Monitoring Analytics

Testimony of Joseph E. Bowring House Environmental Resources and Energy Committee

The Independent Market Monitor for PJM

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My name is Joseph Bowring. I am the Independent Market Monitor for the PJM Interconnection and head of the Market Monitoring Unit (MMU).

Thank you for the opportunity to speak today.

FERC assigns three core functions to the MMU: reporting, monitoring and market design.[1] These functions are interrelated and overlap. The PJM Market Monitoring Plan establishes these functions, providing that the MMU is responsible for monitoring: compliance with the PJM Market Rules; actual or potential design flaws in the PJM Market Rules; structural problems in the PJM Markets that may inhibit a robust and competitive market; the actual or potential exercise of market power or violation of the market rules by a Market Participant; PJM's implementation of the PJM Market Rules or operation of the PJM Markets; and such matters as are necessary to prepare reports.[2]

My testimony today is based on the MMU's State of the Market Report and on the MMU's recent Analysis of the 2025/2026 RPM Base Residual Auction, Part A.[3] I have attached part of the Introduction to the State of the Market Report and the analysis of the recent PJM capacity auction.

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1 18 CFR § 35.28(g)(3)(ii); see also *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶31,281 (2008) ("Order No. 719"), *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶31,292 (2009), *reh'g denied*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

2 OATT Attachment M § IV; 18 CFR § 1c.2.

3 See the *2024 Quarterly State of the Market Report for PJM: January through June* found at <https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2024.shtml> (August 8, 2024) and the *Analysis of the 2025/2026 RPM Base Residual Auction – Part A*, found at <https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_A_20240920.pdf> (September 20, 2024).

Introduction

2024 Q2 in Review

Reliability is a core goal of PJM. Maintaining and improving competitive markets should also be a core goal of PJM. The goal of competition in PJM is to provide customers reliable wholesale power at the lowest possible price, but no lower. The PJM energy markets have done that. The PJM markets work, even if not perfectly. The results of PJM markets were reliable in the first six months of 2024. The results of the energy market were competitive in the first six months of 2024. The PJM markets bring customers the benefits of competition when the market rules allow competition to work and prevent the exercise of market power.

The most significant PJM market result to date in 2024 occurred in July, after the first six months of 2024. A detailed MMU analysis of the July capacity market auction for the 2025/2026 Delivery Year will be posted when complete. The dramatic increases in capacity market prices and customer payments from that auction illustrate the risks of making significant changes to market design without thorough testing. The new ELCC model, with its disproportionately heavy emphasis on historical winter availability and weather, was a significant source of the increased prices because it reduced supply via derates to the MW value of capacity by much more than it decreased demand. The increases in capacity market prices also illustrate the results of not having uniform RPM must offer rules for all generation. The rules inexplicably exempt intermittent resources and capacity storage resources from the RPM must offer requirement despite the fact that they use scarce access to the grid in the form of CIRs. A significant level of intermittent and storage capacity resources were withheld from the market in this auction. While the PJM capacity market supply and demand fundamentals imply higher capacity market prices than in recent prior auctions, the extreme prices in the 2025/2026 BRA were not primarily a result of the fundamentals.

The extremely tight capacity market conditions that resulted from the current PJM ELCC capacity market rules highlight the significance for future capacity market auctions of the ongoing efforts to place new data center loads behind nuclear power plants and potentially other thermal generators and thus remove that capacity from the capacity market. Removal of even a relatively small amount of capacity from the market would have a significant impact on capacity market prices. The gains for the specific co-located loads come at the expense of other customers in the PJM markets. The core benefit to the specific co-located loads is avoiding the costs associated with both state and federal regulation. The co-located load would avoid paying distribution charges and transmission charges and would not be directly subject to the rate regulation of the state public utility commission or the FERC.

If this co-located load approach were extended to all the nuclear plants in PJM, the impact on the PJM grid and markets would be extreme. Power flows on the grid that was built in significant part to deliver low cost nuclear energy to load would change significantly. Energy prices would increase significantly as low cost nuclear energy is displaced by higher cost energy on the overall supply curve. Capacity prices would increase as the supply of capacity to the market is reduced. Emissions would also increase as thermal resources that are next in the supply curve are dispatched to meet load to replace the nuclear energy. Establishing this precedent would undermine PJM reliability and PJM competitive markets.

Power grids were built to permit all participants to take advantage of the diverse characteristics of loads and of generation. When a generator is on an outage, other generators are available on the grid to replace the output. The co-located model would directly remove significant capacity from the market but the co-located load would continue to rely on the grid for backup. The co-located proposals illustrate the basic fact that the co-located load cannot and will not be isolated from the grid. The co-located load model would rely on the grid for backup while pretending to be isolated from the grid.

The issue of co-located load has extremely large significance for the future of PJM markets. PJM has not explained how it plans to meet expected increases in the demand for power, given the extreme tightness of the capacity market under the current ELCC model and given ongoing generator retirements, even without removing multiple large base load units from the system. PJM's latest reliability report and PJM's RTEP do not address the potential significant changes that would result from increases in co-located load. No co-located load should be approved without such analysis and a stakeholder review process and a consideration of the facts by the Commission.

The result of the 2025/2026 BRA make even more critical the fact that the markets face a challenge from potentially high levels of expected thermal generator retirements, with no clear source of replacement capacity or the fuel required for that capacity.

Markets provide incentives for innovation and efficiency. Organized, competitive wholesale power markets are the best way to facilitate the least cost path to decarbonization. Renewables can compete, without guaranteed long term contracts. New entrant solar and wind resources are competitive with existing coal resources in PJM. The Inflation Reduction Act incentives further reduced the costs of these resources. Innovation will occur in renewable technologies in unpredictable and beneficial ways. But the PJM markets are not perfect. Significant changes to the market design continue, including some that improve markets and some that do not. Significant issues with the market design remain. It is not guaranteed that the market design will successfully adapt to the changing realities, including the role of renewable and intermittent resources, the role of distributed resources, the role of regulated EDCs in competitive wholesale power markets, and the role of states and the federal government in subsidizing resources and in environmental regulation. Competition should also include transmission. Competition to build transmission provides incentives for new and creative solutions and puts downward pressure on costs. The current competitive process for transmission is not perfect and needs continued improvement in order to bring the benefits of competition to customers. Explicit competition between transmission and generation solutions to reliability issues should be incorporated in the market design.

FERC made an explicit decision to rely on competitive markets rather than traditional regulation to provide just and reasonable rates in PJM. Failing to effectively address market power would mean that competition cannot effectively replace traditional regulation and cannot result in just and reasonable rates. Competitive markets are not a luxury. Effective market power mitigation is a core part of competitive markets. The goal of competitive markets is reliable power at the lowest possible price. PJM has made proposals in both the capacity market and the energy market that would undermine market power mitigation. To date, both proposals have been rejected by FERC. Contrary to the positions of some generators, the evidence supports the fact that market power mitigation as applied in PJM is fully consistent with competitive markets and does not suppress market prices.

While competitive markets are critical, markets alone cannot solve all the issues faced in the PJM wholesale power market. The wholesale power market exists in a broader environment including climate change, fuel supply issues and the wider economy that affects the demand for power.

The basic challenge is to first identify and then match supply and demand, of both energy and capacity, so that reliability can be maintained. PJM and federal and state regulators cannot hope to balance supply and demand without first having a clear and reasonably accurate measure of both existing and expected supply and demand. Providing clear information to regulators and market participants about the actual and expected supply-demand balance is essential so that decisions about market design, about the timing of environmental regulations, about pipeline siting, and about transmission siting can all recognize the likely impact on the balance between supply and demand and therefore reliability.

Supply is not a fixed number but is a function of other factors including state and federal environmental rules, market design, fuel supply and queue design. Demand is a function of forces in the broader economy, including the addition of data centers. Supply includes existing resources included in the expected retirement category and new supply. The expected retirement category can be affected by environmental regulatory decisions. The new supply category is also affected by environmental regulatory decisions but also by market design and the queue rules governing new entry and fuel supply.

Markets exist in a broader regulatory environment that creates significant constraints for markets. The simple fact is that the sources of new capacity that could fully replace the retiring capacity have not been clearly identified.

That task is a complex one and includes significant factors outside the market design, including state and federal environmental policies and siting decisions. While market signals are essential, market signals alone cannot resolve some of the nonmarket constraints.

While there are multiple centrifugal forces acting on PJM markets, there are still options available to maintain well functioning markets. Steps that can be taken immediately to offset those forces include: improve the capacity market design; identify the availability of firm gas supply; ensure transparent information from pipelines; identify the need for dual fuel capacity; modify the RMR process; add expedited queue options to replace retiring resources; and include direct comparisons between generation and transmission options to address reliability issues.

One of the key challenges facing the PJM markets is the potentially high level of expected thermal resource retirements between now and 2030 with no clear source of replacement capacity. Although the exact numbers may vary, an estimated total of between 24,000 MW and 58,000 MW of thermal resources are at risk of retirement, including 4,285 MW of announced retirements, 19,635 MW of retirements as a result of state and federal environmental regulations, and 33,744 MW of retirements for economic reasons, based on expected forward prices. All of the units at risk may not retire. The actual level of MW that will retire for regulatory and economic reasons is uncertain. The probability of retirement is highest for the units that explicitly plan to retire, very high for units expected to retire for regulatory reasons, and significantly lower for units identified as uneconomic. There is some uncertainty in each category and all of the decisions can be affected by the actions of environmental and economic regulators.

Replacing retiring generation does not mean building more of exactly the same generation or that the new supply of energy would have the same characteristics as the old supply. Both the energy and capacity of retiring resources must be replaced and that can happen with a very different resource mix and very different deployment of thermal resources. On a full cost basis, renewable energy is cost competitive with other energy sources and can be expected to replace some or all of the energy output from retiring thermal resources. But replacing the capacity and reliability value of the retiring thermal resources in the immediate future will also require adding new thermal generation, most likely gas-fired and dual fuel, to ensure reliability when energy from the renewable sources is not available, although it is likely to operate at reduced capacity factors. Access to gas pipeline capacity is the most significant barrier to entry for thermal resources, although thermal resources also face queue issues. Interconnection queue issues are a significant barrier to entry for renewable resources.

The retiring capacity consists primarily of coal steam plants and CTs. If all of the coal units identified as at risk (30,417 MW) are replaced by new gas-fired CCs, those new units would require a significant amount of firm gas pipeline capacity if the new units are single fuel. The new CC plants would require 4.8 BCF/day of firm pipeline capacity, based on the maximum output level of the CCs, to replace that coal capacity. If only the coal units identified as at risk based both on explicit plans to retire and on regulatory reasons are replaced, the installed capacity of those coal resources would require 2.0 BCF/day of firm pipeline capacity based on the maximum output level of the CCs to replace that coal capacity. The level of firm pipeline capacity required to replace the capacity and reliability value of the retiring coal units could be reduced if the new CCs invested in dual fuel capability.

Given current constraints on the gas pipeline system, the potential sources of the firm gas supply required to replace potential retirements are not clear. It is essential that FERC, the states, PJM, PJM stakeholders and all segments of the gas industry (transportation, storage and commodity) address the issues of firm gas availability and the dual fuel options. PJM should immediately start a process to identify the available and potential sources of gas supply to the PJM market area in order to permit an evaluation of the risks to reliability and the related need for dual fuel capacity. PJM will rely on existing and new gas-fired and dual fuel generation in the foreseeable future and it is essential that such resources have the gas supply arrangements that will permit them to provide reliability and flexibility and competitive offers and have accurate real time information from the gas pipelines about the terms under which gas transportation is available.

The current PJM interconnection queue does not include adequate thermal capacity to replace the potentially retiring thermal capacity. The apparent level of MW in the interconnection queues is a misleading indicator of the level of capacity MW that is likely to actually go into service in PJM markets for all resource types.

Of the 6,923.1 MW of combined cycle capacity in the queues, 2,820.2 MW (40.7 percent of the total) are expected to go into service as capacity based on historical completion rates and ELCC derate factors. Of the 104,797.8 MW of renewable capacity in the queues, 2,445.6 MW (2.3 percent of the total) are expected to go into service as capacity based on historical completion rates and ELCC derate factors. Of the 45,935.2 MW of battery capacity in the queues, 101.8 MW (0.2 percent of the total) are expected to go into service as capacity based on historical completion rates and ELCC derate factors.

The current interconnection queue does include renewable resources that could displace a significant proportion of the energy from retiring thermal capacity, for the parts of the day when ambient conditions permit. Of the 186,837.5 MW, on an energy basis, of renewable projects in the queue, 30,463.9 MW (16.3 percent) are expected to go in service based on historical completion rates and be capable of generating energy at that level when it is deliverable and ambient conditions permit.

New generation from the queue is going into service. In the first six months of 2024, 1,195.1 MW of new generation from the queue went in service, of which 1,175.1 MW were solar and wind units, and 20.0 MW were battery units. In 2023, 4,621.3 MW of new generation from the queue went in service, of which 1,367.4 MW were solar and wind units, 3,176.1 MW were CCs and CTs, and 60.8 MW were battery units.

Competition starts with open access to the transmission grid. The fundamental purpose of the queue process is to provide open access to the grid and to ensure that the energy from capacity resources is deliverable so that capacity resources can meet their must offer obligations in the energy market and provide reliable energy supply during all conditions. All new generation must go through the queue process. PJM's queue reforms will improve the management of that access which faces the challenge of integrating a large number of relatively small renewable projects in addition to a smaller number of traditional thermal resources. The queue reform process should continue in order to remove or reduce the barriers to the addition of new supply to the system. An expedited queue process under the control of PJM to address identified reliability needs is essential.

The next step in improving the interconnection process is needed now. Rules should be developed promptly to permit PJM to advance projects in the queue if they would resolve, or partially resolve, reliability issues that result, for example, from unit retirements. The rules should be consistent with the flexibility included in the new queue process but add the option for PJM to expedite the interconnection and commercial operation of projects in the queue that would address identified reliability issues, consistent with the standing of the projects in the queue. CIRs from retiring units should be made available to the pool on the retirement date of the retiring resource, so that resources in the queue can use them.

Current proposals that would permit generation owners to avoid the queue process and directly transfer the generation capacity interconnection rights (CIRs) from retiring units to an affiliate or directly sell the CIRs to an unaffiliated entity and advance the recipient of the CIRs ahead of other units in the queue should be rejected. In effect, this approach, if adopted by the large number of retiring units, would create a chaotic, bilateral private queue process that would replace and disrupt the recently redesigned PJM queue process.

Instead, the PJM queue process should continue to define available and needed CIRs for all capacity queue projects. The PJM queue process is based on a set of defined rules and is a much more efficient and equitable process for providing access to the grid than the proposed private process. CIRs from retiring units should be made available to the next resource in the queue that can use them, on the retirement date of the retiring resource. Generation owners should not be deemed to have monopoly property rights in CIRs. Generation owners should not be given the unilateral right to determine who the next market entrant will be or to extract monopoly rents from potential new entrants. The value of CIRs is a result of the entire transmission system which has been paid for by customers and other generators. The value of CIRs is a result of the existence of a network and is not a result solely or even primarily of the investment that may or may not have been required in order to get CIRs. The cost of CIRs is part of project costs included in generation owners' investment decisions like any other project cost and subject to the same risk and reward structure. Open access to the transmission system by new resources should not be limited by claims to own the access rights by retiring units.

In addition, the proposal to bypass the PJM interconnection process with a private, bilateral process ignores the fact that if the new resource is a renewable resource or a storage resource, the new resource does not have a capacity market must offer requirement. The PJM interconnection process could be bypassed, CIRs transferred and then the resource does not offer into the capacity market. In that case, scarce CIRs would be withheld by a generator who does not provide capacity and customers would have to pay for an additional capacity resource instead. The fundamental purpose of the queue process for capacity resources is to provide open access to the grid and to ensure that the energy from capacity resources is deliverable so that capacity resources can meet their must offer obligations in the energy market and provide reliable energy supply. In order to ensure that open access, all capacity resources should be required to have a must offer obligation in the capacity market. If they do not, such resources are effectively withholding access to the grid from capacity resources that would take on a must offer obligation in the capacity market. The result creates market power for the resources with no must offer obligation, noncompetitively limits access to the grid, increases capacity market prices above the competitive level, and creates uncertainty and unpredictable volatility in the capacity market.

The potential level of retirements makes a solution to the RMR (reliability must run) question essential. One of the potential results of an increase in unit retirements is an increased number of RMR contracts that provide for out of market payments to units that PJM defines to be required for reliability, until the PJM transmission grid can be expanded to support reliability. The need for RMR contracts is evidence of a failure in market design. It should never be the case that a resource does not clear in the capacity market auction and then, when it wants to retire as a result, is deemed critical to reliability and not allowed to retire. That does happen in PJM. In addition, the substantial overpayments for RMR service that result from PJM's interpretation of the current rules create an incentive to request RMR contracts because the RMR payments generally exceed market revenues and exceed market revenues by a wide margin in the most recent cases.

The addition of a planned transmission project, for example in response to a retirement and RMR, changes the parameters of the capacity auction for the area, changes the amount of capacity needed in the area, changes the capacity market supply and demand fundamentals in the area and may effectively forestall the ability of generation to compete. But there is no mechanism to permit a direct comparison, let alone competition, between transmission and generation alternatives to meet load in the affected area. There is no mechanism to evaluate whether the generation or transmission alternative is less costly, whether there is more risk associated with the generation or transmission alternatives, or who bears the risks associated with each alternative. Creating such a mechanism should be an explicit goal of PJM market design.

The definitions of reliability for the capacity market and transmission planners should be the same. That will require a change to the capacity market rules that do not now define reliability as stringently as the transmission planning criteria. In addition, RMR units are included in the supply of capacity for auctions after the unit has declared the intent to retire. Such inclusion overstates market supply and suppresses the capacity market price signal needed to incent the new entry needed to replace the retiring unit. Retiring units should be required to provide notice at least 18 months in advance of retirement, in order to allow the markets to respond. If an RMR is still needed, the rules governing compensation should be clarified to provide for fair compensation, including an incentive, for all the costs that the owners of such units incur in order to provide this service, but no more than that.

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

The only purpose of the capacity market is to make the energy market work. That means two specific things. The capacity market needs to define the total MWh of energy that are needed to reliably serve load in all hours. The capacity market needs to provide the missing money; the capacity market needs to allow all cleared capacity resources the opportunity to cover their net avoidable costs on an annual basis to ensure the economic sustainability of the reliable energy market. The capacity market is an administrative construct designed to achieve these two purposes.

PJM's proposed ELCC approach to capacity market design has not been adequately tested, introduces volatility into asset values and capacity market outcomes and relies on PJM's ex ante ELCC model to define the asset values of capacity resources rather than relying on the resource owners to demonstrate asset value based on investment in improved reliability and actual ongoing performance. Risk based on the level of uncertainty created by PJM's new capacity market design combined with the extreme PAI penalties has a negative impact on the risk and economic viability of units considering retirement. Strong incentives need to be designed and scaled so that they have the intended effect of improving availability without increasing uncertainty and adding risk that weakens the incentives to invest in PJM generation.

One of the benefits of competitive power markets is that changes in input prices and changes in the balance of supply and demand are reflected immediately in energy prices for both price decreases and price increases. Energy prices increased in the first six months of 2024 from the first six months of 2023. The real-time load-weighted average LMP in the first six months of 2024 increased $2.36 per MWh, or 8.1 percent from the first six months of 2023, from $29.33 per MWh to $31.70 per MWh. Of the $2.36 per MWh increase, $1.08 per MWh (45.5 percent) was in the transmission constraint penalty factor component of LMP, $0.26 per MWh (11.1 percent) was in the fuel and consumables cost components of LMP, $0.16 per MWh (6.6 percent) was in the emissions cost components of LMP, $0.13 per MWh (5.7 percent) was in the scarcity component of LMP, and -0.05 per MWh (-2.2 percent) was in the market power components of LMP.

The total price of wholesale power increased $1.51 per MWh, or 2.8 percent, from $53.25 per MWh in the first six months of 2023 to $54.76 per MWh in the first six months of 2024. Energy (57.9 percent), capacity (5.6 percent) and transmission charges (32.7 percent) are the three largest components of the total price of wholesale power, comprising 96.2 percent of the total price per MWh in the first six months of 2024. Starting in the third quarter of 2019, the cost of transmission per MWh of wholesale power has been higher than the cost of capacity.

In the first six months of 2024, generation from coal units increased 10.3 percent, generation from natural gas units increased 7.6 percent, generation from oil units increased 25.1 percent, generation from wind units increased 9.0 percent, and generation from solar units increased 52.3 percent compared to the first six months of 2023.

Net revenue is a key measure of overall market performance as well as a measure of the incentive to invest in generation to serve PJM markets. Energy market net revenues are significantly affected by energy prices and fuel prices. Energy prices and eastern gas prices increased and western gas and coal prices decreased in the first six months of 2024 compared to the first six months of 2023. The net effects were that in the first six months of 2024, average energy market theoretical net revenues increased by 86 percent for a new combustion turbine (CT), increased by 52 percent for a new combined cycle (CC), increased by 629 percent for a new coal plant (CP), increased by 2 percent for a new nuclear plant, increased by 334 percent for a new diesel (DS), increased by 3 percent for a new onshore wind installation, increased by

9 percent for a new offshore wind installation and increased by 9 percent for a new solar installation.

Changes in forward energy market prices significantly affect the expected profitability of nuclear plants in PJM. Based on forward prices as of June 28, 2024, for energy, and known forward prices for capacity, all the nuclear plants in PJM are expected to cover their avoidable costs from energy and capacity market revenues in 2025 and 2026, without subsidies. All PJM nuclear plants are expected to have a surplus excluding any subsidy amount in 2024, with the exception of Davis Besse and Perry, both single unit plants. All PJM nuclear plants, including Davis Besse and Perry are expected to have a surplus in 2024 when the IRA nuclear subsidies are included.

The evolution of wholesale power markets is far from complete. The PJM markets need rules in order to provide reliable energy through competition. The foundational principle of using markets, with rules to prevent the exercise of market power and provide competitive results, is essential. Private investors, regardless of technology or subsidies, will put capital at risk and earn compensatory returns in markets that are not skewed in favor of any specific technology and in markets that are stable and that do not add risk and volatility. The core elements of the PJM market design remain robust. The use of locational marginal prices (LMP) in the energy market and locational prices in the capacity market continue to be essential to getting the price signals right. Technological and policy changes do not require that the core elements change. But the market design can and must be improved and made more reliable and more efficient and more competitive. The current capacity market design adds unnecessary risk and volatility that are not part of the market fundamentals. The ELCC approach needs to incorporate hourly data and pay resources based on actual availability rather than on assumed performance derived from a very limited data set of performance based on unrepresentative extreme historical weather. The capacity market also needs to eliminate artificial PAI risk that leads to uneconomic retirements and exits from PJM. The capacity market needs to apply a uniform must offer requirement to all capacity resources that have scarce CIRs. The queue process should allow for an expedited process to resolve identified reliability issues. The markets will also need support from regulators whose decisions create and/or limit the options available to investors in PJM resources. Competition to build transmission should be expanded.

In the interests of all market participants, PJM, its actual and potential market participants and stakeholders, PJM state regulators, and the FERC will need to continue to work constructively to refine the competitive market design and to ensure the continued effectiveness of PJM markets in providing customers wholesale power at the lowest possible price, but no lower.

PJM Market Summary Statistics

Table 1-1 shows selected summary statistics describing PJM markets.

Table 1-1 PJM market summary statistics: January through June, 2023 and 2024[1]

	2023 (Jan-Jun)	2024 (Jan-Jun)	Percent Change
Average Hourly Load Plus Exports (MWh)	89,146	93,605	5.0%
Average Hourly Generation Plus Imports (MWh)	90,773	95,382	5.1%
Peak Load Plus Export (MWh)	130,389	148,109	13.6%
Peak Load Excluding Export (MWh)	121,302	144,245	18.9%
Installed Capacity at June 30 (MW)	178,213	177,007	(0.7%)
Load Weighted Average Real Time LMP ($/MWh)	$29.33	$31.70	8.1%
Total Congestion Costs ($ Million)	$396.5	$701.5	76.9%
Total Uplift Credits ($ Million)	$54.8	$169.4	209.3%
Total PJM Billing ($ Billion)	$23.26	$24.33	4.6%

1 In Table 1-1, the MMU uses Total PJM Billing values provided by PJM. For 2019 and after, the MMU has modified the Total PJM Billing calculation to better reflect historical PJM total billing through the PJM settlement process.

Analysis of the

2025/2026 RPM Base Residual Auction

Part A

The Independent Market Monitor for PJM

September 20, 2024

Introduction

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

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

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

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

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

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

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

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

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

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

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

Conclusions

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

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

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

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

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

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

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

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

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

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

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

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

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

Recommendations

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

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

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

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

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

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

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

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

Summary of Results

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Summary Results Tables

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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