



Monitoring
Analytics

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

The Independent Market Monitor for PJM

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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

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

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_RASTE-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

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 ($ICAP * AUCAP \text{ Factor}$). 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.

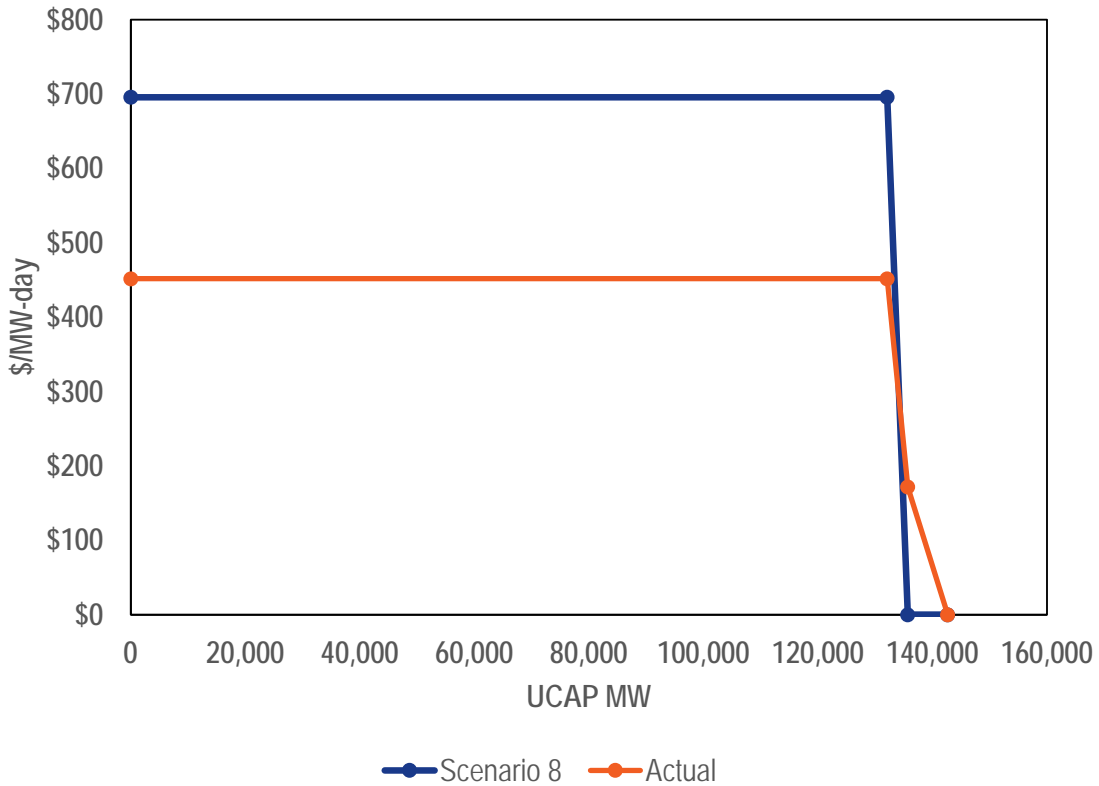
Table 1 shows the impact on RPM revenues for Scenario 8. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM BRA were \$14,687,047,358. If the 2025/2026 RPM BRA had been cleared using a VRR curve based on a CC as the reference resource, 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).

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

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.

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).

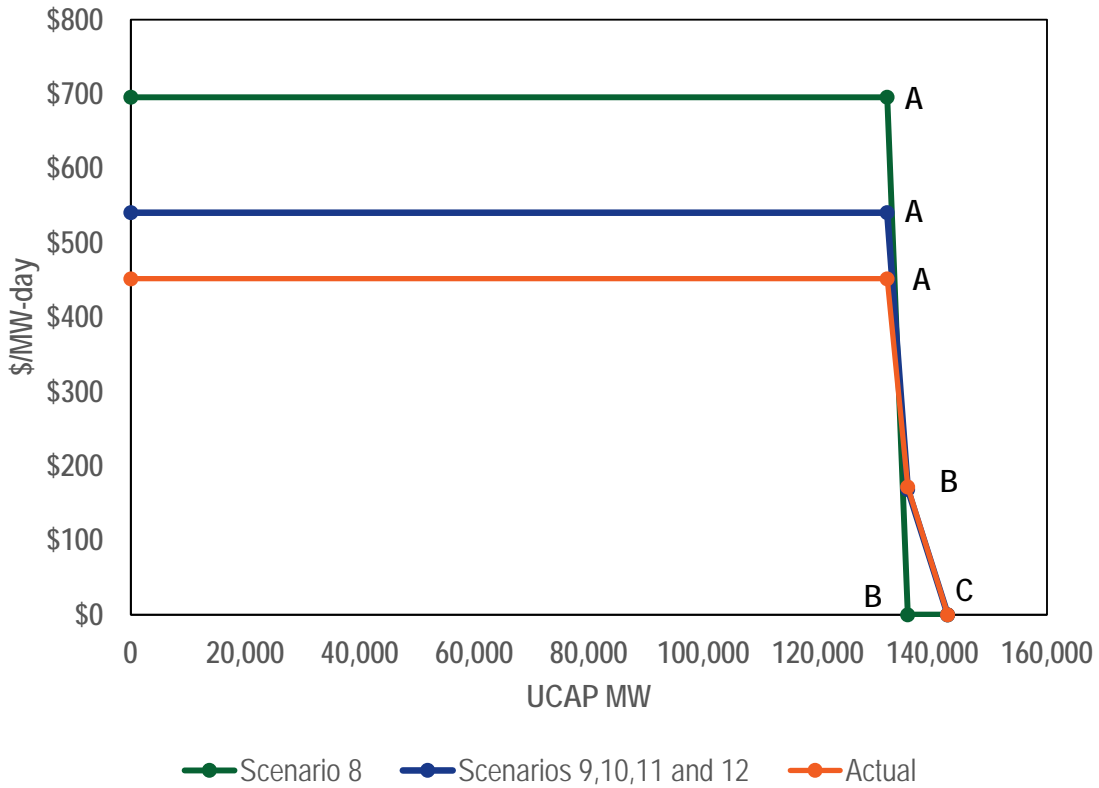
Table 2 shows the impact on RPM revenues for Scenario 10. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM BRA were \$14,687,047,358. If, in addition to Scenario 9, the capacity of the RMR resources in the BGE LDA had been included 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 $1.75 * \text{Net CONE}$ rather than $1.0 * \text{Net CONE}$ 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	Scenario Description	Scenario Impact			
		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
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	Scenario Description	Scenario Impact		
		RPM Revenue (\$ per Delivery Year)	RPM Revenue Change (\$ per Delivery Year)	Percent Change Scenario to Actual Actual to Scenario
0	Actual results	\$14,687,047,358	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%)
10	Scenario 9 and RMR resources	\$10,995,403,198	\$3,691,644,159	33.6%
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%
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%

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	Scenario Description	Scenario Impact		
		RPM Revenue (\$ per Delivery Year)	RPM Revenue Change (\$ per Delivery Year)	Percent Change Scenario to Actual Actual to Scenario
0	Actual results	\$14,687,047,358	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%)
14	Scenario 13 and RMR resources	\$10,995,403,198	\$3,691,644,159	33.6%
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%
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%

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 $1.75 * \text{Net CONE}$ rather than $1.0 * \text{Net CONE}$ 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	Scenario Description	Scenario Impact		
		RPM Revenue (\$ per Delivery Year)	RPM Revenue Change (\$ per Delivery Year)	Percent Change Scenario to Actual Actual to Scenario
0	Actual results	\$14,687,047,358	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	Scenario Description	Scenario Impact		
		RPM Revenue (\$ per Delivery Year)	RPM Revenue Change (\$ per Delivery Year)	Percent Change Scenario to Actual Actual to Scenario
0	Actual results	\$14,687,047,358	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	Scenario Description	Scenario Impact		
		RPM Revenue (\$ per Delivery Year)	RPM Revenue Change (\$ per Delivery Year)	Percent Change Scenario to Actual Actual to Scenario
0	Actual results	\$14,687,047,358	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	Scenario Description	Scenario Impact		
		RPM Revenue (\$ per Delivery Year)	RPM Revenue Change (\$ per Delivery Year)	Percent Change Scenario to Actual Actual to Scenario
0	Actual results	\$14,687,047,358	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	Scenario Description	Scenario Impact		
		RPM Revenue (\$ per Delivery Year)	RPM Revenue Change (\$ per Delivery Year)	Percent Change Scenario to Actual Actual to Scenario
0	Actual results	\$14,687,047,358	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	Scenario Description	Scenario Impact			
		Cleared UCAP (MW)	Cleared UCAP Change (MW)	Percent Change	
				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	Scenario Description	Scenario Impact			
		Cleared UCAP (MW)	Cleared UCAP Change (MW)	Percent Change 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	Scenario Description	Scenario Impact			
		Cleared UCAP (MW)	Cleared UCAP Change (MW)	Percent Change 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	Scenario Description	Scenario Impact			
		Cleared UCAP (MW)	Cleared UCAP Change (MW)	Percent Change 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	Scenario Description	Scenario Impact			
		Cleared UCAP (MW)	Cleared UCAP Change (MW)	Percent Change	
				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	Scenario Description	Scenario Impact			
		Cleared UCAP (MW)	Cleared UCAP Change (MW)	Percent Change	
				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	Scenario Description	Scenario Impact			
		Cleared UCAP (MW)	Cleared UCAP Change (MW)	Percent Change	
				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

Scenario	Scenario Description	Cleared UCAP		Percent Change	
		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%