 186 FERC ¶ 61,080 (January 30, 2024).

9 See "Executive Summary of IMM Capacity market design proposal: Sustainable Capacity Market (SCM)," IMM presentation to the PJM Board of Managers, (August 23, 2023) <https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_RASTF-CIFP_SCM_Executive_Summary_20230816.pdf>.

10 The MMU's position is that CIRs should be returned to the pool of available transmission at the time of a resource's retirement and not held for one year.

level of capacity from intermittent and capacity storage resources increases. The failure to apply the RPM must offer requirement consistently could also result in very significant changes in supply from auction to auction that would create price volatility and uncertainty in the capacity market and put PJM's reliability margin at risk. The capacity market was designed on the basis of a must buy requirement for load and a corresponding must offer requirement for capacity resources. Holding aside the market power issue, the capacity market can work only if both are enforced.

The reasons for the categorical exemption of intermittent resources and storage to date were based on the seasonality of the resources and on PJM's imposition of performance assessment interval (PAI) penalties for nonperformance when performance was not physically possible, e.g. PAI penalties to solar for not producing at night. Neither applies to all the exempt resources and neither is a good reason to exempt these resources. As the role of categorically exempt intermittents and storage grows it is essential to reestablish the must offer obligation for all resources. The inclusion of a must offer obligation for categorically exempt intermittent and capacity storage resources should be coupled with the removal of PAI penalty liability for such resources when it is not physically possible to perform. This is not the removal of performance penalties from wind and solar resources and it is not discriminatory. It is a recognition of the reality that wind and solar resources are not capable of performing at defined times. The capacity market has included balanced must buy and must sell obligations from its inception. The current rules can and should be changed to restore that balance.

The MMU recommends that PJM treat the inclusion of RMR resources in the capacity market consistently. PJM currently includes RMR units in the reliability analysis for RPM auctions but does not include the RMR units in the supply curves. This approach is internally inconsistent. It would be internally consistent to leave the RMR units out of the CETO/CETL analysis. It would also be internally consistent to include the RMR units in the supply of capacity and in the CETO/CETL analysis. Including RMR resources in the capacity supply curve does not mean forcing unit owners to offer or to take on PAI risk, for example. It simply means that PJM would recognize the fact that PJM does treat RMR resources as a source of reliability. The goal is to ensure that the underlying supply and demand fundamentals are included in the capacity market prices. These two options have very different implications for capacity market prices. There are times when a price signal for the entry of generation is appropriate, e.g. when the goal is to allow generation to compete to replace the transmission option, in whole or in part. There are times when a price signal for the entry of generation is not needed or appropriate, e.g. when PJM has committed to the construction of new transmission that will eliminate the price signal when complete. The relevant rules can and should be changed.

The MMU recommends that the ELCC be significantly refined to include hourly data that would permit unit specific ELCC ratings, to weight summer and winter risk in a more balanced manner, to eliminate PAI risks, and to pay for actual hourly performance rather than based on relatively inflexible class capacity accreditation ratings derived from a small number of hours of poor performance. Specifically, in the short run the MMU recommends that capacity accreditation recognize the winter capability of thermal resources rather than limiting such resources to summer ratings. Most of the risk recognized in the ELCC model is winter risk but the ELCC accreditation values for thermal resources are capped at the summer ratings. That unnecessarily limits supply and changes the ELCC values for all other resources and changes the system accredited unforced capacity and therefore AUCAP, the maximum level of load that can be served by the existing resources and therefore the reliability requirement. The CIRs of such resources are currently limited by the summer ratings but those rules can and should be changed given the use of the ELCC approach. There is no reason that excess winter CIRs cannot be assigned to these resources immediately.

The MMU recommends that the reference resource be a CT rather than a CC. The MMU recommends that the ELCC value used to convert the gross CONE in ICAP terms for a CT to the gross CONE in UCAP terms be the ELCC based on winter ratings. The MMU recommends that the maximum price on the VRR curve be set to 1.5 times the net CONE rather than the greater of gross CONE and 1.75 times net CONE.

Summary of Results

Cleared generation and DR for the entire RTO of 134,224.2 MW resulted in a reserve margin of 18.6 percent and a net excess of 870.9 MW over the reliability requirement adjusted for FRR and PRD of 133,353.3 MW.[11] Net excess is defined as cleared MW of capacity and DR minus the reliability requirement, adjusted for FRR and PRD.

The net excess unforced capacity in the 2025/2026 RPM Base Residual Auction is based on the ELCC approach and the net excess unforced capacity in the 2024/2025 RPM Base Residual Auction is based on the prior EFORd approach. Net excess is significantly affected by the method used to define UCAP. Under the ELCC approach, UCAP is the derated ICAP based on the ELCC Accredited UCAP Factor for the resource (ICAP * AUCAP Factor). Under the EFORd approach, UCAP is ICAP adjusted by the unit forced outage rate (ICAP * (1 – EFORd)). The supply and demand balance in the PJM system will appear much tighter using the ELCC approach than the EFORd approach for exactly the same resources.

Net excess decreased 7,215.9 MW from the net excess of 8,086.8 MW in the 2024/2025 RPM Base Residual Auction. This comparison overstates the reduction in net excess because the

[11] These reserve margin calculations do not consider Fixed Resource Requirement (FRR) load.

net excess for the 2024/2025 BRA was in EFORd terms while the net excess for the 2025/2026 BRA was in ELCC terms.

The intersection of the supply curve and the downward sloping VRR demand curve resulted in a clearing price for Capacity Performance Resources of $269.92 per MW-day for the rest of RTO.

Table 1 shows the summary of the revenue impacts of the scenarios analyzed in Part C. The results of the scenarios presented in the Analysis of the 2025/2026 RPM Base Residual Auction Part A ("Part A") and Part B ("Part B") are based on VRR curves that are no longer applicable for the 2026/2027 RPM Base Residual Auction. The results of individual scenarios are not strictly additive. The combined results of multiple scenarios are shown for scenarios that address multiple results simultaneously. The quantitative results are estimates. The report makes explicit when the quantitative results depend on assumptions. Even in those cases, the quantitative results are correct as to direction and order of magnitude. The RPM Revenue column shows the revenues that resulted from the defined scenario only. The RPM Revenue Change column shows the difference between the actual RPM total revenues and the total RPM revenues that resulted from the defined scenario. A positive number means that the existing market design elements in the defined scenario resulted in an increase in RPM revenues compared to the MMU recommendation. A negative number means that the existing market design elements in the defined scenario resulted in a decrease in RPM revenues compared to the MMU recommendation. The Percent Change columns show the percent change in RPM revenues for the defined scenario from two perspectives. The Scenario to Actual Percent column shows the difference between the revenues under the defined scenario and the actual auction results as a percent of the revenues under the defined scenario. The Actual to Scenario Percent column shows the difference between the revenues under the defined scenario and the actual auction results as a percent of the revenues under the actual auction results.

In Scenario 8, the MMU analyzed the impact on the actual auction results for the 2025/2026 BRA of using a VRR curve based on the posted VRR parameters for the upcoming 2026/2027 RPM BRA. For the 2026/2027 RPM BRA, the maximum price (point A) is set at gross CONE for the reference combined cycle (CC) resource because gross CONE ($695.83 per UCAP MW-day for the Rest of RTO) is greater than 1.75 times net CONE for the CC ($0 per UCAP MW-day for the Rest of RTO). Gross CONE ($ per UCAP MW-day) is derived from the $ per ICAP MW-Year of Levelized Revenue Requirement using the ELCC based class average accredited UCAP factor for the technology class of the reference resource.[12] Net CONE is calculated using expected forward energy and ancillary service revenues. The price for point B is set at the 0.75 times net CONE for the CC.[13] The corresponding MW quantities are set at 98.9 percent of the reliability requirement for point A, 101.6 percent of the reliability requirement for point B and 105.8 percent of the reliability requirement for point C.[14]

Figure 1 shows the RTO VRR curve for Scenario 8 and the actual VRR curve used for the 2025/2026 RPM Base Residual Auction.

Table 1 shows the impact on RPM revenues for Scenario 8. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM BRA were $14,687,047,358. If the 2025/2026 RPM BRA had been cleared using a VRR curve based on a CC as the reference resource, a 1.75 multiplier for net CONE and a forward net revenue offset, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM BRA would have been $15,689,595,599, an increase of $1,002,548,242, or 6.8 percent, compared to the actual results (Scenario 8). From another perspective, the actual 2025/2026 VRR curve resulted in 6.4 percent lower 2025/2026 RPM BRA revenues compared to what RPM revenues would have been had PJM cleared the auction using a CC as the reference resource, a 1.75 multiplier for net CONE and a forward net revenue offset (Scenario 8).

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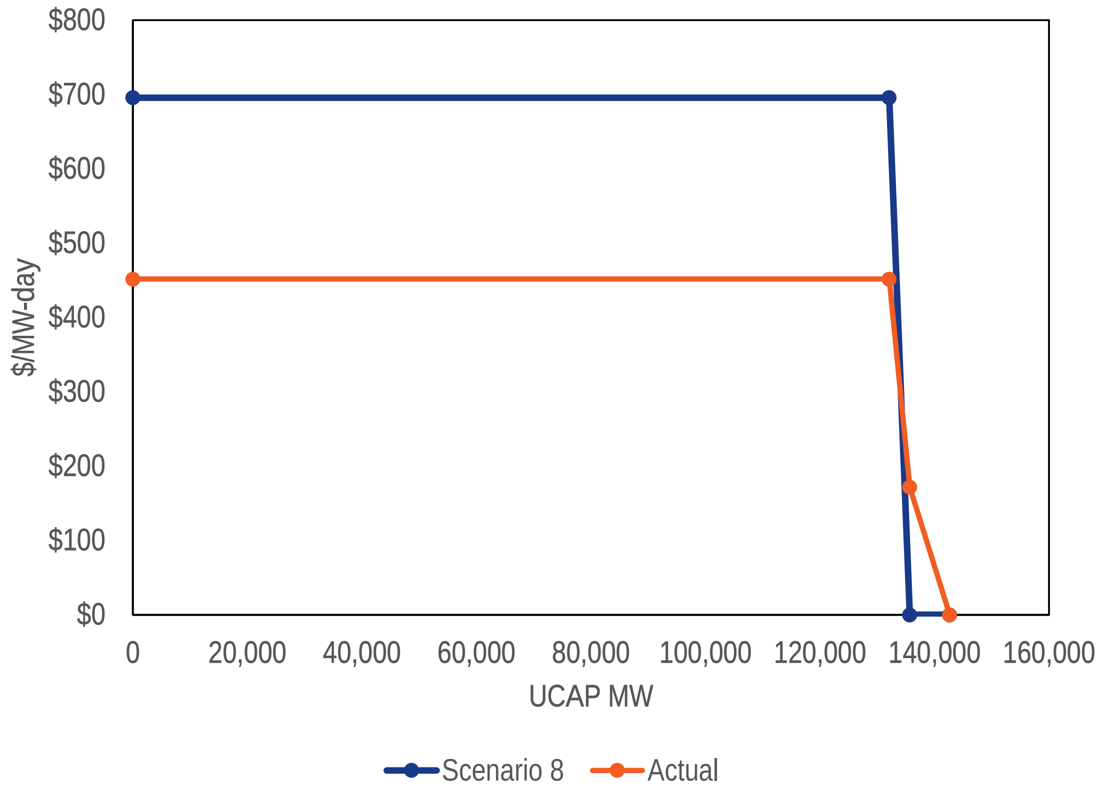
12 $Gross\ CONE\ (\$\ per\ UCAP\ MWDay) = \frac{Levelized\ Revenue\ Requirement\ (\$\ per\ ICAP\ MW\ Year)}{Number\ of\ Days\ in\ Delivery\ Year * Reference\ Resource\ AUCAP\ Factor}$

13 See "PJM Manual 18: PJM Capacity Market," § 3.3 Parameters of the Variable Resource Requirement, Rev. 59 (June 27, 2024).

14 Ibid.

Figure 1 RTO VRR Curves: Actual and Scenario 8



In Scenarios 9, 10, 11 and 12 the MMU analyzed the impact on the actual auction results for the 2025/2026 BRA of using a VRR curve based on the use of a Combustion Turbine (CT) as the reference resource rather than a CC, in combination with scenarios 2, 3 and 4 from Part A. The maximum price (point A) is set at the greater of gross CONE ($540.51 per UCAP MW-day for the Rest of RTO) and a multiplier of 1.0 times net CONE ($224.50 per UCAP MW-day for the Rest of RTO) for the reference CT resource.[15] Gross CONE was higher than 1.0 times net CONE for all modeled LDAs. Net CONE for the CT is calculated using expected forward energy and ancillary service revenues, forward net revenues. The price for point B is set at the 0.75 times net CONE for the CT. The corresponding MW quantities are the same as Scenario 8.

Figure 2 shows the RTO VRR curve for Scenarios 9, 10, 11 and 12, and the actual VRR curve used for the 2025/2026 RPM Base Residual Auction.

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[15] CT Gross CONE from 2026/2027 Default New Entry MOPR Offer Prices <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2026-2027/2026-2027-dy-mopr-prices-for-new-entry.ashx> (July 5, 2024). Forward E&AS revenues provided by PJM.

Table 2 shows the impact on RPM revenues for Scenario 9. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If the 2025/2026 RPM BRA had been cleared using a VRR curve based on a CT as the reference resource, a 1.0 multiplier for net CONE and a forward net revenue offset, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $16,671,256,307, an increase of $1,984,208,950, or 13.5 percent, compared to the actual results (Scenario 9). From another perspective, the actual 2025/2026 VRR curve resulted in 11.9 percent lower 2025/2026 RPM BRA revenues compared to what RPM revenues would have been had PJM cleared the auction using a CT as the reference resource, a 1.0 multiplier for net CONE and a forward net revenue offset (Scenario 9).

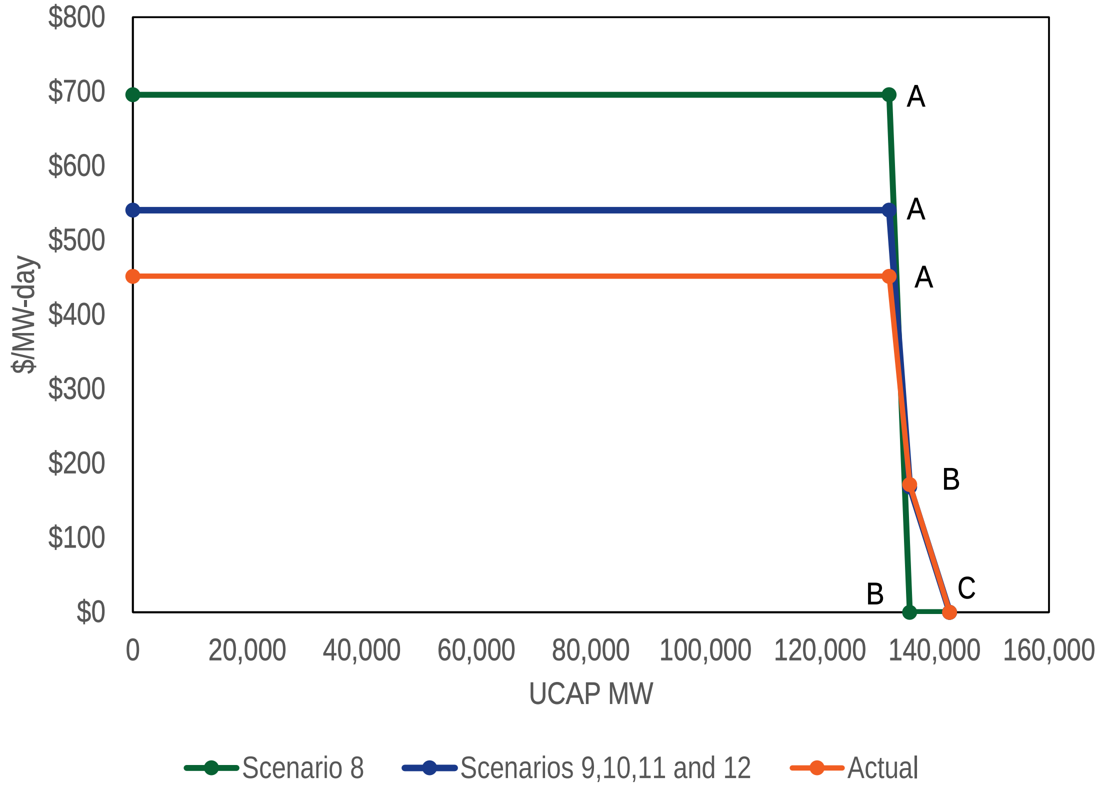
Table 2 shows the impact on RPM revenues for Scenario 10. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM BRA were $14,687,047,358. If, in addition to Scenario 9, the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM BRA, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $10,995,403,198, a decrease of $3,691,644,159, or 25.1 percent, compared to the actual results. From another perspective, if in addition to Scenario 9, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day resulted in a 33.6 percent increase in RPM revenues for the 2025/2026 RPM Base Residual Auction compared to what RPM revenues would have been had the capacity of the RMR resources been included in the supply curve at $0 per MW-day (Scenario 10).

Table 2 shows the impact on RPM revenues for Scenario 11. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If, in addition to Scenario 9, marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, if the capacity of the RMR resources in the BGE LDA been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $8,771,874,183, a decrease of $5,915,173,175, or 40.3 percent, compared to the actual results. From another perspective, if in addition to Scenario 9, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day and marginal ELCC based accreditation did not consider higher winter generation capacity ratings for CC and CT resources, resulted in a 67.4 percent increase in RPM revenues for the 2025/2026 RPM BRA compared to what RPM revenues would have been had the capacity of the RMR resources in the BGE LDA been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction and had marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction (Scenario 11).

Table 2 shows the impact on RPM revenues for Scenario 12. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If, in addition to Scenario 9, the MW capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, if marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, if the capacity of the RMR resources in the BGE LDA been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $6,923,416,413, a decrease of $7,763,630,945, or 52.9 percent, compared to the actual results. From another perspective, if in addition to Scenario 9, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day, marginal ELCC based accreditation did not consider higher winter generation capacity ratings for CC and CT resources and the MW categorically exempt from the RPM must offer requirement that that did not offer had been offered, resulted in a 112.1 percent increase in RPM revenues for the 2025/2026 RPM BRA compared to what RPM revenues would have been if the MW capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, if marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction and if the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction (Scenario 12).

Table 3 shows the results of Scenarios 13, 14, 15 and 16. These scenarios are identical to the scenarios in Table 2 except that the scenarios in Table 3 use 1.75 * Net CONE rather than 1.0 * Net CONE as the Net CONE component of the maximum price calculation. In general, gross CONE was the effective maximum price in scenarios 9 – 16. The results in Table 3 are very similar to the results in Table 2.

Figure 2 RTO VRR Curves: Actual, Scenario 8 and Scenarios 9, 10, 11 and 12



Summary Results Tables

Table 1 Scenario summary for 2025/2026 RPM Base Residual Auction: CC Reference Resource; 1.75 * Net CONE; Forward Net Revenue in VRR curve

			Scenario Impact		
				Percent Change	
Scenario	Scenario Description	RPM Revenue ($ per Delivery Year)	RPM Revenue Change ($ per Delivery Year)	Scenario to Actual	Actual to Scenario
0	Actual results	$14,687,047,358	NA	NA	NA
8	VRR curve based on higher of CC Gross CONE and 1.75xNet CONE calculated using forward E&AS offset	$15,689,595,599	($1,002,548,242)	(6.4%)	6.8%

Table 2 Scenario summary for 2025/2026 RPM Base Residual Auction: CT Reference Resource; 1.0 * Net CONE; Forward Net Revenue in VRR curve

			Scenario Impact		
				Percent Change	
Scenario	Scenario Description	RPM Revenue ($ per Delivery Year)	RPM Revenue Change ($ per Delivery Year)	Scenario to Actual	Actual to Scenario
0	Actual results	$14,687,047,358	NA	NA	NA
9	VRR curve based on higher of CT gross CONE and 1.0 times net CONE calculated using forward E&AS offset	$16,671,256,307	($1,984,208,950)	(11.9%)	13.5%
10	Scenario 9 and RMR resources	$10,995,403,198	$3,691,644,159	33.6%	(25.1%)
11	Scenario 9 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$8,771,874,183	$5,915,173,175	67.4%	(40.3%)
12	Scenario 9 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$6,923,416,413	$7,763,630,945	112.1%	(52.9%)

Table 3 Scenario summary for 2025/2026 RPM Base Residual Auction: CT Reference Resource; 1.75 * Net CONE; Forward Net Revenue in VRR curve

			Scenario Impact		
				Percent Change	
Scenario	Scenario Description	RPM Revenue ($ per Delivery Year)	RPM Revenue Change ($ per Delivery Year)	Scenario to Actual	Actual to Scenario
0	Actual results	$14,687,047,358	NA	NA	NA
13	VRR curve based on higher of CT gross CONE and 1.75 times net CONE calculated using forward E&AS offset	$16,680,092,261	($1,993,044,904)	(11.9%)	13.6%
14	Scenario 13 and RMR resources	$10,995,403,198	$3,691,644,159	33.6%	(25.1%)
15	Scenario 13 and winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$8,771,874,183	$5,915,173,175	67.4%	(40.3%)
16	Scenario 13 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$6,923,416,413	$7,763,630,945	112.1%	(52.9%)

In Scenarios 17, 18, 19 and 20 the MMU analyzed the impact on the actual auction results for the 2025/2026 BRA of using a VRR curve based on the use of a Combustion Turbine (CT) as the reference resource rather than a CC, in combination with scenarios 2, 3 and 4 from Part A. The maximum price (point A) is set at the greater of gross CONE ($540.51 per UCAP MW-day for the Rest of RTO) and a multiplier of 1.0 times net CONE ($317.70 per UCAP MW-day for the Rest of RTO) for the reference CT resource.[16] Gross CONE was higher than 1.0 times net CONE for all modeled LDAs. The only difference between Scenarios 9 – 16 and Scenarios 17 – 24 is that in Scenarios 17 – 24 Net CONE for the CT is calculated using historical energy and ancillary service revenues, historical net revenues, rather than forward looking net revenues. The price for point B is set at the 0.75 times net CONE for the CT. The corresponding MW quantities are the same as Scenario 8.

[16] CT Gross CONE and CT historical E&AS values from 2026/2027 Default New Entry MOPR Offer Prices <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2026-2027/2026-2027-dy-mopr-prices-for-new-entry.ashx> (July 5, 2024).

Table 4 shows the impact on RPM revenues for Scenario 17. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If the 2025/2026 RPM BRA had been cleared using a VRR curve based on a CT as the reference resource, a 1.0 multiplier for net CONE and an historical net revenue offset, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $18,508,465,316, an increase of $3,821,417,958, or 26.0 percent, compared to the actual results (Scenario 17). From another perspective, the actual 2025/2026 VRR curve resulted in 20.6 percent lower 2025/2026 RPM BRA revenues compared to what RPM revenues would have been had PJM cleared the auction using a CT as the reference resource, a 1.0 multiplier for net CONE and an historical net revenue offset (Scenario 17).

Table 4 shows the impact on RPM revenues for Scenario 18. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM BRA were $14,687,047,358. If, in addition to Scenario 17, the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM BRA, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $13,688,897,951, a decrease of $998,149,406, or 6.8 percent, compared to the actual results. From another perspective, if in addition to Scenario 17, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day resulted in a 7.3 percent increase in RPM revenues for the 2025/2026 RPM Base Residual Auction compared to what RPM revenues would have been had the capacity of the RMR resources been included in the supply curve at $0 per MW-day (Scenario 18).

Table 4 shows the impact on RPM revenues for Scenario 19. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If, in addition to Scenario 17, marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, if the capacity of the RMR resources in the BGE LDA been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $11,668,605,299, a decrease of $3,018,442,059, or 20.6 percent, compared to the actual results. From another perspective, if in addition to Scenario 17, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day and marginal ELCC based accreditation did not consider higher winter generation capacity ratings for CC and CT resources, resulted in a 25.9 percent increase in RPM revenues for the 2025/2026 RPM BRA compared to what RPM revenues would have been had the capacity of the RMR resources in the BGE LDA been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction and had marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction (Scenario 19).

Table 4 shows the impact on RPM revenues for Scenario 20. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If, in addition to Scenario 17, the MW capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, if marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, if the capacity of the RMR resources in the BGE LDA been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $8,500,672,089, a decrease of $6,186,375,269, or 42.1 percent, compared to the actual results. From another perspective, if in addition Scenario 17, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day and marginal ELCC based accreditation did not consider higher winter generation capacity ratings for CC and CT resources, the MW categorically exempt from the RPM must offer requirement that that did not offer had been offered, resulted in a 72.8 percent increase in RPM revenues for the 2025/2026 RPM BRA compared to what RPM revenues would have been if the MW capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, if marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction and if the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction (Scenario 20).

Table 5 shows the results of Scenarios 21, 22, 23 and 24. These scenarios are identical to the scenarios in Table 4 except that the scenarios in Table 5 use 1.75 * Net CONE rather than 1.0 * Net CONE as the Net CONE component of the maximum price calculation. In general, gross CONE was the effective maximum price in scenarios 17 – 24. The results in Table 5 are very similar to the results in Table 4.

Table 4 Scenario summary for 2025/2026 RPM Base Residual Auction: CT Reference Resource; 1.0 * Net CONE; Historical Net Revenue in VRR curve

			Scenario Impact		
				Percent Change	
Scenario	Scenario Description	RPM Revenue ($ per Delivery Year)	RPM Revenue Change ($ per Delivery Year)	Scenario to Actual	Actual to Scenario
0	Actual results	$14,687,047,358	NA	NA	NA
17	VRR curve based on higher of CT gross CONE and 1.0 times net CONE calculated using historical E&AS offset	$18,508,465,316	($3,821,417,958)	(20.6%)	26.0%
18	Scenario 17 and RMR resources	$13,688,897,951	$998,149,406	7.3%	(6.8%)
19	Scenario 17 and winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$11,668,605,299	$3,018,442,059	25.9%	(20.6%)
20	Scenario 17 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$8,500,672,089	$6,186,375,269	72.8%	(42.1%)

Table 5 Scenario summary for 2025/2026 RPM Base Residual Auction: CT Reference Resource; 1.75 * Net CONE; Historical Net Revenue in VRR curve

			Scenario Impact		
				Percent Change	
Scenario	Scenario Description	RPM Revenue ($ per Delivery Year)	RPM Revenue Change ($ per Delivery Year)	Scenario to Actual	Actual to Scenario
0	Actual results	$14,687,047,358	NA	NA	NA
21	VRR curve based on higher of CT gross CONE and 1.75 times net CONE calculated using historical E&AS offset	$18,716,327,928	($4,029,280,571)	(21.5%)	27.4%
22	Scenario 21 and RMR resources	$13,688,897,951	$998,149,406	7.3%	(6.8%)
23	Scenario 21 and winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$11,668,605,299	$3,018,442,059	25.9%	(20.6%)
24	Scenario 21 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$8,500,672,089	$6,186,375,269	72.8%	(42.1%)

Table 6, Table 7, and Table 8 show the results of selected scenarios with higher forecasted peak loads. Scenario 25 and Scenario 26 in Table 6 show the results of Scenario 8 with 2.5 percent higher forecasted peak load and 5.0 percent higher forecasted peak load. Scenario 27, Scenario 28, Scenario 29 and Scenario 30 in Table 7 show the results of Scenarios 13, 14, 15, and 16 with 2.5 percent higher forecasted peak load. Scenario 31, Scenario 32, Scenario 33 and Scenario 34 in Table 8 show the results of Scenarios 13, 14, 15, and 16 with 5.0 percent higher forecasted peak load.

Table 6 Scenario summary for 2025/2026 RPM Base Residual Auction: CC Reference Resource; 1.75 * Net CONE; Forward Net Revenue in VRR curve; Higher Forecasted Peak Load

			Scenario Impact		
				Percent Change	
Scenario	Scenario Description	RPM Revenue ($ per Delivery Year)	RPM Revenue Change ($ per Delivery Year)	Scenario to Actual	Actual to Scenario
0	Actual results	$14,687,047,358	NA	NA	NA
25	VRR curve based on higher of CC gross CONE and 1.75 times net CONE calculated using forward E&AS offset	$33,716,443,356	($19,029,395,999)	(56.4%)	129.6%
26	VRR curve based on higher of CC gross CONE and 1.75 times net CONE calculated using forward E&AS offset	34,413,395,927	(19,726,348,569)	(57.3%)	134.3%

Table 7 Scenario summary for 2025/2026 RPM Base Residual Auction: CT Reference Resource; 1.75 * Net CONE; Forward Net Revenue in VRR curve; 2.5 Percent Higher Forecasted Peak Load

			Scenario Impact		
				Percent Change	
Scenario	Scenario Description	RPM Revenue ($ per Delivery Year)	RPM Revenue Change ($ per Delivery Year)	Scenario to Actual	Actual to Scenario
0	Actual results	$14,687,047,358	NA	NA	NA
27	VRR curve based on higher of CT gross CONE and 1.75 times net CONE calculated using forward E&AS offset	$26,772,578,885	($12,085,531,528)	(45.1%)	82.3%
28	Scenario 27 and RMR resources	$23,838,937,839	($9,151,890,481)	(38.4%)	62.3%
29	Scenario 27 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$21,235,916,604	($6,548,869,247)	(30.8%)	44.6%
30	Scenario 27 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$13,473,937,677	$1,213,109,681	9.0%	(8.3%)

Table 8 Scenario summary for 2025/2026 RPM Base Residual Auction: CT Reference Resource; 1.75 * Net CONE; Forward Net Revenue in VRR curve; 5.0 Percent Higher Forecasted Peak Load

			Scenario Impact		
				Percent Change	
Scenario	Scenario Description	RPM Revenue ($ per Delivery Year)	RPM Revenue Change ($ per Delivery Year)	Scenario to Actual	Actual to Scenario
0	Actual results	$14,687,047,358	NA	NA	NA
31	VRR curve based on higher of CT gross CONE and 1.75 times net CONE calculated using forward E&AS offset	$26,772,578,885	($12,085,531,528)	(45.1%)	82.3%
32	Scenario 31 and RMR resources	$27,101,099,782	($12,414,052,425)	(45.8%)	84.5%
33	Scenario 31 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$28,188,304,298	($13,501,256,940)	(47.9%)	91.9%
34	Scenario 31 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$28,514,872,062	($13,827,824,704)	(48.5%)	94.1%

Table 9 through Table 16 show the summary of the cleared UCAP MW impact of all the scenarios analyzed. The Cleared UCAP column shows the cleared MW that resulted from the specific scenario only. The Cleared UCAP Change column shows the difference between the actual RPM cleared UCAP MW and the total RPM cleared UCAP MW that resulted from the specific scenario. A positive number means that the specific scenario resulted in a reduction in cleared MW. A negative number means that the specific scenario resulted in an increase in cleared MW. The percent columns show the percent change in RPM cleared MW for the specific scenario from two perspectives. The Scenario to Actual Percent column shows the difference between the MW under the defined scenario and the defined baseline as a percent of the MW under the defined scenario. The Actual to Scenario Percent column shows the difference between the MW under the defined scenario and the defined baseline as a percent of the MW under the defined baseline.

Table 9 shows the impact on the cleared UCAP MW for the auction for Scenario 8. The Cleared UCAP column shows the cleared MW that resulted from the defined scenario only.

Table 10 shows the impact on the cleared UCAP MW for the auction for Scenarios 9 through 12. In Scenarios 9, 10, 11 and 12 the MMU analyzed the impact on the actual auction results for the 2025/2026 BRA of using a VRR curve based on the use of a Combustion Turbine (CT) as the reference resource rather than a CC, in combination with scenarios 2, 3 and 4 from Part A.

Table 11 shows the impact on the cleared UCAP MW for the auction for Scenarios 13 through 16. Scenarios 13, 14, 15 and 16 are identical to the scenarios in Table 10 except that the scenarios in Table 11 use 1.75 * Net CONE rather than 1.0 * Net CONE as the Net CONE component of the maximum price calculation.

Table 12 shows the impact on the cleared UCAP MW for the auction for Scenarios 17 through 20. In Scenarios 17, 18, 19 and 20 the MMU analyzed the impact on the actual auction results for the 2025/2026 BRA of using a VRR curve based on the use of a Combustion Turbine (CT) as the reference resource rather than a CC, in combination with scenarios 2, 3 and 4 from Part A.

Table 13 shows the impact on the cleared UCAP MW for the auction for Scenarios 21 through 24. Scenarios 21, 22, 23 and 24 are identical to the scenarios in Table 12 except that the scenarios in Table 13 use 1.75 * Net CONE rather than 1.0 * Net CONE as the Net CONE component of the maximum price calculation.

Table 14 shows the impact on the cleared UCAP MW for Scenarios 25 and 26. Scenarios 25 and 26 are both identical to Scenario 8 except that Scenarios 25 and 26 include higher load forecasts.

Table 15 shows the impact on the cleared UCAP MW for Scenarios 27, 28, 29 and 30. Scenarios 27, 28, 29 and 30 are identical to Scenarios 13, 14, 15 and 16 except that Scenarios 27, 28, 29 and 30 include a higher load forecast.

Table 16 shows the impact on the cleared UCAP MW for Scenarios 31, 32, 33 and 34. Scenarios 31, 32, 33 and 34 are identical to Scenarios 13, 14, 15 and 16 except that Scenarios 31, 32, 33 and 34 include a higher load forecast.

Table 9 Scenario summary for 2025/2026 RPM Base Residual Auction: CC Reference Resource; 1.75 * Net CONE; Forward Net Revenue in VRR curve

		Scenario Impact			
				Percent Change	
Scenario	Scenario Description	Cleared UCAP (MW)	Cleared UCAP Change (MW)	Scenario to Actual	Actual to Scenario
0	Actual results	135,684.0	NA	NA	NA
8	VRR curve based on higher of CC gross CONE and 1.75 times net CONE calculated using forward E&AS offset	135,631.4	52.6	0.0%	(0.0%)

Table 10 Scenario summary for 2025/2026 RPM Base Residual Auction: CT Reference Resource; 1.0 * Net CONE; Forward Net Revenue in VRR curve

		Scenario Impact			
				Percent Change	
Scenario	Scenario Description	Cleared UCAP (MW)	Cleared UCAP Change (MW)	Scenario to Actual	Actual to Scenario
0	Actual results	135,684.0	NA	NA	NA
9	VRR curve based on higher of CT gross CONE and 1.0 times net CONE calculated using forward E&AS offset	135,688.6	(4.6)	(0.0%)	0.0%
10	Scenario 9 and RMR resources	137,106.0	(1,422.0)	(1.0%)	1.0%
11	Scenario 9 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	142,384.9	(6,700.9)	(4.7%)	4.9%
12	Scenario 9 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	143,394.8	(7,710.8)	(5.4%)	5.7%

Table 11 Scenario summary for 2025/2026 RPM Base Residual Auction: CT Reference Resource; 1.75 * Net CONE; Forward Net Revenue in VRR curve

		Scenario Impact			
				Percent Change	
Scenario	Scenario Description	Cleared UCAP (MW)	Cleared UCAP Change (MW)	Scenario to Actual	Actual to Scenario
0	Actual results	135,684.0	NA	NA	NA
13	VRR curve based on higher of CT gross CONE and 1.75 times net CONE calculated using forward E&AS offset	135,704.1	(20.1)	(0.0%)	0.0%
14	Scenario 13 and RMR resources	137,106.0	(1,422.0)	(1.0%)	1.0%
15	Scenario 13 and winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	142,384.9	(6,700.9)	(4.7%)	4.9%
16	Scenario 13 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	143,394.8	(7,710.8)	(5.4%)	5.7%

Table 12 Scenario summary for 2025/2026 RPM Base Residual Auction: CT Reference Resource; 1.0 * Net CONE; Historical Net Revenue in VRR curve

		Scenario Impact			
				Percent Change	
Scenario	Scenario Description	Cleared UCAP (MW)	Cleared UCAP Change (MW)	Scenario to Actual	Actual to Scenario
0	Actual results	135,684.0	NA	NA	NA
17	VRR curve based on higher of CT gross CONE and 1.0 times net CONE calculated using historical E&AS offset	135,704.3	(20.3)	(0.0%)	0.0%
18	Scenario 17 and RMR resources	137,276.7	(1,592.7)	(1.2%)	1.2%
19	Scenario 17 and winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	142,689.7	(7,005.7)	(4.9%)	5.2%
20	Scenario 17 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	144,171.8	(8,487.8)	(5.9%)	6.3%

Table 13 Scenario summary for 2025/2026 RPM Base Residual Auction: CT Reference Resource; 1.75 * Net CONE; Historical Net Revenue in VRR curve

		Scenario Impact			
				Percent Change	
Scenario	Scenario Description	Cleared UCAP (MW)	Cleared UCAP Change (MW)	Scenario to Actual	Actual to Scenario
0	Actual results	135,684.0	NA	NA	NA
21	VRR curve based on higher of CT gross CONE and 1.75 times net CONE calculated using historical E&AS offset	135,704.3	(20.3)	(0.0%)	0.0%
22	Scenario 21 and RMR resources	137,276.7	(1,592.7)	(1.2%)	1.2%
23	Scenario 21 and winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	142,689.7	(7,005.7)	(4.9%)	5.2%
24	Scenario 21 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	144,171.8	(8,487.8)	(5.9%)	6.3%

Table 14 Scenario summary for 2025/2026 RPM Base Residual Auction: CC Reference Resource; 1.75 * Net CONE; Forward Net Revenue in VRR curve; Higher Forecasted Peak Load

		Scenario Impact			
				Percent Change	
Scenario	Scenario Description	Cleared UCAP (MW)	Cleared UCAP Change (MW)	Scenario to Actual	Actual to Scenario
0	Actual results	135,684.0	NA	NA	NA
25	VRR curve based on higher of CC gross CONE and 1.75 times net CONE calculated using forward E&AS offset	135,704.3	(20.3)	(0.0%)	0.0%
26	VRR curve based on higher of CC gross CONE and 1.75 times net CONE calculated using forward E&AS offset	135,704.3	(20.3)	(0.0%)	0.0%

Table 15 Scenario summary for 2025/2026 RPM Base Residual Auction: CT Reference Resource; 1.75 * Net CONE; Forward Net Revenue in VRR curve; 2.5 Percent Higher Forecasted Peak Load

		Scenario Impact			
				Percent Change	
Scenario	Scenario Description	Cleared UCAP (MW)	Cleared UCAP Change (MW)	Scenario to Actual	Actual to Scenario
0	Actual results	135,684.0	NA	NA	NA
27	VRR curve based on higher of CT gross CONE and 1.75 times net CONE calculated using forward E&AS offset	135,704.3	(20.3)	(0.0%)	0.0%
28	Scenario 27 and RMR resources	137,369.5	(1,685.5)	(1.2%)	1.2%
29	Scenario 27 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	142,858.6	(7,174.6)	(5.0%)	5.3%
30	Scenario 27 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	144,469.7	(8,785.7)	(6.1%)	6.5%

Table 16 Scenario summary for 2025/2026 RPM Base Residual Auction: CT Reference Resource; 1.75 * Net CONE; Forward Net Revenue in VRR curve; 5.0 percent Higher Forecasted Peak Load

		Cleared UCAP			
				Percent Change	
Scenario	Scenario Description	Cleared UCAP (MW)	Cleared UCAP Change (MW)	Scenario to Actual	Actual to Scenario
0	Actual results	135,684.0	NA	NA	NA
31	VRR curve based on higher of CT gross CONE and 1.75 times net CONE calculated using forward E&AS offset	135,704.3	(20.3)	(0.0%)	0.0%
32	Scenario 31 and RMR resources	137,369.5	(1,685.5)	(1.2%)	1.2%
33	Scenario 31 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	142,880.3	(7,196.3)	(5.0%)	5.3%
34	Scenario 31 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	144,535.6	(8,851.6)	(6.1%)	6.5%

ATTACHMENT D

Analysis of the 2025/2026 RPM Base Residual Auction Part D

The Independent Market Monitor for PJM

December 6, 2024

Introduction

This report, Part D of what will be a comprehensive report, prepared by the Independent Market Monitor for PJM (IMM or MMU), presents a fourth set of sensitivity analyses of the nineteenth Reliability Pricing Model (RPM) Base Residual Auction (BRA) for the 2025/2026 Delivery Year which was held from July 17 to 23, 2024. The sensitivities in Part C and Part D also address the implications of market design changes for the 2026/2027 BRA. The MMU prepares a comprehensive report for each RPM Base Residual Auction. In this case, rather than waiting until all sensitivities are completed, the MMU will present the results of sensitivities as they are completed in order to provide information to stakeholders that is relevant to decision making about the 2026/2027 BRA, previously scheduled for December 4 to 10, 2024, and now delayed for approximately six months. The MMU will provide a comprehensive report later. The results reported by the MMU are not forecasts or predictions of the outcome of the 2026/2027 BRA.

The capacity market is getting tighter. The result will be higher capacity market prices. In a well designed market, capacity market prices reflect the underlying supply and demand fundamentals. The results of the 2025/2026 BRA illustrate the amplified impact of not getting the details of the market design right when the market is tight. The MMU analysis shows that while a significant increase in capacity market payments was based on the fundamentals, market design and market power issues resulted in actual capacity market payments that were approximately twice as high as needed in the 2025/2026 auction. Without significant changes to key details of the market design, prices in the 2026/2027 auction will be significantly higher than in the 2025/2026 auction and also not consistent with market fundamentals.[1]

The market design details that had a significant impact on the results of the 2025/2026 auction were: the shift from the EFORd availability metric to the ELCC availability metric; the impact of withholding by categorically exempt resources; the impact of using summer ratings rather than winter ratings for combined cycle (CC) and combustion turbine (CT) resources; the impact of the exclusion of two reliability must run (RMR) plants from the capacity market supply curve; and the use of Gross CONE rather than 1.5 times Net CONE as the maximum price in the market.

An increase in demand will further tighten the market, and prices in the next capacity auction will reflect both that increase and the market design issues. The MMU analysis

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1 *See* reports analyzing the 2025/2026 RPM Base Residual Auction, "Analysis of the 2025/2026 RPM Base Residual Auction - Part A," (Sep. 20, 2024), "Analysis of the 2025/2026 RPM Base Residual Auction - Part B," (Oct. 15, 2024), "Analysis of the 2025/2026 RPM Base Residual Auction - Part C," (Nov. 6, 2024). These reports can be found at <https://www.monitoringanalytics.com/reports/Reports/2024.shtml>.

shows that with a 5.0 percent increase in load forecast over the load forecast used in the 2025/2026 auction and Gross CONE as the maximum price, total payments would increase by more than 80 percent over the actual 2025/2026 payments, to $28,514,872,062, even if a CT is used as a reference resource and RMR capacity is fully included in the supply curve. (Scenario 32 in Part C.) That level of increase is in significant part the result of using Gross CONE rather than 1.5 times Net CONE as the maximum price on the capacity market demand curve (VRR curve).

A goal of market design should be to be consistent and predictable and transparent. A consistent, predictable and transparent design would provide a stable investment environment for generators and a stable price environment for customers who both consume and invest. New supply requires competitive incentives and a stable investment environment. The objective of the market design should be markets that work, markets that work for generators and markets that work for customers. The objective of the market design should also be markets that are transparent and understandable to market participants and to regulators. The capacity market design should be as simple as possible to meet its objectives. The current capacity market design does not meet these standards.

The results of the scenarios presented in the Analysis of the 2025/2026 RPM Base Residual Auction Part A ("Part A") and Part B ("Part B") are based on the VRR curves that were used in the 2025/2026 BRA but will not be used in the 2026/2027 RPM BRA. The Part C report addresses the impacts of PJM's initially posted VRR curve parameters for the 2026/2027 BRA based on the actual data from the 2025/2026 BRA, the scenarios from Part A and Part B, use of a CT as the reference resource, and two load growth scenarios. The reported sensitivity results are not predictions or forecasts of the outcome of the 2026/2027 BRA. The sensitivity results show the direction and magnitude of the impacts on capacity market revenues of the proposed market design changes if they had been implemented in the 2025/2026 BRA. Actual conditions could change for the 2026/2027 BRA including changes in supply, in demand and in offer behavior.

The Part C report addresses, explains and quantifies the combined impact of specific critical market design choices in the 2025/2026 BRA that were identified in Part A and further analyzed in Part B, and market design choices for the 2026/2027 BRA. The Part C report and the Part D report focus on the potential impacts of market design choices for the 2026/2027 BRA, currently expected to be run in July 2025, and particularly the impact of increases in forecast load. This Part D report, when compared with the results in the Part C report, demonstrates the significant impact of using the higher of Gross CONE and 1.5 times Net CONE as the maximum price on the VRR curve when there is forecast load growth above that used in the 2025/2026 BRA. The scenarios analyzed in Part D include use of a CT as the reference resource, a maximum price defined by 1.5 times Net CONE, and two load growth scenarios, combined with the separate and combined impacts on market outcomes of the three identified MMU proposed changes: the impact of the exclusion of two reliability must run (RMR) plants from the capacity market supply curve;

the impact of using summer ratings rather than winter ratings for CC and CT resources; and the impact of withholding by categorically exempt resources.[2]

The preliminary RTO wide peak load forecast for the 2025/2026 BRA was 153,883.0 MW. The posted preliminary RTO wide peak load forecast for the 2026/2027 BRA was 157,197.0 MW, 3,313.9 MW or 2.2 percent higher than the peak load forecast for 2025/2026 BRA. The MMU analyzed two peak load forecast scenarios. The MMU scenarios include an increase in the peak load forecast to 157,730.1 MW, an increase of 3,847.1 MW or 2.5 percent, over the preliminary peak load forecast for 2025/2026 BRA and an increase in the peak load forecast to 161,577.2 MW, an increase of 7,694.2 MW or 5.0 percent, over the preliminary peak load forecast used in the 2025/2026 BRA.

Recognizing that the quantitative results are estimates, based on explicitly stated assumptions, the results show the direction and magnitude of the combined impacts of the identified factors in the PJM capacity market design.

The results reported in Part D can be used to evaluate potential market design changes for the 2026/2027 BRA.[3]

In summary, holding everything else constant, if the 2025/2026 RPM BRA had been cleared using a VRR curve with a maximum price of 1.5 times Net CONE based on updated calculations of Net CONE for a CT as the reference resource, a forward net revenue offset, and a 2.5 percent increase in the peak load forecast, the capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, the marginal ELCC based accreditation had included higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $9,165,738,398, a decrease of $5,521,308,959, or 37.6 percent, compared to the actual results (Scenario 50).

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[2] The values stated in this report for the RTO and LDAs refer to the aggregate level including all nested LDAs unless otherwise specified. For example, RTO values include the entire PJM market and all LDAs. Rest of RTO values are RTO values net of nested LDA values.

[3] See "Consultation With Members Regarding Future 205 Filing on Capacity Market," Special Markets and Reliability Committee, November 7, 2024 <https://www.pjm.com/-/media/committees-groups/committees/mrc/2024/20241107-special/item-02---capacity-market-adjustments---presentation.ashx>.

In summary, holding everything else constant, if the 2025/2026 RPM BRA had been cleared using a VRR curve with a maximum price of 1.5 times Net CONE based on updated calculations of Net CONE for a CT as the reference resource, a forward net revenue offset, and a 5.0 percent increase in the peak load forecast, the MW capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, the marginal ELCC based accreditation had included higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $15,963,442,312, an increase of $1,276,394,955, or 8.7 percent, compared to the actual results (Scenario 54).

The significance of the Part D results is highlighted by a comparison with the Part C results. With an increase in the peak load forecast of 5.0 percent, the market would clear at the maximum price, even with the MMU's three identified proposed changes. As a result, the use of Gross CONE rather than 1.5 times Net CONE as the maximum price on the VRR curve, without the MMU's three identified proposed changes, would result in RPM revenues of $26,772,578,885, (Scenario 31) while the use of 1.5 times Net CONE would result in RPM revenues of $15,963,442,312 (Scenario 54). With an increase in the peak load forecast of 5.0 percent, the use of Gross CONE as the maximum price would result in an increase in RPM revenues of $10,809,136,573, or 67.7 percent, compared to the use of 1.5 times Net CONE together with the MMU's three identified proposed changes.

The Part C results show that if the maximum price were set at Gross CONE for a CT and the peak load forecast increased by 2.5 percent, RPM revenues would increase by $12,085,531,528 or 82.3 percent, to $26,772,578,885 (Scenario 27). With the MMU's three identified proposed changes, RPM revenues would decrease by $1,213,109,681 or 8.3 percent, to $13,473,937,677 (Scenario 30).

The Part C results show that if the maximum price were set at Gross CONE for a CT and the peak load forecast increased by 5.0 percent, RPM revenues would increase by $12,085,531,528 or 82.3 percent, to $26,772,578,885 (Scenario 31). With the MMU's three identified proposed changes, RPM revenues would increase by $13,827,824,704 or 94.1 percent, to $28,514,872,062 (Scenario 34).

The capacity market exists to make the energy market work, by providing the additional net revenues required for the incentive to invest in new units and to maintain old units. The definition of capacity is not the ability to provide energy during one peak hour or five peak hours, as implied by the methods used by PJM and LSEs to allocate the costs of capacity to load. The obligations of capacity resources include the requirement to offer their full ICAP in the energy and reserves markets every day. The need for the energy from capacity is not limited to one peak hour or five peak hours. Customers require energy from capacity resources all 8,760 hours per year. Rather than develop a complicated seasonal capacity market based on an arbitrary definition of seasons, the hourly value of the energy from capacity should be explicitly recognized in the capacity market.[4] Under the hourly approach, products with different characteristics at different times of the year (so called seasonal products) would not need to be matched with peak period products.

The MMU recognizes that implementation of the recommendations in this report would require rule changes in some cases.

Conclusions

The capacity market is, by design, always tight in the sense that total supply is generally only slightly larger than demand. The PJM Capacity Market is a locational market and local markets frequently have different supply demand balances than the aggregate market.[5] While the market may be long at times, that is not the equilibrium state. Capacity in excess of demand is not sold and, if it does not earn or does not expect to earn adequate revenues from the full set of PJM markets, or does not have value as a hedge, may be expected to retire, provided the market sets appropriate price signals to reflect the availability of excess supply. Capacity in excess of demand means capacity in excess of the demand as defined by the capacity demand curve, called the Variable Resource Requirement (VRR) curve. PJM rules require load to pay for the level of capacity defined by the VRR curve. Correctly defined, excess capacity means capacity in excess of the peak load forecast plus the reserve margin, the level of capacity PJM is required to purchase in order to maintain reliability, measured in UCAP.

The demand for capacity in the capacity market is almost entirely inelastic because the market rules require loads to purchase their share of the system capacity requirement. The downward sloping portion of the VRR curve is everywhere inelastic. The result is that any supplier that owns more capacity than the typically small difference between total supply and the VRR defined demand is individually pivotal and therefore has structural market power. Any supplier that, jointly with two other suppliers, owns more capacity than the

4 See "Executive Summary of IMM Capacity market design proposal: Sustainable Capacity Market (SCM)," IMM presentation to the PJM Board of Managers, (August 23, 2023) <https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_RASTF-CIFP_SCM_Executive_Summary_20230816.pdf>.

5 The locational element of the PJM Capacity Market is limited to the recognition of different LDAs which were initially defined by transmission zones but now also include subzones. However the PJM Capacity Market is not fully locational because it treats all capacity within an LDA as equivalent rather than recognizing the impacts of internal transmission constraints.

difference between supply and the VRR defined demand either in aggregate or for a local market is jointly pivotal and therefore has structural market power.

The market design for capacity leads, almost unavoidably, to structural market power in the capacity market. The capacity market is unlikely ever to approach a competitive market structure in the absence of a substantial and unlikely structural change that results in much greater diversity of ownership. Market power is and will remain endemic to the structure of the PJM Capacity Market. Nonetheless a competitive outcome can be assured by appropriate market power mitigation rules. Detailed market power mitigation rules are included in the PJM Open Access Transmission Tariff (OATT or Tariff). Reliance on the RPM design for competitive outcomes means reliance on the market power mitigation rules. Attenuation of those rules means that market participants are not able to rely on the competitiveness of the market outcomes.

There are currently two important gaps in the market power rules for the PJM Capacity Market. Unlike all other generation capacity resources, Intermittent Resources, Capacity Storage Resources, and Hybrid Resources consisting exclusively of components that in isolation would be Intermittent Resources or Capacity Storage Resources, are categorically exempt from the RPM must offer requirement. Capacity Storage Resources include pumped storage hydroelectric, impoundment hydroelectric, flywheel, and battery. Intermittent Resources include wind, solar, landfill gas, run of river hydroelectric, and other renewable resources. As a result, a significant level of such resources withhold their capacity. The result is to increase the clearing prices above the competitive level. This can benefit the owners of capacity portfolios that include such resources as well as resources with an RPM must offer requirement. The MMU recommends that all capacity resources have a must offer obligation. The MMU also recommends that performance penalties not be applied to solar and wind resources when they are not capable of performing based on ambient conditions. For example, solar resources should be subject to performance penalties if they fail to perform when the sun is shining but should not be subject to performance penalties in the middle of the night. This would be a rational application of the PAI penalties that recognizes the physical capabilities of resources and is therefore not discriminatory. Demand resources (DR) have always been treated more favorably than generation capacity resources. Demand resources also do not have an RPM must offer requirement. Demand resources, unlike all other capacity resources, are not subject to market seller offer caps to protect against the exercise of market power. When demand resources are pivotal, as they were for the 2025/2026 BRA, they have structural market power and can and do exercise market power. The result is to increase the clearing prices above the competitive level. If the resources clear, it benefits the resources directly. Even if the resources do not clear, higher prices can benefit the owners of capacity portfolios that include such resources as well as resources with an RPM must offer requirement. The MMU recommends that demand resources have defined and enforced market seller offer caps, like all other capacity resources.

In the capacity market, as in other markets, market power is the ability of a market participant to increase the market price above the competitive level or to decrease the market price below the competitive level. In order to evaluate whether actual prices reflect the exercise of market power, it is necessary to evaluate whether market offers are consistent with competitive offers. The market seller offer cap defines a competitive offer in the capacity market, regardless of whether the concern is efforts to increase the market price above the competitive level or to reduce the market price below the competitive level. As in all other markets, the competitive offer in the capacity market is the marginal cost of capacity. A competitive offer in the capacity market is equal to net ACR.[6]

All participants to which the three pivotal supplier (TPS) test was applied (in the RTO, BGE, and DOM RPM markets) failed the three pivotal supplier test. The result was that offer caps were applied to all sell offers for Existing Generation Capacity Resources when the capacity market seller did not pass the test, the submitted sell offer exceeded the tariff defined offer cap, and the submitted sell offer, absent mitigation, would have resulted in a higher market clearing price.[7] [8]

Based on the data and this analysis in Part A, Part B and Part C, the MMU concludes that the results of the 2025/2026 RPM Base Residual Auction were significantly affected by flawed market design decisions including PJM's ELCC approach, by the failure to offer categorically exempt resources including, in some cases, the exercise of market power through the withholding of categorically exempt resources, and the exercise of market power through high offers from demand resources, and by the exclusion from supply of the defined RMR resources. The BRA prices do not solely reflect supply and demand fundamentals but also reflect, in significant part, PJM decisions about the definition of supply and demand. The auction results were not solely the result of the introduction of the ELCC approach and do in part reflect the tightening of supply and demand conditions

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6 174 FERC ¶ 61,212 ("March 18th Order") at 65.

7 Prior to November 1, 2009, existing DR and EE were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 (2009) at P 30.

8 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation, and treating a proposed increase in the capability of a Generation Capacity Resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).

in the PJM Capacity Market. PJM's ELCC filing that created many of these issues was approved by FERC.[9]

Based on the data and the analysis in Part C, the MMU concludes that prices based on market fundamentals would have been significantly higher in the 2025/2026 BRA than in the 2024/2025 BRA, but that PJM's design choices resulted in the prices in the 2025/2026 BRA approximately twice as high (112.1 percent) as supported by the fundamentals (Scenario 16).

Based on the data and the analysis in Part C and Part D, the MMU concludes that there is a significant risk of much higher capacity market prices in the 2026/2027 BRA than in the 2025/2026 BRA if the forecast peak load is from to 2.5 to 5.0 percent higher than the forecast peak load used in the 2025/2026 BRA, primarily as a result of PJM's use of Gross CONE as the maximum price rather than 1.5 times Net CONE. The MMU concludes that use of 1.5 times Net CONE as the maximum price, with the MMU's three identified proposed changes, and with 5.0 percent higher forecast load, would result in an increase of $1,276,394,955 over the actual revenues in the 2025/2026 BRA (Scenario 54). The MMU concludes that use of Gross CONE as the maximum price, not including the MMU's three identified proposed changes, and with 5.0 percent higher forecast load, would result in an increase of $12,085,531,528 over the actual revenues in the 2025/2026 (Scenario 31). That is the increase that would result from PJM's proposal. That increase would be excessive and would not be based on market fundamentals.

The initial VRR curve, introduced in 2007, had a maximum price equal to 1.5 times the Net Cost of New Entry (Net CONE). The use of Net CONE was based on the logic of the capacity market, to ensure that between the energy and capacity markets the cost of entry was covered. Net CONE was the missing money that needed to be recoverable in the capacity market. Net CONE was the equilibrating factor between the capacity market and energy market. The use of Gross CONE is inconsistent with that basic capacity market logic. Gross CONE was introduced as the maximum price based on concerns that Net CONE would be too low. The maximum point on the VRR curve for the 2025/2026 BRA was the higher of Gross CONE or 1.5 times Net CONE, and Gross CONE was actually used. However, if the logic of the markets implies a low Net CONE, that is the right answer. There is nothing inherently wrong with a low Net CONE that requires abandoning the basic capacity market logic. Gross CONE was an intervention designed to increase capacity market prices based on a judgment about what prices should be despite the fact that the basic economic logic did not support that increase. If there is an issue with the calculation of Net CONE, it should be addressed directly rather than by ignoring its central role in the design of the capacity market. As Gross CONE numbers are

[9] 186 FERC ¶ 61,080 (January 30, 2024).

reasonably well defined, much more focus on getting the net revenues used in the forward auctions is required in order to ensure that market participants have confidence in the Net CONE values used in the auctions.

Recommendations

The recommendations in Part A and Part B are related primarily to the results of the sensitivity analyses presented in both Part A and Part B. The recommendations in Part C include the recommendations in Part A and Part B and add additional recommendations. Part D emphasizes the recommendation that 1.5 times Net CONE be used as the maximum price on the VRR curve rather than Gross CONE.

The MMU recommends that the must offer rule in the capacity market apply to all capacity resources.[10] Prior to the implementation of the capacity performance design, all existing capacity resources, except DR, were subject to the RPM must offer requirement. There is no reason to exempt intermittent and capacity storage resources, including hydro, from the RPM must offer requirement. The same rules should apply to all capacity resources. The purpose of the RPM must offer rule, which has been in place since the beginning of the capacity market in 1999, is to ensure that the capacity market works based on the inclusion of all demand and all supply, and to prevent the exercise of market power via withholding of supply. The purpose of the RPM must offer requirement is also to ensure equal access to the transmission system through capacity interconnection rights (CIRs). If a resource has CIRs but fails to use them by not offering in the capacity market, the resource is withholding and is also denying the opportunity to offer to other resources that would use the CIRs. For these reasons, existing resources are required to return CIRs to the market within one year after retirement.[11] The same logic should be applied to categorically exempt intermittent and storage capacity resources. The failure to apply the RPM must offer requirement will create increasingly significant market design issues, artificially high capacity prices, and market power issues in the capacity market as the level of capacity from intermittent and capacity storage resources increases. The failure to apply the RPM must offer requirement consistently could also result in very significant changes in supply from auction to auction that would create price volatility and uncertainty in the capacity market and put PJM's reliability margin at risk. The capacity market was designed on the basis of a must buy requirement for load and a corresponding

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10 See "Executive Summary of IMM Capacity market design proposal: Sustainable Capacity Market (SCM)," IMM presentation to the PJM Board of Managers, (August 23, 2023) <https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_RASTF-CIFP_SCM_Executive_Summary_20230816.pdf>.

11 The MMU's position is that CIRs should be returned to the pool of available transmission at the time of a resource's retirement and not held for one year.

must offer requirement for capacity resources. Holding aside the market power issue, the capacity market can work only if both are enforced.

The reasons for the categorical exemption of intermittent resources and storage to date were based on the seasonality of the resources and on PJM's imposition of performance assessment interval (PAI) penalties for nonperformance when performance was not physically possible, e.g. PAI penalties to solar for not producing at night. Neither applies to all the exempt resources and neither is a good reason to exempt these resources. As the role of categorically exempt intermittents and storage grows it is essential to reestablish the must offer obligation for all resources. The inclusion of a must offer obligation for categorically exempt intermittent and capacity storage resources should be coupled with the removal of PAI penalty liability for such resources when it is not physically possible to perform. This is not the removal of performance penalties from wind and solar resources and it is not discriminatory. It is a recognition of the reality that wind and solar resources are not capable of performing at defined times. The capacity market has included balanced must buy and must sell obligations from its inception. The current rules can and should be changed to restore that balance. PJM's recent suggestion that as part of extending the must offer obligation, the market seller offer caps must be changed for categorically exempt resources based on the risk imposed by PJM's illogical imposition of PAI penalties on such resources when they cannot perform (e.g. solar at night) is not consistent with the actual risks faced by such resources rather than the risks unnecessarily created by PJM's PAI design.[12]

The MMU recommends that PJM treat the inclusion of RMR resources in the capacity market consistently. PJM currently includes RMR units in the reliability analysis for RPM auctions but does not include the RMR units in the supply curves. This approach is internally inconsistent. It would be internally consistent to leave the RMR units out of the CETO/CETL analysis. It would also be internally consistent to include the RMR units in the supply of capacity and in the CETO/CETL analysis. Including RMR resources in the capacity supply curve does not mean forcing unit owners to offer or to take on PAI risk, for example. It simply means that PJM would recognize the fact that PJM does treat RMR resources as a source of reliability. The goal is to ensure that the underlying supply and demand fundamentals are included in the capacity market prices. These two options have very different implications for capacity market prices. There are times when a price signal for the entry of generation is appropriate, e.g. when the goal is to allow generation to compete to replace the transmission option, in whole or in part. There are times when a price signal for the entry of generation is not needed or appropriate, e.g. when PJM has

12 Market Implementation Committee (MIC). Comments by Adam Keech (December 4, 2024).

committed to the construction of new transmission that will eliminate the price signal when complete. The relevant rules can and should be changed.

The MMU recommends that the ELCC be significantly refined to include hourly data that would permit unit specific ELCC ratings, to weight summer and winter risk in a more balanced manner, to eliminate PAI risks, and to pay for actual hourly performance rather than based on relatively inflexible class capacity accreditation ratings derived from a small number of hours of poor performance. Specifically, in the short run the MMU recommends that capacity accreditation recognize the winter capability of thermal resources rather than limiting such resources to summer ratings. Most of the risk recognized in the ELCC model is winter risk but the ELCC accreditation values for thermal resources are capped at the summer ratings. That unnecessarily limits supply and changes the ELCC values for all other resources and changes the system accredited unforced capacity and therefore AUCAP, the maximum level of load that can be served by the existing resources and therefore the reliability requirement. The CIRs of such resources are currently limited by the summer ratings but those rules can and should be changed given the use of the ELCC approach. There is no reason that excess winter CIRs cannot be assigned to these resources immediately.

The MMU recommends that the reference resource be a CT rather than a CC. The MMU recommends that the ELCC value used to convert the Gross CONE in ICAP terms for a CT to the Gross CONE in UCAP terms be the ELCC based on winter ratings.

The MMU recommends that the maximum price on the VRR curve be set to 1.5 times the Net CONE rather than the greater of Gross CONE and 1.75 times Net CONE.

Summary of Results

Cleared generation and DR for the entire RTO of 134,224.2 MW resulted in a reserve margin of 18.6 percent and a net excess of 870.9 MW over the reliability requirement adjusted for FRR and PRD of 133,353.3 MW.[13] Net excess is defined as cleared MW of capacity and DR minus the reliability requirement, adjusted for FRR and PRD.

The net excess unforced capacity in the 2025/2026 RPM Base Residual Auction is based on the ELCC approach and the net excess unforced capacity in the 2024/2025 RPM Base Residual Auction is based on the prior EFORd approach. Net excess is significantly affected by the method used to define UCAP. Under the ELCC approach, UCAP is the derated ICAP based on the ELCC Accredited UCAP Factor for the resource (ICAP * AUCAP Factor). Under the EFORd approach, UCAP is ICAP adjusted by the unit forced outage rate (ICAP * (1 – EFORd)). The supply and demand balance in the PJM system will

13 These reserve margin calculations do not consider Fixed Resource Requirement (FRR) load.

appear much tighter using the ELCC approach than the EFORd approach for exactly the same resources.

Net excess decreased 7,215.9 MW from the net excess of 8,086.8 MW in the 2024/2025 RPM Base Residual Auction. This comparison overstates the reduction in net excess because the net excess for the 2024/2025 BRA was in EFORd terms while the net excess for the 2025/2026 BRA was in ELCC terms.

The intersection of the supply curve and the downward sloping VRR demand curve resulted in a clearing price for Capacity Performance Resources of $269.92 per MW-day for the rest of RTO.

Table 2 through Table 6 show the summary of the revenue impacts of the scenarios analyzed in Part D. The results of the scenarios presented in the Analysis of the 2025/2026 RPM Base Residual Auction Part A ("Part A") and Part B ("Part B") are based on VRR curves that are not applicable for the 2026/2027 RPM Base Residual Auction. The Part C report addressed the impacts of PJM's posted VRR curve parameters for the 2026/2027 BRA based on the actual data from the 2025/2026 BRA, the scenarios from Part A and Part B, use of a CT as the reference resource, and two load growth scenarios. The results of the scenarios presented in the Analysis of the 2025/2026 RPM Base Residual Auction Part C ("Part C") are based on VRR curves using the higher of Gross CONE and Net CONE times a multiplier. The results of the scenarios presented in this Part D ("Part D") report are based on the VRR curves applicable for 2026/2027 RPM Base Residual Auction using only Net CONE times a multiplier rather than the higher of Gross CONE and a multiplier of Net CONE. The differences between the results of Part C and Part D demonstrate the significant impact of using Gross CONE rather than Net CONE as the maximum price on the VRR curve. The results of individual scenarios are not strictly additive. The combined results of multiple scenarios are shown for scenarios that address multiple results simultaneously. The quantitative results are estimates. The report makes explicit when the quantitative results depend on assumptions. Even in those cases, the quantitative results are correct as to direction and order of magnitude.

The RPM Revenue column shows the revenues that resulted from the defined scenario only. The RPM Revenue Change column shows the difference between the actual RPM total revenues and the total RPM revenues that resulted from the defined scenario. A positive number means that the existing market design elements in the defined scenario resulted in an increase in RPM revenues compared to the MMU recommendation. A negative number means that the existing market design elements in the defined scenario resulted in a decrease in RPM revenues compared to the MMU recommendation. The Percent Change columns show the percent change in RPM revenues for the defined scenario from two perspectives. The Scenario to Actual Percent column shows the difference between the revenues under the defined scenario and the actual auction results as a percent of the revenues under the defined scenario. The Actual to Scenario Percent column shows the difference between the revenues under the defined scenario and the actual auction results as a percent of the revenues under the actual auction results.

In Scenarios 35, 36, 37 and 38 (Table 2) the MMU analyzed the impact on the actual auction results for the 2025/2026 BRA of using a VRR curve based on a Combustion Turbine (CT) as the reference resource rather than a CC and using 1.0 * Net CONE rather than the higher of 1.0 * Net CONE and Gross CONE, in combination with scenarios 2, 3 and 4 from Part A. The maximum price (point A) is set at 1.0 * Net CONE ($224.50 per UCAP MW-day for the Rest of RTO) for the reference CT resource.[14] Net CONE for the CT is calculated using forward net revenues. The price for point B is set at 0.75 times Net CONE.[15] The MW quantities are set at 98.9 percent of the reliability requirement for point A, 101.6 percent of the reliability requirement for point B and 105.8 percent of the reliability requirement for point C.[16]

Figure 1 shows the RTO VRR curve for Scenario 35 and the actual VRR curve used for the 2025/2026 RPM Base Residual Auction.

Table 2 shows the impact on RPM revenues for Scenario 35. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If the 2025/2026 RPM BRA had been cleared using a VRR curve based on a CT as the reference resource, a forward net revenue offset, a 1.0 multiplier for Net CONE rather than the higher of Gross CONE and a multiplier for Net CONE, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $9,656,613,126, a decrease of $5,030,434,231, or 34.3 percent, compared to the actual results (Scenario 35). From another perspective, the actual 2025/2026 VRR curve resulted in a 52.1 percent increase in 2025/2026 RPM BRA revenues compared to what RPM revenues would have been had PJM cleared the auction using a CT as the reference resource, a 1.0 multiplier for Net CONE and a forward net revenue offset (Scenario 35).

Table 2 shows the impact on RPM revenues for Scenario 36. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the

14 CT Gross CONE from Final Default CONE Values. See MIC Special Session – Default ACR Values <https://www.pjm.com/-/media/committees-groups/committees/mic/2023/20230113-special/item-03---final-updated-of-default-cone-values.ashx> (January 13, 2023). Forward E&AS revenues provided by PJM.

15 See "PJM Manual 18: PJM Capacity Market," § 3.3 Parameters of the Variable Resource Requirement, Rev. 59 (June 27, 2024).

16 Ibid.

2025/2026 RPM BRA were $14,687,047,358. If, in addition to Scenario 35, the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM BRA, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $8,143,618,135, a decrease of $6,543,429,222, or 44.6 percent, compared to the actual results. From another perspective, if in addition to Scenario 35, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day resulted in an 80.4 percent increase in RPM revenues for the 2025/2026 RPM Base Residual Auction compared to what RPM revenues would have been had the capacity of the RMR resources been included in the supply curve at $0 per MW-day (Scenario 36).

Table 2 shows the impact on RPM revenues for Scenario 37. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If, in addition to Scenario 35, marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, if the capacity of the RMR resources in the BGE LDA been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $7,941,726,044, a decrease of $6,745,321,314, or 45.9 percent, compared to the actual results. From another perspective, if in addition to Scenario 35, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day and marginal ELCC based accreditation did not consider higher winter generation capacity ratings for CC and CT resources, resulted in an 84.9 percent increase in RPM revenues for the 2025/2026 RPM BRA compared to what RPM revenues would have been had the capacity of the RMR resources in the BGE LDA been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction and had marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction (Scenario 37).

Table 2 shows the impact on RPM revenues for Scenario 38. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If, in addition to Scenario 35, the MW of capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, if marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, if the capacity of the RMR resources in the BGE LDA been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $6,071,959,881, a decrease of $8,615,087,476, or 58.7 percent, compared to the actual results. From another perspective, if in addition to Scenario 35, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day, marginal ELCC based accreditation did not consider higher winter generation capacity ratings for CC and CT resources and the MW categorically exempt from the RPM must offer requirement that did not offer had been offered, resulted in a 141.9 percent increase in RPM revenues for the 2025/2026 RPM BRA compared to what RPM revenues would have been if the MW capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, if marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction and if the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction (Scenario 38).

In Scenarios 39, 40, 41 and 42 (Table 3) the MMU analyzed the impact on the actual auction results for the 2025/2026 BRA of using a VRR curve based on a Combustion Turbine (CT) as the reference resource rather than a CC and using 1.5 * Net CONE rather than the higher of 1.5 * Net CONE and Gross CONE, in combination with scenarios 2, 3 and 4 from Part A. The maximum price (point A) is set at 1.5 times Net CONE ($336.75 per UCAP MW-day for the Rest of RTO) for the reference CT resource.[17] Net CONE for the CT is calculated using forward net revenues. The price for point B is set at 0.75 times Net CONE.[18] The MW quantities are the same as Scenario 35.

Figure 1 shows the RTO VRR curve for Scenario 39 and the actual VRR curve used for the 2025/2026 RPM Base Residual Auction.

Table 3 shows the impact on RPM revenues for Scenario 39. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If the 2025/2026 RPM BRA had been cleared using a VRR curve based on a CT as the reference resource, a forward net revenue offset, a 1.5 multiplier for Net CONE rather than the higher of Gross CONE and a multiplier for Net CONE, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $9,922,689,454, a decrease of $4,764,357,903, or 32.4 percent, compared to the actual results (Scenario 39). From another perspective, the actual 2025/2026 VRR curve resulted in a 48.0 percent increase in 2025/2026 RPM BRA revenues compared to what RPM revenues

17 CT Gross CONE from Final Default CONE Values. See MIC Special Session – Default ACR Values <https://www.pjm.com/-/media/committees-groups/committees/mic/2023/20230113-special/item-03---final-updated-of-default-cone-values.ashx> (January 13, 2023). Forward E&AS revenues provided by PJM.

18 See "PJM Manual 18: PJM Capacity Market," § 3.3 Parameters of the Variable Resource Requirement, Rev. 59 (June 27, 2024).

would have been had PJM cleared the auction using a CT as the reference resource, a 1.5 multiplier for Net CONE and a forward net revenue offset (Scenario 39).

Table 3 shows the impact on RPM revenues for Scenario 40. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM BRA were $14,687,047,358. If, in addition to Scenario 39, the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM BRA, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $8,710,479,295, a decrease of $5,976,568,062, or 40.7 percent, compared to the actual results. From another perspective, if in addition to Scenario 39, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day resulted in a 68.6 percent increase in RPM revenues for the 2025/2026 RPM Base Residual Auction compared to what RPM revenues would have been had the capacity of the RMR resources been included in the supply curve at $0 per MW-day (Scenario 40).

Table 3 shows the impact on RPM revenues for Scenario 41. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If, in addition to Scenario 39, marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, if the capacity of the RMR resources in the BGE LDA been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $8,036,975,859, a decrease of $6,650,071,498, or 45.3 percent, compared to the actual results. From another perspective, if in addition to Scenario 39, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day and marginal ELCC based accreditation did not consider higher winter generation capacity ratings for CC and CT resources, resulted in an 82.7 percent increase in RPM revenues for the 2025/2026 RPM BRA compared to what RPM revenues would have been had the capacity of the RMR resources in the BGE LDA been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction and had marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction (Scenario 41).

Table 3 shows the impact on RPM revenues for Scenario 42. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If, in addition to Scenario 39, the MW capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, if marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, if the capacity of the RMR resources in the BGE LDA been included in the supply curve at $0 per MW-day in the

2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $6,725,957,280, a decrease of $7,961,090,078, or 54.2 percent, compared to the actual results. From another perspective, if in addition to Scenario 39, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day, marginal ELCC based accreditation did not consider higher winter generation capacity ratings for CC and CT resources and the MW categorically exempt from the RPM must offer requirement that did not offer had been offered, resulted in an 118.4 percent increase in RPM revenues for the 2025/2026 RPM BRA compared to what RPM revenues would have been if the MW capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, if marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction and if the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction (Scenario 42).

In Scenarios 43, 44, 45 and 46 (Table 4) the MMU analyzed the impact on the actual auction results for the 2025/2026 BRA of using a VRR curve based on a Combustion Turbine (CT) as the reference resource rather than a CC and using 1.75 * Net CONE rather than the higher of 1.75 * Net CONE and Gross CONE, in combination with scenarios 2, 3 and 4 from Part A. The maximum price (point A) is set at 1.75 times Net CONE ($392.88 per UCAP MW-day for the Rest of RTO) for the reference CT resource.[19] Net CONE for the CT is calculated using forward net revenues. The price for point B is set at the 0.75 times Net CONE.[20] The MW quantities are the same as Scenario 35 and Scenario 39.

Table 1 shows the price coordinates used for the point A of the VRR curves in the 2025/2026 BRA and identified scenarios. In the 2025/2026 BRA, the price coordinate for RTO was $451.61 per MW-day which is the higher of 2025/2026 RTO Gross CONE calculated using CT as the reference resource, and 1.5 times 2025/2026 RTO Net CONE using an historical net revenue offset. For Scenarios 36 through 46, the price coordinate for RTO is the identified multiplier times the 2026/2027 RTO Net CONE calculated using CT as the reference resource and forward net revenue offset.

[19] CT Gross CONE from Final Default CONE Values. See MIC Special Session – Default ACR Values <https://www.pjm.com/-/media/committees-groups/committees/mic/2023/20230113-special/item-03---final-updated-of-default-cone-values.ashx> (January 13, 2023). Forward E&AS revenues provided by PJM.

[20] See "PJM Manual 18: PJM Capacity Market," § 3.3 Parameters of the Variable Resource Requirement, Rev. 59 (June 27, 2024).

Figure 1 shows the RTO VRR curve for Scenario 43 and the actual VRR curve used for the 2025/2026 RPM Base Residual Auction.

Table 4 shows the impact on RPM revenues for Scenario 43. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If the 2025/2026 RPM BRA had been cleared using a VRR curve based on a CT as the reference resource, a forward net revenue offset, a 1.75 multiplier for Net CONE rather than the higher of Gross CONE and a multiplier for Net CONE, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $11,582,638,741, a decrease of $3,104,408,617, or 21.1 percent, compared to the actual results (Scenario 43). From another perspective, the actual 2025/2026 VRR curve resulted in a 26.8 percent increase in 2025/2026 RPM BRA revenues compared to what RPM revenues would have been had PJM cleared the auction using a CT as the reference resource, a 1.75 multiplier for Net CONE and a forward net revenue offset (Scenario 43).

Table 4 shows the impact on RPM revenues for Scenario 44. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM BRA were $14,687,047,358. If, in addition to Scenario 43, the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM BRA, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $9,942,592,479, a decrease of $4,744,454,879, or 32.3 percent, compared to the actual results. From another perspective, if in addition to Scenario 43, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day resulted in a 47.7 percent increase in RPM revenues for the 2025/2026 RPM Base Residual Auction compared to what RPM revenues would have been had the capacity of the RMR resources been included in the supply curve at $0 per MW-day (Scenario 44).

Table 4 shows the impact on RPM revenues for Scenario 45. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If, in addition to Scenario 43, marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, if the capacity of the RMR resources in the BGE LDA been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $8,287,591,005, a decrease of $6,399,456,353, or 43.6 percent, compared to the actual results. From another perspective, if in addition to Scenario 43, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day and marginal ELCC based accreditation did not consider higher winter generation capacity ratings for CC and CT resources, resulted in a 77.2 percent increase in RPM revenues for the 2025/2026 RPM BRA compared to what RPM revenues would have been had the capacity of the RMR resources in the BGE LDA been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction and had marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction (Scenario 45).

Table 4 shows the impact on RPM revenues for Scenario 46. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If, in addition to Scenario 43, the MW capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, if marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, if the capacity of the RMR resources in the BGE LDA been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $6,442,190,933, a decrease of $8,244,856,424, or 56.1 percent, compared to the actual results. From another perspective, if in addition to Scenario 43, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day, marginal ELCC based accreditation did not consider higher winter generation capacity ratings for CC and CT resources and the MW categorically exempt from the RPM must offer requirement that did not offer had been offered, resulted in a 128.0 percent increase in RPM revenues for the 2025/2026 RPM BRA compared to what RPM revenues would have been if the MW capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, if marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction and if the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction (Scenario 46).

Figure 1 RTO VRR Curves: Actual, Scenario 35, Scenario 39 and Scenario 43

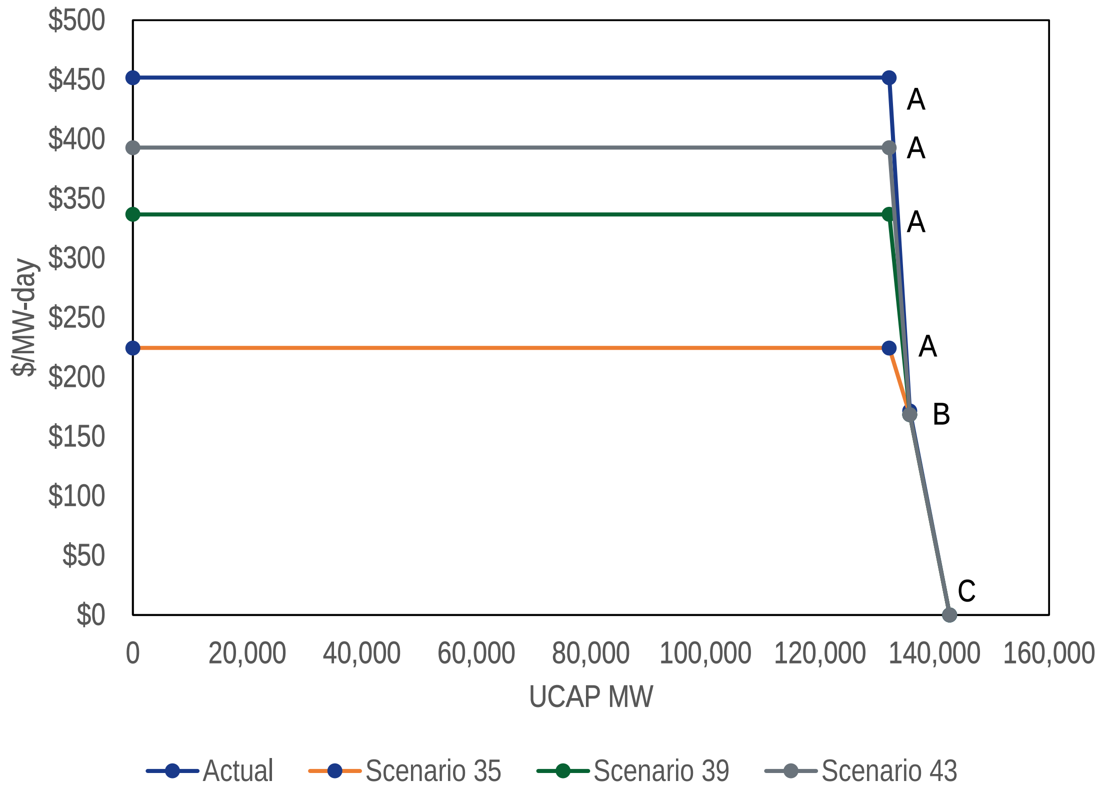

Table 1 Price coordinates used for Point A of the VRR Curve in the 2025/2026 BRA and scenarios

	2025/2026 BRA Max (Gross CONE,1.5*Net CONE) ($/MW-day)	Scenarios 35,36,37,38 1.0*Net CONE for 2026/2027 BRA ($/MW-day)	Scenarios 39,40,41,42 1.5*Net CONE for 2026/2027 BRA ($/MW-day)	Scenarios 43,44,45,46 1.75*Net CONE for 2026/2027 BRA ($/MW-day)
RTO	$451.61	$224.50	$336.75	$392.88
MAAC	$456.19	$292.92	$439.38	$512.61
EMAAC	$466.32	$376.91	$565.37	$659.60
SWMAAC	$466.35	$162.86	$244.29	$285.01
PSEG	$496.46	$415.56	$623.35	$727.24
PS-NORTH	$496.46	$415.56	$623.35	$727.24
DPL-SOUTH	$461.66	$278.03	$417.05	$486.56
PEPCO	$466.35	$271.56	$407.35	$475.24
ATSI	$444.26	$230.72	$346.07	$403.75
ATSI-CLEVELAND	$444.26	$230.72	$346.07	$403.75
COMED	$450.48	$345.41	$518.12	$604.47
BGE	$466.35	$54.16	$81.24	$94.78
PPL	$438.47	$336.60	$504.90	$589.05
DAY	$444.26	$170.83	$256.24	$298.95
DEOK	$444.26	$201.93	$302.90	$353.38
DOM	$444.26	$116.06	$174.09	$203.10

Summary Results Tables

Table 2 Scenario summary for 2025/2026 RPM Base Residual Auction: CT Reference Resource; 1.0 * Net CONE; Forward Net Revenue in VRR curve

			Scenario Impact		
				Percent Change	
Scenario	Scenario Description	RPM Revenue ($ per Delivery Year)	RPM Revenue Change ($ per Delivery Year)	Scenario to Actual	Actual to Scenario
0	Actual results	$14,687,047,358	NA	NA	NA
35	VRR curve based on 1.00 times net CONE calculated using forward E&AS offset	$9,656,613,126	$5,030,434,231	52.1%	(34.3%)
36	Scenario 35 and RMR resources	$8,143,618,135	$6,543,429,222	80.4%	(44.6%)
37	Scenario 35 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$7,941,726,044	$6,745,321,314	84.9%	(45.9%)
38	Scenario 35 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$6,071,959,881	$8,615,087,476	141.9%	(58.7%)

Table 3 Scenario summary for 2025/2026 RPM Base Residual Auction: CT Reference Resource; 1.5 * Net CONE; Forward Net Revenue in VRR curve

			Scenario Impact		
				Percent Change	
Scenario	Scenario Description	RPM Revenue ($ per Delivery Year)	RPM Revenue Change ($ per Delivery Year)	Scenario to Actual	Actual to Scenario
0	Actual results	$14,687,047,358	NA	NA	NA
39	VRR curve based on 1.50 times net CONE calculated using forward E&AS offset	$9,922,689,454	$4,764,357,903	48.0%	(32.4%)
40	Scenario 39 and RMR resources	$8,710,479,295	$5,976,568,062	68.6%	(40.7%)
41	Scenario 39 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$8,036,975,859	$6,650,071,498	82.7%	(45.3%)
42	Scenario 39 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$6,725,957,280	$7,961,090,078	118.4%	(54.2%)

Table 4 Scenario summary for 2025/2026 RPM Base Residual Auction: CT Reference Resource; 1.75 * Net CONE; Forward Net Revenue in VRR curve

			Scenario Impact		
				Percent Change	
Scenario	Scenario Description	RPM Revenue ($ per Delivery Year)	RPM Revenue Change ($ per Delivery Year)	Scenario to Actual	Actual to Scenario
0	Actual results	$14,687,047,358	NA	NA	NA
43	VRR curve based on 1.75 times net CONE calculated using forward E&AS offset	$11,582,638,741	$3,104,408,617	26.8%	(21.1%)
44	Scenario 43 and RMR resources	$9,942,592,479	$4,744,454,879	47.7%	(32.3%)
45	Scenario 43 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$8,287,591,005	$6,399,456,353	77.2%	(43.6%)
46	Scenario 43 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$6,442,190,933	$8,244,856,424	128.0%	(56.1%)

Table 5 and Table 6 show the results of selected scenarios with higher forecasted peak loads than used in the 2025/2026 BRA. The preliminary RTO wide peak load forecast for the 2025/2026 BRA was 153,883.0 MW. The posted preliminary RTO wide peak load forecast for the 2026/2027 BRA was 157,196.98 MW, 3,313.9 MW or 2.2 percent higher than the peak load forecast for 2025/2026 BRA.[21] PJM is currently revising their peak load forecast for the 2025/2026 and 2026/2027 Delivery Years following a substantial number of Large Load Adjustment requests received from LSEs and EDCs.[22] The revised 2025/2026 load forecast will be effective for the 2025/2026 Third Incremental Auction expected to be conducted in February 2025. PJM has indicated that the proposed industrial and data center load spread across eleven transmission zones, but mainly concentrated in Dominion and AEP Transmission Zones, is the primary reason for the expected higher demand in the immediate future.[23] PJM estimated that the preliminary accepted requests added up to approximately 9,000 MW for 2025 and approximately 12,000 MW for 2026.[24]

The MMU analyzed two scenarios with higher forecasted peak loads. Scenarios 47, 48, 49 and 50 shows the impact on RPM revenues due to 2.5 percent higher forecasted peak load or 3,847.1 MW higher than used in the 2025/2026 BRA. Scenarios 51, 52, 53 and 54 shows the impact on RPM revenues due to 5.0 percent higher forecasted peak load or 7,694.2 MW higher than used in the 2025/2026 BRA.

Scenario 47, Scenario 48, Scenario 49 and Scenario 50 in Table 5 show the results of Scenarios 39, 40, 41, and 42 from Table 3 with 2.5 percent higher forecasted peak load. In Scenarios 39, 40, 41 and 42 (Table 3) the MMU analyzed the impact on the actual auction results for the 2025/2026 BRA of using a VRR curve based on a Combustion Turbine (CT) as the reference resource rather than a CC and using 1.5 * Net CONE rather than the higher

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21 PJM published the peak load forecast as part of the Planning Period Parameters for the 2026/2027 BRA, previously scheduled for December 4 to 10, 2024, and now delayed for approximately six months.

22 See Load Forecast 2025: Potential Model Improvements, Assumptions Review, presented at Load Analysis Subcommittee Meeting <https://www.pjm.com/-/media/committees-groups/subcommittees/las/2024/20240919/20240919-item-04---forecast-model-updates.ashx> (September 19, 2024)

23 See Load Adjustment Requests Summary for 2025 Load Forecast - Preliminary, presented at Planning Committee Meeting <https://www.pjm.com/-/media/committees-groups/committees/pc/2024/20241203/20241203-item-07----large-load-adjustment-requests-summary.ashx> (December 2, 2024)

24 The approximate MW for accepted requests were deduced from the stacked area plots presented by PJM. See Load Adjustment Requests Summary for 2025 Load Forecast – Preliminary, presented at Load Analysis Subcommittee Meeting at Slide 9 <https://www.pjm.com/-/media/committees-groups/subcommittees/las/2024/20241125/20241125-item-05---preliminary-load-adjustment-requests-summary.ashx> (November 25, 2024)

of 1.5 * Net CONE and Gross CONE, in combination with scenarios 2, 3 and 4 from Part A. The maximum price (point A) is set at 1.5 times Net CONE ($336.75 per UCAP MW-day for the Rest of RTO) for the reference CT resource.[25] Net CONE for the CT is calculated using forward net revenues. The price for point B is set at 0.75 times Net CONE.[26] The MW quantities are the same as Scenario 35.

Table 5 shows the impact on RPM revenues for Scenario 47 which is Scenario 39 from Table 3 with 2.5 percent higher forecasted peak load. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If the 2025/2026 RPM BRA had been cleared using a VRR curve based on a CT as the reference resource, a forward net revenue offset, a 1.5 multiplier for Net CONE rather than the higher of Gross CONE and 1.5 times Net CONE, and with 2.5 percent higher forecasted peak load, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $14,992,263,281, an increase of $305,215,923, or 2.1 percent, compared to the actual results (Scenario 47). From another perspective, the actual 2025/2026 VRR curve resulted in a 2.0 percent decrease in 2025/2026 RPM BRA revenues compared to what RPM revenues would have been under Scenario 47.

Table 5 shows the impact on RPM revenues for Scenario 48 which is Scenario 40 from Table 3 with 2.5 percent higher forecasted peak load. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM BRA were $14,687,047,358. If, in addition to Scenario 47, the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM BRA, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $12,233,162,290, a decrease of $2,453,885,067, or 16.71 percent, compared to the actual results. From another perspective, if in addition to Scenario 47, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day resulted in a 20.1 percent increase in RPM revenues for the 2025/2026 RPM Base Residual Auction compared to what RPM revenues would have been under Scenario 48.

Table 5 shows the impact on RPM revenues for Scenario 49 which is Scenario 41 from Table 3 with 2.5 percent higher forecasted peak load. Based on actual auction clearing

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25 CT Gross CONE from Final Default CONE Values. See MIC Special Session – Default ACR Values <https://www.pjm.com/-/media/committees-groups/committees/mic/2023/20230113-special/item-03---final-updated-of-default-cone-values.ashx (January 13, 2023). Forward E&AS revenues provided by PJM.

26 See "PJM Manual 18: PJM Capacity Market," § 3.3 Parameters of the Variable Resource Requirement, Rev. 59 (June 27, 2024).

prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If, in addition to Scenario 47, marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, if the capacity of the RMR resources in the BGE LDA been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $12,724,537,456, a decrease of $1,962,509,901, or 13.4 percent, compared to the actual results. From another perspective, if in addition to Scenario 47, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day and marginal ELCC based accreditation did not consider higher winter generation capacity ratings for CC and CT resources, resulted in an 15.4 percent increase in RPM revenues for the 2025/2026 RPM BRA compared to what RPM revenues would have been under Scenario 49.

Table 5 shows the impact on RPM revenues for Scenario 50, which is Scenario 42 from Table 3 with 2.5 percent higher forecasted peak load. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If, in addition to Scenario 47, the MW capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, if marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, if the capacity of the RMR resources in the BGE LDA been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been 9,165,738,398, a decrease of $5,521,308,959, or 37.6 percent, compared to the actual results. From another perspective, if in addition to Scenario 47, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day, marginal ELCC based accreditation did not consider higher winter generation capacity ratings for CC and CT resources and the MW categorically exempt from the RPM must offer requirement that did not offer had been offered, resulted in an 60.2 percent increase in RPM revenues for the 2025/2026 RPM BRA compared to what RPM revenues would have been under Scenario 50.

Table 5 Scenario summary for 2025/2026 RPM Base Residual Auction: CT Reference Resource; 1.5 * Net CONE; Forward Net Revenue in VRR curve; 2.5 Percent Higher Forecasted Peak Load

			Scenario Impact		
				Percent Change	
Scenario	Scenario Description	RPM Revenue ($ per Delivery Year)	RPM Revenue Change ($ per Delivery Year)	Scenario to Actual	Actual to Scenario
0	Actual results	$14,687,047,358	NA	NA	NA
47	VRR curve based on 1.50 times net CONE calculated using forward E&AS offset	$14,992,263,281	($305,215,923)	(2.0%)	2.1%
48	Scenario 47 and RMR resources	$12,233,162,290	$2,453,885,067	20.1%	(16.7%)
49	Scenario 47 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$12,724,537,456	$1,962,509,901	15.4%	(13.4%)
50	Scenario 47 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$9,165,738,398	$5,521,308,959	60.2%	(37.6%)

Scenario 51, Scenario 52, Scenario 53 and Scenario 54 in Table 6 show the results of Scenarios 39, 40, 41, and 42 from Table 3 with 5.0 percent higher forecasted peak load. In Scenarios 39, 40, 41 and 42 (Table 3) the MMU analyzed the impact on the actual auction results for the 2025/2026 BRA of using a VRR curve based on a Combustion Turbine (CT) as the reference resource rather than a CC and using 1.5 * Net CONE rather than the higher of 1.5 * Net CONE and Gross CONE, in combination with scenarios 2, 3 and 4 from Part A. The maximum price (point A) is set at 1.5 times Net CONE ($336.75 per UCAP MW-day for the Rest of RTO) for the reference CT resource.[27] Net CONE for the CT is calculated using forward net revenues. The price for point B is set at 0.75 times Net CONE.[28] The MW quantities are the same as Scenario 35.

Table 6 shows the impact on RPM revenues for Scenario 51 which is Scenario 39 from Table 3 with 5.0 percent higher forecasted peak load. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If the 2025/2026 RPM BRA had been cleared using a VRR curve based on a CT as the reference resource, a forward net revenue offset, a 1.5 multiplier for Net CONE rather than the higher of Gross CONE and 1.5 times Net CONE, and with 5.0 percent higher forecasted peak load, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $16,667,694,486, an increase of $1,980,647,128, or 13.5 percent,

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27 CT Gross CONE from Final Default CONE Values. See MIC Special Session – Default ACR Values <https://www.pjm.com/-/media/committees-groups/committees/mic/2023/20230113-special/item-03---final-updated-of-default-cone-values.ashx> (January 13, 2023). Forward E&AS revenues provided by PJM.

28 See "PJM Manual 18: PJM Capacity Market," § 3.3 Parameters of the Variable Resource Requirement, Rev. 59 (June 27, 2024).

compared to the actual results (Scenario 51). From another perspective, the actual 2025/2026 VRR curve resulted in an 11.9 percent decrease in 2025/2026 RPM BRA revenues compared to what RPM revenues would have been under Scenario 51.

Table 6 shows the impact on RPM revenues for Scenario 52 which is Scenario 40 from Table 3 with 5.0 percent higher forecasted peak load. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM BRA were $14,687,047,358. If, in addition to Scenario 51, the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM BRA, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $16,872,370,463, an increase of $2,185,323,105, or 14.9 percent, compared to the actual results. From another perspective, if in addition to Scenario 51, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day resulted in a 13.0 percent decrease in RPM revenues for the 2025/2026 RPM Base Residual Auction compared to what RPM revenues would have been under Scenario 52.

Table 6 shows the impact on RPM revenues for Scenario 53 which is Scenario 41 from Table 3 with 5.0 percent higher forecasted peak load. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If, in addition to Scenario 51, marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, if the capacity of the RMR resources in the BGE LDA been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $17,549,723,556, an increase of$2,862,676,198, or 19.5 percent, compared to the actual results. From another perspective, if in addition to Scenario 51, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day and marginal ELCC based accreditation did not consider higher winter generation capacity ratings for CC and CT resources, resulted in a 16.3 percent decrease in RPM revenues for the 2025/2026 RPM BRA compared to what RPM revenues would have been under Scenario 53.

Table 6 shows the impact on RPM revenues for Scenario 54, which is Scenario 42 from Table 3 with 5.0 percent higher forecasted peak load. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If, in addition to Scenario 51, the MW capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, if marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, if the capacity of the RMR resources in the BGE LDA been included in the supply curve at $0 per MW-day in the

2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $15,963,442,312, an increase of $1,276,394,955, or 8.7 percent, compared to the actual results. From another perspective, if in addition to Scenario 51, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day, marginal ELCC based accreditation did not consider higher winter generation capacity ratings for CC and CT resources and the MW categorically exempt from the RPM must offer requirement that did not offer had been offered, resulted in a 8.0 percent decrease in RPM revenues for the 2025/2026 RPM BRA compared to what RPM revenues would have been under Scenario 54.

Table 6 Scenario summary for 2025/2026 RPM Base Residual Auction: CT Reference Resource; 1.50 * Net CONE; Forward Net Revenue in VRR curve; 5.0 Percent Higher Forecasted Peak Load

		Scenario Impact			
				Percent Change	
Scenario	Scenario Description	RPM Revenue ($ per Delivery Year)	RPM Revenue Change ($ per Delivery Year)	Scenario to Actual	Actual to Scenario
0	Actual results	$14,687,047,358	NA	NA	NA
51	VRR curve based on 1.50 times net CONE calculated using forward E&AS offset	$16,667,694,486	($1,980,647,128)	(11.9%)	13.5%
52	Scenario 51 and RMR resources	$16,872,370,463	($2,185,323,105)	(13.0%)	14.9%
53	Scenario 51 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$17,549,723,556	($2,862,676,198)	(16.3%)	19.5%
54	Scenario 51 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$15,963,442,312	($1,276,394,955)	(8.0%)	8.7%

Table 7 through Table 11 show the summary of the cleared UCAP MW impact of all the scenarios analyzed. The Cleared UCAP column shows the cleared MW that resulted from the specific scenario only. The Cleared UCAP Change column shows the difference between the actual RPM cleared UCAP MW and the total RPM cleared UCAP MW that resulted from the specific scenario. A positive number means that the specific scenario resulted in a reduction in cleared MW. A negative number means that the specific scenario resulted in an increase in cleared MW. The percent columns show the percent change in RPM cleared MW for the specific scenario from two perspectives. The Scenario to Actual Percent column shows the difference between the MW under the defined scenario and the defined baseline as a percent of the MW under the defined scenario. The Actual to Scenario Percent column shows the difference between the MW under the defined scenario and the defined baseline as a percent of the MW under the defined baseline.

Table 7 shows the impact on the cleared UCAP MW for Scenarios 35 through 38.

Table 8 shows the impact on the cleared UCAP MW for the auction for Scenarios 39 through 42.

Table 10 shows the impact on the cleared UCAP MW for the auction for Scenarios 43 through 46.

Table 11 shows the impact on the cleared UCAP MW for Scenarios 47 through 50.

Table 11 shows the impact on the cleared UCAP MW for Scenarios 51 through 54.

Table 7 Scenario summary for 2025/2026 RPM Base Residual Auction: CC Reference Resource; 1.0 * Net CONE; Forward Net Revenue in VRR curve

		Scenario Impact			
				Percent Change	
Scenario	Scenario Description	Cleared UCAP (MW)	Cleared UCAP Change (MW)	Scenario to Actual	Actual to Scenario
0	Actual results	135,684.0	NA	NA	NA
35	VRR curve based on 1.00 times net CONE calculated using forward E&AS offset	135,431.4	252.6	0.2%	(0.2%)
36	Scenario 35 and RMR resources	136,996.7	(1,312.7)	(1.0%)	1.0%
37	Scenario 35 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	142,340.4	(6,656.4)	(4.7%)	4.9%
38	Scenario 35 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	143,335.4	(7,651.4)	(5.3%)	5.6%

Table 8 Scenario summary for 2025/2026 RPM Base Residual Auction: CT Reference Resource; 1.5 * Net CONE; Forward Net Revenue in VRR curve

		Scenario Impact			
				Percent Change	
Scenario	Scenario Description	Cleared UCAP (MW)	Cleared UCAP Change (MW)	Scenario to Actual	Actual to Scenario
0	Actual results	135,684.0	NA	NA	NA
39	VRR curve based on 1.50 times net CONE calculated using forward E&AS offset	135,457.1	226.9	0.2%	(0.2%)
40	Scenario 39 and RMR resources	137,080.4	(1,396.4)	(1.0%)	1.0%
41	Scenario 39 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	142,440.4	(6,756.4)	(4.7%)	5.0%
42	Scenario 39 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	143,391.8	(7,707.8)	(5.4%)	5.7%

Table 9 Scenario summary for 2025/2026 RPM Base Residual Auction: CT Reference Resource; 1.75 * Net CONE; Forward Net Revenue in VRR curve

		Scenario Impact			
				Percent Change	
Scenario	Scenario Description	Cleared UCAP (MW)	Cleared UCAP Change (MW)	Scenario to Actual	Actual to Scenario
0	Actual results	135,684.0	NA	NA	NA
43	VRR curve based on 1.75 times net CONE calculated using forward E&AS offset	135,530.5	153.5	0.1%	(0.1%)
44	Scenario 43 and RMR resources	137,143.9	(1,459.9)	(1.1%)	1.1%
45	Scenario 43 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	142,516.5	(6,832.5)	(4.8%)	5.0%
46	Scenario 43 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	143,389.7	(7,705.7)	(5.4%)	5.7%

Table 10 Scenario summary for 2025/2026 RPM Base Residual Auction: CT Reference Resource; 1.50 * Net CONE; Forward Net Revenue in VRR curve; 2.5 Percent Higher Forecasted Peak Load

		Scenario Impact		Percent Change	
Scenario	Scenario Description	Cleared UCAP (MW)	Cleared UCAP Change (MW)	Scenario to Actual	Actual to Scenario
0	Actual results	135,684.0	NA	NA	NA
47	VRR curve based on 1.50 times net CONE calculated using forward E&AS offset	135,604.8	79.2	0.1%	(0.1%)
48	Scenario 47 and RMR resources	137,195.6	(1,511.6)	(1.1%)	1.1%
49	Scenario 47 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	142,706.4	(7,022.4)	(4.9%)	5.2%
50	Scenario 47 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	144,245.0	(8,561.0)	(5.9%)	6.3%

Table 11 Scenario summary for 2025/2026 RPM Base Residual Auction: CT Reference Resource; 1.50 * Net CONE; Forward Net Revenue in VRR curve; 5.0 percent Higher Forecasted Peak Load

		Scenario Impact		Percent Change	
Scenario	Scenario Description	Cleared UCAP (MW)	Cleared UCAP Change (MW)	Scenario to Actual	Actual to Scenario
0	Actual results	135,684.0	NA	NA	NA
51	VRR curve based on 1.50 times net CONE calculated using forward E&AS offset	135,604.8	79.2	0.1%	(0.1%)
52	Scenario 51 and RMR resources	137,270.0	(1,586.0)	(1.2%)	1.2%
53	Scenario 51 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	142,780.8	(7,096.8)	(5.0%)	5.2%
54	Scenario 51 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	144,389.1	(8,705.1)	(6.0%)	6.4%

ATTACHMENT E

Analysis of the 2025/2026 RPM Base Residual Auction Part E

The Independent Market Monitor for PJM

January 31, 2025

Introduction

This report, Part E of what will be a comprehensive report, prepared by the Independent Market Monitor for PJM (IMM or MMU), presents a fifth set of sensitivity analyses of the nineteenth Reliability Pricing Model (RPM) Base Residual Auction (BRA) for the 2025/2026 Delivery Year which was held from July 17 to 23, 2024. The sensitivities in Part C, Part D, and Part E also address the implications of market design changes for the 2026/2027 BRA. The MMU prepares a comprehensive report for each RPM Base Residual Auction. In this case, rather than waiting until all sensitivities are completed, the MMU will present the results of sensitivities as they are completed in order to provide information to stakeholders that is relevant to decision making about the 2026/2027 BRA, previously scheduled for December 4 to 10, 2024, and now delayed for approximately six months. The MMU will provide a comprehensive report later. The results reported by the MMU are not forecasts or predictions of the outcome of the 2026/2027 BRA.

The capacity market is getting tighter. The result will be higher capacity market prices. In a well designed market, capacity market prices reflect the underlying supply and demand fundamentals. The results of the 2025/2026 BRA illustrate the amplified impact of not getting the details of the market design right when the market is tight. The MMU analysis shows that while a significant increase in capacity market payments was based on the fundamentals, market design and market power issues resulted in actual capacity market payments that were approximately twice as high as needed in the 2025/2026 auction. Without significant changes to key details of the market design, prices in the 2026/2027 auction will be significantly higher than in the 2025/2026 auction and also not consistent with market fundamentals.[1] The use of Gross CONE as the maximum price is an example of a PJM market design choice and a PJM parameter choice that were not well supported and that result in market outcomes not consistent with market fundamentals.

The market design details that had a significant impact on the results of the 2025/2026 auction were: the shift from the EFORd availability metric to the ELCC availability metric; the impact of withholding by categorically exempt resources; the impact of using summer ratings rather than winter ratings for combined cycle (CC) and combustion turbine (CT) resources; the impact of the exclusion of two reliability must run (RMR) plants from the capacity market supply curve; and the use of Gross CONE rather than 1.5 times Net CONE as the maximum price in the market.

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1 *See* reports analyzing the 2025/2026 RPM Base Residual Auction, "Analysis of the 2025/2026 RPM Base Residual Auction - Part A," (Sep. 20, 2024), "Analysis of the 2025/2026 RPM Base Residual Auction - Part B," (Oct. 15, 2024), "Analysis of the 2025/2026 RPM Base Residual Auction - Part C," (Nov. 6, 2024). These reports can be found at <https://www.monitoringanalytics.com/reports/Reports/2024.shtml>.

An increase in demand will further tighten the market, and prices in the next capacity auction will reflect both that increase and the market design issues. The MMU analysis shows that with a 5.0 percent increase in load forecast over the load forecast used in the 2025/2026 auction and Gross CONE as the maximum price, total payments would increase by 71 percent over the actual 2025/2026 payments, to $25,121,976,644, even if a CT is used as a reference resource and RMR capacity is fully included in the supply curve (Scenario 64). That level of increase is in significant part the result of using Gross CONE rather than 1.5 times Net CONE as the maximum price on the capacity market demand curve (VRR curve).

A goal of market design should be to be consistent and predictable and transparent. A consistent, predictable and transparent design would provide a stable investment environment for generators and a stable price environment for customers who both consume and invest. New supply requires competitive incentives and a stable investment environment. The objective of the market design should be markets that work, markets that work for generators and markets that work for customers. The objective of the market design should also be markets that are transparent and understandable to market participants and to regulators. The capacity market design should be as simple as possible to meet its objectives. The current capacity market design does not meet these standards.

The results of the scenarios presented in the Analysis of the 2025/2026 RPM Base Residual Auction Part A (“Part A”) and Part B (“Part B”) are based on the VRR curves that were used in the 2025/2026 BRA but will not be used in the 2026/2027 BRA. The Part C report addresses the impacts of PJM’s initially posted VRR curve parameters for the 2026/2027 BRA based on the actual data from the 2025/2026 BRA, the scenarios from Part A and Part B, use of a CT as the reference resource, a maximum price defined by Gross CONE, 1.0 times Net CONE, and 1.75 times Net CONE and two load growth scenarios. The Part D report addresses the impacts of using a CT as the reference resource, a maximum price defined by 1.0 times Net CONE, 1.5 times Net CONE and 1.75 times Net CONE, rather than the higher of Gross CONE and a multiplier of Net CONE, and two load growth scenarios.

The purpose of Part E is to update the 5.0 percent load growth scenarios to include PJM updates to Gross CONE and Net CONE values, and to include the 1.5 times Net CONE scenarios for completeness. The results of Part E are intended to facilitate a comprehensive review of the implications of the design choices identified to date.

The reported sensitivity results are not predictions or forecasts of the outcome of the 2026/2027 BRA. The sensitivity results in Part E show the direction and magnitude of the impacts on capacity market revenues of the proposed market design changes if they had been implemented in the 2025/2026 BRA, updated to reflect current Gross CONE and Net CONE values and including the impact of load growth. Actual conditions could change for the 2026/2027 BRA including changes in supply, in demand and in offer behavior.

Recognizing that the quantitative results are estimates, based on explicitly stated assumptions, the results show the direction and magnitude of the combined impacts of the identified factors in the PJM capacity market design.

The results reported in Part E can be used to evaluate potential market design changes for the 2026/2027 BRA.[2]

The Part E report addresses the impacts of using a CT as the reference resource; a maximum price defined by the higher of Gross CONE and 1.0 times Net CONE; a maximum price defined by 1.0 times Net CONE; a maximum price defined by the higher of Gross CONE and 1.5 times Net CONE, a maximum price defined by 1.5 times Net CONE, and the 5.0 percent increase load growth in all scenarios. In each case, Part E shows the separate and combined impacts on market outcomes of the three identified MMU proposed changes: the impact of the exclusion of two reliability must run (RMR) plants from the capacity market supply curve; the impact of using summer ratings rather than winter ratings for CC and CT resources; and the impact of withholding by categorically exempt resources.[3]

The results of the scenarios analyzed in Part E confirm the results in Part C and Part D. All the Part E scenarios include a CT as the reference resource and Net CONE based on forward net revenues with 5.0 percent load growth. The use of Gross CONE as the maximum price on the VRR curve (Point A) results in a significant increase in revenues. The use of Gross CONE results in an increase of $10,137,220,971, or 69.0 percent, compared to the actual results (Scenario 55 and Scenario 63). The use of Gross CONE (Scenario 55) results in an increase of $14,956,918,659, or 151.6 percent, compared to the use of 1.0 times Net CONE as the maximum price (Scenario 59). The use of Gross CONE (Scenario 63) results in an increase of $10,005,027,887 or 67.5 percent compared to the use of 1.5 times Net CONE as the maximum price (Scenario 67).

The use of Gross CONE, with the RMR resources in the BGE LDA included in the supply curve at $0 per MW-day, results in an increase of $10,434,929,287, or 71.0 percent, compared to the actual results (Scenario 56 and Scenario 64). The use of Gross CONE (Scenario 56) with the RMR resources in the BGE LDA included in the supply curve at $0

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2 See "Consultation With Members Regarding Future 205 Filing on Capacity Market," Special Markets and Reliability Committee, November 7, 2024 <https://www.pjm.com/-/media/committees-groups/committees/mrc/2024/20241107-special/item-02---capacity-market-adjustments---presentation.ashx>.

3 The values stated in this report for the RTO and LDAs refer to the aggregate level including all nested LDAs unless otherwise specified. For example, RTO values include the entire PJM market and all LDAs. Rest of RTO values are RTO values net of nested LDA values.

per MW-day, results in an increase of $15,135,602,079 or 151.6 percent compared to the use of 1.0 times Net CONE as the maximum price (Scenario 60). The use of Gross CONE (Scenario 64) with the RMR resources in the BGE LDA included in the supply curve at $0 per MW-day, results in an increase of $10,124,195,877, or 67.5 percent, compared to the use of 1.5 times Net CONE as the maximum price (Scenario 68).

The capacity market exists to make the energy market work, by providing the additional net revenues required for the incentive to invest in new units and to maintain old units. The definition of capacity is not the ability to provide energy during one peak hour or five peak hours, as implied by the methods used by PJM and LSEs to allocate the costs of capacity to load. The obligations of capacity resources include the requirement to offer their full ICAP in the energy and reserves markets every day. The need for the energy from capacity is not limited to one peak hour or five peak hours. Customers require energy from capacity resources all 8,760 hours per year. Rather than develop a complicated seasonal capacity market based on an arbitrary definition of seasons, the hourly value of the energy from capacity should be explicitly recognized in the capacity market.[4] Under the hourly approach, products with different characteristics at different times of the year (so called seasonal products) would not need to be matched with peak period products.

The MMU recognizes that implementation of the recommendations in this report would require rule changes in some cases.

Conclusions

The capacity market is, by design, always tight in the sense that total supply is generally only slightly larger than demand. The PJM Capacity Market is a locational market and local markets frequently have different supply demand balances than the aggregate market.[5] While the market may be long at times, that is not the equilibrium state. Capacity in excess of demand is not sold and, if it does not earn or does not expect to earn adequate revenues from the full set of PJM markets, or does not have value as a hedge, may be expected to retire, provided the market sets appropriate price signals to reflect the

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4 See "Executive Summary of IMM Capacity market design proposal: Sustainable Capacity Market (SCM)," IMM presentation to the PJM Board of Managers, (August 23, 2023) <https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_RASTF-CIFP_SCM_Executive_Summary_20230816.pdf>.

5 The locational element of the PJM Capacity Market is limited to the recognition of different LDAs which were initially defined by transmission zones but now also include subzones. However the PJM Capacity Market is not fully locational because it treats all capacity within an LDA as equivalent rather than recognizing the impacts of internal transmission constraints.

availability of excess supply. Capacity in excess of demand means capacity in excess of the demand as defined by the capacity demand curve, called the Variable Resource Requirement (VRR) curve. PJM rules require load to pay for the level of capacity defined by the VRR curve. Correctly defined, excess capacity means capacity in excess of the peak load forecast plus the reserve margin, the level of capacity PJM is required to purchase in order to maintain reliability, measured in UCAP.

The demand for capacity in the capacity market is almost entirely inelastic because the market rules require loads to purchase their share of the system capacity requirement. The downward sloping portion of the VRR curve is everywhere inelastic. The result is that any supplier that owns more capacity than the typically small difference between total supply and the VRR defined demand is individually pivotal and therefore has structural market power. Any supplier that, jointly with two other suppliers, owns more capacity than the difference between supply and the VRR defined demand either in aggregate or for a local market is jointly pivotal and therefore has structural market power.

The market design for capacity leads, almost unavoidably, to structural market power in the capacity market. The capacity market is unlikely ever to approach a competitive market structure in the absence of a substantial and unlikely structural change that results in much greater diversity of ownership. Market power is and will remain endemic to the structure of the PJM Capacity Market. Nonetheless a competitive outcome can be assured by appropriate market power mitigation rules. Detailed market power mitigation rules are included in the PJM Open Access Transmission Tariff (OATT or Tariff). Reliance on the RPM design for competitive outcomes means reliance on the market power mitigation rules. Attenuation of those rules means that market participants are not able to rely on the competitiveness of the market outcomes.

There are currently two important gaps in the market power rules for the PJM Capacity Market. Unlike all other generation capacity resources, Intermittent Resources, Capacity Storage Resources, and Hybrid Resources consisting exclusively of components that in isolation would be Intermittent Resources or Capacity Storage Resources, are categorically exempt from the RPM must offer requirement. Capacity Storage Resources include pumped storage hydroelectric, impoundment hydroelectric, flywheel, and battery. Intermittent Resources include wind, solar, landfill gas, run of river hydroelectric, and other renewable resources. As a result, a significant level of such resources withhold their capacity. The result is to increase the clearing prices above the competitive level. This can benefit the owners of capacity portfolios that include such resources as well as resources with an RPM must offer requirement. The MMU recommends that all capacity resources have a must offer obligation. The MMU also recommends that performance penalties not be applied to solar and wind resources when they are not capable of performing based on ambient conditions. For example, solar resources should be subject to performance penalties if they fail to perform when the sun is shining but should not be subject to performance penalties in the middle of the night. This would be a rational application of the PAI penalties that recognizes the physical capabilities of resources and is therefore not discriminatory. Demand resources (DR) have always been treated more favorably than generation capacity resources. Demand resources also do not have an RPM must offer requirement. Demand resources, unlike all other capacity resources, are not subject to market seller offer caps to protect against the exercise of market power. When demand resources are pivotal, as they were for the 2025/2026 BRA, they have structural market power and can and do exercise market power. The result is to increase the clearing prices above the competitive level. If the resources clear, it benefits the resources directly. Even if the resources do not clear, higher prices can benefit the owners of capacity portfolios that include such resources as well as resources with an RPM must offer requirement. The MMU recommends that demand resources have defined and enforced market seller offer caps, like all other capacity resources.

In the capacity market, as in other markets, market power is the ability of a market participant to increase the market price above the competitive level or to decrease the market price below the competitive level. In order to evaluate whether actual prices reflect the exercise of market power, it is necessary to evaluate whether market offers are consistent with competitive offers. The market seller offer cap defines a competitive offer in the capacity market, regardless of whether the concern is efforts to increase the market price above the competitive level or to reduce the market price below the competitive level. As in all other markets, the competitive offer in the capacity market is the marginal cost of capacity. A competitive offer in the capacity market is equal to net ACR.[6]

All participants to which the three pivotal supplier (TPS) test was applied (in the RTO, BGE, and DOM RPM markets) failed the three pivotal supplier test. The result was that offer caps were applied to all sell offers for Existing Generation Capacity Resources when the capacity market seller did not pass the test, the submitted sell offer exceeded the tariff defined offer cap, and the submitted sell offer, absent mitigation, would have resulted in a higher market clearing price.[7] [8]

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6 174 FERC ¶ 61,212 ("March 18th Order") at 65.

7 Prior to November 1, 2009, existing DR and EE were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 (2009) at P 30.

8 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation, and treating a proposed increase in the capability

Based on the data and the analysis in Part A, Part B, Part C, Part D and Part E, the MMU concludes that the results of the 2025/2026 RPM Base Residual Auction were significantly affected by flawed market design decisions including PJM's ELCC approach, by the failure to offer categorically exempt resources including, in some cases, the exercise of market power through the withholding of categorically exempt resources, and the exercise of market power through high offers from demand resources, and by the exclusion from supply of the defined RMR resources. The BRA prices do not solely reflect supply and demand fundamentals but also reflect, in significant part, PJM decisions about the definition of supply and demand. The auction results were not solely the result of the introduction of the ELCC approach and do in part reflect the tightening of supply and demand conditions in the PJM Capacity Market. PJM's ELCC filing that created many of these issues was approved by FERC.[9] Part E updates the analysis to reflect changes in Gross and Net CONE and demonstrates that the choice of Gross CONE as the maximum price will significantly increase total capacity market revenues if there is load growth over the level of load used in the 2025/2026 BRA.

Recommendations

The recommendations in Part A and Part B are related primarily to the results of the sensitivity analyses presented in both Part A and Part B. The recommendations in Part C include the recommendations in Part A and Part B and add additional recommendations. Part D emphasizes the recommendation that 1.5 times Net CONE be used as the maximum price on the VRR curve rather than Gross CONE. Part E updates the 5.0 percent load growth scenarios to include PJM updates to Gross CONE and Net CONE values, and to include the 1.5 times Net CONE scenarios for completeness. The results of Part E are intended to facilitate a comprehensive review of the implications of the design choices identified to date. Part E further emphasizes and demonstrates the impact of PJM's choice of Gross CONE as the maximum price on the VRR curve.

The MMU recommends that the must offer rule in the capacity market apply to all capacity resources.[10] Prior to the implementation of the capacity performance design, all

of a Generation Capacity Resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).

9 186 FERC ¶ 61,080 (January 30, 2024).

10 See "Executive Summary of IMM Capacity market design proposal: Sustainable Capacity Market (SCM)," IMM presentation to the PJM Board of Managers, (August 23, 2023) <https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_RASTF-CIFP_SCM_Executive_Summary_20230816.pdf>.

existing capacity resources, except DR, were subject to the RPM must offer requirement. There is no reason to exempt intermittent and capacity storage resources, including hydro, from the RPM must offer requirement. The same rules should apply to all capacity resources. The purpose of the RPM must offer rule, which has been in place since the beginning of the capacity market in 1999, is to ensure that the capacity market works based on the inclusion of all demand and all supply, and to prevent the exercise of market power via withholding of supply. The purpose of the RPM must offer requirement is also to ensure equal access to the transmission system through capacity interconnection rights (CIRs). If a resource has CIRs but fails to use them by not offering in the capacity market, the resource is withholding and is also denying the opportunity to offer to other resources that would use the CIRs. For these reasons, existing resources are required to return CIRs to the market within one year after retirement.[11] The same logic should be applied to categorically exempt intermittent and storage capacity resources. The failure to apply the RPM must offer requirement will create increasingly significant market design issues, artificially high capacity prices, and market power issues in the capacity market as the level of capacity from intermittent and capacity storage resources increases. The failure to apply the RPM must offer requirement consistently could also result in very significant changes in supply from auction to auction that would create price volatility and uncertainty in the capacity market and put PJM's reliability margin at risk. The capacity market was designed on the basis of a must buy requirement for load and a corresponding must offer requirement for capacity resources. Holding aside the market power issue, the capacity market can work only if both are enforced.

The reasons for the categorical exemption of intermittent resources and storage to date were based on the seasonality of the resources and on PJM's imposition of performance assessment interval (PAI) penalties for nonperformance when performance was not physically possible, e.g. PAI penalties to solar for not producing at night. Neither applies to all the exempt resources and neither is a good reason to exempt these resources. As the role of categorically exempt intermittents and storage grows it is essential to reestablish the must offer obligation for all resources. The inclusion of a must offer obligation for categorically exempt intermittent and capacity storage resources should be coupled with the removal of PAI penalty liability for such resources when it is not physically possible to perform. This is not the removal of performance penalties from wind and solar resources and it is not discriminatory. It is a recognition of the reality that wind and solar resources are not capable of performing at defined times. The capacity market has included balanced must buy and must sell obligations from its inception. The current rules can and should be changed to restore that balance. PJM's recent suggestion that as part of

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11 The MMU's position is that CIRs should be returned to the pool of available transmission at the time of a resource's retirement and not held for one year.

extending the must offer obligation, the market seller offer caps must be changed for categorically exempt resources based on the risk imposed by PJM's illogical imposition of PAI penalties on such resources when they cannot perform (e.g. solar at night) is not consistent with the actual risks faced by such resources rather than the risks unnecessarily created by PJM's PAI design.[12]

The MMU recommends that PJM treat the inclusion of RMR resources in the capacity market consistently. PJM currently includes RMR units in the reliability analysis for RPM auctions but does not include the RMR units in the supply curves. This approach is internally inconsistent. It would be internally consistent to leave the RMR units out of the CETO/CETL analysis and out of the market supply curve. It would also be internally consistent to include the RMR units in the CETO/CETL analysis and in the supply of capacity. Including RMR resources in the capacity supply curve does not mean forcing unit owners to offer or to take on PAI risk, for example. It simply means that PJM would recognize the fact that PJM does treat RMR resources as a source of reliability. The goal is to ensure that the underlying supply and demand fundamentals are included in the capacity market prices. These two options have very different implications for capacity market prices. There are times when a price signal for the entry of generation is appropriate, e.g. when the goal is to allow generation to compete to replace the transmission option, in whole or in part. There are times when a price signal for the entry of generation is not needed or appropriate, e.g. when PJM has committed to the construction of new transmission that will eliminate the price signal when complete. The relevant rules can and should be changed.

The MMU recommends that the ELCC be significantly refined to include hourly data that would permit unit specific ELCC ratings, to weight summer and winter risk in a more balanced manner, to eliminate PAI risks, and to pay for actual hourly performance rather than based on relatively inflexible class capacity accreditation ratings derived from a small number of hours of poor performance. Specifically, in the short run the MMU recommends that capacity accreditation recognize the winter capability of thermal resources rather than limiting such resources to summer ratings. Most of the risk recognized in the ELCC model is winter risk but the ELCC accreditation values for thermal resources are capped at the summer ratings. That unnecessarily limits supply and changes the ELCC values for all other resources and changes the system accredited unforced capacity and therefore AUCAP, the maximum level of load that can be served by the existing resources and therefore the reliability requirement. The CIRs of such resources are currently limited by the summer ratings but those rules can and should be

12 Market Implementation Committee (MIC). Comments by Adam Keech (December 4, 2024).

changed given the use of the ELCC approach. There is no reason that excess winter CIRs cannot be assigned to these resources immediately.

The MMU recommends that the reference resource be a CT rather than a CC. The MMU recommends that the ELCC value used to convert the Gross CONE in ICAP terms for a CT to the Gross CONE in UCAP terms be the ELCC based on winter ratings.

The MMU recommends that the maximum price on the VRR curve be set to 1.5 times the Net CONE rather than the greater of Gross CONE and 1.75 times Net CONE and to cap the maximum price at Gross CONE.[13]

Results

Table 2 through Table 5 show the summary of the revenue impacts of the scenarios analyzed in Part E.

The results of individual scenarios are not strictly additive. The combined results of multiple scenarios are shown for scenarios that address multiple results simultaneously. The quantitative results are estimates. The report makes explicit when the quantitative results depend on assumptions. Even in those cases, the quantitative results are correct as to direction and order of magnitude. The RPM Revenue column shows the revenues that resulted from the defined scenario only. The RPM Revenue Change column shows the difference between the actual RPM total revenues and the total RPM revenues that resulted from the defined scenario. A positive number means that the existing market design elements in the defined scenario resulted in an increase in RPM revenues compared to the MMU recommendation. A negative number means that the existing market design elements in the defined scenario resulted in a decrease in RPM revenues compared to the MMU recommendation. The Percent Change columns show the percent change in RPM revenues for the defined scenario from two perspectives. The Scenario to Actual Percent column shows the difference between the revenues under the defined scenario and the actual auction results as a percent of the revenues under the defined scenario. The Actual to Scenario Percent column shows the difference between the

13 In some LDAs the result of using a 1.5 multiplier is greater than Gross CONE. For the CT reference resource, 1.5 * Net CONE is an average of 72 percent of Gross CONE across all LDAs and 1.5 * Net CONE is greater than Gross CONE for four of the 17 LDAs, with a maximum excess over Gross CONE of 13 percent and an average excess of 9 percent for those four LDAs. Results updated, based on PJM updates to Gross CONE and Net CONE, from "*Comments of the Independent Market Monitor for PJM*," Docket No. ER25-682 at 23 (January 6, 2025).

revenues under the defined scenario and the actual auction results as a percent of the revenues under the actual auction results.

In all scenarios included in Part E, the MMU analyzed the impact on the actual auction results for 2025/2026 BRA under the assumption that the forecasted peak load would be 5.0 percent higher than that used in the 2025/2026 BRA. The preliminary RTO wide peak load forecast for the 2025/2026 BRA was 153,883.0 MW. PJM revised the peak load forecast for the 2025/2026 and 2026/2027 Delivery Years following a substantial number of Large Load Adjustment requests received from LSEs and EDCs.[14] The final RTO wide peak load forecast for the 2025/2026 Delivery Year is 154,534.1 MW, 651.1 MW or 0.4 percent higher than the preliminary peak load forecast for 2025/2026 BRA.[15] The RTO wide preliminary peak load forecast for the 2026/2027 BRA is 158,937 MW, 5,054 MW or 3.3 percent higher than the preliminary peak load forecast for 2025/2026 BRA.[16] The revised 2025/2026 load forecast will be effective for the 2025/2026 Third Incremental Auction expected to be conducted in February 2025. PJM has indicated that the proposed industrial and data center load spread across eleven transmission zones, but mainly concentrated in Dominion and AEP Transmission Zones, is the primary reason for the expected higher demand in the immediate future. PJM estimated that the preliminary accepted requests added up to approximately 9,000 MW for 2025 and approximately 12,000 MW for 2026.[17]

[14] See 2025 PJM Long-Term Load Forecast Report <https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2025-load-report.pdf> (January 24, 2025).

[15] The forecast peak load values used in RPM auctions includes adjustments for load served outside PJM.

[16] The peak load forecast value for the 2026/2027 Delivery Year excludes adjustments for load served outside PJM. The planning parameters for the 2026/2027 BRA including the preliminary peak load forecast adjusted for load served outside PJM will be released no later than March 31, 2025. The final peak load forecast for the 2026/2027 Delivery Year will be released in January 2026. The planning parameters for the 2026/2027 Third IA including the final peak load forecast adjusted for load served outside PJM will be released sometime in January 2026, based on a February 2026 auction opening.

[17] See Load Adjustment Requests Summary for 2025 Load Forecast - Preliminary, presented at Planning Committee Meeting <https://www.pjm.com/-/media/committees-groups/committees/pc/2024/20241203/20241203-item-07----large-load-adjustment-requests-summary.ashx> (December 2, 2024)

Prices for Point A on VRR Curve

Table 1 shows the price coordinates used for point A of the VRR curves in Part E. The price coordinates are based on PJM's updates to Gross CONE and Net CONE values provided after Part C and Part D.[18] [19] Gross CONE decreased from the original Combustion Turbine (CT) MOPR parameters that PJM posted for the 2026/2027 Base Residual Auction in August 2024 because PJM changed the reference resource for the VRR curve from a gas fired CT with firm gas (single fuel) to a gas fired CT with nonfirm gas and oil backup (dual fuel). PJM also updated the net revenue offset and therefore the Net CONE values using the November fuel and energy forward prices for the delivery year.

Table 1 Price coordinates used for Point A of the VRR Curve in the scenarios

	Scenarios 55,56,57,58 Max (Gross CONE, 1.0*Net CONE) ($/MW-day)	Scenarios 59,60,61,62 1.0*Net CONE ($/MW-day)	Scenarios 63,64,65,66 Max (Gross CONE, 1.5*Net CONE) ($/MW-day)	Scenarios 67,68,69,70 1.5*Net CONE ($/MW-day)
RTO	$499.32	$199.63	$499.32	$299.45
MAAC	$497.66	$256.03	$497.66	$384.05
EMAAC	$471.65	$315.68	$473.52	$473.52
SWMAAC	$492.46	$146.01	$492.46	$219.02
PSEG	$471.65	$354.34	$531.51	$531.51
PS-NORTH	$471.65	$354.34	$531.51	$531.51
DPL-SOUTH	$471.65	$216.81	$471.65	$325.22
PEPCO	$492.46	$227.55	$492.46	$341.33
ATSI	$511.88	$213.94	$511.88	$320.91
ATSI-CLEVELAND	$511.88	$213.94	$511.88	$320.91
COMED	$522.98	$335.50	$522.98	$503.25
BGE	$492.46	$64.47	$492.46	$96.71
PPL	$497.66	$301.38	$497.66	$452.07
DAY	$511.88	$168.40	$511.88	$252.60
DEOK	$511.88	$188.92	$511.88	$283.38
DOM	$511.88	$96.82	$511.88	$145.23
JCPL	$471.65	$351.65	$527.48	$527.48

18 In Part C and Part D, CT Gross CONE are from 2026/2027 Default New Entry MOPR Offer Prices <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2026-2027/2026-2027-dy-mopr-prices-for-new-entry.ashx> (July 5, 2024). Forward E&AS revenues are provided by PJM.

19 See Attachment D, FERC Docket No. ER25-682-000, Revisions to PJM Capacity Market (December 9, 2024). Forward E&AS revenues are provided by PJM.

Results: Higher of Gross CONE and 1.0 Net CONE; Forward Net Revenues; 5.0 increase in Forecasted Load

In Scenarios 55, 56, 57 and 58, the MMU analyzed the impact on the actual auction results for the 2025/2026 BRA of using a VRR curve based on the use of a Combustion Turbine (CT) as the reference resource rather than a CC, in combination with scenarios 2, 3 and 4 from Part A and a 5.0 percent higher forecasted peak load than used in the 2025/2026 BRA.[20] The maximum price (point A) is set at the greater of updated Gross CONE ($499.32 per UCAP MW-day for the Rest of RTO) and a multiplier of 1.0 times Net CONE ($199.63 per UCAP MW-day for the Rest of RTO) for the reference CT resource.[21] Gross CONE ($ per UCAP MW-day) is derived from the $ per ICAP MW-Year of Levelized Revenue Requirement using the ELCC based class average accredited UCAP factor for the technology class of the reference resource.[22] The ELCC based accredited UCAP factor of the reference CT resource was 0.79. Net CONE for the CT is calculated using expected forward energy and ancillary service revenues. Gross CONE was higher than 1.0 times Net CONE for all modeled LDAs. The price for point B is set at the 0.75 times Net CONE for the CT.[23]

Table 2 shows the impact on RPM revenues for Scenario 55. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If the 2025/2026 BRA had been cleared using a VRR curve based on a CT as the reference resource, the maximum price (point A) set at the higher of Gross CONE and 1.0 times Net CONE with a forward net revenue offset, a 5.0 percent higher forecasted peak load and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $24,824,268,329, an increase of $10,137,220,971, or 69.0 percent, compared to the actual results (Scenario 55). From another perspective, the actual 2025/2026 VRR curve resulted in 40.8 percent lower 2025/2026 BRA revenues compared to what RPM revenues would have been had PJM cleared the auction using a CT as the reference resource, the maximum price (point A) set at the higher of Gross CONE and 1.0

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20 Scenarios 2, 3 and 4 address the impact of the failure to offer by some categorically exempt resources, the impact of excluding RMR supply and the impact of understated winter ratings for thermal resources. These scenarios are included in the analysis in Parts A, B, C, D and E.

21 See Attachment D, FERC Docket No. ER25-682-000, Revisions to PJM Capacity Market (December 9, 2024). Forward E&AS revenues are provided by PJM.

22 $Gross\ CONE\ (\$\ per\ UCAP\ MWDay) = \frac{Levelized\ Revenue\ Requirement\ (\$\ per\ ICAP\ MW\ Year)}{Number\ of\ Days\ in\ Delivery\ Year * Reference\ Resource\ AUCAP\ Factor}$

23 See "PJM Manual 18: PJM Capacity Market," § 3.3 Parameters of the Variable Resource Requirement, Rev. 59 (June 27, 2024).

times Net CONE with a forward net revenue offset, and 5.0 percent higher forecasted peak load (Scenario 55).

Table 2 shows the impact on RPM revenues for Scenario 56. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 BRA were $14,687,047,358. If, in addition to Scenario 55, the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 BRA, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $25,121,976,644, an increase of $10,434,929,287, or 71.0 percent, compared to the actual results. From another perspective, if in addition to Scenario 55, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day resulted in a 41.5 percent decrease in RPM revenues for the 2025/2026 RPM Base Residual Auction compared to what RPM revenues would have been had the capacity of the RMR resources been included in the supply curve at $0 per MW-day (Scenario 56).

Table 2 shows the impact on RPM revenues for Scenario 57. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If, in addition to Scenario 55, marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, if the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $26,034,414,477, an increase of $11,347,367,120, or 77.3 percent, compared to the actual results. From another perspective, if in addition to Scenario 55, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day and marginal ELCC based accreditation did not consider higher winter generation capacity ratings for CC and CT resources, resulted in a 43.6 percent decrease in RPM revenues for the 2025/2026 BRA compared to what RPM revenues would have been had the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction and had marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction (Scenario 57).

Table 2 shows the impact on RPM revenues for Scenario 58. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If, in addition to Scenario 55, the MW capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, if marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, if the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $26,336,095,882, an increase of $11,649,048,525, or 79.3 percent, compared to the actual results. From another perspective, if in addition to Scenario 55, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day, marginal ELCC based accreditation did not consider higher winter generation capacity ratings for CC and CT resources and the MW categorically exempt from the RPM must offer requirement that did not offer had been offered, resulted in a 44.2 percent decrease in RPM revenues for the 2025/2026 BRA compared to what RPM revenues would have been if the MW capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, if marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction and if the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction (Scenario 58).

Table 2 Scenario summary for 2025/2026 RPM Base Residual Auction: CT Reference Resource; Higher of Gross CONE and 1.0 * Net CONE; Forward Net Revenue in VRR curve; 5.0 Percent Higher Forecasted Peak Load

		Scenario Impact			
				Percent Change	
Scenario	Scenario Description	RPM Revenue ($ per Delivery Year)	RPM Revenue Change ($ per Delivery Year)	Scenario to Actual	Actual to Scenario
0	Actual results	$14,687,047,358	NA	NA	NA
55	VRR curve based on higher of CT Gross CONE and 1.0 times Net CONE calculated using forward E&AS offset	$24,824,268,329	($10,137,220,971)	(40.8%)	69.0%
56	Scenario 55 and RMR resources	$25,121,976,644	($10,434,929,287)	(41.5%)	71.0%
57	Scenario 55 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$26,034,414,477	($11,347,367,120)	(43.6%)	77.3%
58	Scenario 55 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$26,336,095,882	($11,649,048,525)	(44.2%)	79.3%

Results: 1.0* Net CONE; Forward Net Revenues; 5.0 Increase in Forecasted Load

In Scenarios 59, 60, 61 and 62 the MMU analyzed the impact on the actual auction results for the 2025/2026 BRA of using a VRR curve based on the use of a Combustion Turbine (CT) as the reference resource rather than a CC and using 1.0 * Net CONE rather than the higher of 1.0 * Net CONE and Gross CONE, in combination with scenarios 2, 3 and 4 from Part A and a 5.0 percent higher forecasted peak load than used in the 2025/2026 BRA. The maximum price (point A) is set at 1.0 * Net CONE ($199.63 per UCAP MW-day for the Rest of RTO) for the reference CT resource rather than the higher of Gross CONE and a multiplier for Net CONE.[24] The price for point B is set at the 0.75 times Net CONE for the CT. The corresponding MW quantities are the same as Scenario 8 analyzed in Part C.

Table 3 shows the impact on RPM revenues for Scenario 59. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If the 2025/2026 BRA had been cleared using a VRR curve based on a CT as the reference resource, a 1.0 multiplier for Net CONE with a forward net revenue offset rather than the higher of Gross CONE and a multiplier for Net CONE, a 5.0 percent higher forecasted peak load, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $9,867,349,670, a decrease of $4,819,697,688, or 32.8 percent, compared to the actual results (Scenario 59). From another perspective, the actual 2025/2026 VRR curve resulted in 48.8 percent higher 2025/2026 BRA revenues compared to what RPM revenues would have been had PJM cleared the auction using a CT as the reference resource, a 1.0 multiplier for Net CONE with a forward net revenue offset rather than the higher of Gross CONE and a multiplier for Net CONE and 5.0 percent higher forecasted peak load (Scenario 59).

Table 3 shows the impact on RPM revenues for Scenario 60. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 BRA were $14,687,047,358. If, in addition to Scenario 59, the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 BRA, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $9,986,374,565, a decrease of $4,700,672,792, or 32.0 percent, compared to the actual results. From another perspective, if in addition to Scenario 59, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day resulted in a 47.1 percent increase in RPM revenues for the 2025/2026 RPM Base Residual Auction compared to what RPM revenues would have been had the capacity of the RMR resources been included in the supply curve at $0 per MW-day (Scenario 60).

Table 3 shows the impact on RPM revenues for Scenario 61. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If, in addition to Scenario 59, marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, if the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, and everything else had remained the

[24] See Attachment D, FERC Docket no. ER25-682-000, Revisions to PJM Capacity Market (December 9, 2024). Forward E&AS revenues are provided by PJM.

same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $10,387,918,732, a decrease of $4,299,128,626, or 29.3 percent, compared to the actual results. From another perspective, if in addition to Scenario 59, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day and marginal ELCC based accreditation did not consider higher winter generation capacity ratings for CC and CT resources, resulted in a 41.4 percent increase in RPM revenues for the 2025/2026 BRA compared to what RPM revenues would have been had the capacity of the RMR resources in the BGE LDA been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction and had marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction (Scenario 61).

Table 3 shows the impact on RPM revenues for Scenario 62. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If, in addition to Scenario 59, the MW capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, if marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, if the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $9,944,171,083, a decrease of $4,742,876,275, or 32.3 percent, compared to the actual results. From another perspective, if in addition to Scenario 59, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day and marginal ELCC based accreditation did not consider higher winter generation capacity ratings for CC and CT resources, the MW categorically exempt from the RPM must offer requirement that did not offer had been offered, resulted in a 47.7 percent increase in RPM revenues for the 2025/2026 BRA compared to what RPM revenues would have been if the MW capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, if marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction and if the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction (Scenario 62).

Table 3 Scenario summary for 2025/2026 RPM Base Residual Auction: CT Reference Resource; 1.0 * Net CONE; Forward Net Revenues in VRR curve; 5.0 Percent Higher Forecasted Peak Load

		Scenario Impact			
				Percent Change	
Scenario	Scenario Description	RPM Revenue ($ per Delivery Year)	RPM Revenue Change ($ per Delivery Year)	Scenario to Actual	Actual to Scenario
0	Actual results	$14,687,047,358	NA	NA	NA
59	VRR curve based on 1.0 times Net CONE calculated using forward E&AS offset	$9,867,349,670	$4,819,697,688	48.8%	(32.8%)
60	Scenario 59 and RMR resources	$9,986,374,565	$4,700,672,792	47.1%	(32.0%)
61	Scenario 59 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$10,387,918,732	$4,299,128,626	41.4%	(29.3%)
62	Scenario 59 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$9,944,171,083	$4,742,876,275	47.7%	(32.3%)

Results: Higher of Gross CONE and 1.5 Net CONE; Forward Net Revenues; 5.0 increase in Forecasted Load

In Scenarios 63, 64, 65 and 67, the MMU analyzed the impact on the actual auction results for the 2025/2026 BRA of using a VRR curve based on the use of a Combustion Turbine (CT) as the reference resource rather than a CC, in combination with scenarios 2, 3 and 4 from Part A and a 5.0 percent higher forecasted peak load than used in the 2025/2026 BRA. The maximum price (point A) is set at the greater of updated Gross CONE ($499.32 per UCAP MW-day for the Rest of RTO) and a multiplier of 1.5 times updated Net CONE ($199.63 per UCAP MW-day for the Rest of RTO) for the reference CT resource.[25] Gross CONE ($ per UCAP MW-day) is derived from the $ per ICAP MW-Year of Levelized Revenue Requirement using the ELCC based class average accredited UCAP factor for the technology class of the reference resource.[26] Net CONE is calculated using expected forward energy and ancillary service revenues. Gross CONE was higher than 1.5 times Net CONE for all modeled LDAs except for EMAAC, PSEG, PS-NORTH and JCPL LDAs. Net CONE for the CT is calculated using expected forward energy and ancillary service revenues. The price for point B is set at the 0.75 times Net CONE for the CT.[27] The corresponding MW quantities are the same as Scenario 8 analyzed in Part C.

25 See Attachment D, FERC Docket no. ER25-682-000, Revisions to PJM Capacity Market (December 9, 2024). Forward E&AS revenues are provided by PJM.

26 $$Gross\ CONE\ (\$\ per\ UCAP\ MWDay) = \frac{Levelized\ Revenue\ Requirement\ (\$\ per\ ICAP\ MW\ Year)}{Number\ of\ Days\ in\ Delivery\ Year * Reference\ Resource\ AUCAP\ Factor}$$

27 See "PJM Manual 18: PJM Capacity Market," § 3.3 Parameters of the Variable Resource Requirement, Rev. 59 (June 27, 2024).

Table 4 shows the impact on RPM revenues for Scenario 63. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If the 2025/2026 BRA had been cleared using a VRR curve based on a CT as the reference resource, the maximum price (point A) set at the higher of Gross CONE and 1.5 times Net CONE with a forward net revenue offset, a 5.0 percent higher forecasted peak load and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $24,824,268,329, an increase of $10,137,220,971, or 69.0 percent, compared to the actual results (Scenario 63). From another perspective, the actual 2025/2026 VRR curve resulted in 40.8 percent lower 2025/2026 BRA revenues compared to what RPM revenues would have been had PJM cleared the auction using a CT as the reference resource, the maximum price (point A) set at the higher of Gross CONE and 1.5 times Net CONE with a forward net revenue offset, and 5.0 percent higher forecasted peak load (Scenario 63).

Table 4 shows the impact on RPM revenues for Scenario 64. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 BRA were $14,687,047,358. If, in addition to Scenario 63, the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 BRA, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $25,121,976,644, an increase of $10,434,929,287, or 71.0 percent, compared to the actual results. From another perspective, if in addition to Scenario 63, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day resulted in a 41.5 percent decrease in RPM revenues for the 2025/2026 RPM Base Residual Auction compared to what RPM revenues would have been had the capacity of the RMR resources been included in the supply curve at $0 per MW-day (Scenario 64).

Table 4 shows the impact on RPM revenues for Scenario 65. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If, in addition to Scenario 63, marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, if the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $26,034,414,477, an increase of $11,347,367,120, or 77.3 percent, compared to the actual results. From another perspective, if in addition to Scenario 63, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day and marginal ELCC based accreditation did not consider higher winter generation capacity ratings for CC and CT resources, resulted in a 43.6 percent decrease in RPM revenues for the 2025/2026 BRA compared to what RPM revenues would have been had the capacity of the RMR resources in the BGE LDA been included in the supply curve at

$0 per MW-day in the 2025/2026 RPM Base Residual Auction and had marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction (Scenario 65).

Table 4 shows the impact on RPM revenues for Scenario 66. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If, in addition to Scenario 63, the MW capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, if marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, if the capacity of the RMR resources in the BGE LDA been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $26,336,095,882, an increase of $11,649,048,525, or 79.3 percent, compared to the actual results. From another perspective, if in addition to Scenario 63, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day, marginal ELCC based accreditation did not consider higher winter generation capacity ratings for CC and CT resources and the MW categorically exempt from the RPM must offer requirement that did not offer had been offered, resulted in a 44.2 percent decrease in RPM revenues for the 2025/2026 BRA compared to what RPM revenues would have been if the MW capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, if marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction and if the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction (Scenario 66).

Table 4 Scenario summary for 2025/2026 RPM Base Residual Auction: CT Reference Resource; Higher of Gross CONE and 1.50 * Net CONE; Forward Net Revenue in VRR curve; 5.0 Percent Higher Forecasted Peak Load

		Scenario Impact			
				Percent Change	
Scenario	Scenario Description	RPM Revenue ($ per Delivery Year)	RPM Revenue Change ($ per Delivery Year)	Scenario to Actual	Actual to Scenario
0	Actual results	$14,687,047,358	NA	NA	NA
63	VRR curve based on higher of CT Gross CONE and 1.5 times Net CONE calculated using forward E&AS offset	$24,824,268,329	($10,137,220,971)	(40.8%)	69.0%
64	Scenario 63 and RMR resources	$25,121,976,644	($10,434,929,287)	(41.5%)	71.0%
65	Scenario 63 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$26,034,414,477	($11,347,367,120)	(43.6%)	77.3%
66	Scenario 63 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$26,336,095,882	($11,649,048,525)	(44.2%)	79.3%

Results: 1.5* Net CONE; Forward Net Revenues; 5.0 Increase in Forecasted Load

In Scenarios 67, 68, 69 and 70, the MMU analyzed the impact on the actual auction results for the 2025/2026 BRA of using a VRR curve based on the use of a Combustion Turbine (CT) as the reference resource rather than a CC and using 1.5 * Net CONE rather than the higher of 1.5 * Net CONE and Gross CONE, in combination with scenarios 2, 3 and 4 from Part A and a 5.0 percent higher forecasted peak load than used in the 2025/2026 BRA. The maximum price (point A) is set at 1.5 * Net CONE ($199.63 per UCAP MW-day for the Rest of RTO) for the reference CT resource rather than the higher of Gross CONE and a multiplier for Net CONE.[28] The price for point B is set at the 0.75 times Net CONE for the CT. The corresponding MW quantities are the same as Scenario 8 analyzed in Part C.

Table 5 shows the impact on RPM revenues for Scenario 67. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If the 2025/2026 BRA had been cleared using a VRR curve based on a CT as the reference resource, a 1.5 multiplier for Net CONE with a forward net revenue offset rather than the higher of Gross CONE and a multiplier for Net CONE, a 5.0 percent higher forecasted peak load, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $14,819,240,442, an increase of $132,193,084, or 0.9 percent, compared to the actual results (Scenario 67). From another perspective, the actual 2025/2026 VRR curve resulted in 0.9 percent lower 2025/2026 BRA revenues compared to what RPM revenues would have been had PJM cleared the auction using a CT as the reference resource, a 1.5 multiplier for Net CONE with a forward net revenue offset rather than the higher of Gross CONE and a multiplier for Net CONE and 5.0 percent higher forecasted peak load (Scenario 67).

Table 5 shows the impact on RPM revenues for Scenario 68. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 BRA were $14,687,047,358. If, in addition to Scenario 67, the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 BRA, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $14,997,780,767, an increase of $310,733,409, or 2.1 percent, compared to the actual results. From another perspective, if in addition to Scenario 67, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day resulted in a 2.1 percent decrease in RPM revenues for the 2025/2026 RPM Base Residual Auction compared to what RPM

[28] See Attachment D, FERC Docket no. ER25-682-000, Revisions to PJM Capacity Market (December 9, 2024). Forward E&AS revenues are provided by PJM.

revenues would have been had the capacity of the RMR resources been included in the supply curve at $0 per MW-day (Scenario 68).

Table 5 shows the impact on RPM revenues for Scenario 69. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If, in addition to Scenario 67, marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, if the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $15,600,107,074, an increase of $913,059,716, or 6.2 percent, compared to the actual results. From another perspective, if in addition to Scenario 67, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day and marginal ELCC based accreditation did not consider higher winter generation capacity ratings for CC and CT resources, resulted in a 5.9 percent decrease in RPM revenues for the 2025/2026 BRA compared to what RPM revenues would have been had the capacity of the RMR resources in the BGE LDA been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction and had marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction (Scenario 69).

Table 5 shows the impact on RPM revenues for Scenario 70. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If, in addition to Scenario 67, the MW capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, if marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, if the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $13,928,517,231, a decrease of $758,530,127, or 5.2 percent, compared to the actual results. From another perspective, if in addition to Scenario 67, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day and marginal ELCC based accreditation did not consider higher winter generation capacity ratings for CC and CT resources, the MW categorically exempt from the RPM must offer requirement that did not offer had been offered, resulted in a 5.4 percent increase in RPM revenues for the 2025/2026 BRA compared to what RPM revenues would have been if the MW capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, if marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction and if the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction (Scenario 70).

Table 5 Scenario summary for 2025/2026 RPM Base Residual Auction: CT Reference Resource; 1.50 * Net CONE; Forward Net Revenue in VRR curve; 5.0 Percent Higher Forecasted Peak Load

			Scenario Impact		
				Percent Change	
Scenario	Scenario Description	RPM Revenue ($ per Delivery Year)	RPM Revenue Change ($ per Delivery Year)	Scenario to Actual	Actual to Scenario
0	Actual results	$14,687,047,358	NA	NA	NA
67	VRR curve based on 1.50 times Net CONE calculated using forward E&AS offset	$14,819,240,442	($132,193,084)	(0.9%)	0.9%
68	Scenario 67 and RMR resources	$14,997,780,767	($310,733,409)	(2.1%)	2.1%
69	Scenario 67 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$15,600,107,074	($913,059,716)	(5.9%)	6.2%
70	Scenario 67 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$13,928,517,231	$758,530,127	5.4%	(5.2%)

Results: Cleared UCAP MW

Table 6 through Table 9 show the summary of the cleared UCAP MW impact of all the scenarios analyzed. The Cleared UCAP column shows the cleared MW that resulted from the specific scenario only. The Cleared UCAP Change column shows the difference between the actual RPM cleared UCAP MW and the total RPM cleared UCAP MW that resulted from the specific scenario. A positive number means that the specific scenario resulted in a reduction in cleared MW. A negative number means that the specific scenario resulted in an increase in cleared MW. The percent columns show the percent change in RPM cleared MW for the specific scenario from two perspectives. The Scenario to Actual Percent column shows the difference between the MW under the defined scenario and the defined baseline as a percent of the MW under the defined scenario. The Actual to Scenario Percent column shows the difference between the MW under the defined scenario and the defined baseline as a percent of the MW under the defined baseline.

Table 6 shows the impact on the cleared UCAP MW for the auction for Scenarios 55 through 58. In Scenarios 55, 56, 57 and 58, the MMU analyzed the impact on the actual auction results for the 2025/2026 BRA of using a VRR curve based on the use of a Combustion Turbine (CT) as the reference resource rather than a CC, in combination with scenarios 2, 3 and 4 from Part A and a 5.0 percent higher forecasted peak load than used in the 2025/2026 BRA. The maximum price (point A) is set at the greater of Gross CONE and a multiplier of 1.0 times Net CONE for the reference CT resource.

Table 7 shows the impact on the cleared UCAP MW for the auction for Scenarios 59 through 62. In Scenarios 59, 60, 61 and 62, the MMU analyzed the impact on the actual auction results for the 2025/2026 BRA of using a VRR curve based on the use of a Combustion Turbine (CT) as the reference resource rather than a CC, in combination with scenarios 2, 3 and 4 from Part A and a 5.0 percent higher forecasted peak load than used in the 2025/2026 BRA. The maximum price (point A) is set at 1.0 * Net CONE for the reference CT resource rather than the higher of Gross CONE and a multiplier for Net CONE.

Table 8 shows the impact on the cleared UCAP MW for the auction for Scenarios 63 through 66. In Scenarios 63, 64, 65 and 66, the MMU analyzed the impact on the actual auction results for the 2025/2026 BRA of using a VRR curve based on the use of a Combustion Turbine (CT) as the reference resource rather than a CC, in combination with scenarios 2, 3 and 4 from Part A and a 5.0 percent higher forecasted peak load than used in the 2025/2026 BRA. The maximum price (point A) is set at the greater of Gross CONE and a multiplier of 1.5 times Net CONE for the reference CT resource.

Table 9 shows the impact on the cleared UCAP MW for the auction for Scenarios 67 through 70. In Scenarios 67, 68, 69 and 70, the MMU analyzed the impact on the actual auction results for the 2025/2026 BRA of using a VRR curve based on the use of a Combustion Turbine (CT) as the reference resource rather than a CC, in combination with scenarios 2, 3 and 4 from Part A and a 5.0 percent higher forecasted peak load than used in the 2025/2026 BRA. The maximum price (point A) is set at 1.5 * Net CONE for the reference CT resource rather than the higher of Gross CONE and a multiplier for Net CONE.

Table 6 Scenario summary for 2025/2026 RPM Base Residual Auction: CT Reference Resource; 1.0 * Net CONE; Forward Net Revenue in VRR curve; 5.0 Percent Higher Forecasted Peak Load

		Scenario Impact			
				Percent Change	
Scenario	Scenario Description	Cleared UCAP (MW)	Cleared UCAP Change (MW)	Scenario to Actual	Actual to Scenario
0	Actual results	135,684.0	NA	NA	NA
55	VRR curve based on higher of CT Gross CONE and 1.0 times Net CONE calculated using forward E&AS offset	135,704.3	(20.3)	(0.0%)	0.0%
56	Scenario 55 and RMR resources	137,337.8	(1,653.8)	(1.2%)	1.2%
57	Scenario 55 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	142,848.6	(7,164.6)	(5.0%)	5.3%
58	Scenario 55 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	144,503.9	(8,819.9)	(6.1%)	6.5%

Table 7 Scenario summary for 2025/2026 RPM Base Residual Auction: CT Reference Resource; 1.0 * Net CONE; Forward Net Revenue in VRR curve; 5.0 Percent Higher Forecasted Peak Load

		Scenario Impact			
				Percent Change	
Scenario	Scenario Description	Cleared UCAP (MW)	Cleared UCAP Change (MW)	Scenario to Actual	Actual to Scenario
0	Actual results	135,684.0	NA	NA	NA
59	VRR curve based on 1.0 times Net CONE calculated using forward E&AS offset	135,419.7	264.3	0.2%	(0.2%)
60	Scenario 59 and RMR resources	137,053.2	(1,369.2)	(1.0%)	1.0%
61	Scenario 59 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	142,564.0	(6,880.0)	(4.8%)	5.1%
62	Scenario 59 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	144,210.8	(8,526.8)	(5.9%)	6.3%

Table 8 Scenario summary for 2025/2026 RPM Base Residual Auction: CT Reference Resource; 1.5 * Net CONE; Forward Net Revenue in VRR curve; 5.0 Percent Higher Forecasted Peak Load

		Scenario Impact			
				Percent Change	
Scenario	Scenario Description	Cleared UCAP (MW)	Cleared UCAP Change (MW)	Scenario to Actual	Actual to Scenario
0	Actual results	135,684.0	NA	NA	NA
63	VRR curve based on higher of CT Gross CONE and 1.5 times Net CONE calculated using forward E&AS offset	135,704.3	(20.3)	(0.0%)	0.0%
64	Scenario 63 and RMR resources	137,337.8	(1,653.8)	(1.2%)	1.2%
65	Scenario 63 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	142,848.6	(7,164.6)	(5.0%)	5.3%
66	Scenario 63 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	144,503.9	(8,819.9)	(6.1%)	6.5%

Table 9 Scenario summary for 2025/2026 RPM Base Residual Auction: CT Reference Resource; 1.5 * Net CONE; Forward Net Revenue in VRR curve; 5.0 Percent Higher Forecasted Peak Load

		Scenario Impact			
				Percent Change	
Scenario	Scenario Description	Cleared UCAP (MW)	Cleared UCAP Change (MW)	Scenario to Actual	Actual to Scenario
0	Actual results	135,684.0	NA	NA	NA
67	VRR curve based on 1.50 times Net CONE calculated using forward E&AS offset	135,584.1	99.9	0.1%	(0.1%)
68	Scenario 67 and RMR resources	137,217.6	(1,533.6)	(1.1%)	1.1%
69	Scenario 67 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	142,728.4	(7,044.4)	(4.9%)	5.2%
70	Scenario 67 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	144,382.6	(8,698.6)	(6.0%)	6.4%

ATTACHMENT F

Analysis of the 2025/2026 RPM Base Residual Auction Part F

The Independent Market Monitor for PJM

February 4, 2025

Introduction

This report, Part F of what will be a comprehensive report, prepared by the Independent Market Monitor for PJM (IMM or MMU), presents a sixth set of sensitivity analyses of the nineteenth Reliability Pricing Model (RPM) Base Residual Auction (BRA) for the 2025/2026 Delivery Year which was held from July 17 to 23, 2024. The sensitivities in Part F are focused on the implications of the maximum price and minimum price agreed upon by the Governor of Pennsylvania and PJM ("Agreement").[1] The MMU presents the results of these sensitivities in order to provide information to stakeholders that is relevant to decision making about the 2026/2027 BRA, now scheduled for July 9 to 15, 2025, and specifically about the Agreement. The results reported by the MMU are not forecasts or predictions of the outcome of the 2026/2027 BRA.

The Part F report addresses the impacts of using a maximum price of $325/MW-day in UCAP terms and a minimum price of $175/MW-day in UCAP terms and the 5.0 percent increase load growth in all scenarios. In each case, Part F shows the separate and combined impacts on market outcomes of the three identified MMU proposed changes: the inclusion of the two reliability must run (RMR) plants in the capacity market supply curve; the use of winter ratings rather than summer ratings for thermal resources; and the requirement to offer for categorically exempt resources.[2] The Agreement and the method of implementation both matter.

The basic conclusion is that, if implemented consistent with the MMU implementation approach, the Agreement would result in market revenues lower than the market revenues that would result from PJM's proposal to use a maximum price of the greater of Gross CONE and 1.75 times Net CONE by $8,731,577,104 per year if the three additional MMU recommendations were not implemented. [3] This calculation compares the results of

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1 *See* Commonwealth of Pennsylvania, "What Industry Leaders, Lawmakers, and Consumer Advocates Are Saying About Governor Shapiro's Action to Save Consumers Over $21 Billion in Utility Charges," (January 31, 2025) <https://www.pa.gov/governor/newsroom/2025-press-releases/-industry-leaders--lawmakers-consumer-adv-saying-about-shapiro-s.html> and also; Email to PJM Members "PA Governor Shapiro Complaint – PJM Notice of Consultation (January 28, 2025).

2 The values stated in this report for the RTO and LDAs refer to the aggregate level including all nested LDAs unless otherwise specified. For example, RTO values include the entire PJM market and all LDAs. Rest of RTO values are RTO values net of nested LDA values.

3 The results of PJM's filed proposal are the same regardless of whether the VRR curve is based on the higher of Gross CONE and 1.0 times Net CONE (Scenario 55 from Part E), the higher of Gross CONE and 1.5 times Net CONE (Scenario 59 from Part E) or the higher of Gross CONE

MMU Scenario 55 (from Part E) for the PJM result and Scenario 79 (from Part F) for the Agreement result. These comparisons all include an increase in forecasted peak load of 5.0 percent over the load used in the 2025/2026 BRA. There are more details in this Part F.

The current definition of the price at Point B on the VRR curve is .75 times Net CONE. Based on the information available, the Agreement does not define Point B. The MMU recommends that the price at Point B be defined as .75 times the defined maximum price and that definition is incorporated in Part F. This is the most logical interpretation of the price at Point B under the stated Agreement terms. The maximum price is interpreted as Net CONE given that the Agreement replaces the various CONE values for Point A with a defined price. Point B remains part of the VRR curve unless Point B falls below the minimum price. The price at Point C is the $175/MW-day minimum price defined in the Agreement.

Under the defined VRR curve for the 2025/2026 BRA, the corresponding MW quantities are set at 98.9 percent of the reliability requirement for point A, 101.6 percent of the reliability requirement for point B and 106.8 percent of the reliability requirement for point C.[4] [5] Although the Agreement does not define the MW points, the MMU recommends that the MW points remain as defined in the VRR curve.

The scenarios in Part F do not explicitly model the minimum price because the minimum price is not a binding constraint in any scenario.

The purpose of Part F is to facilitate a comprehensive review of the implications of the maximum price and minimum price together with additional design choices and to show the implications of the details of the associated implementation.

PJM makes two mistakes in its implementation approach to creating a new VRR curve and to the definition of the maximum price.

The first mistake is that PJM does not propose to create a new VRR curve with a consistently defined new Point A, Point B and Point C. Rather, PJM simply uses the existing VRR curve including a maximum price of Gross CONE and draws a horizontal

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and 1.75 times Net CONE. The Gross CONE exceeds 1.75 times Net CONE for all price separated LDAs in all these scenarios.

4 OATT Attachment DD § 5.10(a)(i).

5 For the 2026/2027 and subsequent delivery years, the corresponding MW quantities are set at 99.0 percent of the reliability requirement for point A, 101.5 percent of the reliability requirement for point B and 104.5 percent of the reliability requirement for point C.

line at the maximum price from the Y axis until it intersects the existing VRR curve. PJM also draws another horizontal line at the minimum price from the Y axis until it intersects the existing VRR curve. This approach is not consistent with defining a new maximum price at $325/MW-day and creating a new, internally consistent VRR curve. (See Figure 1.)

The result of PJM's approach is that Point A on the VRR curve is no longer defined by the maximum price and 99.0 percent of the reliability requirement MW. PJM's equivalent of Point A, the first inflection point on the VRR curve, now occurs at a MW point that is greater than the reliability requirement. PJM's approach increases the MW that will clear at the maximum price compared to the VRR curve definition. In addition, PJM continues to define Point B based on 0.75*Net CONE despite the fact that Net CONE no longer affects Point A. PJM's proposed use of Net CONE results in 10 of 17 LDAs with a Point B that is less than the minimum price.

The second mistake is that PJM does not propose to implement the maximum price of $325 from the Agreement. Rather, PJM proposes to modify the maximum price based on the ELCC value for the reference technology, a dual fuel CT. PJM's approach is that the maximum price of $325/MW-day in UCAP terms equals a maximum price of $256.75/MW-day in ICAP terms, using a dual fuel CT ELCC of .79. PJM proposes to make the ICAP price the defined price and change the UCAP price to match it if the ELCC for the dual fuel CT changes. Under PJM's approach, if the ELCC increases, the maximum price would decrease. Under PJM's approach, if the ELCC decreases, the maximum price would increase.

For example, if the reference resource's ELCC based accredited UCAP factor were reduced from 0.79 to 0.73, the maximum price would increase from $325/MW-day to more than $350/MW-day ($352/MW-day). If the RTO cleared at the $350/MW-day maximum price (Scenario 83), this would result in an increase of $1,240,735,375 in annual capacity market revenues compared to using a $325/MW-day maximum price (Scenario 79).

PJM's proposal is inconsistent with a maximum price of $325/MW-day. The Agreement maximum price is a price in UCAP terms. The maximum price is a fixed value in UCAP terms and should be implemented as a fixed value. PJM's reversed proposal would convert the Agreement price to an ICAP price and make the ICAP price the fixed value. The PJM capacity market price is defined in UCAP terms. The Agreement is defined in UCAP terms. PJM's proposal is that if the ELCC changes the ICAP price calculated at an ELCC of .79 would remain the same and the Agreement UCAP price must change. There is no reason to introduce this calculation, this change in the maximum price or the associated confusion. If the ELCC changes, the Agreement maximum price remains the same and the calculated ICAP price would change. Given the volatility of PJM's ELCC values, PJM's ability to change ELCC results by switching forecasts, and the multiple issues with PJM's calculations of ELCC values, especially for thermal resources like CTs, there is no reason to make the Agreement maximum price a function of the ELCC values. The PJM proposal to make the maximum price in the Agreement a function of the ELCC for dual fuel CTs is inconsistent with creating certainty for market participants.

Conclusions

Applying the maximum price and the minimum price defined by the Agreement is a reasonable starting place for immediate capacity market design reforms that should be made prior to the 2026/2027 BRA. The approach defined by the Agreement is similar to the MMU recommendation to use 1.5 times Net CONE, capped at Gross CONE, as the maximum price or Point A on the VRR curve. The results of applying the Agreement are comparable to the results of applying the MMU recommendation on the maximum price. These conclusions assume that the Agreement is implemented as recommended by the MMU.

The Agreement maximum price of $325/MW-Day is 14 percent higher than the average of 1.5 * Net CONE values for all LDAs.

In addition, the three related MMU recommendations that are not addressed in the Agreement and remain as contested issues at FERC should also be implemented.

Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If the 2025/2026 RPM BRA had been cleared using a VRR curve capped at $325.00 per UCAP MW-day, a 5.0 percent higher forecasted peak load and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $16,092,691,225, an increase of $1,405,643,867, or 9.6 percent, compared to the actual results (Scenario 79).

The Agreement proposal would result in market revenues lower than the market revenues that would result from PJM's proposal to use a maximum price of the greater of Gross CONE and 1.75 times Net CONE by $8,731,577,104 per year if the three additional MMU recommendations were not implemented.[6] This calculation compares the results of MMU Scenario 55 (from Part E) for the PJM result and Scenario 79 (from Part F) for the Agreement result. These comparisons all include an increase in forecasted peak load of 5.0 percent over the load used in the 2025/2026 BRA.

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[6] The results of PJM's filed proposal are the same regardless of whether the VRR curve is based on the higher of Gross CONE and 1.0 times Net CONE (Scenario 55 from Part E), the higher of Gross CONE and 1.5 times Net CONE (Scenario 59 from Part E) or the higher of Gross CONE and 1.75 times Net CONE. The Gross CONE exceeds 1.75 times Net CONE for all price separated LDAs in all these scenarios.

The Agreement proposal would result in market revenues lower than PJM's proposal to use a maximum price of the greater of Gross CONE and 1.75 times Net CONE by $8,833,732,106 per year if the MMU RMR recommendation were implemented but the two additional MMU recommendations were not implemented. This calculation compares the results of MMU Scenario 56 (from Part E) for the PJM result and Scenario 80 (from Part F) for the Agreement result. These comparisons all include an increase in forecasted peak load of 5.0 percent over the load used in the 2025/2026 BRA.

The Agreement is consistent with a competitive market outcome and consistent with the underlying PJM Capacity Market supply and demand fundamentals. PJM's maximum price point of the greater of Gross CONE and 1.75 times Net CONE is not based on economic logic and is not a basis for a competitive market outcome. The maximum price resulting from the Agreement will be higher than the average of all historical capacity market weighted average BRA clearing prices prior to the 2025/2026 Delivery Year, which is $116.30/MW-day.[7] [8]

The MMU continues to oppose the use of a floor price in the PJM capacity markets.

Recommendations

The MMU recommends approval of the Agreement maximum price of $325/MW-day in UCAP terms and minimum price of $175/MW-day in UCAP terms for the 2026/2027 and the 2027/2028 BRAs.

The MMU recommends that the maximum price apply to the MW for Point A as defined in the PJM tariff for the VRR curve. This maintains the basic logic of the VRR curve. The MW quantity at Point A is set at 99.0 percent of the reliability requirement for the 2026/2027 and subsequent delivery years.

The MMU recommends an explicit definition of the price at Point B as .75 times the maximum price that would correspond to the MW for Point B as defined in the PJM tariff for the VRR curve. This maintains the basic logic of the VRR curve given the maximum

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7 See *2024 Quarterly State of the Market Report for PJM: January through September*, Section 5: Capacity Market, Table 5-19.

8 Some price separated LDAs have had higher prices. In the 2015/2026 BRA, ATSI LDA cleared at $357.00 per MW-day. In the 2024/2025 BRA, DPL South LDA cleared at $426.17 per MW-day as a result of a mistake by PJM. In the 2024/2025 First IA, PSEG North LDA cleared at $410.95 per MW-day. In the 2024/2025 Second IA, PSEG North LDA cleared at $310.00 per MW-day. In the 2024/2025 Third IA, PSEG North LDA cleared at $256.76 per MW-day.

price. The MW quantity at Point B is set at 101.5 percent of the reliability requirement for the 2026/2027 and subsequent delivery years.

The MMU recommends that the price at Point C be defined to be the $175/MW-day minimum price from the Agreement that would correspond with the MW for Point C as defined in the PJM tariff for the VRR curve. This maintains the basic logic of the VRR curve given the minimum price. The MW quantity at Point C is set at 104.5 percent of the reliability requirement for the 2026/2027 and subsequent delivery years.

Although not addressed by the Agreement, the MMU continues to make three short term recommendations and one longer term recommendation. The MMU continues to recommend that the must offer rule in the capacity market apply to all capacity resources in the 2026/2027 BRA and subsequent BRAs, without conditions. The MMU continues to recommend that the capacity of the RMR units be included in both the CETO/CETL analysis and in the supply of capacity in all BRAs during which RMR units are designated. The MMU continues to recommend that the ELCC capacity accreditation recognize the winter capability of thermal resources rather than limiting such resources to summer ratings.

In the longer term, ideally by the 2027/2028 BRA, the MMU recommends that the ELCC approach be significantly refined to include hourly data that would permit unit specific ELCC ratings, to weight summer and winter and all hourly risk in a more balanced manner, to eliminate PAI risks, and to pay for actual hourly unit specific performance rather than based on relatively inflexible class capacity accreditation ratings derived from a small number of hours of poor performance.

Summary

Table 5 through Table 8 show the summary of the revenue impacts of the scenarios analyzed in Part F.

The results of individual scenarios are not strictly additive. The combined results of multiple scenarios are shown for scenarios that address multiple results simultaneously. The quantitative results are estimates. The report makes explicit when the quantitative results depend on assumptions. Even in those cases, the quantitative results are correct as to direction and order of magnitude. The RPM Revenue column shows the revenues that resulted from the defined scenario only. The RPM Revenue Change column shows the difference between the actual RPM total revenues and the total RPM revenues that resulted from the defined scenario. A positive number means that the existing market design elements in the defined scenario resulted in an increase in RPM revenues compared to the MMU recommendation. A negative number means that the existing market design elements in the defined scenario resulted in a decrease in RPM revenues compared to the MMU recommendation. The Percent Change columns show the percent change in RPM revenues for the defined scenario from two perspectives. The Scenario to

Actual Percent column shows the difference between the revenues under the defined scenario and the actual auction results as a percent of the revenues under the defined scenario. The Actual to Scenario Percent column shows the difference between the revenues under the defined scenario and the actual auction results as a percent of the revenues under the actual auction results.

In all scenarios included in Part F, the MMU analyzed the impact on the actual auction results for the 2025/2026 BRA under the assumption that the forecasted peak load would be 5.0 percent higher than that used in the 2025/2026 BRA. The preliminary RTO wide peak load forecast for the 2025/2026 BRA was 153,883.0 MW. PJM revised the peak load forecast for the 2025/2026 and 2026/2027 Delivery Years following a substantial number of Large Load Adjustment requests received from LSEs and EDCs.[9] The final RTO wide peak load forecast for the 2025/2026 Delivery Year is 154,534.1 MW, 651.1 MW or 0.4 percent higher than the preliminary peak load forecast for the 2025/2026 BRA.[10] The RTO wide preliminary peak load forecast for the 2026/2027 BRA is 158,937 MW, 5,054 MW or 3.3 percent higher than the preliminary peak load forecast for the 2025/2026 BRA.[11] The revised 2025/2026 load forecast will be effective for the 2025/2026 Third Incremental Auction expected to be conducted in February 2025. PJM has indicated that the proposed industrial and data center load spread across 11 transmission zones, but mainly concentrated in the Dominion and AEP Transmission Zones, is the primary reason for the expected higher demand in the immediate future. PJM estimated that the preliminary accepted requests added up to approximately 9,000 MW for 2025 and approximately 12,000 MW for 2026.[12]

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9 See 2025 PJM Long-Term Load Forecast Report <https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2025-load-report.pdf> (January 24, 2025).

10 The forecast peak load values used in RPM auctions includes adjustments for load served outside PJM.

11 The peak load forecast value for the 2026/2027 Delivery Year excludes adjustments for load served outside PJM. The planning parameters for the 2026/2027 BRA including the preliminary peak load forecast adjusted for load served outside PJM will be released no later than March 31, 2025. The final peak load forecast for the 2026/2027 Delivery Year will be released in January 2026. The planning parameters for the 2026/2027 Third IA including the final peak load forecast adjusted for load served outside PJM will be released sometime in January 2026, based on a February 2026 auction opening.

12 See Load Adjustment Requests Summary for 2025 Load Forecast - Preliminary, presented at Planning Committee Meeting <https://www.pjm.com/-/media/committees-

The scenarios compare the results of implementing the Agreement under a 5.0 percent increase in forecast load scenario using the MMU's proposed approach to the results of the 2025/2026 BRA that did not include that increase in load. The result of increasing the load forecast is to increase the demand and to increase total market revenues, holding everything else constant. The scenarios include a range of maximum prices for comparison purposes, but the scenario with a $325/MW-day maximum price reflects the maximum price from the Agreement.

In order to calculate the difference between the results from implementing the Agreement with the results of implementing PJM's filed proposal, scenarios 79, 80, 81 and 82 from Part F need to be compared with scenarios 55, 56, 57 and 58 from Part E. Those Part E scenarios show the revenues that result from implementing PJM's filed proposal including a maximum price equal to the greater of Gross CONE and 1.75 times Net CONE, plus the three MMU recommendations. These comparisons all include an increase in forecasted peak load of 5.0 percent over the load used in the 2025/2026 BRA.[13]

The basic conclusion is that, if implemented consistent with the MMU implementation approach, the Agreement would result in market revenues lower than the market revenues that would result from PJM's proposal to use a maximum price of the greater of Gross CONE and 1.75 times Net CONE by $8,731,577,104 per year if the three additional MMU recommendations were not implemented. This calculation compares the results of MMU Scenario 55 (from Part E) for the PJM result and Scenario 79 (from Part F) for the Agreement result. These comparisons all include an increase in forecasted peak load of 5.0 percent over the load used in the 2025/2026 BRA. There are more details in this Part F.

Prices for Point A on VRR Curve

Table 1 shows the price coordinates used for the maximum price, the price at point A of the VRR curves included in the scenarios in Part F. The price coordinates include the Agreement value of $325/MW-day and a range above and below that value. Table 1 also shows the price coordinates for the prices at Point B, corresponding to each Point A.

The current definition of the price at Point B on the VRR curve is .75 times Net CONE. In each scenario defined in Part F, the price at Point B is defined as .75 times the defined

groups/committees/pc/2024/20241203/20241203-item-07----large-load-adjustment-requests-summary.ashx> (December 2, 2024)

13 The results of PJM's filed proposal are the same regardless of whether the VRR curve is based on the higher of Gross CONE and 1.0 times Net CONE (Scenario 55 from Part E), the higher of Gross CONE and 1.5 times Net CONE (Scenario 59 from Part E) or the higher of Gross CONE and 1.75 times Net CONE. The Gross CONE exceeds 1.75 times Net CONE for all price separated LDAs in all these scenarios.

maximum price. This is the most logical interpretation of the price of Point B under the Agreement terms. The maximum price is interpreted as Net CONE given that the Agreement replaces the various CONE values for Point A with a defined price. Point B remains part of the VRR curve unless Point B falls below the minimum price.

Table 2 shows the prices coordinates of the VRR curves for the RTO and each modeled LDA based on PJM's approach that uses the higher of Gross CONE and 1.75 times Net CONE as the maximum price. The price coordinates are based on PJM's updates to Gross CONE and Net CONE values. The MW quantities correspond to 5.0 percent higher forecasted peak load than used in the 2025/2026 BRA.

Table 3 shows the price coordinates of the VRR curves for the RTO and each modeled LDA under PJM's proposed approach to implementing the Agreement.[14] The price coordinates are based on PJM's updates to Gross CONE and Net CONE values. The MW quantities correspond to 5.0 percent higher forecasted peak load than used in the 2025/2026 BRA. Under PJM's proposed implementation of the Agreement, the maximum price ($325/MW-day) and minimum price ($175/MW-day) are applied to PJM's original proposed VRR curve. The price coordinate for Point B would be same as the original VRR curve, which is set at 0.75 times Net CONE. Point B falls below the minimum price for 10 of 17 LDAs under PJM's approach.

Table 4 shows the price coordinates of the VRR curves for the RTO and each modeled LDA under the MMU's proposed approach to implementing the Agreement. The MW quantities correspond to 5.0 percent higher forecasted peak load than used in the 2025/2026 BRA. Under the MMU proposed implementation of the Agreement, the maximum price ($325/MW-day) and minimum price ($175/MW-day) are applied and the price coordinate for Point B is equal to the greater of 0.75 times the maximum price and the minimum price.

Figure 1 compares the VRR curves under the PJM proposal and MMU proposal for the RTO. The price coordinates are based on PJM's updates to Gross CONE and Net CONE values. The MW quantities correspond to 5.0 percent higher forecasted peak load than used in the 2025/2026 BRA.

Figure 2 compares the VRR curves under the PJM proposal and MMU proposal for the PSEG LDA. The price coordinates are based on PJM's updates to Gross CONE and Net

[14] See Consultation: Capacity Market Demand Curve Adjustments Pursuant to Proposed Settlement, to be presented at Special Members Committee Meeting <https://www.pjm.com/-/media/DotCom/committees-groups/committees/mc/2025/20250207-special/item-01a---capacity-market-demand-curve-adjustments-pursuant-to-proposed-settlement.pdf> (February 7, 2025).

CONE values. The MW quantities correspond to 5.0 percent higher forecasted peak load than used in the 2025/2026 BRA. For the PSEG LDA, 1.75 times Net CONE is greater than Gross CONE.

The scenarios do not explicitly model the minimum price because the minimum price is not a binding constraint in any scenario.

PJM's updates to Gross CONE and Net CONE values were provided after Part C and Part D.[15] [16] Gross CONE decreased from the original Combustion Turbine (CT) MOPR parameters that PJM posted for the 2026/2027 Base Residual Auction in October 2024 because PJM changed the reference resource for the VRR curve from a gas fired CT with firm gas (single fuel) to a gas fired CT with nonfirm gas and oil backup (dual fuel). PJM also updated the net revenue offset and therefore the Net CONE values using the November fuel and energy forward prices for the delivery year.

Table 1 Price coordinates used for Point A and Point B of the VRR Curve in the scenarios

	Maximum Price ($/UCAP MW-day)	Point B ($/UCAP MW-day)
Scenarios 71,72,73,74	$250.00	$187.50
Scenarios 75,76,77,78	$300.00	$225.00
Scenarios 79,80,81,82	$325.00	$243.75
Scenarios 83,84,85,86	$350.00	$262.50

15 In Part C and Part D, CT Gross CONE are from 2026/2027 Default New Entry MOPR Offer Prices <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2026-2027/2026-2027-dy-mopr-prices-for-new-entry.ashx> (July 5, 2024). Forward E&AS revenues are provided by PJM.

16 See Attachment D, FERC Docket No. ER25-682-000, Revisions to PJM Capacity Market (December 9, 2024). Forward E&AS revenues are provided by PJM.

Table 2 PJM Filed Proposal: Price coordinates using CT as the reference resource; maximum price set at the higher of Gross CONE and 1.75 times Net CONE; Forward E&AS offset; No maximum and minimum prices

	Point A		Point B		Point C	
	$/MW-day	MW	$/MW-day	MW	$/MW-day	MW
RTO	$499.32	138,699.1	$149.72	142,485.7	$0.00	149,778.2
MAAC	$497.66	52,755.5	$192.02	54,195.8	$0.00	56,969.6
EMAAC	$552.44	30,612.9	$236.76	31,448.7	$0.00	33,058.2
SWMAAC	$492.46	13,348.7	$109.51	13,713.4	$0.00	14,415.9
PSEG	$620.10	10,546.7	$265.76	10,834.6	$0.00	11,389.2
PS-NORTH	$620.10	5,356.2	$265.76	5,502.5	$0.00	5,784.1
DPL-SOUTH	$471.65	2,720.1	$162.61	2,794.4	$0.00	2,937.4
PEPCO	$492.46	6,485.2	$170.66	6,662.2	$0.00	7,003.2
ATSI	$511.88	12,052.0	$160.46	12,381.0	$0.00	13,014.6
ATSI-CLEVELAND	$511.88	5,008.3	$160.46	5,145.0	$0.00	5,408.4
COMED	$587.13	20,590.6	$251.63	21,152.7	$0.00	22,235.3
BGE	$492.46	6,864.4	$48.35	7,051.8	$0.00	7,412.7
PPL	$527.42	8,669.0	$226.04	8,905.6	$0.00	9,361.4
DAY	$511.88	3,483.1	$126.30	3,578.1	$0.00	3,761.3
DEOK	$511.88	5,500.5	$141.69	5,650.6	$0.00	5,939.9
DOM	$511.88	25,463.0	$72.62	26,158.1	$0.00	27,496.9

Table 3 PJM Agreement Proposal: Price coordinates using CT as the reference resource; Maximum price at $325/MW-day and minimum price at $175/MW-day[17]

	Point A		Point B		Point C		Point D	
	$/MW-day	MW	$/MW-day	MW	$/MW-day	MW	$/MW-day	MW
RTO	$325.00	140,587.2	$175.00	142,211.9	$175.00	+Inf.		
MAAC	$325.00	53,569.2	$192.02	54,195.8	$175.00	54,441.7	$175.00	+Inf.
EMAAC	$325.00	31,215.1	$236.76	31,448.7	$175.00	31,868.5	$175.00	+Inf.
SWMAAC	$325.00	13,508.2	$175.00	13,651.0	$175.00	+Inf.		
PSEG	$325.00	10,786.5	$265.76	10,834.6	$175.00	11,024.0	$175.00	+Inf.
PS-NORTH	$325.00	5,478.0	$265.76	5,502.5	$175.00	5,598.7	$175.00	+Inf.
DPL-SOUTH	$325.00	2,755.4	$175.00	2,791.4	$175.00	+Inf.		
PEPCO	$325.00	6,577.3	$175.00	6,659.8	$175.00	+Inf.		
ATSI	$325.00	12,227.0	$175.00	12,367.4	$175.00	+Inf.		
ATSI-CLEVELAND	$325.00	5,081.0	$175.00	5,139.3	$175.00	+Inf.		
COMED	$325.00	21,029.8	$251.63	21,152.7	$175.00	21,482.4	$175.00	+Inf.
BGE	$325.00	6,935.1	$175.00	6,998.4	$175.00	+Inf.		
PPL	$325.00	8,827.9	$226.04	8,905.6	$175.00	9,008.5	$175.00	+Inf.
DAY	$325.00	3,529.1	$175.00	3,566.1	$175.00	+Inf.		
DEOK	$325.00	5,576.3	$175.00	5,637.1	$175.00	+Inf.		
DOM	$325.00	25,758.7	$175.00	25,996.1	$175.00	+Inf.		

[17] See Consultation: Capacity Market Demand Curve Adjustments Pursuant to Proposed Settlement, to be presented at Special Members Committee Meeting <https://www.pjm.com/-/media/DotCom/committees-groups/committees/mc/2025/20250207-special/item-01a---capacity-market-demand-curve-adjustments-pursuant-to-proposed-settlement.pdf> (February 7, 2025).

Table 4 IMM Agreement Proposal: Price coordinates using $325/MW-day as the maximum price and $175/MW-day as the minimum price and 0.75 times maximum Price for Point B

	Point A		Point B		Point C		Point D	
	$/MW-day	MW	$/MW-day	MW	$/MW-day	MW	$/MW-day	MW
RTO	$325.00	138,699.1	$243.75	142,485.7	$175.00	144,542.6	$175.00	+Inf.
MAAC	$325.00	52,755.5	$243.75	54,195.8	$175.00	54,978.2	$175.00	+Inf.
EMAAC	$325.00	30,612.9	$243.75	31,448.7	$175.00	31,902.7	$175.00	+Inf.
SWMAAC	$325.00	13,348.7	$243.75	13,713.4	$175.00	13,911.5	$175.00	+Inf.
PSEG	$325.00	10,546.7	$243.75	10,834.6	$175.00	10,991.0	$175.00	+Inf.
PS-NORTH	$325.00	5,356.2	$243.75	5,502.5	$175.00	5,581.9	$175.00	+Inf.
DPL-SOUTH	$325.00	2,720.1	$243.75	2,794.4	$175.00	2,834.7	$175.00	+Inf.
PEPCO	$325.00	6,485.2	$243.75	6,662.2	$175.00	6,758.4	$175.00	+Inf.
ATSI	$325.00	12,052.0	$243.75	12,381.0	$175.00	12,559.7	$175.00	+Inf.
ATSI-CLEVELAND	$325.00	5,008.3	$243.75	5,145.0	$175.00	5,219.3	$175.00	+Inf.
COMED	$325.00	20,590.6	$243.75	21,152.7	$175.00	21,458.0	$175.00	+Inf.
BGE	$325.00	6,864.4	$243.75	7,051.8	$175.00	7,153.6	$175.00	+Inf.
PPL	$325.00	8,669.0	$243.75	8,905.6	$175.00	9,034.2	$175.00	+Inf.
DAY	$325.00	3,483.1	$243.75	3,578.1	$175.00	3,629.8	$175.00	+Inf.
DEOK	$325.00	5,500.5	$243.75	5,650.6	$175.00	5,732.2	$175.00	+Inf.
DOM	$325.00	25,463.0	$243.75	26,158.1	$175.00	26,535.7	$175.00	+Inf.

Figure 1 Comparison of VRR Curves for RTO

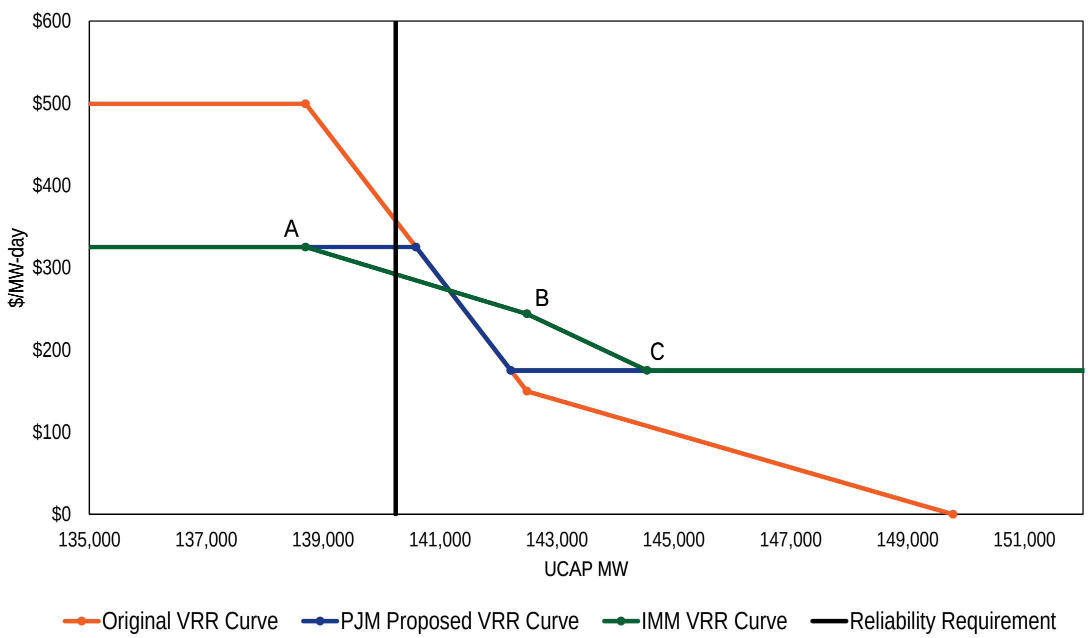
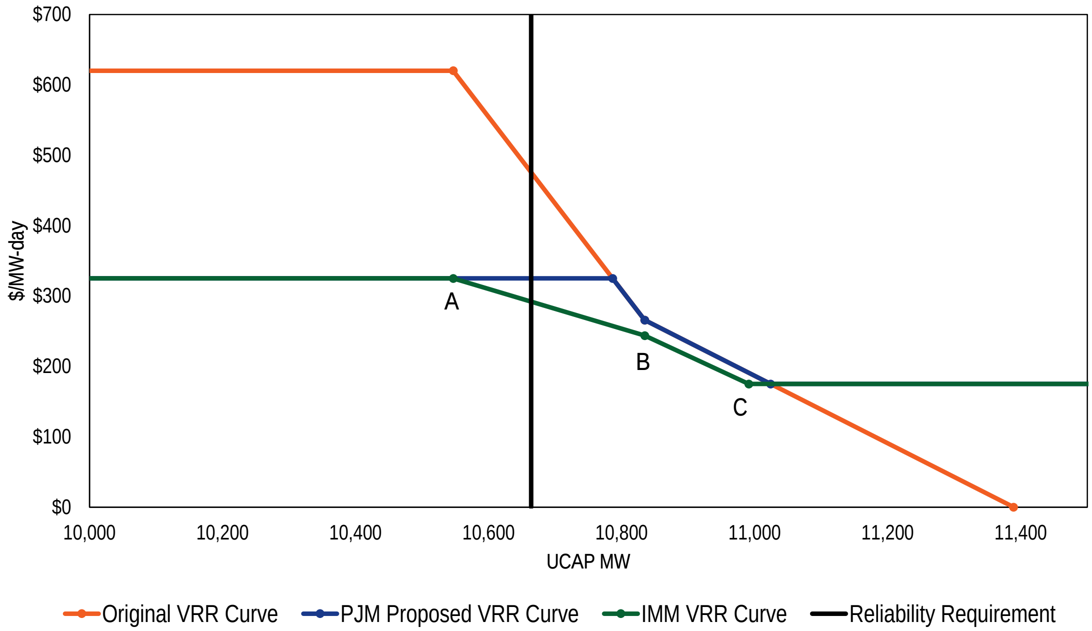


Figure 2 Comparison of VRR Curves for PSEG LDA



Results: $250 per MW-day Cap; 5.0 increase in Forecasted Load

In Scenarios 71, 72, 73 and 74, the MMU analyzed the impact on the actual auction results for the 2025/2026 BRA of using a VRR curve capped at $250.00 per UCAP MW-day, in combination with scenarios 2, 3 and 4 from Part A and a 5.0 percent higher forecasted peak load than used in the 2025/2026 BRA.[18] The maximum price (point A) is set at $250.00 per UCAP MW-day. The price for point B is set at the 0.75 times the maximum price ($187.50 per UCAP MW-day). The corresponding MW quantities are the same as Scenario 8 analyzed in Part C.

Table 5 shows the impact on RPM revenues for Scenario 71. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If the 2025/2026 RPM BRA had been cleared using a VRR curve capped at $250.00 per UCAP MW-day, a 5.0 percent higher forecasted peak load and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $12,372,204,250, a decrease of $2,314,843,108, or 15.8 percent, compared to the actual results (Scenario 71). From another perspective, the actual 2025/2026 VRR curve resulted in 18.7 percent higher 2025/2026 RPM BRA revenues compared to what RPM revenues

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[18] Scenarios 2, 3 and 4 address the impact of the failure to offer by some categorically exempt resources, the impact of excluding RMR supply and the impact of understated winter ratings for thermal resources. These scenarios are included in the analysis in Parts A, B, C, D and E.

would have been had PJM cleared the auction using a VRR curve with maximum price (point A) set at $250.00 per UCAP MW-day, and 5.0 percent higher forecasted peak load (Scenario 71).

Table 5 shows the impact on RPM revenues for Scenario 72. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM BRA were $14,687,047,358. If, in addition to Scenario 71, the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM BRA, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $12,522,702,875, a decrease of $2,164,344,483, or 14.7 percent, compared to the actual results. From another perspective, if in addition to Scenario 71, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day resulted in a 17.3 percent increase in RPM revenues for the 2025/2026 RPM Base Residual Auction compared to what RPM revenues would have been had the capacity of the RMR resources been included in the supply curve at $0 per MW-day (Scenario 72).

Table 5 shows the impact on RPM revenues for Scenario 73. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If, in addition to Scenario 71, marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, if the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $13,025,563,375, a decrease of $1,661,483,983, or 11.3 percent, compared to the actual results. From another perspective, if in addition to Scenario 71, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day and marginal ELCC based accreditation did not consider higher winter generation capacity ratings for CC and CT resources, resulted in a 12.8 percent increase in RPM revenues for the 2025/2026 RPM BRA compared to what RPM revenues would have been had the capacity of the RMR resources in the BGE LDA been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction and had marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction (Scenario 73).

Table 5 shows the impact on RPM revenues for Scenario 74. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If, in addition to Scenario 55, the MW capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, if marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, if the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $13,176,536,500, a decrease of $1,510,510,858, or 10.3 percent, compared to the actual results. From another perspective, if in addition to Scenario 71, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day, marginal ELCC based accreditation did not consider higher winter generation capacity ratings for CC and CT resources and the MW categorically exempt from the RPM must offer requirement that did not offer had been offered, resulted in a 11.5 percent increase in RPM revenues for the 2025/2026 RPM BRA compared to what RPM revenues would have been if the MW capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, if marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction and if the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction (Scenario 74).

Table 5 Scenario summary for 2025/2026 RPM Base Residual Auction: VRR Curve Capped at $250 per MW-day; 5.0 Percent Higher Forecasted Peak Load

		Scenario Impact			
				Percent Change	
Scenario	Scenario Description	RPM Revenue ($ per Delivery Year)	RPM Revenue Change ($ per Delivery Year)	Scenario to Actual	Actual to Scenario
0	Actual results	$14,687,047,358	NA	NA	NA
71	VRR curve based on $250 per UCAP MW-Day Cap	$12,372,204,250	$2,314,843,108	18.7%	(15.8%)
72	Scenario 55 and RMR resources	$12,522,702,875	$2,164,344,483	17.3%	(14.7%)
73	Scenario 55 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$13,025,563,375	$1,661,483,983	12.8%	(11.3%)
74	Scenario 55 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$13,176,536,500	$1,510,510,858	11.5%	(10.3%)

Results: $300 per MW-day Cap; 5.0 Increase in Forecasted Load

In Scenarios 75, 76, 77 and 78, the MMU analyzed the impact on the actual auction results for the 2025/2026 BRA of using a VRR curve capped at $300.00 per UCAP MW-day, in combination with scenarios 2, 3 and 4 from Part A and a 5.0 percent higher forecasted peak load than used in the 2025/2026 BRA. The maximum price (point A) is set at $300.00 per UCAP MW-day. The price for point B is set at the 0.75 times the maximum price ($225.00 per UCAP MW-day). The corresponding MW quantities are the same as Scenario 8 analyzed in Part C.

Table 6 shows the impact on RPM revenues for Scenario 71. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If the 2025/2026 RPM BRA had been cleared using a VRR curve capped at $300.00 per UCAP MW-day, a 5.0 percent higher forecasted peak load and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $14,853,806,400, an increase of $166,759,042, or 1.1 percent, compared to the actual results (Scenario 75). From another perspective, the actual 2025/2026 VRR curve resulted in 1.1 percent lower 2025/2026 RPM BRA revenues compared to what RPM revenues would have been had PJM cleared the auction using a VRR curve with maximum price (point A) set at $300.00 per UCAP MW-day, and 5.0 percent higher forecasted peak load (Scenario 75).

Table 6 shows the impact on RPM revenues for Scenario 76. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM BRA were $14,687,047,358. If, in addition to Scenario 75, the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM BRA, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $15,033,036,000, an increase of $345,988,642, or 2.4 percent, compared to the actual results. From another perspective, if in addition to Scenario 75, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day resulted in a 2.3 percent decrease in RPM revenues for the 2025/2026 RPM Base Residual Auction compared to what RPM revenues would have been had the capacity of the RMR resources been included in the supply curve at $0 per MW-day (Scenario 76).

Table 6 shows the impact on RPM revenues for Scenario 77. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If, in addition to Scenario 75, marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, if the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $15,636,643,800, an increase of $949,596,442, or 6.5 percent, compared to the actual results. From another perspective, if in addition to Scenario 75, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day and marginal ELCC based accreditation did not consider higher winter generation capacity ratings for CC and CT resources, resulted in a 6.1 percent decrease in RPM revenues for the 2025/2026 RPM BRA compared to what RPM revenues would have been had the capacity of the RMR resources in the BGE LDA been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction and had marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction (Scenario 77).

Table 6 shows the impact on RPM revenues for Scenario 78. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If, in addition to Scenario 75, the MW capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, if marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, if the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $15,818,490,450, an increase of $1,131,443,092, or 7.7 percent, compared to the actual results. From another perspective, if in addition to Scenario 75, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day and marginal ELCC based accreditation did not consider higher winter generation capacity ratings for CC and CT resources, the MW categorically exempt from the RPM must offer requirement that did not offer had been offered, resulted in a 7.2 percent decrease in RPM revenues for the 2025/2026 RPM BRA compared to what RPM revenues would have been if the MW capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, if marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction and if the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction (Scenario 78).

Table 6 Scenario summary for 2025/2026 RPM Base Residual Auction: VRR Curve Capped at $300 per MW-day; 5.0 Percent Higher Forecasted Peak Load

		Scenario Impact			
				Percent Change	
Scenario	Scenario Description	RPM Revenue ($ per Delivery Year)	RPM Revenue Change ($ per Delivery Year)	Scenario to Actual	Actual to Scenario
0	Actual results	$14,687,047,358	NA	NA	NA
75	VRR curve based on $300 per UCAP MW-Day Cap	$14,853,806,400	($166,759,042)	(1.1%)	1.1%
76	Scenario 59 and RMR resources	$15,033,036,000	($345,988,642)	(2.3%)	2.4%
77	Scenario 59 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$15,636,643,800	($949,596,442)	(6.1%)	6.5%
78	Scenario 59 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$15,818,490,450	($1,131,443,092)	(7.2%)	7.7%

Results: $325 per MW-day Cap; 5.0 increase in Forecasted Load

In Scenarios 79, 80, 81 and 82, the MMU analyzed the impact on the actual auction results for the 2025/2026 BRA of using a VRR curve capped at $325.00 per UCAP MW-day, in combination with scenarios 2, 3 and 4 from Part A and a 5.0 percent higher forecasted peak load than used in the 2025/2026 BRA. The maximum price (point A) is set at $325.00 per UCAP MW-day. The price for point B is set at the 0.75 times the maximum price ($243.75 per UCAP MW-day). The corresponding MW quantities are the same as Scenario 8 analyzed in Part C.

Table 7 shows the impact on RPM revenues for Scenario 79. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If the 2025/2026 RPM BRA had been cleared using a VRR curve capped at $325.00 per UCAP MW-day, a 5.0 percent higher forecasted peak load and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $16,092,691,225, an increase of $1,405,643,867, or 9.6 percent, compared to the actual results (Scenario 79). From another perspective, the actual 2025/2026 VRR curve resulted in 8.7 percent lower 2025/2026 RPM BRA revenues compared to what RPM revenues would have been had PJM cleared the auction using a VRR curve with maximum price (point A) set at $325.00 per UCAP MW-day, and 5.0 percent higher forecasted peak load (Scenario 79).

Table 7 shows the impact on RPM revenues for Scenario 80. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM BRA were $14,687,047,358. If, in addition to Scenario 79, the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM BRA, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $16,288,244,538, an increase of $1,601,197,180, or 10.9 percent, compared to the actual results. From another perspective, if in addition to Scenario 79, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day resulted in a 9.8 percent decrease in RPM revenues for the 2025/2026 RPM Base Residual Auction compared to what RPM revenues would have been had the capacity of the RMR resources been included in the supply curve at $0 per MW-day (Scenario 80).

Table 7 shows the impact on RPM revenues for Scenario 81. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If, in addition to Scenario 79, marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, if the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have $16,941,963,188, an increase of $2,254,915,830, or 15.4 percent, compared to the actual results. From another perspective, if in addition to Scenario 79, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day and marginal ELCC based accreditation did not consider higher winter generation capacity ratings for CC and CT resources, resulted in a 13.3 percent decrease in RPM revenues for the 2025/2026 RPM BRA compared to what RPM revenues would have been had the capacity of the RMR resources in the BGE LDA been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction and had marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction (Scenario 81).

Table 7 shows the impact on RPM revenues for Scenario 82. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If, in addition to Scenario 79, the MW capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, if marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, if the capacity of the RMR resources in the BGE LDA been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $17,138,323,150, an increase of $2,451,275,792, or 16.7 percent, compared to the actual results. From another perspective, if in addition to Scenario 79, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day, marginal ELCC based accreditation did not consider higher winter generation capacity ratings for CC and CT resources and the MW categorically exempt from the RPM must offer requirement that did not offer had been offered, resulted in a 14.3 percent decrease in RPM revenues for the 2025/2026 RPM BRA compared to what RPM revenues would have been if the MW capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, if marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction and if the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction (Scenario 82).

Table 7 Scenario summary for 2025/2026 RPM Base Residual Auction: VRR Curve Capped at $325 per MW-day; 5.0 Percent Higher Forecasted Peak Load

		Scenario Impact			
				Percent Change	
Scenario	Scenario Description	RPM Revenue ($ per Delivery Year)	RPM Revenue Change ($ per Delivery Year)	Scenario to Actual	Actual to Scenario
0	Actual results	$14,687,047,358	NA	NA	NA
79	VRR curve based on $325 per UCAP MW-Day Cap	$16,092,691,225	($1,405,643,867)	(8.7%)	9.6%
80	Scenario 79 and RMR resources	$16,288,244,538	($1,601,197,180)	(9.8%)	10.9%
81	Scenario 79 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$16,941,963,188	($2,254,915,830)	(13.3%)	15.4%
82	Scenario 79 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$17,138,323,150	($2,451,275,792)	(14.3%)	16.7%

Results: $350 per MW-day Cap; 5.0 Increase in Forecasted Load

In Scenarios 83, 84, 85 and 86, the MMU analyzed the impact on the actual auction results for the 2025/2026 BRA of using a VRR curve capped at $350.00 per UCAP MW-day, in combination with scenarios 2, 3 and 4 from Part A and a 5.0 percent higher forecasted peak load than used in the 2025/2026 BRA. The maximum price (point A) is set at $350.00 per UCAP MW-day. The price for point B is set at the 0.75 times the maximum price ($262.50 per UCAP MW-day). The corresponding MW quantities are the same as Scenario 8 analyzed in Part C.

Table 8 shows the impact on RPM revenues for Scenario 83. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If the 2025/2026 RPM BRA had been cleared using a VRR curve capped at $350.00 per UCAP MW-day, a 5.0 percent higher forecasted peak load and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $17,333,426,600, an increase of $2,646,379,242, or 18.0 percent, compared to the actual results (Scenario 83). From another perspective, the actual 2025/2026 VRR curve resulted in 15.3 percent lower 2025/2026 RPM BRA revenues compared to what RPM revenues would have been had PJM cleared the auction using a VRR curve with maximum price (point A) set at $325.00 per UCAP MW-day, and 5.0 percent higher forecasted peak load (Scenario 83).

Table 8 shows the impact on RPM revenues for Scenario 84. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM BRA were $14,687,047,358. If, in addition to Scenario 83, the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM BRA, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $17,544,022,475, an increase of $2,856,975,117, or 19.5 percent, compared to the actual results. From another perspective, if in addition to Scenario 83, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day resulted in a 16.3 percent decrease in RPM revenues for the 2025/2026 RPM Base Residual Auction compared to what RPM revenues would have been had the capacity of the RMR resources been included in the supply curve at $0 per MW-day (Scenario 84).

Table 8 shows the impact on RPM revenues for Scenario 85. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If, in addition to Scenario 83, marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, if the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $18,248,027,175, an increase of $3,560,979,817, or 24.2 percent, compared to the actual results. From another perspective, if in addition to Scenario 83, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day and marginal ELCC based accreditation did not consider higher winter generation capacity ratings for CC and CT resources, resulted in a 19.5 percent decrease in RPM revenues for the 2025/2026 RPM BRA compared to what RPM revenues would have been had the capacity of the RMR resources in the BGE LDA been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction and had marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction (Scenario 85).

Table 8 shows the impact on RPM revenues for Scenario 86. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If, in addition to Scenario 83, the MW capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, if marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, if the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $18,459,491,750, an increase of $3,772,444,392, or 25.7 percent, compared to the actual results. From another perspective, if in addition to Scenario 83, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day and marginal ELCC based accreditation did not consider higher winter generation capacity ratings for CC and CT resources, the MW categorically exempt from the RPM must offer requirement that did not offer had been offered, resulted in a 20.4 percent decrease in RPM revenues for the 2025/2026 RPM BRA compared to what RPM revenues would have been if the MW capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, if marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction and if the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction (Scenario 86).

Table 8 Scenario summary for 2025/2026 RPM Base Residual Auction: VRR Curve Capped at $350 per MW-day; 5.0 Percent Higher Forecasted Peak Load

		Scenario Impact			
				Percent Change	
Scenario	Scenario Description	RPM Revenue ($ per Delivery Year)	RPM Revenue Change ($ per Delivery Year)	Scenario to Actual	Actual to Scenario
0	Actual results	$14,687,047,358	NA	NA	NA
83	VRR curve based on $350 per UCAP MW-Day Cap	$17,333,426,600	($2,646,379,242)	(15.3%)	18.0%
84	Scenario 67 and RMR resources	$17,544,022,475	($2,856,975,117)	(16.3%)	19.5%
85	Scenario 67 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$18,248,027,175	($3,560,979,817)	(19.5%)	24.2%
86	Scenario 67 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$18,459,491,750	($3,772,444,392)	(20.4%)	25.7%

Results: Cleared UCAP MW

Table 9 through Table 12 show the summary of the cleared UCAP MW impact of all the scenarios analyzed. The Cleared UCAP column shows the cleared MW that resulted from the specific scenario only. The Cleared UCAP Change column shows the difference between the actual RPM cleared UCAP MW and the total RPM cleared UCAP MW that resulted from the specific scenario. A positive number means that the specific scenario resulted in a reduction in cleared MW. A negative number means that the specific scenario resulted in an increase in cleared MW. The percent columns show the percent change in RPM cleared MW for the specific scenario from two perspectives. The Scenario to Actual Percent column shows the difference between the MW under the defined scenario and the defined baseline as a percent of the MW under the defined scenario. The Actual to Scenario Percent column shows the difference between the MW under the defined scenario and the defined baseline as a percent of the MW under the defined baseline.

Table 9 shows the impact on the cleared UCAP MW for the auction for Scenarios 71 through 74. In Scenarios 71, 72, 73 and 74, the MMU analyzed the impact on the actual auction results for the 2025/2026 BRA of using a VRR curve capped at $250.00 per UCAP MW-day, in combination with scenarios 2, 3 and 4 from Part A and a 5.0 percent higher forecasted peak load than used in the 2025/2026 BRA. The maximum price (point A) is set at $250.00 per UCAP MW-day. The price for point B is set at the 0.75 times the maximum price ($187.50 per UCAP MW-day).

Table 10 shows the impact on the cleared UCAP MW for the auction for Scenarios 75 through 78. In Scenarios 75, 76, 77 and 78, the MMU analyzed the impact on the actual auction results for the 2025/2026 BRA of using a VRR curve capped at $300.00 per UCAP MW-day, in combination with scenarios 2, 3 and 4 from Part A and a 5.0 percent higher forecasted peak load than used in the 2025/2026 BRA. The maximum price (point A) is set at $300.00 per UCAP MW-day. The price for point B is set at the 0.75 times the maximum price ($225.00 per UCAP MW-day).

Table 11 shows the impact on the cleared UCAP MW for the auction for Scenarios 79 through 82. In Scenarios 79, 80, 81 and 82, the MMU analyzed the impact on the actual auction results for the 2025/2026 BRA of using a VRR curve capped at $325.00 per UCAP MW-day, in combination with scenarios 2, 3 and 4 from Part A and a 5.0 percent higher forecasted peak load than used in the 2025/2026 BRA. The maximum price (point A) is set at $325.00 per UCAP MW-day. The price for point B is set at the 0.75 times the maximum price ($243.75 per UCAP MW-day).

Table 12 shows the impact on the cleared UCAP MW for the auction for Scenarios 83 through 86. In Scenarios 83, 84, 85 and 86, the MMU analyzed the impact on the actual auction results for the 2025/2026 BRA of using a VRR curve capped at $350.00 per UCAP MW-day, in combination with scenarios 2, 3 and 4 from Part A and a 5.0 percent higher forecasted peak load than used in the 2025/2026 BRA. The maximum price (point A) is set at $350.00 per UCAP MW-day. The price for point B is set at the 0.75 times the maximum price ($262.50 per UCAP MW-day).

Table 9 Scenario summary for 2025/2026 RPM Base Residual Auction: VRR Curve Capped at $250 per MW-day; 5.0 Percent Higher Forecasted Peak Load

		Scenario Impact			
				Percent Change	
Scenario	Scenario Description	Cleared UCAP (MW)	Cleared UCAP Change (MW)	Scenario to Actual	Actual to Scenario
0	Actual results	135,684.0	NA	NA	NA
71	VRR curve based on $250 per UCAP MW-Day Cap	135,585.8	98.2	0.1%	(0.1%)
72	Scenario 55 and RMR resources	137,235.1	(1,551.1)	(1.1%)	1.1%
73	Scenario 55 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	142,745.9	(7,061.9)	(4.9%)	5.2%
74	Scenario 55 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	144,400.4	(8,716.4)	(6.0%)	6.4%

Table 10 Scenario summary for 2025/2026 RPM Base Residual Auction: VRR Curve Capped at $300 per MW-day; 5.0 Percent Higher Forecasted Peak Load

		Scenario Impact			
				Percent Change	
Scenario	Scenario Description	Cleared UCAP (MW)	Cleared UCAP Change (MW)	Scenario to Actual	Actual to Scenario
0	Actual results	135,684.0	NA	NA	NA
75	VRR curve based on $300 per UCAP MW-Day Cap	135,651.2	32.8	0.0%	(0.0%)
76	Scenario 59 and RMR resources	137,288.0	(1,604.0)	(1.2%)	1.2%
77	Scenario 59 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	142,800.4	(7,116.4)	(5.0%)	5.2%
78	Scenario 59 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	144,461.1	(8,777.1)	(6.1%)	6.5%

Table 11 Scenario summary for 2025/2026 RPM Base Residual Auction: VRR Curve Capped at $325 per MW-day; 5.0 Percent Higher Forecasted Peak Load

		Scenario Impact			
				Percent Change	
Scenario	Scenario Description	Cleared UCAP (MW)	Cleared UCAP Change (MW)	Scenario to Actual	Actual to Scenario
0	Actual results	135,684.0	NA	NA	NA
79	VRR curve based on $325 per UCAP MW-Day Cap	135,660.2	23.8	0.0%	(0.0%)
80	Scenario 79 and RMR resources	137,308.7	(1,624.7)	(1.2%)	1.2%
81	Scenario 79 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	142,819.5	(7,135.5)	(5.0%)	5.3%
82	Scenario 79 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	144,474.8	(8,790.8)	(6.1%)	6.5%

Table 12 Scenario summary for 2025/2026 RPM Base Residual Auction: VRR Curve capped at $350 per MW-day; 5.0 Percent Higher Forecasted Peak Load

		Scenario Impact			
				Percent Change	
Scenario	Scenario Description	Cleared UCAP (MW)	Cleared UCAP Change (MW)	Scenario to Actual	Actual to Scenario
0	Actual results	135,684.0	NA	NA	NA
83	VRR curve based on $350 per UCAP MW-Day Cap	135,682.4	1.6	0.0%	(0.0%)
84	Scenario 67 and RMR resources	137,330.9	(1,646.9)	(1.2%)	1.2%
85	Scenario 67 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	142,841.7	(7,157.7)	(5.0%)	5.3%
86	Scenario 67 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	144,497.0	(8,813.0)	(6.1%)	6.5%

Table 13 shows the clearing prices for the scenarios analyzed in Part F. There was no price separation between LDAs in any of the scenarios analyzed. All LDAs in every scenario analyzed cleared at the maximum price on the VRR curve. The clearing price was set by the maximum price in every scenario analyzed.

Table 13 Clearing Prices by Scenario

	Clearing Price (All LDAs) ($/UCAP MW-day)
Scenarios 71,72,73,74	$250.00
Scenarios 75,76,77,78	$300.00
Scenarios 79,80,81,82	$325.00
Scenarios 83,84,85,86	$350.00

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Eagleville, Pennsylvania,
this 17th day of March, 2025.

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