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

The Independent Market Monitor for PJM

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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

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[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%