UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Sierra Club, et al.,	)	
	)	
Complainants,	)	
	)	
v.	)	**Docket No. EL24-148-000**
	)	
PJM Interconnection, L.L.C.,	)	
	)	
Respondent.	)	

COMPLAINT OF SIERRA CLUB, NATURAL RESOURCES DEFENSE COUNCIL, PUBLIC CITIZEN, SUSTAINABLE FERC PROJECT AND UNION OF CONCERNED SCIENTISTS

Nick Lawton
Senior Attorney, Clean Energy Program
Earthjustice
1001 G Street, NW Suite 1000
Washington, DC 20001
(202) 780-4835
nlawton@earthjustice.org

Casey A. Roberts
Senior Attorney
Sierra Club Environmental Law Program
1536 Wynkoop St., Suite 200
Denver, Colorado, 80202
T: (303) 454-3355
casey.roberts@sierraclub.org

Justin Vickers
Senior Attorney
Sierra Club Environmental Law Program
1229 W Glenlake Ave.
Chicago, IL 60660
(224) 420-0614
justin.vickers@sierraclub.org

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Pursuant to Sections 206 and 306 of the Federal Power Act ("FPA"),[1] and Rule 206 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or "Commission"),[2] Sierra Club, Natural Resources Defense Council, Public Citizen, Sustainable FERC Project, and the Union of Concerned Scientists (collectively "Public Interest Organizations" or "PIOs") file this Complaint against PJM Interconnection, LLC ("PJM"). PIOs request that the Commission: (1) establish a refund effective date pursuant to section 206 of the FPA as of the date of this compliant; (2) find that PJM's capacity market rules are unjust and unreasonable because they fail to require a consistent accounting of the resource adequacy contributions of power plants operating under Reliability Must Run ("RMR") arrangements and lead to excessive costs for consumers; and (3) order PJM to reform its capacity market rules to consistently account for RMR units' resource adequacy contributions.

I. INTRODUCTION

This Complaint challenges unjust and unreasonable rules in PJM's capacity market that have already caused \$4 billion to \$5 billion dollars in excessive costs for consumers in PJM's most recent capacity auction—and that may cause \$12 billion to \$15 billion more in three upcoming capacity auctions unless the Commission requires reforms. In particular, this Complaint challenges PJM's failure to consistently account in its capacity market for the resource adequacy value of generators operating under Reliability Must Run ("RMR") arrangements. RMR arrangements require consumers to pay power plants that would otherwise retire to stay online in order to maintain reliability. Yet PJM does not accurately account for these RMR units' contributions to resource adequacy during capacity auctions—despite

[1] 16 U.S.C. §§ 824e, 825e.
[2] 18 C.F.R. § 385.206.

consumers paying these power plants to remain in service, despite having explicit authority in numerous RMR arrangements to call these power plants to operate during capacity emergencies, and despite its own stated expectation that these plants will operate when called. Instead, by failing either to require RMR units to bid into the capacity market or to adjust its capacity procurement targets to account for the expected performance of RMR units, PJM forces consumers to pay again to procure the same capacity services that the RMR units already provide. This approach is unjust and unreasonable.

Notably, other regions already have rules—which the Commission has repeatedly approved—that better protect consumers against inflated capacity prices associated with RMR arrangements. Both the New York Independent System Operator ("NYISO") and ISO New England ("ISO-NE") have Commission-approved rules in place that require RMR units to participate in their capacity markets to avoid forcing consumers "to pay twice for the same capacity need"—precisely the outcome that has occurred in PJM.[3] This Complaint asks the Commission to bring PJM's practices into alignment with existing practices in other markets that the Commission has already found are just and reasonable because they protect consumers from unreasonable and excessive costs.

The costs for consumers from PJM's unjust and unreasonable rules are extreme. As detailed below, PJM's most recent capacity auction resulted in record-high prices, and the failure to account for RMR units' resource adequacy contributions caused excessive costs for consumers. As detailed below, Monitoring Analytics, the Independent Market Monitor ("IMM") for PJM, calculates that these excessive costs amount to $4.2 billion.[4] Similarly, an independent

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[3] *See ISO-New England, Inc.*, 165 FERC ¶ 61,202 at P 83 (2018).
[4] Monitoring Analytics, Analysis of the 2025/2026 RPM Base Residual Auction Part A, at 2 (Sept. 20, 2024) ("IMM Analysis of 2025/2026 Auction"),

report from Synapse Energy Economics ("Synapse") prepared for the Maryland Office of the People's Counsel finds that these excessive costs amount to $5 billion.[5] As a result, electricity bills for consumers will rise throughout the PJM region—with the most extreme price increases falling on the shoulders of consumers who already bear some of the highest energy burdens in the nation. Under PJM's current rules, consumers in the Baltimore Gas & Electric ("BGE") Locational Delivery Area ("LDA") must pay not only the lion's share of hundreds of millions of dollars annually to keep multiple RMR units operating, but also the highest prices for capacity that are possible in PJM's capacity market. From just the most recent auction, these ratepayers' monthly bills will likely increase by nineteen percent, costing the average household an extra twenty-one dollars per month. This cost increase is especially harmful because the BGE LDA includes disadvantaged communities who already face some of the highest energy burdens in the country, according to the Department of Energy ("DOE").

Unless the Commission acts to protect consumers, energy burdens from PJM's unjust and unreasonable rules will likely continue to skyrocket under PJM's rapid-fire schedule for upcoming capacity auctions. PJM's next Base Residual Auctions ("BRA") will take place in December 2024, June 2025, and December 2025—with a mere six months between each auction. Although PJM maintains that high capacity prices send a signal for investment in new generation, PJM's rapid schedule leaves insufficient time for new generation to come online—especially because PJM's interconnection queue remains badly backlogged and because PJM is resisting accelerating its interconnection process to come up to the pace that the Commission

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https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_A_20240920.pdf. The IMM's analysis document is included as Attachment 1 to this complaint.

[5] Md. Office of People's Counsel, Bill and Rate Impacts of PJM's 2025/2026 Capacity Market Results & Reliability Must-Run Units in Maryland, at 8 (Aug. 2024) ("Synapse Report"), https://opc.maryland.gov/Portals/0/Files/Publications/RMR%20Bill%20and%20Rates%20Impact%20Report_2024-08-14%20Final.pdf?ver=V9hZfyTmjLeNVt2Dg3cTgw%3d%3d. The Synapse Report document is included as Attachment 2 to this complaint.

required in its recent Order No. 2023. The fast pace of PJM's capacity auctions and the slow pace of its interconnection queue mean that new generation is highly unlikely to be able to come online quickly enough to prevent price spikes like the one caused by PJM's most recent auction. In other words, unless the Commission acts, PJM's upcoming auctions are likely to each create another $4.2 billion to $5 billion in excessive costs for consumers.

Failing to account for resource adequacy provided by RMR units produces capacity market price signals that are disconnected from the actual supply and demand balance on the grid. As explained in the attached testimony of economist James F. Wilson,[6] this distorted supply-demand balance is economically inefficient because it signals a degree of scarcity that does not exist. The result is artificially elevated prices that harm the markets by encouraging inefficient decisions by both supply and demand side market participants.

Importantly, the relief requested in this Complaint would not undermine the capacity market's ability to send accurate signals for necessary investment in new capacity resources, or retention of existing resources. PIOs recognize that when the inputs to the capacity market are well-designed, capacity prices can signal the need for new generation to ensure resource adequacy. However, when high capacity prices are inflated by ignoring generation that consumers are already paying to stay online and that an RTO is authorized to call to perform during capacity emergencies, those prices are not reflecting a true resource adequacy need and are excessive and unreasonable. As detailed below, if PJM's capacity market had accounted for the resource adequacy contributions of RMR resources in the most recent capacity auction, as PIOs maintain is necessary, the resulting prices would have been more accurate and substantially lower—but would still have been among the highest capacity prices PJM has seen in a decade. In

[6] *See generally* Affidavit of James F. Wilson, included as Attachment 3 to this complaint ("Wilson Aff.").

short, properly accounting for RMR units will not dull the capacity market's ability to send appropriate signals for new investment, but will instead send more accurate price signals that investors can depend upon.

II. BACKGROUND

A. RMRs require consumers to pay retiring resources to stay online to maintain reliability until transmission solutions are complete.

When a generation owner chooses to deactivate an asset, PJM studies how that deactivation will affect the stability of the transmission system.[7] If PJM concludes that the deactivation will result in violations of reliability criteria established by the North American Electric Reliability Corporation ("NERC"), then PJM works with the affected transmission system owners to plan upgrades that will alleviate the reliability impacts.[8] If these upgrades will not be in place by the retiring resource's planned deactivation date and operational measures are not available to avoid the NERC criteria violations, then PJM will seek to retain the generator under Part V of the Open Access Transmission Tariff, in what is commonly known as an RMR arrangement.[9] PJM's legal framework for these arrangements was approved by the Commission nearly 20 years ago.[10]

A recent analysis presented by PJM planning staff indicates that historically half of all generator deactivations have triggered reliability concerns.[11] Of these, about sixty percent provided sufficient advanced notice for mitigation upgrades (i.e., transmission solutions) to be

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[7] PJM Open Access Transmission Tariff ("OATT") at Title V § 113.2, available at https://agreements.pjm.com/oatt/4240 (last visited Sept. 24, 2024).
[8] Perry Ng, Generation Deactivation Education, PJM, at slide 10 (Oct. 12, 2023), https://www.pjm.com/-/media/committees-groups/task-forces/destf/2023/20231012/20231012-item-07---generation-deactivation-education.ashx.
[9] *Id.* at slide 13.
[10] *PJM Interconnection, LLC*, 110 FERC ¶ 61,053 (2005).
[11] Perry Ng, 2023 DESTF Additional Education Historical Statistics related to Deactivation, PJM (Nov. 9, 2023), https://www.pjm.com/-/media/committees-groups/task-forces/destf/2023/20231109/20231109-item-04---historical-stats-deactivation.ashx.

constructed by the deactivation date, while in about a third of cases, interim operational measures were available to avoid an RMR. Five percent of unit deactivations (by number) resulted in an RMR.

These RMR arrangements authorize PJM to dispatch the RMR units under various circumstances as needed to support reliability.[12] Once the transmission solution is complete, the RMR is no longer needed and can be terminated, and the generator may deactivate. For much of the current RPM delivery year, the PJM region has one unit operating under an RMR arrangement—NRG's 410 megawatt ("MW") Indian River 4 coal unit in Delaware. Beginning with the 2025/2026 delivery year, RMR arrangements at the Brandon Shores and HA Wagner plants in Maryland will go into effect.

Unlike many RTO/ISOs, PJM cannot require a retiring resource to enter into an RMR arrangement; instead, in PJM, RMR arrangements are purely voluntary.[13] If a generator chooses to continue operating under an RMR arrangement, it may either opt into a default rate known as the Deactivation Avoidable Cost Credit formula rate provided for in Part V, Sections 114–116 of the PJM Open Access Transmission Tariff ("OATT"), or the generator may instead file with the Commission a unit-specific cost-of-service recovery rate under Section 119 of the PJM OATT.

The costs of RMR arrangements vary widely but can be substantial. In PJM, consumers have paid around $595 million for RMRs in the last twelve years.[14] Recently filed RMRs at

[12] For example, PJM may dispatch these resources for a broad range of reliability, but not economic, purposes, including "Thermal, Reactive, Stability, Capacity Shortages, [and] System Restoration." *See* Vince Stefanowicz, RMR Unit Scheduling in Operations, PJM, at slide 2 (Nov. 9, 2023) ("RMR Unit Scheduling in Operations"), https://www.pjm.com/-/media/committees-groups/task-forces/destf/2023/20231109/20231109-item-08---rmr-unit-scheduling-in-operations.ashx. For additional detail, *see infra* § III(A)(1).

[13] Asya Staevska and Pauline Foley, RTO/ISO Deactivation Processes, PJM, at slide 7 (Jan. 18, 2023), https://www.pjm.com/-/media/committees-groups/task-forces/destf/2024/20240118/20240118-item-04---rto-iso-deactivation-processes.ashx, (noting that PJM's purely voluntary approach contrasts with that of other RTOs).

[14] *See* Monitoring Analytics, RMR History, at slide 4 (Feb. 15, 2024) ("RMR History Slides"), https://www.pjm.com/-/media/committees-groups/task-forces/destf/2024/20240215/20240215-item-03---rmr-

Talen Energy Corporation's Brandon Shores and Wagner fossil units in Maryland seek to recover from consumers as much as $830 million for three-and-a-half years of service, just in fixed costs.[15] These costs may be higher if the transmission owners are unable to complete the solutions by the end of 2028—the current planned in-service date.[16] Notably, consumers in the BGE LDA will bear the vast majority of these RMR costs[17]—the same consumers who will pay record high prices of $466.35/MW-day for capacity during the first year of the Brandon Shores and Wagner RMR based on an apparent shortage of capacity resources in the LDA.[18]

B. PJM allows RMR units to choose whether to participate in the capacity market.

Under PJM's rules, a resource that plans to deactivate may obtain an exception to PJM's requirement that generation resources (other than "intermittent" and energy storage resources) must offer into the Reliability Pricing Model ("RPM"), otherwise known as the capacity

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history.ashx (listing "actual" costs identified by the IMM for various RMR arrangements, which total to $595 million).

[15] *See, e.g.*, Brandon Shores LLC, RMR Arrangement – Continuing Operations Rate Schedule, Docket No. ER24-1790 (Apr. 18, 2024), Accession No. 20240418-5176 (seeking fixed costs and project investment for continuing operations that amount to nearly $650 million); H.A. Wagner LLC, RMR Arrangement – Continuing Operations Rate Schedule, Docket No. ER24-1787 (Apr. 18, 2024), Accession No. 20240418-5128 (seeking over $200 million in fixed costs and project investment for continuing operations that amount to over $200 million). This cost estimate reflects the initial filings by Brandon Shores LLC and H.A. Wagner LLC, and may be reduced following litigation. *See also* Protest and Comments of the Maryland Office of People's Counsel and the Southern Maryland Electric Cooperative, at 7 Tbl. 1, Docket Nos. ER24-1787 & ER24-1790 (May 16, 2024), Accession No. 20240516-5193 (listing annual and cumulative costs for the Brandon Shores and Wagner RMRs, including a cumulative $628.6 million for the Brandon Shores RMR and a cumulative $201.7 million for the Wagner RMR, for a cumulative total of $830.4 million).

[16] Synapse Report, *supra* note 5 at 9 (noting that "the projected completion date of December 2028 for these transmission solutions is highly uncertain; there could be delays in the project construction and execution, further imposing RMR costs on electric customers").

[17] OATT at Part V § 120 (cost allocation for RMR follows cost of transmission solution); *see also* Synapse Report, *supra* note 5, at 8–9 (noting that "BGE customers can expect to pay an estimated 74 percent" of the cost of RMR units in that LDA).

[18] PJM, 2025/2026 Base Residual Auction Report (July 30, 2024) ("PJM 2025/2026 Base Residual Auction Report"), https://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-report.ashx; *see also* Synapse Report, *supra* note 5 at 6 (noting that the most recent auction had a "total annual cost to electric customers of $14.7 billion, a substantial increase from the $2.2 billion in capacity costs in the 2024/2025 delivery year").

market.[19] If a generator opts to accept an RMR arrangement, it then has a choice whether or not to offer the retained resource into the capacity market.[20]

Because PJM does not publish data regarding which resources have offered into the capacity market, or received capacity obligations, there is no comprehensive, publicly available information about how often RMR resources choose not to offer into the auction. However, PJM has recently observed that "RMR units typically do not participate in capacity auctions,"[21] and as discussed below, it is evident that Talen chose not to offer Brandon Shores and Wagner into the Base Residual Auction during the first year of their anticipated RMR arrangement (2025/2026), which contributed to the historically high prices in that auction.[22] Nevertheless, there are instances in which RMR resources have made commitments to offer into RPM. In 2012, FirstEnergy sought to deactivate seven units it operated in Ohio, Pennsylvania, and Maryland totaling 2,689 MWs.[23] Pursuant to Part V, Section 114, FirstEnergy sought agreement with the PJM IMM on the appropriate levels for each component of the Deactivation Avoidable Cost Rate for each unit. In the resulting agreement, filed with the Commission as part of FirstEnergy's

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[19] OATT, Tariff, Attach. DD § 6.6(g) (providing that a resource qualifies for an exception to the capacity market must-offer requirement if it has a "documented plan in place to retire the resource prior to or during the delivery year, and has submitted a notice of Deactivation regardless of whether PJM has asked the unit to continue to operate beyond its requested deactivation date").

[20] *See* David Mroz and Tim Bachus, Treatment of Deactivations in RPM, PJM, at slide 2 (Nov. 9, 2023), https://www.pjm.com/-/media/committees-groups/task-forces/destf/2023/20231109/20231109-item-06---treatment-of-resources-in-rpm.ashx ("Reliability Must Run (RMR) arrangement would stipulate whether unit is subject to must-offer"); Monitoring Analytics, Part V (RMR) CETO Impacts, at slide 2 (Aug. 19, 2024), https://www.pjm.com/-/media/committees-groups/task-forces/destf/2024/20240819/20240819-item-05---rmr-ceto-impacts.ashx (describing RMR capacity market offer options as "[o]ffer[ing] as [a] price taker" or "[d]o not offer").

[21] PJM, PJM Response to the 2023 State of the Market Report, at 4 (Aug. 2024) ("PJM Response to the 2023 State of the Market Report"), https://www.pjm.com/-/media/library/reports-notices/state-of-the-market/20240822-pjm-response-to-the-2023-state-of-the-market-report.ashx.

[22] Synapse Report, *supra* note 5 at 24 (describing the price impact of the RMR units' non-participation in the 2025/2026 capacity auction).

[23] *See, e.g.*, FirstEnergy Serv. Co., Informational Filing regarding Deactivation Avoidable Cost (DAC) Rate under Section 116 of the PJM Interconnection, L.L.C.'s Open Access Transmission Tariff, at Attach. 1 (Deactivation Notice), Docket No. ER12-2710 (Jul. 10, 2012), Accession No. 20120710-5165.

informational filing, FirstEnergy committed to offer the capacity of any unit that did not already have a capacity obligation into the incremental auction "at a price of zero dollars."[24]

PJM has also established rules for RMR resources that do offer into capacity auctions. For instance, such resources must abide by the requirements of capacity resources with respect to offers into the day-ahead and real-time energy markets.[25] Similarly, PJM has noted that when an RMR unit undertakes a capacity commitment, "all obligations of a capacity resource apply."[26]

PJM's rules include an important inconsistency in how they account for RMR units' continued operation. Although PJM does not require RMR units to offer into the capacity auction, it does include these units when modeling the PJM system for purposes of determining the amount of capacity that can be transferred into constrained LDAs under peak load emergency conditions, and how much capacity is available within each LDA. As the IMM has explained, "[t]his approach is internally inconsistent" and could be resolved by either including RMR units as supply or by excluding these resources from the analysis of how much capacity can be imported into an LDA.[27] Relevant here, PJM has explained that it includes the RMR unit in these calculations because the "RMR unit is expected to produce MWs under emergency conditions,"[28] and because "the RMR units [are] expected to be operating and impacting power flows on the system during times of reliability need."[29] PJM has further concluded that

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[24] *See, e.g., id.* at Attach. 4 (IMM Agreement dated Apr. 10, 2012) ("To the extent that a Generating Unit does not already have a capacity commitment, FE Genco will offer such Generating Unit's capacity into every Reliability Pricing Model Incremental Auction at a price of zero dollars.").
[25] Keyur Patel, Treatment of Reliability Must Run (RMR) Arrangement Resource in Day-ahead and Real-time Energy Market, PJM (Nov. 9, 2023), https://www.pjm.com/-/media/committees-groups/task-forces/destf/2023/20231109/20231109-item-07---treatment-of-rmr-resources-in-da-and-rt-market.ashx.
[26] *Id.* at slide 2.
[27] IMM Analysis of 2025/2026 Auction, *supra* note 4 at 6.
[28] Patricio Rocha-Garrido and Michael Herman, PJM CETO/CETL & Load Deliverability, at slide 16 (Aug. 19, 2024) ("PJM CETO/CETL & Load Deliverability"), https://www.pjm.com/-/media/committees-groups/task-forces/destf/2024/20240819/20240819-item-04---ceto-cetl-and-load-deliverability-test.ashx.
[29] PJM Response to the 2023 State of the Market Report, *supra* note 21 at 4.

"[e]xcluding these units from the analysis could result in an incomplete and potentially inaccurate assessment of local reliability needs," and lead to "distorted price signals that would incent generation where transmission upgrades could have replaced that need."[30] PJM has not addressed the inconsistency between considering RMR units as available for purposes of modeling capacity import limits because it expects these units to generate energy during capacity emergencies, but failing to account for these units in capacity auctions.

C. Several RTO/ISOs require units operating under RMRs to participate in their capacity markets or similar resource adequacy constructs.

PJM's approach of allowing RMR units to decide whether to participate in its capacity market is an outlier among RTO/ISOs. The Commission has repeatedly approved mechanisms in other RTO/ISOs that ensure that markets account for the fact that RMRs require consumers to pay otherwise retiring units to continue to be available to maintain reliability. The Commission has consistently found that it is critical for markets to avoid "requiring ratepayers to pay twice to satisfy the same capacity need."[31]

1. NYISO

The New York Independent System Operator ("NYISO") requires RMR units to participate in its capacity market as price-takers by submitting bids of $0.00.[32] In 2015, the Commission determined under section 206 of the FPA that NYISO's tariff was unjust and unreasonable because it did not "contain provisions governing the retention of and compensation to generating units needed for reliability," i.e. RMR units.[33] Consequently, NYISO developed

[30] *Id.*
[31] *New York Indep. Sys. Operator, Inc.* ("*NYISO II*"), 161 FERC ¶ 61,189 at P 55 (2017); *see also New York Indep. Sys. Operator, Inc.* ("*NYISO I*"), 155 FERC ¶ 61,076 at PP 82–83 (2016); *ISO New England, Inc.*, 165 FERC ¶ 61,202 at PP 82–83.
[32] *NYISO II*, 161 FERC ¶ 61,189 at PP 55, 62.
[33] *NYISO I*, 155 FERC ¶ 61,076 at PP 1–2.

tariff revisions that included a requirement for "RMR generators to offer all of their unforced capacity (UCAP) into an installed capacity (ICAP) spot market auction," unless an RMR unit had a pre-existing bilateral agreement excusing it from this requirement.[34]

Although NYISO initially proposed exceptions to the requirement for RMR units to be "price-takers,"[35] the Commission "reject[ed] NYISO's proposal to impose a capacity offer price on RMR generators higher than $0.00/kW-month as unjust and unreasonable."[36] The Commission reasoned that if RMR units have bids higher than $0.00 and fail to clear the capacity auction, the result would be that "another generator that otherwise would not have cleared will clear instead," which would mean that "ratepayers will pay twice—once for the cost of the RMR agreement, and again for the generator that otherwise would not have cleared the market."[37] The Commission thus found that "[i]t is more efficient for RMR generators to offer their UCAP at $0.00/kW-month as 'price-takers.'"[38] The Commission also found that this price-taking approach was consistent with its precedent regarding another "form of RMR agreement" in NYISO, and "continue[d] to believe" that any market rule that resulted in a non-zero bid "would allow for inefficient outcomes and is thus unreasonable."[39] The Commission sustained this decision on rehearing.[40]

[34] *Id.* at P 74.
[35] *Id.*
[36] *Id.* at P 82.
[37] *Id.*
[38] *Id.*
[39] *Id.*
[40] *NYISO II*, 161 FERC ¶ 61,189 at PP 54–63. Although NYISO argued that non-zero bids would be appropriate for RMR units needed for resource adequacy as opposed to local transmission security, the Commission found that there was no record basis to "discern under what circumstances NYISO would need an RMR for resource adequacy, and thus, under NYISO's proposal, would need to be subject to an offer floor." *Id.* at P 62.

2. *ISO-NE*

ISO-NE developed requirements for resources retained for "fuel security" purposes to participate in its Forward Capacity Market ("FCM") as price-takers by submitting bids of $0.00.[41] Under this approach, so-called "fuel security resources" entered into a type of RMR arrangement that is an out-of-market agreement to retain resources that would otherwise retire in order to maintain reliability. As in NYISO, this requirement resulted from a process that the Commission instituted under section 206 of the FPA based on a preliminary finding that ISO New England, Inc.'s ("ISO-NE") tariff may be unjust and unreasonable because it lacked provisions providing for "a short-term, cost-of-service agreement to address demonstrated fuel security concerns."[42] The Commission thus directed ISO-NE to develop generally applicable tariff terms that would, among other reforms, explain "how such resources would be treated in the [capacity market]."[43] In response, ISO-NE proposed tariff revisions that "allow for the retention of a resource for fuel-security reasons" and address how such resources must participate in the capacity market.[44]

ISO-NE proposed that fuel security resources would be required to participate in its capacity market "as price-takers," meaning that these resources would be bid into auctions "at a price of zero to ensure that the resource clears the auction."[45] ISO-NE explained that this price-taker treatment avoids "unreasonably suppressing capacity prices" or "inflated [capacity auction] prices."[46] ISO-NE did not propose alternative approaches such as allowing non-zero bids or allowing fuel security resources to decline participation in the capacity market because those

[41] *ISO New England, Inc.*, 165 FERC ¶ 61,202 at PP 57, 82.
[42] *Id.* at PP 3–4.
[43] *Id.* at P 58.
[44] *Id.* at P 5.
[45] *Id.* at P 57.
[46] *Id.*

"alternatives would result in the [capacity auction] not accounting for a retained resource's contribution to resource adequacy" and thus procuring "excess resources."[47] Similarly, ISO-NE reasoned that "not accounting for the capacity value of a resource retained for fuel security" would cause its capacity auction to "clear at a price that does not reflect the true marginal reliability impact of procured capacity."[48] ISO-NE's price-taker treatment of retained resources aimed to avoid that "costly and inefficient outcome."[49]

Numerous commenters supported ISO-NE's proposal to require retained resources to participate in the capacity market as price-takers, including the New England States Committee on Electricity ("NESCOE"), the American Public Power Association, certain public interest organizations, and Potomac Economics, which is ISO-NE's external market monitor.[50] Potomac Economics explained that "the price-taker proposal will result in efficient capacity prices" and thus was "the most efficient solution."[51]

ISO-NE defended its proposal to treat retained resources as price-takers against a charge that this approach would "suppress capacity prices" by explaining that "once a resource is retained for fuel security, it is appropriate to consider its contributions to resource adequacy when determining capacity awards and prices since the retained resources will continue to contribute to resource adequacy."[52] In contrast, ignoring or discounting retained resources' contributions to resource adequacy would lead to capacity prices "based on an inflated estimate of capacity's incremental contributions to resource adequacy," which "would lead the region to

[47] *Id.* at P 58.
[48] *Id.*
[49] *Id.*
[50] *Id.* at PP 60–63.
[51] *Id.* at P 63.
[52] *Id.* at P 78.

procure more capacity than specified by its demand curves, resulting in an expensive and inefficient outcome for the region."[53]

The Commission accepted ISO-NE's proposal to require fuel security resources to participate in the capacity market as price-takers.[54] The Commission specifically "agree[d] that the year-round resource adequacy contributions of resources retained for fuel security should be counted in the capacity market and therefore f[ound] that such resources should be entered into the [capacity auction] as price-takers to ensure that they clear."[55] The Commission also found that ISO-NE's price-taking approach to fuel security units is consistent with Commission precedent in the *NYISO* decisions discussed above.[56]

In approving ISO-NE's price-taker approach, the Commission emphasized the need to prevent unreasonable price increases for consumers by reiterating the point several times. For example, the Commission reinforced the consistency between ISO-NE and NYISO by noting that "using a non-zero price may result in a reliability must-run resource not clearing the market and allowing a resource to clear that would not have otherwise cleared," which the Commission noted would be "inefficient and unreasonable because it would require ratepayers to pay twice for the same capacity need and would result in over-procuring capacity."[57] Similarly, the Commission rejected the argument that a purported "distinction between resources retained for reliability and resources retained for fuel security" could justify a non-zero price, reiterating that "[i]f resources needed for fuel security are not entered into the [capacity auction] as price-takers, they risk not clearing in the [capacity auction] and their resource adequacy contributions to the

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[53] *Id.*.
[54] *Id.* at P 82.
[55] *Id.*
[56] *Id.* at PP 83–84.
[57] *Id.* at P 83 (citing *NYISO I*, 155 FERC ¶ 61,076 at P 82 and *NYISO II*, 161 FERC ¶ 61,189 at P 55).

system would not be counted."[58] The Commission again explained that "such an outcome would result in a higher clearing price and a higher procurement quantity, which would create an inefficient and unreasonable market outcome."[59] The Commission also noted its agreement with Potomac Economics that "as long as resources are retained for fuel security purposes, including such resources in the [capacity auction] as price takers prevents an artificial and inefficient increase in [capacity auction] prices."[60]

Further, the Commission specifically approved ISO-NE's rejection of alternative approaches that would allow non-zero bids under certain circumstances. In doing so, the Commission reiterated that "retaining a resource outside of the [capacity auction] would not account for its contribution to meeting ISO-NE's resource adequacy needs, would result in procuring excess capacity, and would distort the capacity price."[61] The Commission similarly approved ISO-NE's rejection of an alternative of allowing non-zero bids set through the independent market monitor's mitigation, finding that this approach could only account for retained resources' contributions to resource adequacy if "that resource's IMM-mitigated bid clears the [capacity auction.]"[62] The Commission recognized "that it is not possible to avoid an impact on either the pricing in the [capacity auction] or the quantity of resources procured to satisfy resource adequacy when finding that a resource must be retained for fuel security," and emphasized that ISO-NE acted reasonably by "protect[ing] against inefficiently over-procuring capacity resources by reflecting a fuel security resource's contribution to resource adequacy in the [capacity auction]."[63]

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[58] *Id.* at P 85.
[59] *Id.*
[60] *Id.*
[61] *Id.* at P 87.
[62] *Id.*
[63] *Id.*

The Commission also found that "the price taker design accurately reflects a fuel security resource's low going-forward costs."[64] The Commission emphasized prior precedent noting that "in calculating the going forward costs of these reliability resources, it is reasonable to deduct their reliability must run revenues, because the revenues do not overstate the value provided by the resources to customers."[65] Because RMR arrangements "provide the revenue that these resources need to remain available and reduce their going-forward costs to *de minimis* or zero," the Commission found that "it is just and reasonable for ISO-NE to enter fuel security resources as price takers in the [capacity auction.]"[66]

Although ISO-NE only sought temporary authorization to retain resources for fuel security, which has since lapsed, ISO-NE recently confirmed that it continues to view price taker treatment for retained resources as the correct approach. In a stakeholder presentation in September 2024, ISO-NE described potential reforms it may propose for its capacity market, such as development of a seasonal auction.[67] In that presentation, ISO-NE explained that "[r]esources retained for local transmission security are treated as price takers in the capacity market" and that the "ISO finds that this treatment continues to be appropriate and efficient."[68]

3. CAISO

While the California Independent System Operator ("CAISO") does not administer a capacity market like those in NYISO, ISO-NE, or PJM, CAISO does require RMR units to participate in its markets and "align[s] RMR obligations with those of resource adequacy

[64] *Id.* at P 88.
[65] *Id.* (cleaned up).
[66] *Id.*
[67] Chris Geissler, Capacity Auction Reforms: Continued Discussion of Project Scope, ISO-NE (Sept. 10, 2024), https://www.iso-ne.com/static-assets/documents/100015/a03a_mc_2024_09-10_capacity_auction_reforms_iso_presentation.pdf.
[68] *Id.* at slide 20.

resources . . . to help support grid reliability and resilience."[69] CAISO also applies its Resource Adequacy Availability Incentive Mechanism ("RAAIM") to RMR resources,[70] which aims to treat RMR units "just like [resource adequacy] . . . resources."[71] CAISO's RAAIM provides bonus payments for units with availability exceeding a certain threshold and imposes penalties on units with availability below a minimum threshold; the purpose of the RAAIM is to ensure that "resources are available for CAISO to meet [] reliability needs,"[72] which is similar to PJM's Capacity Performance system or ISO-NE's Pay for Performance system.

CAISO explained in its proposal to require RMR units to participate in its markets that this requirement "will help ensure that ratepayers get the full benefit of paying the full cost of service of an RMR resource, while guarding against depressing market prices."[73] CAISO also explained that "less than full participation of RMR resources in the markets could lead to unnecessary over-procurement and deprive ratepayers of receiving the full value of the RMR resources for which they are paying."[74] The Commission agreed, concluding that "the benefits of the must offer obligation discussed above outweigh the potential price impacts."[75]

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[69] *California Independent Sys. Operator Corp.* ("*CAISO*"), 168 FERC ¶ 61,199 at P 72 (2019).
[70] *Id.*
[71] CAISO, Tariff Amendment to Improve the Reliability Must-Run Framework, at 6, Docket No. ER19-1641 (Apr. 23, 2019), Accession No. 20190423-5000.
[72] *See* California Public Utilities Commission, Resource Adequacy Availability Incentive Mechanism, at slides 3–4 (May 15, 2024), https://stakeholdercenter.caiso.com/InitiativeDocuments/CPUC-Resource-Adequacy-Availability-Incentive-Mechanism-May-15-2024.pdf.
[73] *CAISO*, 168 FERC ¶ 61,199 at P 62.
[74] *Id.* at P 68.
[75] *Id.* at P 73. While CAISO's bidding requirement is distinct from NYISO and ISO-NE in that CAISO requires RMR units to bid into its markets at levels that reflect "the resource's full marginal costs," CAISO explained that this approach was necessary because it "cannot predict with certainty the specific hours every day when a resource will be needed." *Id.* at P 62. The Commission agreed, finding that "CAISO must ensure that RMR resources will be available to meet reliability needs whenever they arise through the market optimization." *Id.* at P 72. In other words, CAISO requires marginal cost-based bidding because it relies on clearing in the energy market to determine real-time performance obligations, which is distinct from the capacity markets in other RTO/ISOs, in which an obligation to actually perform is triggered by an RTO/ISO's dispatch instructions during a capacity event.

D. The non-participation of RMR units in PJM's capacity market reduces overall supply and increases prices for consumers.

PJM's approach of allowing RMR units to choose whether to participate in the capacity market effectively reduces the overall supply in capacity auctions—even while consumers are paying RMR units to remain operational and when RMR arrangements enable PJM to call on an RMR unit to perform during a capacity event. As documented in a recent report from Synapse Energy Economics, PJM entered into 17 RMR arrangements since 2005 (not counting the recent RMR arrangements with Brandon Shores and Wagner), and "nearly all, if not *all*, of the past 17 RMRs have not participated in PJM's capacity market."[76] Similarly, "[n]either Brandon Shores nor Wagner participated in the most recent 2025/2026 capacity market auction and are not expected to participate in future auctions."[77] Hence, units' entry into RMR arrangements in PJM has historically reduced the available supply in its capacity auctions and will likely continue to do so moving forward. The fact that RMR arrangements reduce capacity supply in PJM distinguishes PJM from other RTO/ISOs such as NYISO and ISO-NE, where, as discussed above, RMR units are required to bid into the capacity market as price-takers.

Although numerous factors contribute to the clearing price in PJM's capacity auctions, the fact that RMR arrangements effectively reduce supply puts upward pressure on prices. All else being equal, any reduction in supply in the capacity market will increase prices.[78] Indeed, PJM indicated that the reduction in supply associated with retiring resources was a key driver of increased prices in its most recent capacity auction.[79]

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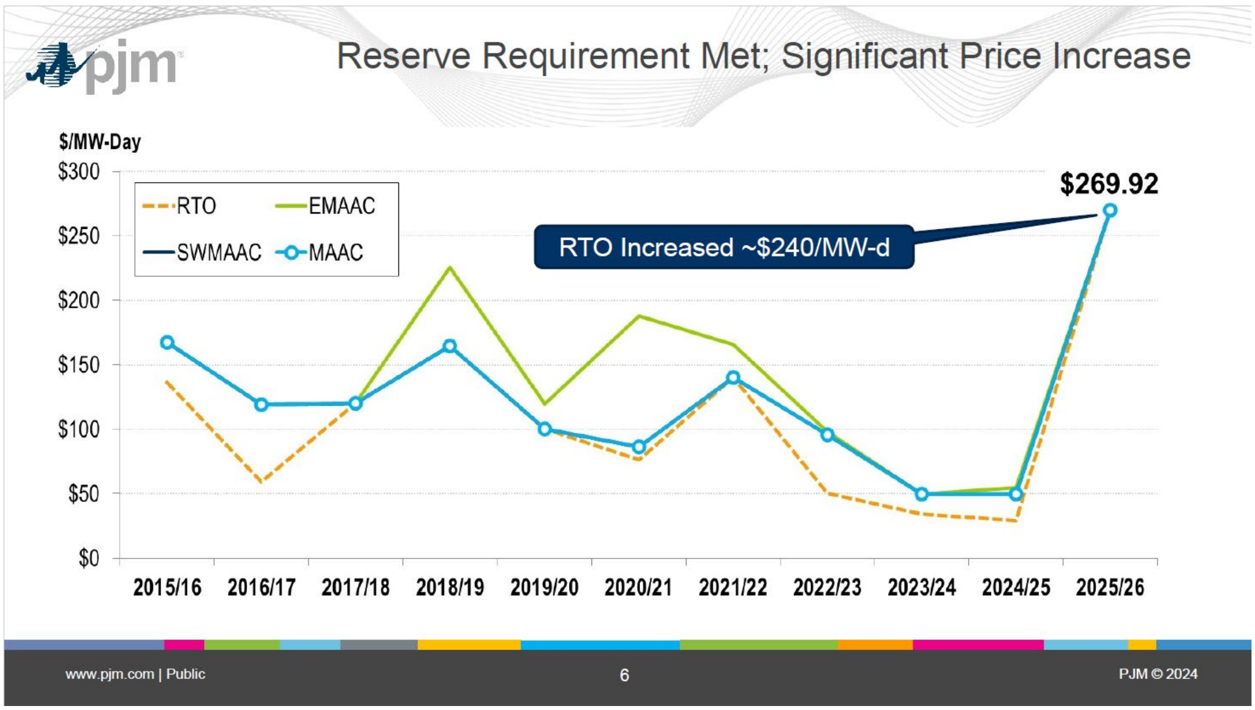
[76] Synapse Report, *supra* note 5 at 15.
[77] *Id.*
[78] *See*, *e.g.*, Synapse Report, *supra* note 5 at 15 ("For an LDA that is already constrained, such as the BGE LDA—and without additional transmission upgrades or new generation to address constraints—if a unit no longer provides supply in the capacity market, clearing prices are pushed upwards.").
[79] PJM, 2025/2026 Base Residual Auction Report, *supra* note 18 at 3 (describing "[s]ignificant decrease in overall supply from retirements (actual retirements plus must offer exceptions for future retirements)" as an important factor driving high prices in the 2025/26 BRA).

E. The non-participation of RMR units in the most recent capacity auction in PJM had a significant effect on prices.

PJM's most recent capacity auction for the 2025/2026 delivery year yielded "a more than 800 percent increase in system-wide prices relative to the prior [auction] for the 2024/2025 delivery year, a price spike unprecedented in PJM."[80] The following chart compares this "significant price increase" to results from PJM's capacity auctions over the prior decade:[81]



Capacity prices in PJM were especially high in constrained LDAs, which are areas with limited capacity and where transmission constraints limit the amount of energy that can be imported during capacity events.[82] In the 2025/2026 auction, both the BGE LDA and the Dominion

[80] Synapse Report, *supra* note 5 at 6.
[81] PJM, 2025/2026 Base Residual Auction Results, at slides 4–5 (Aug. 21, 2024), https://pjm.com/-/media/committees-groups/committees/mrc/2024/20240821/20240821-item-08---2025-2026-base-residual-auction---presentation.ashx.
[82] *See* PJM, Manual 18: PJM Capacity Market, at 24 (June 27, 2024),https://www.pjm.com/~/media/documents/manuals/m18.ashx (noting that "[a]n LDA with Capacity Emergency Transfer Limit (CETL) less than 1.15 times Capacity Emergency Transfer Objective (CETO) will be modeled as a constrained LDA in RPM" and that other factors, such as "other reliability concerns" may lead PJM to model an LDA as constrained).

("DOM") LDA "cleared short of their reliability requirements due to load growth and retirements" and "[p]rices in these LDAs are at the price caps" of $466.35 and $444.26, respectively.[83] For the BGE LDA, "[t]his is a six-fold increase from the 2024/2025 BGE LDA [auction] clearing price of $73/MW-day."[84]

The non-participation of RMR units in PJM's most recent auction contributed significantly to the dramatic increase in capacity prices. As the Synapse Report describes, "[t]he most notable driver behind BGE LDA's record high capacity price is the removal of four generating units from the capacity market, starting in the 2025/2026 delivery year," namely Brandon Shores units 1 and 2, and Wagner units 3 and 4.[85] These units, which are located in the BGE LDA, are subject to RMR arrangements that allow PJM to call on them to perform during a capacity emergency—but which allow the units to choose whether to participate in the capacity market.[86] "Importantly, these RMR units d[id] not participate in the capacity market as supply-side resources, dramatically reducing supply in the already-constrained BGE LDA."[87]

To determine the impact of these RMR units' non-participation in the capacity market, Synapse conducted a "counterfactual analysis of clearing prices in PJM" based on a trio of conservative assumptions about suppliers' bidding behavior. First, Synapse assumed that if these units were to participate in the auction, their bids would be at levels no higher than roughly double the clearing price of prior auctions; because most of these units cleared in prior auctions

[83] Tim Horger & Adam Keech, 2025/2026 Base Residual Auction Results, at slide 4, PJM (Aug. 21, 2024), https://pjm.com/-/media/committees-groups/committees/mrc/2024/20240821/20240821-item-08---2025-2026-base-residual-auction---presentation.ashx.
[84] Synapse Report, *supra* note 5 at 7.
[85] *Id*.
[86] *See infra* § III(B)(1) at Tbl. 1 (citing RMR provisions specifying that PJM may dispatch these units during capacity emergencies).
[87] Synapse Report, *supra* note 5 at 8. Outside the scope of this proceeding, Sierra Club has engaged in related advocacy regarding the RMR units in the BGE LDA, as described in the declaration of Justin Vickers, which is included as Attachment 4 to this complaint.

that had a clearing price of \$73/MW-day, Synapse assumed that their bids would have been "at or below \$163.46/MW-day."[88] Second, Synapse assumed that these RMR units were likely "marginal resources or were towards the top of the stack of cleared resources," which again is conservative in light of clearing prices from prior auctions.[89] Finally, Synapse assumed that "with the exception of the Dominion LDA . . . other LDAs would not have separated from the RTO and caused other cascading price impacts," which is conservative because other LDAs did not, in fact, separate even in the more constrained situation in which these RMR units did not participate as supply.[90]

Synapse found that the non-participation of RMR units not only raised "the clearing price for the BGE LDA to the capacity price maximum" but "also likely had spillover effects into the RTO as a whole, increasing the RTO-wide clearing price and impacting customers throughout the region."[91] Synapse specifically found that these RMR units reflect a majority of the capacity in the BGE LDA, and without their participation as supply, the result is that the LDA's clearing price is forced to its cap.[92] However, if these RMR units had participated in the capacity auction, the BGE LDA would not have reached its price cap and instead would have cleared at a significantly lower price along with the rest of the RTO.[93]

The price impact that Synapse identified is significant. Synapse found that if these RMR units had participated under its conservative assumptions, the BGE LDA and the entire RTO would have cleared at a price of \$163.46/MW-day. Notably, while that clearing price would have been significantly lower than the actual clearing price of \$269.92/MW-day, a clearing price of

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[88] Synapse Report, *supra* note 5, at 27; *see also id.* at 27, n.58.
[89] *Id.* at 27.
[90] *Id.*
[91] *Id.* at 9.
[92] *Id.* at 24.
[93] *Id.* at 27 ("In this scenario, BGE, SWMAAC, and MAAC LDAs would not have separated from the RTO.").

$163.46/MW-day would still have been among the highest capacity prices in PJM in the last decade.[94] Still, as Synapse reported, "[i]f the RTO cleared at $163.46/MW-day for the 2025/2026 BRA, electric customers across the RTO would save over $5 billion in that delivery year."[95] Hence, the non-participation of these RMR units in the capacity market "had a region-wide impact that will benefit generators (and cost customers) over $5 billion."[96]

The IMM also conducted a sensitivity analysis of the 2025/2026 capacity auction that quantified the price impact of the non-participation of RMR units in the BGE LDA and found that this factor inflated capacity market revenues by $4.2 billion.[97] The IMM's analysis differed from Synapse's in that the IMM assumed that the RMR units would be "included in the supply curve at $0 per MW-day," i.e., as price-takers.[98] The IMM also compared what "RPM revenues would have been had the capacity of the RMR resources been included" and found that their non-participation "resulted in a 41.2 percent increase in RPM revenues."[99] Importantly, the IMM's analysis also demonstrates that RMR units' non-participation in the capacity market has a very large impact on overall capacity market revenues even though the RMR units represent only a small portion of overall supply. Even though the RMR units' inclusion as supply would have been only "an increase of 1,440.6 UCAP MW, or 1.1 percent, compared to the actual results," the IMM's analysis still showed a price impact of $4.2 billion.[100] Additionally, the IMM's analysis corroborates Synapse's finding that even if the RMR units in the BGE LDA had

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[94] *See* Wilson Aff., *supra* note 6 at P 32.
[95] Synapse Report, *supra* note 5 at 27.
[96] *Id.* at 27.
[97] IMM Analysis of 2025/2026 Auction, *supra* note 4 at 9 ("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 $10,399,791,048, a decrease of $4,287,256,309, or 29.2 percent, compared to the actual results.").
[98] *Id.*
[99] *Id.*
[100] *Id.* at 13, 6.

participated in the capacity auction, the prices would still have been among the highest in the history of the PJM capacity market; the IMM calculated that total auction revenues would have been over $10 billion.[101]

Synapse also found that the high prices driven by RMR units' non-participation in PJM's capacity market will have significant impacts on retail ratepayers. "Across the PJM footprint, electric utility customers will see rising costs as a result of the increased capacity clearing prices for the 2025/2026 delivery year."[102] In the BGE LDA, increased capacity prices will drive ratepayers' monthly bills up by 14%, meaning that "average residential and commercial customers could see their bills increase by $16 per month and $170 per month, respectively."[103]

These increased capacity prices will fall especially heavily on ratepayers in the BGE LDA, because those same customers will also "bear 74 percent of the[] RMR costs" for the Brandon Shores and Wagner units. "As a result, BGE LDA customers could see their bills increase by 5 percent, resulting in an average residential bill increase of $5 per month," and an increase in commercial customers' bills of "$54 per month."[104] Considering "both the capacity market impact and the RMR service arrangement costs together," bills for BGE LDA ratepayers "are likely to increase by 19 percent—an extra $21 on the average residential customer bill and $224 on the average commercial monthly bill."[105] Similarly, "Maryland customers in APS, DPL-

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[101] *Id.* at 9. Analysis from PJM also generally supports the findings from the IMM and the Synapse Report. PJM considered the effect of non-participation by deactivating units and units operating under must-offer exceptions. That category includes "planned retirements," such as units operating under an RMR arrangement, although it also includes retirements that do not require a must-offer exception as well as resources that switched from capacity status to energy-only status—a total of roughly 5,700 MW (ICAP). PJM found that if "all of this would have cleared . . . this would result in a price of around $100/MW-day." Tim Horger & Adam Keech, 2025/2026 Base Residual Auction Results, at slide 32, PJM (Aug. 21, 2024), https://pjm.com/-/media/committees-groups/committees/mrc/2024/20240821/20240821-item-08---2025-2026-base-residual-auction---presentation.ashx.
[102] Synapse Report, *supra* note 5 at 27.
[103] *Id.* at 29.
[104] *Id.*
[105] *Id.*

South, and Pepco zones could see their monthly bills increasing by 24 percent, 2 percent, and 11 percent, respectively," which "translates into a monthly increase of $18, $4, and $14 for the average residential customer" in those zones, respectively.[106]

Critically, the BGE LDA includes numerous disadvantaged communities who already face among the most extreme energy burdens in the nation.[107] These already burdened ratepayers now also bear the heaviest burdens from the skyrocketing prices in PJM's capacity market.

F. RMRs may become more common in PJM given the projected rate of retirements, challenges planning for and building transmission, and the slow pace of PJM's interconnection queue.

Several factors make PJM more likely to enter into an increasing number of RMR contracts in coming years, with potentially significant impacts on capacity prices. First, PJM has stated that "40 [gigawatts ("GW")] of existing generation are at risk of retirement by 2030."[108] PJM projects that 60% of these retiring resources, or 24 GW, will be coal retirements, while 30%, or 12 GW, will be natural gas retirements.[109] The retirement of many generators in a shorter time is more likely to create transmission reliability violations which cause RMR designations.

Second, PJM has expressed concern that the pace of new entry may "be insufficient to keep up with expected retirements and demand growth."[110] Indeed, PJM's interconnection queue remains severely backlogged; at the end of 2023, PJM had more active projects stuck in its queue

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[106] *Id.* at 30.

[107] *See*, *e.g.*, DOE, Climate and Economic Justice Screening Tool: Explore the Map, https://screeningtool.geoplatform.gov/en/#3/33.47/-97.5 (information for census tracts 24510200200, 24510190300, and 24510200400 in Baltimore City, Maryland).

[108] PJM, Energy Transition in PJM: Resource Retirements, Replacements, & Risks, at 2 (Feb. 24, 2023), https://www.pjm.com/-/media/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx.

[109] *Id.* at 3.

[110] *Id.* at 2.

than any other region, and projects languish in PJM's queue longer than in any other region.[111] PJM characterizes the mismatch between the swift expected pace of retirements and the slow slog of new projects through the queue as a "significant reliability concern."[112] However, PJM is also resisting the implementation of the Commission's interconnection reforms in Order No. 2023 by asking the Commission to allow it to retain a study process at least twice as long as the Commission's *pro forma* materials and by requesting waiver of provisions for storage interconnection and Surplus Interconnection Service.[113] The clogged state of PJM's interconnection queue, and the slow pace of its interconnection studies, create a significant risk that new generation may not come online quickly enough to prevent reliability issues associated with the large scale of expected retirements. That mismatch sets the stage for retiring resources to be kept online past their proposed deactivation dates through RMR arrangements.

Third, PJM is slow to develop the type of transmission project that would prevent reliability issues that may trigger the need for an RMR arrangement. While overall transmission costs have grown significantly in the PJM region over the last decade, the dominant form of transmission investment is in local, "supplemental" projects rather than regional projects.[114] Importantly, supplemental projects are ones that "may not be required for . . . system reliability, market efficiency or operational performance,"[115] meaning that supplemental projects are not

[111] *See* Lawrence Berkeley Nat'l Lab'y, Queued Up: 2024 Edition, Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2023, at slide 9, 35 (April 2024) ("Queued Up 2024"), https://emp.lbl.gov/sites/default/files/2024-04/Queued%20Up%202024%20Edition_1.pdf.
[112] PJM Interconnection, LLC, Order Nos. 2023 and 2023-A Compliance Filing of PJM Interconnection, LLC, at 48, Docket No. ER24-2045 (May 16, 2024), Accession No. 20240516-5155.
[113] *See generally id.*
[114] *See* PJM Interconnection, LLC, Protest of Illinois Citizens Utility Board, Delaware Division of the Public Advocate, Office of the People's Counsel for the District of Columbia, Natural Resources Defense Council, Sustainable FERC Project, and Sierra Club, at 7–12, Docket Nos. EL24-119 and ER24-2338 (July 22, 2024) ("Advocates Protest"), Accession No. 20240722-5135 (discussing the lopsided investment in supplemental projects in the PJM region).
[115] PJM Operating Agreement, Schedule 6 § 1.5.6(n), https://agreements.pjm.com/oa/4771.

well suited to address the reliability issues that may lead to RMR arrangements. Moreover, PJM does not adequately plan transmission upgrades to account for generators that are at risk of retirement due to their age, poor performance, or economic troubles. Instead, PJM defers analysis of the needed transmission upgrades until a unit has actually announced its retirement, which may give PJM as few as 90 days to identify needed transmission upgrades. This lack of proactive transmission planning makes RMR arrangements both more likely to be necessary and more likely to be protracted and costly. The IMM has recommended that PJM should plan more proactively for the transmission needs associated with foreseeable retirements, emphasizing that "[i]t is essential that PJM look forward and attempt to plan for foreseeable unit retirements, whether for economic or regulatory reasons."[116] The IMM further stressed that "improvement is needed in the process for ensuring that planning is looking at the probability of retirements, especially of resources that are critical to locational reliability in order to minimize the duration of any RMR requirement."[117]

These three issues—the anticipated slate of retirements, the slow pace of PJM's interconnection queue, and inadequate transmission planning to address foreseeable retirements—mean that RMRs may become increasingly common in PJM. For example, the Union of Concerned Scientists recently commissioned a power flow analysis of the impacts from retirements of coal and gas generators in Illinois that reinforces this possibility.[118] That power flow modeling found that widespread retirement of coal and gas generators in Illinois would

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[116] Monitoring Analytics, Quarterly State of the Market Report for PJM: January through June, at 360 (Aug. 8, 2024) ("Monitoring Analytics, Quarterly State of the Market Report for PJM"), https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2024.shtml ("The planning process should, to the extent possible, evaluate the impact of the loss of units at risk and determine in advance whether transmission upgrades are required.").

[117] *Id.*

[118] *See* James Gignac, *Illinois Has No Time to Waste in Building Its Carbon-Free Electricity Future*, Union of Concerned Scientists (Apr. 3, 2023), https://blog.ucsusa.org/james-gignac/illinois-has-no-time-to-waste-in-building-its-carbon-free-electricity-future/.

create a substantial number of reliability violations in PJM territory.[119] The modeling found that if new clean energy resources are installed quickly enough—which is by no means certain given PJM's clogged interconnection queue—new entry of generation would resolve many, but not all, reliability violations.[120] That modeling illustrates the serious possibility that PJM may seek to keep coal and gas generation online in Illinois through RMR arrangements.

G. Efforts to secure reforms through the stakeholder process.

PIOs have encouraged PJM and its members to proactively resolve the problem discussed in this complaint, the scale and urgency of which became apparent only on July 30, 2024, when PJM published the results for the 2025/2026 Base Residual Auction. On August 30, 2024, a group of six state consumers advocates sent PJM's Board of Managers a letter urging immediate reforms, using PJM's Critical Issue Fast Path process.[121] PIOs filed a supportive letter on September 6, 2024, urging the Board to delay upcoming auctions if necessary and to take immediate action to prevent similar unjust and unreasonable prices in the next several Base Residual Auctions, which will happen in quick succession over the next eighteen months.[122] Because the next Base Residual Auction will occur in mid-December—just three months away—the normal processes for advancing issues through the PJM stakeholder process are too slow to bring about a timely solution. On September 19, 2024, the PJM Board of Managers published a

[119] *Id.*
[120] *Id.*
[121] Md. Office of People's Counsel, Letter to PJM Board of Managers Re: Urgent Reforms to the PJM Capacity Market Regarding Reliability Must Run Units (Aug. 30, 2024), https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/2024/20240903-consumer-advocate-letter-on-capacity-markets.ashx. This letter is included in Attachment 2 to this complaint.
[122] PIOs, Letter to PJM Board of Managers Re: Support for Urgent Reforms Regarding Reliability Must Run Units and the PJM Capacity Market (Sept. 6, 2024), https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/2024/20240906-pios-letter-of-support-to-pjm-bard-on-rmrs-in-rpm.ashx. This letter is included in Attachment 5 to this complaint.

response to the requests by consumer advocates and PIOs, declining to pursue the requested reforms and defending its market rules.[123]

Despite the inadequacy of the regular PJM stakeholder process to address this pressing issue, one of the Complainants—Sierra Club—has proposed a solution in the ongoing Deactivation Enhancements Senior Task Force.[124] PJM has scheduled a vote on this and other solution packages for October 2, 2024. Even if Sierra Club's solution were to move forward, further PJM member consideration and voting would then occur in the Markets and Reliability and Members Committees, adding at least another two months to the timeline.[125] PIOs will update the Commission regarding any relevant developments on Sierra Club's proposal in the Deactivation Enhancement Senior Task Force, but believe that the PJM stakeholder process will be too slow to avoid PJM consumers paying $12 billion to $15 billion in excess costs for capacity in upcoming auctions. Because the PJM Board has stated that it believes the existing rules with respect to RMR participation in the market are appropriate and will not pursue reforms to address the billions of dollars in excessive costs associated with this rule, PIOs have no choice but to initiate this proceeding with the Commission.

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[123] PJM Board of Managers, Response Letter to Consumer Advocates and Complainants Re: Urgent Reforms to PJM Capacity Market RMR Units (Sept. 19, 2024) ("PJM Board of Managers Response"), https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/2024/20240919-pjm-board-response-consumer-advocates-letter-re-urgent-reforms-pjm-capacity-market-re-reliability-must-run-units.ashx. This letter is included in Attachment 5 to this complaint.

[124] Casey Roberts, Sierra Club Proposal for Deactivation Enhancement Senior Task Force (Sept. 20, 2024), at https://www.pjm.com/-/media/committees-groups/task-forces/destf/2024/20240920/20240920-item-06---sierra-club-solution-package.ashx.

[125] PJM, Task Forces Work Plan Meeting Schedules (June 14, 2024), https://www.pjm.com/-/media/committees-groups/task-forces/destf/2024/20240614/20240614-item-03---work-plan.ashx.

III. DISCUSSION

A. RMR units' non-participation in the capacity market creates unjust and unreasonable prices by forcing consumers to pay twice for reliability.

The capacity market exists to ensure that the PJM region can meet its resource adequacy needs at a reasonable cost to consumers.[126] Ignoring existing generation that is helping to serve load when conditions are tightest leads to the procurement of unnecessary generation and forces consumers to pay higher, unjustified costs.

1. RMR arrangements retain resources to be available for a broad range of reliability emergencies, including those related to capacity.

As described above, PJM consumers are already paying dearly for the cost of RMR arrangements, and these costs have escalated in recent years. In some cases, PJM consumers are being asked to pay close to the full embedded cost of the generator, rather than simply the generator's more reasonable going-forward costs. While RMR arrangements are triggered in PJM only by transmission stability circumstances, resources retained by PJM under RMR arrangements are available to supply resource adequacy—that is, they are available during most or all times when capacity is tight on the system. For example, a recent PJM presentation to members explained that PJM may dispatch RMR resources for a broad range of reliability, but not economic, purposes, including "Thermal, Reactive, Stability, *Capacity Shortages*, [and] System Restoration."[127]

Although PJM has eschewed a standardized RMR contract, trends are evident from a review of fifteen RMR arrangements filed with FERC for the PJM region, including all those listed in the RMR History table compiled by the Independent Market Monitor as well as the

[126] *ISO New England, Inc. New England Power Pool*, 118 FERC ¶ 61,157 at P 49 (2007) (The Commission's task in regulating capacity markets is to "ensure that there is enough generation to reliably meet load" without "overcharging . . . customers for unnecessary capacity.").
[127] *See* RMR Unit Scheduling in Operations, *supra* note 12 (emphasis added).

more recent Brandon Shores and Wagner arrangements. With a few exceptions from older arrangements, all of these either give PJM the right to dispatch the unit to achieve broadly defined "reliability" purposes, or specifically give PJM the right to dispatch the RMR units in capacity emergencies. Most notably, the RMR arrangements in effect for the delivery year corresponding to the upcoming 2026/2027 Base Residual Auction (Brandon Shores and Wagner) specify that PJM may call these units in the event of capacity emergencies.[128]

Table 1: Provisions for PJM Dispatch in Reliability Must Run Arrangements

Units	**Docket No.**	**Agreement Provisions re PJM Dispatch**
Brandon Shores 1 & 2	ER24-1790	CORS Section 3.3(a), PJM may dispatch for capacity emergencies. *See* Attachment 6-7.
HA Wagner 1 & 2	ER24-1787	CORS Section 3.3(a), PJM may dispatch for capacity emergencies. *See* Attachment 6-21.
Indian River 4	ER22-1539	RMR Section 3.3(a), PJM may dispatch for a capacity emergencies. *See* Attachment 6-32.
Yorktown Units 1 and 2	ER17-750	Section 116 filing letter indicates dispatch in accordance with U.S. EPA Administrative Compliance Order, under which PJM may dispatch for "generation emergencies." *See* Attachment 6-40.
BL England 2 and 3	ER17-1083	Section 3.2 "Dispatch of the Units": "Subject to the Unit operating limitations identified in Section 3.4 below, PJM may dispatch either or both Units." *See* Attachment 6-44.
Eastlake Unit 1-3, Ashtabula, Lakeshore	ER12-2710	Informational Filings, Section IV: Includes agreements to offer "capacity into every Reliability Pricing Model Incremental Auction at a price of zero dollars." *See* Attachment 6-49, 6-53, 6-57, 6-61, 6-65.
Elrama 4 and Niles 1	ER 12-1901	Informational filing, at Section 3.2: "Subject to the Unit operating limitations identified in Section 3.4,

[128] Brandon Shores LLC, RMR Arrangement – Continuing Operations Rate Schedule, Attach. A, at § 3.3(a), Docket No. ER24-1790 (Apr. 18, 2024) ("Brandon Shores CORS"), Accession No. 20240418-5176; H.A. Wagner LLC, RMR Arrangement – Continuing Operations Rate Schedule, Attach. A, at § 3.3(a), Docket No. ER24-1787 (Apr. 18, 2024) ("Wagner CORS"), Accession No. 20240418-5128; NRG Business Marketing LLC, Settlement Agreement and Offer of Settlement, Docket No. ER22-1539 (April 2, 2024) ("NRG Settlement"), Accession No. 20240402-5138. The RMR arrangements for the RMR units in the BGE LDA, as well as relevant excerpts from the RMR arrangements described in Table 1, are included as Attachment 6 to this complaint.

		PJM may dispatch either or both Units." *See* Attachment 6-69.
Eddystone 2, Cromby 2, and Cromby Diesel	ER10-1418	Per terms of settlement approved by FERC, Section 3.2 "Dispatch of the Units": "Subject to the Unit operating limitations identified in the Consent Decree and the PJM Operating Procedures, PJM may dispatch either or both Units in accordance with the PJM Operating Procedures. At no time may PJM dispatch either Unit on the basis of economic considerations." *See* Attachment 6-73. PJM Operating Procedures (Attachment C to Exelon rate filing), Part 2.d states that PJM may dispatch a unit for a reliability purpose to address the reliability impacts identified in the Deactivation Study, or when PJM anticipates operation will alleviate a Transmission Security Emergency, or to support the system during a generation or transmission outage scheduled to facilitate the construction of the transmission system upgrades identified in the deactivation study. *See* Attachment 6-80.
Brunot Island	ER06-993	Informational filing, "Nature of Service" section as follows: Paragraph II.1 during the term of this tariff OPMW shall continue operating the following units. *See* Attachment Paragraph II.3. except when on outage, units will bid into Day Ahead & Real Time energy markets at market caps. Paragraph II.4. Unit will not be delisted as Capacity Resources for PJM. *See* Attachment 6-82.
Hudson 1, Sewaren 1-4	ER05-644	Cost of Service Recovery Rate Tariff, "Nature of Service" section as follows: Paragraph II.1 during the term of this tariff OPMW shall continue operating the following units. Paragraph II.3. except when on outage, units will bid into DA & RT energy markets at market caps. Paragraph II.4. Unit will not be delisted as Capacity Resources for PJM. *See* Attachment 6-86.

Furthermore, PJM anticipates operation of RMR resources as a general matter during stressed grid conditions. PJM has explained that it includes RMR units in its modeling of the system's capability to import capacity into constrained zones because the "RMR unit is expected to produce MWs under emergency conditions,"[129] and because "the RMR units [are] expected to be operating and impacting power flows on the system during times of reliability need.[130] In other words, PJM considers the physical availability of RMR resources during times of reliability need so likely that to exclude them from its modeling would result in "incomplete and potentially inaccurate assessment of local reliability needs."[131] RMR units unquestionably provide resource adequacy value to the system, even though they are not retained for that reason. In approving ISO-NE's proposal for time-limited authority to retain resources for fuel security purposes, the Commission endorsed ISO-NE's view "that the year-round resource adequacy contributions of resources retained for fuel security should be counted in the capacity market and therefore [found] that such resources should be entered into the [capacity auction] as price-takers to ensure that they clear."[132]

As Mr. Wilson concludes in his attached testimony, an RMR unit contributes to resource adequacy, and therefore holding it out of the auction "misrepresents the true state of supply"[133] to the detriment of consumers and the accuracy of capacity market signals.

[129] PJM CETO/CETL & Load Deliverability, *supra* note 28 at slide 16.
[130] PJM Response to the 2023 State of the Market Report, *supra* note 21 at 4.
[131] *Id.*
[132] *ISO New England Inc.*, 165 FERC ¶ 61,202 at P 82.
[133] Wilson Aff., *supra* note 6 at P 25.

2. Despite paying for reliability through the RMR arrangement, consumers must buy replacement capacity through the auction, sometimes at scarcity prices.

Under PJM's current rules, the resource adequacy value of RMR units is not reflected in the capacity market clearing price. PJM's rules permit RMR units not to offer into the capacity market, and in all but a few cases, they have chosen not to. Nor does PJM have any other procedure in place to account for the operation of these RMR resources when determining how much capacity to purchase. As a result, despite paying in some cases hundreds of millions of dollars annually to support the continued operation of RMR units, consumers must nevertheless buy redundant capacity through the auction. To add insult to injury, in some cases consumers may be required to purchase that redundant capacity at elevated prices reflecting an artificial picture of scarcity.

The most recent auction illustrates how dramatic the impacts can be for consumers. In the 2025/2026 auction, the BGE LDA, where Brandon Shores and Wagner are located, "cleared short of [its] reliability requirements due to load growth and retirements" resulting in prices at the administrative price cap of $466.35.[134] For the BGE LDA, "[t]his is a six-fold increase from the 2024/2025 BGE LDA [auction] clearing price of $73/MW-day."[135] BGE customers will have to pay these artificially elevated prices for capacity already being supplied by the Brandon Shores and Wagner plants, which will cost PJM customers approximately $215 million for the same delivery year.[136] These dramatic price increases are especially unjust and unreasonable

[134] PJM, 2025/2026 Base Residual Auction Results, at slides 4–5 (Aug. 21, 2024), https://pjm.com/-/media/committees-groups/committees/mrc/2024/20240821/20240821-item-08---2025-2026-base-residual-auction---presentation.ashx.
[135] Synapse Report, *supra* note 5, at 7.
[136] Protest and Comments of the Maryland Office of People's Counsel and the Southern Maryland Electric Cooperative, Inc., at Tbl. 1, Docket No. ER 24-1787 (May 16, 2024), Accession No. 20240516-5193.

because the BGE LDA includes consumers who bear some of the most extreme energy burdens in the nation.[137]

Such double procurement is unjust and unreasonable because "[h]olding the unit out of RPM also harms consumers by forcing them to 'pay twice' for resource adequacy; first, consumers bear the unit's cost under the RMR contract, and then they also pay through RPM for the capacity procured to meet the part of the Reliability Requirement that the RMR could and should have satisfied."[138] As the Commission has repeatedly concluded, it is not just and reasonable to impose such redundant purchases of capacity on consumers.[139] In approving an RMR framework for NYISO, the Commission rejected any provision allowing RMR units to make capacity bids higher than $0.00, reasoning that if the RMR unit then failed to clear the capacity auction, the result would be that "another generator that otherwise would not have cleared will clear instead," which would mean that "ratepayers will pay twice—once for the cost of the RMR agreement, and again for the generator that otherwise would not have cleared the market."[140] The Commission approved ISO-NE's similar requirement that retained resources offer into the capacity market as price takers on grounds that "using a non-zero price may result in a reliability must-run resource not clearing the market and allowing a resource to clear that would not have otherwise cleared," which the Commission noted would be "inefficient and unreasonable because it would require ratepayers to pay twice for the same capacity need and would result in over-procuring capacity."[141] Now that the same "inefficient and unreasonable"

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[137] *Infra* § III(D).
[138] Wilson Aff., *supra* note 6 at P 27.
[139] *NYISO II*, 161 FERC ¶ 61,189 at P 55 (finding that it is critical for markets to avoid "requiring ratepayers to pay twice to satisfy the same capacity need."); *see also NYISO I*, 155 FERC ¶ 61,076 at PP 82–83; *ISO New England Inc.*, 165 FERC ¶ 61,202 at PP 82–83.
[140] *NYISO I*, 155 FERC ¶ 61,076 at P 82.
[141] *ISO New England Inc.*, 165 FERC ¶ 61,202 at P 83 (citing *NYISO I*, 155 FERC ¶ 61,076 at P 82 and *NYISO II*, 161 FERC ¶ 61,189 at P 55).

outcomes that the Commission guarded against when approving RMR rules in NYISO and ISO-NE have in fact played out in PJM—with consumers in the BGE LDA and throughout the RTO unjustly and unreasonably forced to pay twice for the same capacity needs—it is critical for the Commission to require reform to PJM's rules.

The Commission has reached similar conclusions in the analogous context of minimum offer price rules ("MOPR"). In recent years, the MOPR worked to require resources supported by state policies to bid at higher prices in the capacity market.[142] In shifting its approach to MOPR starting in 2021, the Commission acknowledged that these resources would be present on the system regardless of whether they cleared the capacity market due to the effect of state policies.[143] As such, the Commission found, in multiple recent proceedings, that market rules which arbitrarily exclude an existing resource from the capacity market were harmful because "their contribution to resource adequacy could be effectively ignored in the [capacity market] to the extent the current MOPR prevents them from clearing."[144] The Commission concluded that the result would be that "the capacity market would clear surplus resources that are not actually needed to maintain resource adequacy," which is not just and reasonable.[145] RMR resources are likewise present on the system by dint of an external driving force—the RMR agreement that

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[142] *See, e.g., ISO-NE*, 179 FERC ¶ 61,139 at P 3 (2022) (describing ISO-NE's MOPR as "requiring new capacity resources to offer their capacity at prices that are at or above a price floor set for each type of resource").

[143] *See, e.g., id.* at P 50 ("[B]ecause state policies typically mandate their development, these state-sponsored resources will likely be developed and available to contribute to ISO-NE's resource adequacy needs.").

[144] *ISO New England, Inc. New England Power Pool Participants Comm.*, 179 FERC ¶ 61,139 at P 50 (2022); *see also New York Indep. Sys. Operator, Inc.*, 179 FERC ¶ 61,102 at P 39 (2022) (finding that NYISO's proposal to no longer apply buyer-side market power mitigation rules to state policy resources "reduces the risk, present under the current BSM Rules, of at least three significant harms: over-procurement of capacity, inflated capacity market prices, and inefficient price signals from the capacity market."). Statement of Chairman Glick and Commissioner Clements Supporting the Focused MOPR, at P 49, Docket No. ER21-2582 (Oct. 19, 2021), Accession No. 20211019-4001 ("Because state-supported resources are available to provide resource adequacy, but those contributions are effectively ignored by PJM when they are pushed out of the market, applying a MOPR to state-supported resources causes an RTO/ISO to procure redundant capacity that is not needed to ensure resource adequacy.").

[145] *ISO New England, Inc. New England Power Pool Participants Comm.*, 179 FERC ¶ 61,139 at P 50.

retains these resources and causes them to operate to support reliability. In both cases, just and reasonable rates require the market to reflect the presence of the resource (RMR or state policy) so that consumers do not buy unnecessary replacement capacity.

In its 2021 filing to implement a narrower Focused MOPR, PJM's Vice President of Market Design, Adam Keech, explained that where a state-supported resource is artificially priced out of the market (in his example, a coal unit), "consumers in the state pay twice, i.e., for both the coal unit and the resource committed through the auction because the coal plant did not clear."[146] Mr. Keech's logic equally applies where a resource is retained for reliability reasons; like the state policy resource that will exist on the system regardless of capacity market clearing, the RMR resource is present and operating at PJM's direction to support reliability. Ignoring it leads unjustly and unreasonably to consumers paying twice for reliability.

Commission precedent is overwhelmingly in favor of requiring RMR units to offer into capacity markets as price takers to prevent consumers from being saddled with unnecessary capacity costs. PJM's rules, which do not require RMR resources to offer into the capacity market or otherwise adjust the amount of capacity procured to reflect the availability of RMR resources to meet resource adequacy needs, are unjust and unreasonable and must be remedied by the Commission.

B. High capacity market prices driven by RMR units' non-participation send inaccurate price signals.

PJM's rules that allow RMR resources not to offer into the capacity market not only require consumers to buy unnecessary capacity, but also produce inaccurate capacity price signals. As James Wilson explains, holding RMR resources out of the capacity auction distorts

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[146] PJM Interconnection, LLC, Revisions to Application of Minimum Offer Price Rule, Attach. D: Affidavit of Adam J. Keech on behalf of PJM Interconnection, L.L.C., at P 11, Docket No. ER21-2582 (July 30, 2021) ("Keech Aff."), Accession No. 20210730-5166.

the supply-demand balance and is "economically inefficient because it will lead to price signals that falsely signal a degree of scarcity that does not exist."[147] Further, "[t]he inaccurate price signals harm markets by encouraging inefficient decisions with respect to existing and potential new resources by market participants on the supply side and demand side."[148] Mr. Wilson relays and endorses the logic previously offered by Potomac Economics and the Commission and explains that because an RMR unit's net going forward costs are covered by the RMR contract, that RMR unit's net going forward cost needed from the capacity market is zero.[149] Because the RMR resource should economically offer at zero, the resulting reduction of the capacity price would be correct. Conversely, if an RMR resource is not reflected in the capacity market, even though it will be operating and its going-forward costs are zero, the resulting capacity prices will be higher than is efficient.

In case after case, the Commission has established that when resources providing resource adequacy are ignored or excluded, the resulting capacity prices send exaggerated signals regarding the need for resource retention and new investment. In approving ISO NE's price-taker treatment for RMR resources, the Commission noted its agreement with ISO-NE's external market monitor, Potomac Economics, that "as long as resources are retained for fuel security purposes, including such resources in the [capacity auction] as price takers prevents an artificial and inefficient increase in [capacity auction] prices."[150] In the same order, addressing ISO-NE's rejection of alternative approaches that would allow non-zero bids, the Commission reiterated that "retaining a resource outside of the [capacity auction] would not account for its

[147] Wilson Aff., *supra* note 6 at P 26.
[148] *Id.*; *see also id.*at P 25 ("[H]olding the unit out of RPM misrepresents the true state of supply, because the RMR unit, which is needed and has been retained for other reliability needs, does indeed contribute to resource adequacy. To remove the RMR unit from RPM distorts the supply-demand balance represented there.").
[149] *Id.* at PP 4, 18.
[150] *ISO New England Inc.*, 165 FERC ¶ 61,202 at P 85.

contribution to meeting ISO-NE's resource adequacy needs, would result in procuring excess capacity, and *would distort the capacity price*."[151]

In the parallel context of MOPR, the Commission has emphasized that "[i]f a resource does not clear due to the application of the [current MOPR], it will be replaced by a resource with a higher-priced offer, which will raise the market clearing price insofar as it causes a more expensive resource to clear on the margin than would otherwise occur."[152] Enabling market clearing by state supported resources would, in the Commission's judgment, "reduce[] the risk . . . of at least three significant harms: over-procurement of capacity, inflated capacity market prices, and inefficient price signals from the capacity market."[153] PJM also recognized the potential for excessive capacity prices that results from excluding resources when moving to its Focused MOPR just three years ago. Its Vice President of Market Design, Adam Keech, explained that if resources are prevented from offering into the auction and capacity prices do not reflect out-of-market actions, "then capacity prices will incentivize resources to be built that are not needed to maintain reliability" and that "[i]t is difficult to see how such prices are just and reasonable."[154]

In a recent letter refusing to reform its capacity market rules before the next auction, the PJM Board of Managers espoused the view that reflecting the resource adequacy value of RMR resources in the capacity market could "fail to incent the new build needed in Maryland and in the rest of the regional transmission organization."[155] Other beneficiaries of the status quo will undoubtedly argue that requiring RMRs to participate in the auction will lead to "price

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[151] *Id.* at P 87 (emphasis added).
[152] *ISO New England Inc. New England Power Pool Participants Comm.*, 179 FERC ¶ 61,139 at P 50 (citing *New York Indep. Sys. Operator, Inc.*, 179 FERC ¶ 61,102 at P 39).
[153] *New York Indep. Sys. Operator, Inc.*, 179 FERC ¶ 61,102 at P 50.
[154] Keech Aff., *supra* note 146 at P 12.
[155] PJM Board of Managers Response, *supra* note 123 at 3.

suppressi[on]."[156] These arguments are unpersuasive and should not deter the Commission from taking appropriate action, fully consistent with its precedent, to protect consumers from skyrocketing prices in future auctions.

At the outset, it cannot be that the market price must be pumped up by artificial means to an extremely high level, such as the inflation of the BGE LDA's price to $466/MW-day in the most recent auction—the highest possible price—in order to attract investment. In the two months since its historically high auction prices were publicized, PJM has explained many factors driving capacity prices up, including demand growth, PJM's recent capacity accreditation changes reducing supply, an increase in the Installed Reserve Margin requirement, and generator retirements.[157] All of these factors appropriately affect the capacity price and send *accurate* signals to the market about where and how much new entry or resource retention is needed. As Mr. Wilson explains, "while additional resources are needed on the PJM system at this time, RPM is designed to set appropriately high prices when resources are needed, [and] it is not necessary or appropriate to distort the supply-demand balance to send a stronger price signal."[158]

The Synapse analysis concludes the market clearing price would still have been $163.46/MW-day had the RMR units participated; this price is also very high by historical standards and would send a strong investment signal as well. Similarly, the IMM has found that if RMR resources in the BGE LDA had participated as price-takers in the most recent auction, overall revenues still "would have been $10,399,791,048," which is among the highest revenues

[156] *See*, *e.g.*, Letter from Todd Snitchler, Elec. Power Supply Ass'n, to PJM Board of Managers Re: Opposition to Critical Issue Fast Path Request on Reliability Must Run Arrangements in Capacity Markets and Possible Auction Delay, at 3 (Sept. 11, 2024), https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/2024/20240912-epsa-p3-letter-regarding-consumer-advocates-request-for-urgent-reforms-to-the-pjm-capacity-market-regarding-rmr-units.ashx.
[157] *See, e.g.,* PJM 2025/2026 Base Residual Auction Report, *supra* note 18.
[158] Wilson Aff., *supra* note 6 at P 32 (internal citations omitted).

in the history of PJM's capacity market.[159] PJM should not be permitted to further increase its price, over what actual market fundamentals would cause, based on a deliberate distortion of the supply picture. Capacity price signals should be adequate to incent the needed investment, but no higher.[160]

The PJM Board's apparent concern with increasing capacity prices by any means necessary also conflicts with its own approval, less than a year ago, of major new transmission projects that will significantly increase the capability of resources outside the BGE zone to serve load there.[161] A market solution to the reliability issues in BGE would be redundant to PJM's planned transmission solution.[162] An order-of-magnitude price spike sends a price signal for new entry that is simply not needed considering the massive transmission solution that is underway.[163] As the IMM puts it, "[t]here 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."[164]

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[159] IMM Analysis of 2025/2026 Auction, *supra* note 4 at 9.
[160] *See, e.g.*, *ISO New England Inc. and New England Power Pool Participants Comm.*, 147 FERC ¶ 61,173 at P 33 (2014) ("the proposed design [] produce[s] prices that are high enough to meet the reliability standard, but not so high as to add unnecessary costs."); *PJM Interconnection, L.L.C.*, 138 FERC ¶ 61,062 at P 84 (2012) (finding "a reasonable balance between maintaining an incentive for resources to commit to providing capacity while not unduly burdening consumers with higher costs").
[161] *See* PJM, Transmission Expansion Advisory Committee (TEAC) Recommendations to the PJM Board, at 4 (July 2023), https://www.pjm.com/-/media/committees-groups/committees/teac/2023/20230711/20230711-pjm-teac-board-whitepaper-july-2023-public.ashx (authorizing construction of two new 500 kV lines, along with numerous other transmission system upgrades, to be completed by the end of 2028).
[162] *See* PJM Response to the 2023 State of the Market Report, supra note 21 at 4 (defending its decision to include the RMR unit in CETO/CETL modeling, in lieu of the eventual transmission solution, and noting that "[t]his consistency removes the potential for distorted price signals that would incent generation where transmission upgrades could have replaced that need.").
[163] This is not to say that no new entry is needed in the BGE zone, and indeed PJM's interconnection queue is full of projects seeking to sell power there. But new entry (and retention of existing resources) should be based on accurate supply and demand information and projections, not artificially elevated price signals.
[164] IMM Analysis of 2025/2026 Auction, *supra* note 4 at 7.

An inaccurate price signal for new entry is particularly unnecessary and counterproductive because investors know that any price spike associated with RMR units not offering into the market, despite their availability, will be short-lived. Any sophisticated developer would know that these prices do not reflect a fundamental change in supply and demand, because the completion of transmission upgrades will alleviate the transmission constraints that have driven higher prices in the BGE LDA. As Mr. Wilson concludes, "market participants are unlikely to respond to a price signal that 1) they know misrepresents the true near-term and longer-term supply-demand balance, and 2) they also know is likely to be short-lived."[165] He explains that"[i]nvestors base their decisions to invest capital on longer-term price expectations, not short-term prices," and will disregard "[t]he extra price signal that results from excluding an RMR unit from RPM[, which] is known to be a distortion of the actual conditions on the system."[166] Such investors also discount the price signal because they "know that transmission to relieve the constraints that the retirement would cause are under construction."[167] As such, the increased prices will only provide windfall profits to existing generators, rather than facilitating necessary new entry.

An inflated price signal is also unnecessary because long-term prices and market fundamentals have already led to a significant amount of new generation entering PJM's queue. The Synapse report notes that there are already thirteen projects in the PJM queue in the BGE LDA, offering roughly 1,200 MW of capacity, with energy storage reflecting 75% of the

[165] Wilson Aff., *supra* note 6 at P 33.
[166] *Id.*
[167] Wilson Aff., *supra* note 6 at P 33. PJM's chief economist has explained that even existing resources deciding whether or not to exit the market look to longer-term price signals when deciding whether or not to undertake cost capital expenditures that would enable continued operation. *See* PJM Interconnection, L.L.C., Revisions to Application of Minimum Offer Price Rule, Attach. E: Affidavit of Dr. Walter F. Graf on behalf of PJM Interconnection, L.L.C., at P 12, Docket No. ER21-2582 (July 30, 2021) ("Graf. MOPR Aff."), Accession No. 20210730-5166 (noting that such costs would need to be recovered over multiple years).

projects.[168] Especially because transmission upgrades will allow for greater imports into the BGE LDA from the rest of the RTO—where hundreds of gigawatts of new generation are in the queue—it is clear that investors have already responded to long-term prices and market fundamentals by seeking to interconnect significant amounts of new generation.

Rhetoric about suppressing market prices is misplaced. While capacity prices would be lower if RMR resources participate, they would not be "suppressed." To the contrary, a price that fails to reflect the resource adequacy contributions of RMR resources would be one that ignores the true supply and demand balance—and thus would not be an accurate price signal. Lower prices do not necessarily signal a flawed price formation mechanism, but are instead, as the Commission has repeatedly found in similar contexts, the correct price given the reality of the system.[169]

In 2018, ISO-NE defended its proposal to treat retained resources as price-takers against a charge that this approach would "suppress capacity prices" by explaining that "once a resource is retained for fuel security, it is appropriate to consider its contributions to resource adequacy when determining capacity awards and prices since the retained resources will continue to contribute to resource adequacy."[170] The Commission agreed with ISO-NE on this point, noting that while "it is not possible to avoid an impact on either the pricing in the [capacity auction] or the quantity of resources procured to satisfy resource adequacy when finding that a resource must be retained for fuel security," it is reasonable to "protect against inefficiently over-

[168] Synapse Report, *supra* note 5 at 32.
[169] *See ISO New England Inc.*, *ISO-NE*, 165 FERC ¶ 61,202 at P 78; *NYISO I*, 155 FERC ¶ 61,076 at P 82 (rejecting proposals for non-zero bids from RMR units because that approach "would allow for inefficient outcomes and is thus unreasonable"); *ISO New England*, 179 FERC ¶ 61,139 at P 50 ("If a resource does not clear due to the application of the [current MOPR], it will be replaced by a resource with a higher-priced offer, which will raise the market clearing price insofar as it causes a more expensive resource to clear on the margin than would otherwise occur." (citing *NYISO*, 179 FERC ¶ 61,102 at P 39)).
[170] *ISO New England Inc.*, 165 FERC ¶ 61,202 at P 78.

procuring capacity resources by reflecting a fuel security resource's contribution to resource adequacy in the [capacity auction]."[171]

In sum, PJM's current rules permitting RMR units to opt out of the capacity market and then not reducing the amount of capacity purchased to reflect the RMR unit's availability results in unjust and unreasonable prices for capacity. The resulting prices reflect an artificial degree of scarcity because they ignore the physical operation of the RMR units. The harm caused to consumers is urgent and substantial—in the last auction consumers paid approximately $5 billion in excess costs, and similar results are likely in the next few auctions.

C. Allowing RMR units not to participate in the capacity market renders the market vulnerable to manipulation.

Because PJM's capacity market is structurally vulnerable to manipulation through the exercise of market power, PJM relies on certain rules and mitigation measures to prevent non-competitive outcomes. However, as discussed below, the absence of any requirement for RMR units to participate in the capacity market renders the market more vulnerable to manipulation through withholding than similar markets in other RTO/ISOs.

As the IMM has explained, "[s]tructural market power is endemic to the capacity market."[172] The capacity market's vulnerability to market power stems from its design, which is "always tight in the sense that total supply is generally only slightly larger than demand."[173] As a result of the inelasticity of demand for capacity, "any supplier that owns more capacity than the typically small difference between total supply and the defined demand is individually pivotal and therefore has structural market power."[174] Similarly, "[a]ny supplier that, jointly with two

[171] *Id.* at P 87.
[172] Monitoring Analytics, Quarterly State of the Market Report for PJM, *supra* note 116116 at 310.
[173] *Id.* at 317.
[174] *Id.* at 318.

other suppliers, owns more capacity than the difference between supply and demand either in aggregate or for a local market is jointly pivotal and therefore has structural market power."[175] The IMM has consistently reported that both the "aggregate market structure" and the "local market structure" for each LDA are "not competitive," in significant part because "for almost all auctions" in its history, both the RTO-wide capacity market and "all LDAs have failed the [three pivotal supplier] test."[176] As a result of this non-competitive market structure, many sellers have market power, which "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."[177]

To prevent the exercise of market power from distorting capacity prices, PJM relies on "appropriate market power mitigation rules."[178] For example, PJM relies on offer caps to prevent sellers from engaging in economic withholding by submitting bids above a competitive level.[179] Critically, all capacity resources must offer into the capacity market unless they are eligible for a limited number of exceptions. One "fundamental goal of the must offer requirement" is "to prevent the exercise of market power via withholding of capacity supply."[180] The IMM recently stressed the importance of the must offer requirement (albeit in the context of objecting to must-offer exceptions to other resources than RMR units), explaining that "[t]he capacity market was designed on the basis of a must buy requirement for load and a corresponding must offer requirement for capacity resources" and that "[t]he capacity market can work only if both are enforced."[181]

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[175] *Id.*
[176] *Id.* at 310.
[177] *Id.* at 318.
[178] *Id.*
[179] *See id.* at 336
[180] *Id.* at 311.
[181] *Id.* at 321 (criticizing must offer exceptions for "intermittent and capacity storage resources").

As the IMM also explained, the must offer requirement helps “ensure open access to the transmission system” through the use of Capacity Interconnection Rights (“CIR”).[182] “If a resource has CIRs that provide access to the transmission system required for the deliverability of energy, but do[es] not offer, those resources are exercising market power by blocking access to the transmission system that could be used by a resource willing to offer into the capacity market.”[183] For that reason, the IMM has recommended that “resources return CIRs to the market on the day of retirement.”[184] The IMM also cautioned that “[t]he failure to apply the 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.”[185] The fact that RMR units retain their CIRs without any must-offer obligation runs contrary to this line of reasoning and makes PJM’s capacity market vulnerable to the volatility and uncertainty that the IMM identified.

PJM’s unusual approach of allowing RMR resources to choose whether to participate in the capacity market also exposes the market to the same type of problems that market power mitigation rules aim to prevent. For example, when RMR units opt not to bid into the capacity market—despite consumers paying these units to be available and despite RMR agreements authorizing PJM to call these units during capacity events—the outcome is a diminution in supply and an increase in overall capacity price similar to the effect of a physical withholding of capacity. As the Court of Appeals for the D.C. Circuit noted, a physical withholding may occur when “a multi-plant generator prematurely withdraws a unit from participation in the Forward

[182] *Id.*
[183] *Id.*; *see also* IMM Analysis of 2025/2026 Auction, *supra* note 4 at 5 (“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.”).
[184] Monitoring Analytics, Quarterly State of the Market Report for PJM*, supra* note 116 at 321.
[185] *Id.*

Capacity Auction, thereby dampening supply, driving up prices, and enjoying higher returns from other plants."[186] The Synapse Report provides troubling hints of this type of outcome in PJM's most recent capacity auction: the non-participation of RMR units decreased supply, especially in the constrained BGE LDA; capacity costs increased by roughly $5 billion; and, as the Synapse Report notes, the owners of the RMR units in the BGE LDA likely earned $360 million more than they would have by bidding the RMR units into the auction.[187]

Although the IMM has a process for evaluating whether a generator's deactivation constitutes an exercise of market power, several factors make it difficult to discern whether that process actually prevents distortion of the capacity market from RMR units' decisions not to participate. As the IMM explains, "[w]hen notified of an intended deactivation, the [market monitoring unit] performs a market power study to ensure that the deactivation is economic, not an exercise of market power through withholding, and consistent with competition."[188] However, the IMM's study is not publicly available, making it difficult to know whether its analysis focuses solely on the proposed deactivation or whether that analysis also encompasses RMR units' decisions about whether to bid into the capacity market. Additionally, some RMR arrangements provide the Commission with a summary of the IMM's findings, which indicate that the IMM does not evaluate whether an RMR unit's decision not to participate in the capacity market may qualify as an exercise of market power.[189] The practice of filing a summary of the

[186] *See, e.g.*, *Exelon Corp. v. FERC*, 911 F.3d 1236, 1238 (D.C. Cir. 2018) (noting that a physical withholding occurs when "a multi-plant generator prematurely withdraws a unit from participation in the Forward Capacity Auction, thereby dampening supply, driving up prices, and enjoying higher returns from other plants").
[187] Synapse Report, *supra* note 5 at 24, 27.
[188] Monitoring Analytics, Quarterly State of the Market Report for PJM*, supra* note 116 at 360.
[189] Deactivation Avoidable Cost Rate Informational Filing under Section 116 of the PJM Interconnection, L.L.C. Open Access Transmission Tariff, at Attachment 3, Docket No. ER17-750 (Jan. 5, 2017), Accession No. 20140105-5186 ("The IMM analysis did not consider any market power issues that could arise in connection with any PJM determination that reliable system operations may require this unit to continue operating after the retirement dates specified above.").

IMM's findings with the Commission is not universal, and PIOs are not aware of any summary of the IMM's findings that has been filed in a publicly available manner regarding the RMR units in the BGE LDA that elected not to participate in PJM's 2025/2026 capacity auction.

More broadly, the IMM persuasively reasons that as a general matter, RMR units do possess market power: "Because such units are needed by PJM for reliability reasons, and the provision of the service is voluntary in PJM, owners of units that PJM needs to remain in service after the desired retirement date have significant market power in establishing the terms of this reliability service which have generally been set through settlement."[190] The Synapse Report also provides persuasive evidence of the market power of RMR units. For example, the Synapse Report documents that RMR units in the BGE LDA represent a majority of the capacity in that area,[191] meaning that they have market power as pivotal suppliers. More critically, the Synapse Report also documents the vulnerability of PJM's capacity market by showing how just a few RMR units were able to drive a very large increase in capacity prices.[192]

Notably, other RTO/ISOs' capacity markets are not vulnerable to the exercise of market power through the non-participation of RMR units, because market rules in other RTO/ISOs require RMR units to participate in capacity auctions as price-takers, as described above. The fact that PJM's capacity market is thus unusually vulnerable to the exercise of market power by RMR units reinforces the need for swift action by the Commission.

[190] Monitoring Analytics, Quarterly State of the Market Report for PJM*, supra* note 116 at 363.
[191] Synapse Report, *supra* note 5 at 24 ("In 2024/2025, Brandon Shores and Wagner represent roughly 75 percent of generation capacity in BGE LDA, and together they were responsible for over 60 percent of all cleared capacity (inclusive of supply-side generators, demand response, and energy efficiency). With Brandon Shores and Wagner removed from the supply stack, the BGE LDA does not have enough capacity to intercept the demand curve to the right of Point A on its VRR curve. There is not enough capacity to exceed Point A's UCAP Level, and as a result, the BGE LDA clearing price is at its maximum, $466.35/MW-day.").
[192] *Id.* at 27 (describing how the 2025/2026 auction would have cleared at a significantly lower price, saving consumers $5 billion, if the RMR units in the BGE LDA had participated); *see also* IMM Analysis of 2025/2026 Auction, *supra* note 4, at 2, 14 (showing that RMR units' non-participation in the most recent auction drove a $4.2 billion increase in overall auction revenues despite those units reflecting 1.1% of supply).

D. Absent immediate action from the Commission, PJM's capacity market will continue to yield unjust and unreasonable outcomes.

PJM plans to conduct three Base Reliability Auctions in the next 15 months, with auctions planned for December 2024, June 2025, and December 2025.[193] Unless the Commission requires PJM to reform its capacity market rules to better incorporate the resource adequacy value of RMR units, the next capacity auctions are very likely to clear at excessive prices, just as the most recent auction did. The stakes for consumers are extremely high; each subsequent auction may cost consumers $4 billion to $5 billion in excess costs.

High capacity market prices are not likely to cause RMR units to bid into the capacity market. As the Synapse Report found, the owners of the RMR units in the BGE LDA likely earned $360 million more by not bidding the RMR units into the capacity market than they would have if the RMR units had bid and cleared.[194] Additionally, RMR units would not likely respond to a high price by offering into the capacity market, because their capacity market earnings would be deducted from their RMR payments.[195]

Similarly, although high capacity prices are intended to serve as a signal for investment in new generation, the rapid pace of the upcoming capacity auctions, combined with the slow pace of PJM's interconnection queue, make it unlikely that new generation will be able to come online quickly enough to change the likely results from upcoming auctions. While a large amount of new generation is currently in PJM's interconnection queue, progress through the queue remains quite slow.[196] For example, while PJM has a "fast lane" interconnection study

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[193] *See* PJM, Capacity Market (RPM), https://www.pjm.com/markets-and-operations/rpm (downloadable as an Excel spreadsheet at "Auction Schedule").
[194] Synapse Report, *supra* note 5 at 8, 27.
[195] *See*, *e.g.*, Brandon Shores CORS, *supra* note 128, at Attachment A § 5.5 (noting that the RMR unit "will credit monthly net revenues . . . earned from any sales of . . . capacity").
[196] *See* Queued Up 2024, *supra* note 111 at 9, 12, 35; *see also* PJM Interconnection, LLC, Protest of Public Interest Organizations, at 6–11, Docket No. ER24-2045-000 (June 20, 2024), Accession No. 20240620-5242 (describing PJM's clogged, lengthy interconnection queue).

process that it expects to use along with its first "transition cycle" to clear 56,000 MW (nameplate) of new generation through the queue, PJM projects that "fast lane" process will be complete "by late 2025."[197] Under the current schedule, at least two, and possibly three, more capacity auctions will have happened—with billions of dollars of excess costs for consumers—by that time. Moreover, PJM is quick to cast doubt on whether new projects that clear the queue will get built promptly[198] (while failing to recognize the role its own queue delays play in delaying project construction).[199] As the Synapse Report notes summarizes, "wait times for new entrants to the queue could be longer than 3.5 years" due to "high uncertainty around queue waiting times, the current backlog, and interconnection reforms," which means that "their entry into the market will not help to address the anticipated RMRs and the related capacity market disruptions."[200]

Furthermore, as discussed above, RMR arrangements may become increasingly common in PJM as it anticipates forty GW of retirements by 2030 and the interconnection queue remains slow.[201] If RMRs become more common, their non-participation in the capacity market is likely to cause even more pervasive and extreme increases in capacity market prices.

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[197] PJM, *PJM Reaches Next Interconnection Milestone*, PJM Inside Lines (Aug. 6, 2024), https://insidelines.pjm.com/pjm-reaches-next-milestone/.

[198] *Id.*

[199] *See Improvements to Generator Interconnection Procedures and Agreements*, 184 FERC ¶ 61,054 at P 43 (2023) ("Order No. 2023") (noting that "delayed interconnection study results or unexpected cost increases can disrupt numerous aspects of generating facility development"); *id.* at P 971 ("Interconnection customers face financial harm when study deadlines are not met, ultimately inhibiting their ability to interconnect to the system in a reliable, efficient, transparent, and timely manner"); *see also* Abraham Silverman, et al., *Outlook for Pending Generation in the PJM Interconnection Queue* at 7 (May 2024), https://www.energypolicy.columbia.edu/wp-content/uploads/2024/05/PJM-Interconnection-CGEP_Report_042924-2.pdf (describing the key finding that "PJM's increasingly lengthy interconnection process is exacerbating siting and permitting challenges and leading to knock-on delays in equipment procurement and financing decisions, suggesting the timeline for new generation in this market will likely remain long for the foreseeable future.").

[200] Synapse Report, *supra* note 5 at 33.

[201] *Supra* § II(F).

All of these factors—the rapid pace of PJM's auctions, the slow pace of the interconnection queue preventing new entry before subsequent auctions cause further excessive prices, and the prospect of an increasing number of RMRs further distorting capacity prices—mean that it is urgent for the Commission to act to require reforms.

Equitable factors further reinforce the urgency for action by the Commission. As described above, ratepayers in the BGE LDA currently bear the brunt of paying for both the majority of the cost of RMR units in that LDA—hundreds of millions of dollars annually—while simultaneously paying the highest prices possible in PJM's capacity market. The BGE LDA also includes numerous disadvantaged communities in which consumers bear some of the highest energy burdens in the nation, according to DOE's Climate and Economic Justice Screening Tool. For example, DOE's screening tool identifies several census tracts in the Baltimore area where consumers are ranked above the 90th percentile, and in some instances as high as the 98th or 99th percentile for energy cost, as measured by average annual costs divided by household income, and in some instances as high as the 98th or 99th percentile for low income.[202] The extreme energy burdens faced by consumers in the BGE LDA highlight how PJM's capacity is causing serious equity and energy and environmental justice problems that require immediate resolution by the Commission.

Recent precedent further reinforces that it is urgent for the Commission to act quickly to prevent inequitable impacts from PJM's capacity auctions because the Commission has little to no ability to redress inequities once PJM reaches critical points in its capacity auction process. For example, the Court of Appeals for the Third Circuit recently held that the filed rate doctrine

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[202] *See*, *e.g.*, DOE, Climate and Economic Justice Screening Tool: Explore the Map, https://screeningtool.geoplatform.gov/en/#3/33.47/-97.5 (information for census tracts 24510200200, 24510190300, and 24510200400 in Baltimore City, Maryland).

constrained the Commission's authority to redress inequitable outcomes from PJM's capacity market, explaining that "equities play no role in [the] application of the filed rate doctrine . . . no matter how compelling the equities" and regardless of whether that rule may "produce a harsh result."[203] In light of the court's ruling, the Commission was required to approve capacity auction results that were based on an "LDA Reliability Requirement [that] was overstated and inaccurate" for the DPL South LDA and that forced ratepayers who already faced significant energy burdens to "pay over $100 million in excess of what would have been necessary" under accurate rules.[204]

Each of the three then-Commissioners filed concurrences expressing strong disagreement with the Commission's inability to redress inequities and disapproval of the inequitable results. Chairman Phillips stressed that "*equity always matters*," that he "did not join this Commission in order to rubber stamp such patently inequitable outcomes," and that the Commission should "take all necessary steps to ensure that we never find ourselves in this position again."[205] Commissioner Clements noted that the filed rate doctrine has led to "a string of unjust outcomes stemming from the courts' narrow view of that doctrine," and emphasized that if PJM fails "to prevent inequitable outcomes, then it will fall to the Commission to cure this failure pursuant to its authority under section 206 of the Federal Power Act."[206] Commissioner Christie reiterated that the excessive prices at issue in that case "would in no universe . . . be considered just and reasonable," emphasized that the application of the filed rate doctrine did in fact lead to inequitable results, and emphasized that the Commission shares responsibility to protect consumers from "dramatic rate increases" and that in light of the complexities and potential

[203] *PJM Power Providers Grp. v. FERC*, 96 F.4th 390, 400–401 (3d Cir. 2024) (quotation marks omitted).
[204] *PJM Interconnection, LLC*, 187 FERC ¶ 61,065 at PP 5, 25–26 (2024).
[205] *Id.* at PP 3–4 (Chair Philips, concurring).
[206] *Id.* at PP 2, 4 (Clements, Comm'r, concurring).

inequities of PJM's capacity market the Commission must ensure "that it is not consumers who must abandon all hope."[207]

The urgency for the Commission to act to prevent inequitable outcomes is even greater here than it was in the recent litigation regarding inequitable outcomes for ratepayers in the DPL South LDA. In that case, the excessive costs for consumers were roughly $100 million, but in this case the excessive costs are vastly greater—at least $4.2 billion from the most recent auction and likely similar impacts from imminent auctions.

PIOs have filed this Complaint as early as possible in order to provide the Commission with as much opportunity as possible to prevent inequitable outcomes. PIOs also strongly encouraged PJM to delay its upcoming capacity auctions so that it could pursue reforms to better account for the resource adequacy contributions of RMR resources and avoid excessive capacity prices and inequitable outcomes.[208] However, despite having delayed previous auctions based on the possibility that its capacity market rules "may be unjust and unreasonable and require change,"[209] the PJM Board recently refused to do so.

E. A range of just and reasonable approaches are available that would avoid inaccurate price signals and harm to consumers

For all the reasons articulated above, PJM current tariff and practices are unjust and unreasonable in failing to account for RMRs when clearing the capacity auction. It is critical that the Commission require PJM to revise its tariff to consistently account for the resource adequacy contributions of RMR units and thus produce capacity rates that send accurate price signals and

[207] *Id.* at PP 1–3 (Christie, Comm'r, concurring) (quotation marks omitted).
[208] Letter from Sierra Club, Earthjustice, Union of Concerned Scientists, Natural Resources Defense Council, and Public Citizen to PJM Board of Managers, Re: Support for Urgent Reforms Regarding Reliability Must Run Units and the PJM Capacity Market (Sept. 6, 2024), https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/2024/20240906-pios-letter-of-support-to-pjm-bard-on-rmrs-in-rpm.ashx.
[209] *See* PJM Interconnection, LLC, Section 205 Filing to Delay Upcoming RPM Auctions at 4, Docket No. ER23-1609, April 11, 2023, Accession No. 20230411-5057.

avoid imposing billions of dollars in excess costs on consumers. As described below, PIOs believe that PJM may justly and reasonably account for RMR units in its capacity market by either including them as supply or by reducing the amount of capacity procured. PIOs respectfully request that the Commission issue an order requiring PJM to submit tariff revisions providing for RMR resources to be reflected in capacity market clearing. PIOs further request that the Commission delay the upcoming 2026/2027 Base Residual Auction for a limited time as needed for the revised tariff to be approved and implemented, or otherwise have the upcoming BRA run subject to refund.

As described in Mr. Wilson's affidavit, there are two basic approaches that PJM could take to address this issue. First, the Commission could require the RMR units to offer into the capacity market as a price taker, "consistent with economic theory and FERC policy."[210] Essentially, this approach would mirror the market rules that the Commission has already approved in NYISO and ISO-NE. This approach would require PJM to amend its OATT provisions regarding exceptions to the must-offer rule, including OATT Attachment DD, section 6.6(g).

Second, Mr. Wilson offers an alternative "economically efficient approach that would continue to allow RMR units to avoid taking on RPM capacity obligations."[211] Under this approach, "the RMR unit's contribution to resource adequacy could be represented within the resource adequacy analysis that determines the locational Reliability Requirements that will be acquired through RPM."[212] As Mr. Wilson explains:

[210] Wilson Aff., *supra* note 6 at P 37. Mr. Wilson observes that to the extent the RMR unit owner faces exposure to Capacity Performance penalties (i.e., that the RMR arrangement does not take that risk off the unit owner), it may be appropriate for the owner to offer the RMR unit at a non-zero price reflecting some degree of Capacity Performance Quantifiable Risk. *Id.* at P 38.
[211] *Id.* at P 39.
[212] *Id.*

> The RMR unit would be represented as a resource with capacity injection rights that is called by PJM when needed for reliability at its location (consistent with the RMR arrangement) within the resource adequacy modeling. The unit's performance characteristics, including outage rate, would be modeled. RMR agreements typically allow necessary investments to remain in operation over the required period, so it would be reasonable to assume future performance would be consistent with historical performance.[213]

Mr. Wilson further explains that "[t]his approach can be expected to reduce the Reliability Requirements in the unit's locational delivery area by roughly the resource adequacy value of the RMR unit in that zone, and also in parent zones."[214] He concludes that "[r]educing the Reliability Requirement this way would result in roughly the same clearing prices, in both the local and parent zones, as including the RMR unit as a supply resource in RPM."[215]

PIOs are aware that PJM has expressed concerns that a must-offer requirement for RMR resources would deter some of those resources from accepting an RMR arrangement.[216] While it seems possible that a capacity market obligation would impose no actual incremental costs on an RMR resource, due to the RMR arrangement covering most or all of the going-forward costs of the unit,[217] this may be a reason for the Commission to consider the demand-side adjustment framework described by Mr. Wilson. Regardless of which approach the Commission chooses, it is critical that the result be capacity price signals that reflect the actual balance of supply and demand on the system with the RMR unit in operation. Complainants urge the Commission to

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[213] *Id.* at P 40.
[214] *Id.* at P 41.
[215] *Id.* The IMM has also proposed two alternative solutions to PJM's inconsistent rules, which are generally consistent with Mr. Wilson's affidavit. *See* IMM Analysis of 2025/2026 Auction, *supra* note 4, at 6 ("The MMU recommends that PJM treat the inclusion of RMR resources in the capacity market consistently. . . . 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.").
[216] PJM Board of Managers Response, *supra* note 123 at 4.
[217] In his recent analysis, the IMM notes that "[i]ncluding 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." IMM Analysis of 2025/2026 Auction, *supra* note 4 at 6.

issue a Show Cause order with a date certain for PJM to bring forward a solution that would achieve this objective.

To ensure the effectiveness of whatever remedy the Commission favors, PIOs respectfully request that the Commission immediately establish a refund date of the date of this Complaint, as authorized under section 206 of the FPA.[218] The FPA explicitly authorizes the Commission to:

> order refunds of any amounts paid, for the period subsequent to the refund effective date through a date fifteen months after such refund effective date, in excess of those which would have been paid under the just and reasonable rate, charge, classification, rule, regulation, practice, or contract which the Commission orders to be thereafter observed and in force.[219]

PJM's capacity auction is a multi-step process,[220] and PIOs believe it is critical that the Commission act swiftly in this case. The immediate establishment of a refund effective date of the date of this Complaint will put PJM and its members on fair notice that the conduct of upcoming capacity auctions will be subject to the Commission's establishment of a just and reasonable set of rules for accounting for the resource adequacy contributions of RMR resources, and that unjust and unreasonable proceeds from upcoming capacity auctions will be subject to refunds.[221]

IV. RULE 206 REQUIREMENTS

To the extent not already provided above, PIOs provide the following additional information required by Rule 206 of the Commission's Rules of Practice and Procedure.[222]

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[218] 16 U.S.C. § 824e.
[219] *Id.* § 824e(b).
[220] The schedule of pre-auction deadlines for December's 2026–27 auction can be downloaded at https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/rpm-auction-schedule.ashx.
[221] *See PJM Power Providers Grp.*, 96 F.4th at 398 (noting the importance of "fair notice" in determining what is retroactive under the filed rate doctrine); *see also Landgraf v. USI Film Products*, 511 U.S. 244, 270 (noting that "retroactivity is a matter on which judges tend to have 'sound . . . instinct[s]', and familiar considerations of fair notice, reasonable reliance, and settled expectations offer sound guidance." (internal citation omitted)).
[222] 18 C.F.R. § 385.206.

A. **Good Faith Estimate of Financial Impact or Harm (Rules 206(b)(3) and (4)):** As documented above, PJM's unjust and unreasonable rules allowing RMR units to choose whether to participate in the capacity market led to an estimated $4.2 to 5 billion in excess costs in the 2025/2026 capacity auction. Those excessive costs will likely increase monthly utility bills for PIOs' members, including PIOs' members in the BGE LDA who will likely see a 19% increase in monthly bills, or $21/month for the average residential customer. Unless the Commission acts quickly, PIOs expect similarly excessive costs from PJM's upcoming auctions in December 2024 and June 2025, which could again drive up monthly utility bills for PIOs' members.

B. **Practical, operational, or other nonfinancial impacts (Rule 206(b)(5)):** PIOs believe that the impacts from PJM's unjust and unreasonable rules regarding RMR units are primarily financial. Because RMR arrangements generally authorize PJM to call on RMR units to provide an array of reliability-related services, as described above, PJM's failure to account for RMR units in the capacity market creates financial harms for consumers in the form of excessive and unreasonable costs, but does not actually prevent or alter the operation of RMR units as PJM may determine they are needed.

C. **Other Pending Matters (Rule 206(b)(6)):** Aspects of this Complaint are at issue in other matters. Whether specific RMR units in the BGE LDA, namely the Brandon Shores and Wagner units, should offer into the capacity market is at issue in ER24-1787 and ER24-1790. However, resolving those matters would not resolve the core issue in this Complaint of whether PJM's capacity market rules are unjust and unreasonable because they fail to account for the capacity value of RMR units that consumers pay to keep online, nor would resolution of those matters establish rules applicable to future RMR resources. Additionally, PIOs do not believe that disputes about the Brandon Shores and Wagner RMR arrangements will likely be resolved quickly enough to affect the outcome of the upcoming capacity auctions currently scheduled for December 2024, June 2025, and December 2025.

PIOs are also working in a stakeholder process in PJM to advocate for reforms that would lead the capacity market to more accurately incorporate the capacity value of RMR units that consumers pay to keep online. However, PIOs do not believe that the PJM stakeholder process will be resolved quickly enough to affect the outcome of the upcoming capacity auctions currently scheduled for December 2024, June 2025, and December 2025.

D. Specific Relief or Remedy Request (Rule 206(b)(7)): The Complaint sets forth in detail the specific relief requested.

E. Documents Supporting the Complaint (Rule 206(b)(8)): In addition to materials cited herein, PIOs are attaching to this complaint the following documents:

- Attachment 1: Monitoring Analytics, Analysis of the 2025/2026 RPM Base Residual Auction Part A
- Attachment 2: Maryland Office of People's Counsel, Bill and Rate Impacts of PJM's 2025/2026 Capacity Market Results & Reliability Must-Run Units in Maryland, Prepared by Synapse Energy Economics
- Attachment 3: Affidavit of James F. Wilson
- Attachment 4: Declaration of Justin Vickers
- Attachment 5: Communications with the PJM Board of Managers
- Attachment 6: Excerpts from RMR arrangements

F. **Alternative Dispute Resolution (Rule 206(b)(9)):** PIOs have not used the Commission's Enforcement Hotline or Dispute Resolution Services and do not believe at this time that alternative dispute resolution would resolve the issues underlying this Complaint. PIOs have no reason to expect that alternative dispute resolution would yield the requested relief.

G. **Form of Notice (Rule 206(b)(10)):** A form of notice of Complaint suitable for publication in the Federal Register is attached.

H. **Fast Track Processing (Rule 206(b)(11)):** PIOs do not seek fast track processing.

I. **Service (Rule 206(c)):** PIOs have served a copy of this Complaint on representatives for the Respondent (including those corporate officials designated by PJM on the FERC website for receipt of complaints) via e-mail, simultaneous with the filing of this Complaint.

V. COMMUNICATIONS

Pursuant to Rule 203(b) of the Commission's Rules of Practice and Procedure,[223] PIOs specify that communications in this matter are to be addressed to the following persons:

Nick Lawton
Senior Attorney
Clean Energy Program
Earthjustice
1001 G Street, NW Suite 1000
Washington, DC 20001
(202) 780-4835
nlawton@earthjustice.org

Justin Vickers
Senior Attorney
Sierra Club Environmental Law Program
1229 W Glenlake Ave.
Chicago, IL 60660
(224) 420-0614
justin.vickers@sierraclub.org

[223] 18 CFR § 385.203(b).

VI. CONCLUSION

For all the reasons explained above, PIOs respectfully request that the Commission establish a refund effective date of the date of this Complaint, find that PJM's failure to consistently account for the resource adequacy contributions of RMR resources is unjust and unreasonable, and protect consumers from having to pay twice for capacity by requiring PJM to amend its capacity market rules.

DATED: September 27, 2024

Respectfully submitted,

/s/ Nick Lawton Nick Lawton Senior Attorney Clean Energy Program Earthjustice 1001 G St. NW, Suite 1000 Washington, DC 20001 (202) 780-4835 nlawton@earthjustice.org	/s/ Justin Vickers Justin Vickers Senior Attorney Sierra Club Environmental Law Program 1229 W Glenlake Ave. Chicago, IL 60660 (224) 420-0614 justin.vickers@sierraclub.org
/s/ Casey A. Roberts Casey A. Roberts Senior Attorney, Sierra Club 1536 Wynkoop St., Suite 200 Denver, Colorado, 80202 T: (303) 454-3355 casey.roberts@sierraclub.org	/s/ Mike Jacobs Mike Jacobs Senior Energy Analyst Union of Concerned Scientists 1825 K St. NW, Suite 800 Washington, DC 20006 (617) 301-8057 mjacobs@ucsusa.org
/s/ Claire Lang-Ree Claire Lang-Ree Advocate, Sustainable FERC Project Natural Resources Defense Council 40 W 20th St. New York, NY, 11216 (530) 414-3243 clangree@nrdc.org	/s/ Thomas Rutigliano Thomas Rutigliano Senior Advocate, Sustainable FERC Project Natural Resources Defense Council 1125 15th Street NW, Suite 300 Washington DC, 20005 trutigliano@nrdc.org

/s/ Tyson Slocum Tyson Slocum Energy Program Director Public Citizen, Inc. 215 Pennsylvania Ave, SE Washington, DC 20003 tslocum@citizen.org	

CERTIFICATE OF SERVICE

I hereby certify that I have on this date caused a copy of the foregoing document to be served upon PJM Interconnection, LLC, at the following addresses obtained from the Commission's list of corporate officials designated to receive services pursuant to 18 C.F.R. § 385.2010(k):

Thomas DeVita
Assistant General Counsel
PJM Interconnection, LLC
2750 Monroe Boulevard
Audubon, PA 19403
Telephone: (610) 635-3042
FERCeService@pjm.com

Steven R. Pincus, Esquire
Associate General Counsel
PJM Interconnection, LLC.
2750 Monroe Boulevard
Audubon, PA 19403
Telephone: 610-666-4370
steven.pincus@pjm.com

Dated: September 27, 2024

/s/ Nick Lawton
Nick Lawton
Senior Attorney
Clean Energy Program
Earthjustice
1001 G Street, NW Suite 1000
Washington, DC 20001
(202) 780-4835
nlawton@earthjustice.org

ATTACHMENT 1:

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

Monitoring Analytics

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

The Independent Market Monitor for PJM

September 20, 2024

Introduction

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

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

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

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

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

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

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

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

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

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

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

Conclusions

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

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

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

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

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

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

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

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

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

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

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

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

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

Recommendations

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

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

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

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

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

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

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

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

Summary of Results

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

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

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

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

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

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

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

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

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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	
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
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	
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
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

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

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

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

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

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

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

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

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

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

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

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

ATTACHMENT 2:

Md. Office of People's Counsel, Bill and Rate Impacts of PJM's 2025/2026 Capacity Market Results & Reliability Must-Run Units in Maryland, Prepared by Synapse Energy Economics

August 30, 2024

Via email

PJM Board of Managers
Mark Takahashi, Chair
Manu Asthana, President and CEO
PJM Interconnection, L.L.C.
2750 Monroe Blvd.
Audubon, PA 19403

Re: Urgent Reforms to the PJM Capacity Market Regarding Reliability Must Run Units

Dear Chairman Takahashi and President Asthana,

The undersigned organizations respectfully request that the PJM Board take immediate action to protect ratepayers throughout the PJM region—and especially in the BGE Load Deliverability Area (LDA)—from unjust and unreasonable prices in the PJM capacity market caused by the non-participation of power plants operating under Reliability Must Run arrangements (RMR). As a recent report demonstrates, the failure of two power plants slated for operation under RMR arrangements starting at the beginning of the delivery year of the just-completed base residual auction (BRA) to participate in that auction could have caused excessive capacity costs of roughly $5 billion.[1] To prevent similarly unjust and unreasonable prices in upcoming capacity auctions, we request that the Board urgently institute a Critical Issue Fast Path process to develop rules that will require the capacity value of RMR units to be considered in the capacity market, effective for the next BRA. If necessary to have time to institute the appropriate changes, the Board may need to delay the auction currently scheduled for December 2024. While several of our organizations have stressed the importance of returning to three-year-forward auctions as soon as possible, we agree that it is critical to revise these rules before another auction commits consumers to paying yet another year of excessive and unreasonable capacity prices.

As the attached report from Synapse Energy Economics on behalf of the Maryland Office of People's Counsel demonstrates, the record-setting price spike in the most recent

[1] *See* Synapse Energy Economics, Inc., *Bill and Rate Impacts of PJM's 2025/2026 Capacity Market Results & Reliability Must-Run Units in Maryland* (Aug. 2024), https://opc.maryland.gov/Portals/0/Files/Publications/RMR%20Bill%20and%20Rates%20Impact%20Report_2024-08-13%20Final%20corrected%208-29-24.pdf?ver=fHKa18_idtwi4Rm4OeK-7A%3d%3d.

PJM capacity auction resulted in large part from the fact that power plants operating under RMRs are not required to—and did not—participate in the capacity market. The most recent capacity auction resulted in a more than 800 percent increase in capacity prices, with RTO-wide prices surging more than nine-fold from $29/MW-day to $270/MW-day, and with prices reaching caps in the constrained BGE LDA of $466/MW-day. However, as the Synapse report shows, if two power plants slated for operation under RMRs during the delivery period covered by the auction—the Brandon Shores and Wagner plants—had participated in this most recent capacity auction, the resulting prices would have been far lower, under certain assumptions regarding bids and clearing prices. The BGE LDA would not have reached its price cap and would instead have cleared along with the rest of the RTO at a price of $163.46/MW-day. In other words, the RMR units' non-participation in the capacity market cost consumers roughly $5 billion.

The record-setting prices stemming from RMR units' non-participation in the capacity auction are unjust and unreasonable. The absence of any requirement for RMR units to participate in the capacity market, or for PJM to consider RMRs in determining capacity needs, unreasonably forces consumers to pay twice for reliability—once to keep RMR units online and again in a capacity market that ignores these units' continued operations.[2]

The lack of any requirement for RMR units to participate in the capacity market renders the market vulnerable to unreasonable outcomes. In the most recent auction, the exclusion of capacity from just two RMR units, the 1,282 MW (nameplate capacity) Brandon Shores plant and the 841 MW (nameplate) Wagner plant, created a $5 billion windfall for generation owners at consumers' expense. And as the Synapse report shows, not offering these two units allowed their owner, Talen Energy, to pocket $360 million more than it otherwise would have from the capacity market.

Moreover, the market's vulnerability to unreasonable outcomes driven by RMR unit non-participation will likely become an increasingly severe problem. PJM anticipates roughly 40 gigawatts (GW) of retirements by 2030. Without significant reforms, PJM lacks adequate procedures to prevent the need for RMRs for many of these retiring units. Hence, RMR generators may look in the future to exploit gaps in the capacity market rules by not bidding into the market, bringing about costly results for customers unless PJM takes swift action.

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[2] *See New York Indep. Sys. Operator, Inc.*, 155 FERC ¶ 61,076 (2016), at P 82, (aff'd on rehearing at *New York Indep. Sys. Operator, Inc*., 161 FERC ¶ 61,189 (2017), at PP 54-63) (finding that RMR units should participate in the capacity market as price takers because if they failed to clear, "ratepayers will pay twice—once for the cost of the RMR agreement, and again for the generator that otherwise would not have cleared the market").

RMR units' non-participation in the capacity market also causes the market to send inaccurate price signals. The temporarily higher prices that result from non-participation of these units signal a degree of capacity scarcity that does not exist, since RMR units are operational during the delivery year in question and in many circumstances available to PJM during capacity emergencies.[3] Furthermore, these price spikes are unlikely to drive significant additional investment in new generation since developers would expect the prices to drop once the needed transmission upgrades are complete, and because of the well-documented delays in PJM's interconnection queue. Such price spikes are unreasonable when they do not reflect the real-world supply-demand balance and are unlikely to prompt near-term resource adequacy improvements.

Other RTO/ISOs prevent these issues by requiring RMR units to participate in their capacity markets. For example, New York ISO and ISO New England both require RMR units to participate in its capacity market as price-takers.[4] Similarly, California ISO requires RMR units to participate in its resource adequacy procurement mechanism.[5] Hence, PJM's failure to require RMR units to participate in its capacity market makes it an outlier among RTOs.

Unless PJM takes swift action, the serious defects in PJM's capacity market stemming from not including RMR units will likely result in unjust and unreasonable prices in subsequent auctions currently scheduled for December 2024 and June 2025. Interconnection of new generation remains slow in PJM, with the queue still badly clogged and no new interconnection requests being processed until at least 2026. Because new generation cannot come online quickly, the high capacity market prices are not an effective signal for new entry but instead a windfall for the owners of existing generation.

For all these reasons, we respectfully request that the PJM Board take immediate action to revise its capacity market rules to require the capacity market to reflect continued operation of RMR units, as supply, decreased capacity need, or other equivalent means. The Board should institute a Critical Issue Fast Path process to develop these rules, while minimizing any delay to the upcoming capacity auction currently

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[3] *See, e.g.*, *ISO New England*, 179 FERC ¶ 61,139 (2022), at PP 50, 52 (finding that excluding resources that will be available from the capacity market forces consumers to buy unnecessary capacity and results in prices that do not send efficient entry and exit signals); *ISO New England Inc.*, 165 FERC ¶ 61,202, at P 83 (2018).

[4] *New York Indep. Sys. Operator, Inc.*, 155 FERC ¶ 61,076 (2016), at P 82; *ISO New England Inc.*, 165 FERC ¶ 61,202, at P 83; *id.* at P 87 ("ISO-NE has demonstrated that retaining a resource outside of the FCA would not account for its contribution to meeting ISO-NE's resource adequacy needs, would result in procuring excess capacity, and would distort the capacity price.").

[5] *California Indep. Sys. Operator*, 168 FERC ¶ 61,199 at PP 7, 72–76 (2019).

scheduled for December 2024. Without such reforms, the capacity market will be unable to deliver just and reasonable results.

We respectfully request that the PJM Board address this issue swiftly—and by no later than September 20, 2024. We hope to collaborate with the PJM Board and PJM staff on prompt reforms to address this serious flaw in the capacity market design through a Critical Issue Fast Path process.

Sincerely,

David S. Lapp
People's Counsel
Maryland Office of People's Counsel

/s/ Ruth Ann Price
Ruth Ann Price
Acting Public Advocate
Delaware Division of the Public Advocate

Sandra Mattavous-Frye
People's Counsel
Office of the People's Counsel for the District of Columbia

Sarah Moskowitz
Executive Director
Citizens Utility Board of Illinois

/s/ Brian O. Lipman
Brian O. Lipman
Director
New Jersey Division of Rate Counsel

Maureen R. Willis
Consumers' Counsel
Office of the Ohio Consumers' Counsel

Bill and Rate Impacts of PJM's 2025/2026 Capacity Market Results & Reliability Must-Run Units in Maryland

OPC
Office of People's Counsel
State of Maryland

August 2024

(corrected 8/29/24)

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Report prepared for the Maryland Office of People's Counsel by Synapse Energy Economics, Inc., a research and consulting firm specializing in economic and policy research, modeling, and analysis to provide electric sector solutions.

GLOSSARY

BRA	Base Residual Auction	The PJM capacity auction, called the Base Residual Auction, procures "capacity" power supply resources in advance of the delivery year to meet electricity "resource adequacy" needs in the PJM service area, which includes all or part of 13 states and the District of Columbia. Auctions are usually held three years in advance of the delivery year. Due to recent changes in market design, among other factors, PJM held the most recent BRA, in July, 2024, for the delivery year starting June 1, 2025 (the BRA 25/26), with the auction held only about one year in advance of the beginning of the delivery year. PJM currently intends to conduct subsequent BRAs on an accelerated basis to enable returning to the 3-year forward schedule. The BRA is the first auction, in a cycle of several auctions for each delivery year underPJM's Reliability Pricing Model (RPM), or capacity market, where the majority of the RPM capacity is procured for a particular delivery year.
CETL	Capacity Emergency Transfer Limit	Capacity Emergency Transfer Limit (CETL) is the capability of the transmission system to support deliveries of electric energy to a given area (or LDA, see below) experiencing a localized capacity emergency as determined in accordance with the PJM Manuals.
CETO	Capacity Emergency Transfer Objective	The amount of electric energy that a given area (a LDA) must be able to import in order to remain within a loss of load expectation of one event in 25 years (or its expected unserved energy (EUE) equivalent under the new PJM reliability metrics starting with the 25/26 BRA) when the area is experiencing a localized capacity emergency.
CONE	Cost of New Entry	CONE represents the total annual net revenue (net of variable operating costs) that a new generation resource would need to recover its capital investment and fixed costs, given reasonable expectations about future cost recovery over its economic life. CONE is the starting point for estimating the Net Cost of New Entry (Net CONE). Net CONE represents the first-year revenues that a new resource would need to earn in the capacity market, after netting out energy and ancillary service (E&AS) margins from CONE. This metric is used in calculating the VRR Curve (see below) which is used to define the administrative cost cap to the BRA.
CSRR	Cost of Service Recovery Rate	One of two options RMR (see below) owners can elect for cost recovery for an RMR agreement. See text for more details on the CSRR method.
CTR	Capacity Transfer Rights	A method of allocating the economic value of transmission import capability that exists into a constrained Locational Deliverability Area (LDA) to Load Serving Entities (LSEs).
DACR	Deactivation Avoidable Cost Rate	One of two options RMR (see below) owners can elect for cost recovery for an RMR arrangement. See text for more details on the DACR method.
DY	Delivery Year	The PJM capacity auction procures commitments for a delivery year, beginning June 1 and ending May 30th. The RPM was and is intended to provide for the conduct of each annual capacity auction (or BRA) three years in advance of the beginning of the running of the delivery year commitment procured through the auction. Currently due to slippage resulting from multiple causes, PJM just completed the most recent BRA, in July, 2024, for the 25/26 delivery year, which begins at the same time

		(June 1, 2025) as the scheduled beginning of the Brandon Shores and Wagner RMR arrangements. The 24/25 delivery year was already procured through a previously completed auction.
E&AS	Energy & Ancillary Services Revenues	Revenues from the energy and ancillary services markets, which are unit-specific. E&AS are historically netted out of Market Seller Offer Caps, and/or Net Cost of New Entry calculations.
EFORd	Equivalent Demand Forced Outage Rate	A measure of the probability that a generating unit will not be available due to a forced outages or forced deratings when there is a demand on the unit to generate.
ELCC	Effective Load Carrying Capability	ELCC provides a way to assess the capacity value (or reliability contribution) of a resource (or a set of resources) that is tied to the loss-of-load probability concept. ELCC can be defined as a measure of the additional load that the system can supply with a particular generator of interest, with no net change in reliability. ELCC can be based on any reliability metric (e.g., Loss of Load Expectation (LOLE), Loss of Load Hours (LOLH), or Expected Unserved Energy (EUE)). PJM shifted from its prior use of LOLE to an EUE metric for the most recently completed BRA (2025/2026) which was conducted in July, 2024
EUE	Expected Unserved Energy	This is defined as a measure of the resource availability to continuously serve all loads at all delivery points while satisfying all planning criteria. The EUE is energy-centric and analyzes all hours of a particular year. Results are calculated in megawatt hours (MWh). The EUE is the summation of the expected number of megawatt hours of load that will not be served in a given year as a result of demand exceeding the available capacity across all hours.
FERC	Federal Energy Regulatory Commission	The federal agency that regulates wholesale electric power sales and transmission rates.
ICAP	Installed Capacity	A MW value based on the summer net dependable capability of a unit and within the capacity interconnection right limits of the bus to which it is connected.
IMM	Independent Market Monitor	PJM's Independent Market Monitor is responsible for guarding against the exercise of market power in PJM's markets and assisting in the maintenance of competitive and nondiscriminatory markets in PJM. The IMM operates independently from PJM staff and members to objectively monitor, investigate, evaluate, and report on PJM's markets. Monitoring Analytics serves as PJM's independent market monitor.
IRM	Installed Reserve Margin	Percentage value used to establish the level of installed capacity resources that provide an acceptable level of reliability.
LDA	Locational Deliverability Area	Sub-regions of PJM's "footprint" used to evaluate locational constraints of the electric grid. An LDA is an area or zone within the wholesale electric markets administered by PJM, in which local effects of transmission, load, and generating resources are separately accounted for in the operation of PJM's markets. In this report, costs described as allocated to or incurred by a LDA mean costs flowed through to the end-use customers located within that LDA. Maryland is covered by all or portions of 4 LDAs: the BGE LDA, roughly equal to BGE's retail service area (and entirely within Maryland); DPL-South (inclusive of the Maryland eastern shore and southern Delaware); Pepco LDA, covering the retail service areas of

		Pepco (both Maryland and DC) and SMECO; and the APS LDA (including Potomac Edison's Maryland service area and extending to the retail service areas of PE's affiliates in West Virginia and Southwest Pennsylvania). The cost impacts analyzed in this report focus on those anticipated for Maryland customers..
LOLE	Loss of Load Expectation	Loss-of-load expectation (LOLE) defines the adequacy of capacity for the entire PJM footprint based on load exceeding available capacity, on average, only once in 10 years. This is generally defined as the expected number of days per year for which the available generation capacity is insufficient to serve the daily peak demand.
MSOC	Market Seller Offer Cap	PJM uses Market Seller Offer Caps to ensure that resources are submitting competitive offers into the capacity market, thus preventing sellers from exerting market power and setting artificially high prices. A resource's MSOC is equivalent to the costs it would avoid if it retired or if it did not clear in the capacity market and did not operate for the delivery year. It is the minimum capacity price a resource needs to take on a capacity obligation and continue operations for another year.
RMR	Reliability Must-Run	A generating unit slated to be retired by its owners but that is needed for reliability reasons. Typically, PJM requests that the unit remain operational beyond its proposed retirement date until transmission upgrades are completed.
RPM	Reliability Pricing Model	PJM's capacity market design that includes a series of auctions to satisfy the reliability requirements of the PJM region for a Delivery Year. The majority of capacity is procured in the first auction for a particular delivery year, which is known as the Base Residual Auction. This auction is intended to be conducted three years in advance of a given delivery year. The RPM model works in conjunction with PJM's Regional Transmission Expansion Planning process to ensure the reliability of the PJM region for future years.
RTO	Regional Transmission Organization	The organization that coordinates, controls, and monitors a multi-state electric grid. In this report, RTO refers to PJM Interconnection, LLC (or PJM) which operates a competitive wholesale electricity market and manages the high-voltage electricity grid to ensure reliability in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.
UCAP	Unforced Capacity	The megawatt (MW) value of a capacity resource in the PJM Capacity Market. PJM currently uses different methods to accredit the amount of UCAP specific resource types may offer into the PJM capacity market but was shifted to a marginal ELCC approach for the recently completed BRA (for delivery year 2025/2026).
VRR Curve	Variable Resource Requirement	A downward sloping demand curve used in the conduct and settlement of the BRA, both PJM wide and for individually constrained LDAs, that relates the maximum price for a given level of capacity resource commitments relative to reliability requirements.

All definitions above are sourced from the PJM website and its educational materials, as well the North American Electric Reliability Corporation (NERC).

1. EXECUTIVE SUMMARY

PJM Interconnection LLC (PJM), the entity that operates the electricity grid for the Mid-Atlantic region and nearby states, administers a capacity market to assure adequate generation capacity to meet peak loads and reliability standards.[1] As part of its responsibilities, PJM procures capacity through annual competitive auctions. On July 30, 2024, PJM released results for its latest capacity market base residual auction (BRA) for the 2025/2026 delivery year that runs from June 1, 2025 to May 31, 2026. The results showed a more than 800 percent increase in system-wide prices relative to the prior BRA for the 2024/2025 delivery year, a price spike unprecedented in PJM. Across the entire PJM footprint, beginning June 1, 2025, these capacity prices will result in a total annual cost to electric customers of $14.7 billion, a substantial increase from the $2.2 billion in capacity costs in the 2024/2025 delivery year. These surging prices are driven primarily by (1) increases in load, (2) various market rule changes that, among other effects, modify how supply (e.g., generation) is valued in the capacity market, and (3) a reduction in capacity market supply due to plant retirements and retirement-related "reliability-must-run" (RMR) arrangements. The Maryland Office of People's Counsel commissioned Synapse Energy Economics (Synapse) to analyze the likely impacts of the changes in the capacity market and these RMR arrangements on the rates paid by Maryland's electric utility customers.

The capacity market auction is conducted for the entire PJM footprint. Capacity-constrained regions, known as locational deliverability areas (LDAs) can sometimes have separate, higher capacity prices from the RTO as a whole. These LDAs exhibit constraints when comparing the local load within the LDA, the local generation within the LDA, and the PJM-administered transmission system's ability to transfer power into the LDA. The different, typically higher clearing prices for the constrained LDAs reflect the tighter balance of load, local generation, and transmission transfer capacity into the LDA when compared with broader areas of the PJM footprint.

Maryland is included in all or portions of four LDAs:

- *Baltimore Gas and Electric (BGE LDA)*, the only LDA entirely located in Maryland, which is comprised of Baltimore Gas and Electric's (BGE) Maryland service territory;
- *Allegheny Power System (APS LDA)*, which covers portions of Maryland, Pennsylvania, Virginia, and West Virginia, including the service territory of Potomac Edison, which serves customers in Western Maryland, and various municipal utilities in the APS LDA footprint;

[1] PJM administers other product markets, in addition to the capacity market, that are paid for by electric customers. PJM administers the "energy" market for the power consumed by customers continuously over time. It also plans and procures the transmission system within its footprint. In relative terms, the costs of the energy and capacity markets and those due to transmission costs are the three principal cost components of wholesale electric costs borne by electric customers. In 2023, they comprised 62%, 8% and 27%, respectively, on average across the PJM footprint of wholesale electric costs. With the results of the recent 25/26 BRA discussed further in the report, capacity costs beginning June 1, 2025 will comprise nearly 27% of total wholesale costs (up from 8% in 2023), assuming energy and transmission costs remain near 2023 levels. PJM Members Committee, Markets Report, MC Webinar, July 22, 2024. Item 05A - 2 - Market Operations Report Appendix. Available at: https://www.pjm.com/committees-and-groups/committees/mc.aspx

- *Delmarva Power South (DPL-South LDA)*, which covers Maryland and Delaware portions of the Delmarva Peninsula, including Maryland utility Delmarva Power; and
- *Potomac Electric Power (Pepco LDA)*, which covers portions of Maryland and Washington, D.C., including Maryland utilities Potomac Electric Power (Pepco) and Southern Maryland Electric Cooperative (SMECO).

Except for the BGE LDA, the Maryland LDAs cover multiple jurisdictions and encompass other utilities within them. For example, the Pepco LDA includes SMECO, which means that the customer impacts discussed in this report for the Pepco LDA apply equally to SMECO customers. Similarly, the impacts on DPL-South LDA apply to customers of Delmarva Power & Light as well as municipal and cooperative electric utilities on Maryland's Eastern Shore.

Over the past several years, the BGE LDA has been capacity-constrained and has seen higher prices relative to other LDAs. Once again, in the latest base residual auction, for the 2025/2026 delivery year, the BGE LDA was capacity-constrained, and this time it cleared at its maximum possible price: $466/MW-day. This is a six-fold increase from the 2024/2025 BGE LDA BRA clearing price of $73/MW-day. The APS, DPL-South, and Pepco LDAs all cleared at the same clearing price as the full RTO, which saw prices of $270/MW-day, a nine-fold increase from the previous year's results ($29/MW-day). Electric customers pay for capacity at these prices, meaning that the results of this auction will be seen on the bills of electric customers in Maryland starting in 2025 or beyond. In the BGE LDA, the total increase in customer costs from the 2024/2025 to the 2025/2026 BRA auction is $504 million. For the average residential customer in the BGE LDA, this means an additional $16 per month on their electric bills for at least a year (Table 1). Similarly, average residential customers in APS, DPL-South, and Pepco LDAs will see an additional $18, $4, and $14 per month, respectively, on their electric bills starting in 2025 or soon after (Table 1).

Table 1. Bill and Rate Impacts of the 2025/2026 capacity market relative to 2024/2025, for the BGE LDA and the Maryland portion of APS, DPL-South, and Pepco LDAs

Maryland LDAs	**Monthly Bill Change (%)**	**Additional Costs on Monthly Bills ($)**	
	All	Residential	Commercial
BGE LDA Customers	14%	$16	$170
APS LDA Customers (Maryland only)	24%	$18	$81
DPL-South LDA Customers (Maryland only)	2%	$4	$16
Pepco LDA Customers (Maryland only)	10%	$14	$163

Source: See description in text.

The most notable driver behind BGE LDA's record high capacity price is the removal of four generating units from the capacity market, starting in the 2025/2026 delivery year. Specifically, in 2023, Talen Energy, the owner of the aging, large, fossil fuel-fired power plants—Brandon Shores Units 1 & 2 and Wagner Units 3 & 4—announced its intent to retire (or deactivate) the plants, effective June 1, 2025. The units are in the BGE LDA, an area already known for its constrained transmission capacity. PJM determined their retirement could cause grid reliability issues until new transmission solutions can be implemented to bring in electricity from other areas and to address power quality issues arising when the power plants are retired.

While the transmission solutions are being built (that address the reliability issues arising from Talen plant retirements), PJM is arranging for the continued operation of these four units past their proposed retirement date of June 2025. The plants would operate under a “reliability must run,” or “RMR” arrangement and receive payments—funded through customer rates—outside of the competitive wholesale power markets. RMR service is intended to ensure grid reliability until the transmission grid can be enhanced to eliminate the grid reliability concerns associated with the plant retirements.

Under these RMR arrangements, ratepayers will pay the power plants’ owner compensation for the continued operation of the plants under a separate “out of market” regime administered by PJM. Importantly, these RMR units do not participate in the capacity market as supply-side resources, dramatically reducing supply in the already-constrained BGE LDA. In fact, without these units participating in the capacity market in 2025/2026, less than 10 percent of BGE’s cleared capacity was from generation within the BGE LDA, pushing the clearing price for the BGE LDA to the capacity price maximum for the LDA.

The capacity shortfall in BGE LDA from the conversion of Brandon Shores and Wagner to RMR service also likely had spillover effects into the RTO as a whole, increasing the RTO-wide clearing price and impacting customers throughout the region. To determine the effects, we conducted a counterfactual analysis of clearing prices in PJM using assumptions described in more detail in section 3.3. We found that if Brandon Shores and Wagner RMR units had remained as supply-side resources in the capacity market under those assumptions, the RTO as a whole would have cleared at $163.46/MW-day. At that price, electric customers across the RTO would save over $5 billion in that delivery year. Further, comparing this counterfactual analysis to the actual results of the capacity market and Talen’s proposed RMR, we found that Talen’s revenues for the 2025-2026 delivery year are $360 million higher than what they would have been had Talen’s units participated in the capacity market.

Furthermore, the BGE LDA is now so constrained that the cleared resources and imported capacity did not meet the LDA’s reliability requirement for the 2025/2026 delivery year in this auction. The reliability requirement is the target amount of capacity required to meet PJM’s reliability standard, i.e., a loss of load probability of no more than once in 25 years for LDAs. In the 2025/2026 delivery year, there is a capacity shortfall of 176 MW relative to the reliability requirement, suggesting that the probability of reliability issues for the BGE LDA could increase starting June 2025, potentially further impacting customers in addition to higher electric rates.

Because the Talen units are within the capacity-constrained zone of the BGE LDA (located entirely within Maryland), and because the RMR cost allocation follows the cost allocation for the transmission solutions that will eliminate the RMR need, Maryland customers will pay most of these out-of-market RMR costs. Currently, PJM projects that the planned transmission solutions will be completed by December 2028, after which the RMR units would no longer be needed. Until that time—or later, if the transmission solutions take longer to construct—customers of local utilities in these constrained areas will pay millions of dollars for RMR service to the power plants’ owner.

Talen Energy is seeking to recover annual fixed costs of over $215 million for Brandon Shores’ and Wagner’s RMR arrangements, combined. These RMRs could cost Maryland’s residents and businesses over $629 million through 2028, the earliest by which the RMR arrangements could end. BGE customers can expect to pay an estimated 74 percent—or roughly $159 million per year—of these costs. As a result, BGE customers could see their bills increase by approximately 5 percent, resulting in an average residential bill increase of $5 per month due to RMR costs alone (Table 2). When combined with the incremental impact of the capacity market costs (Table 1, above), electric customers in the BGE LDA could see average bill increases of $21 per month.

Table 2. Summary of costs associated with Brandon Shores and Wagner RMRs for BGE

BGE LDA Costs	Annual Costs to BGE Customers	Monthly average residential bill increase ($/month)	Annual average residential bill increase ($/year)*	Time frame of cost impacts
RMR Costs	$159 million	$5	$59	June 2025 – December 2028 (or longer with construction delays, ongoing reliability issues, etc.)
Capacity Market Costs *(Incremental)*	$504 million	$16	$188	June 2025 – May 2026 (likely similar impact from June 2026 – May 2028, unless additional capacity becomes available)
Total Incremental Costs	$663 million	$21	$247	June 2025 – May 2026 (likely similar impact from June 2026 – May 2028, unless additional capacity becomes available)

Source: See description in text.
** Numbers are higher than monthly average multiplied by 12 months because of rounding.*

These RMR cost impacts are uncertain. For one, OPC is litigating the amount of recoverable RMR costs before FERC. Second, there is uncertainty in the length of time that PJM will use these units for RMR service. PJM has indicated that it requires Brandon Shores to provide RMR service until December 2028, when it projects that the transmission solutions needed to eliminate the need for the Brandon Shores RMR units will be completed, while the Wagner plant may need to continue providing RMR service beyond 2028. However, if there are major changes to load or other factors that could affect reliability in the region, PJM may determine that Brandon Shores and Wagner need to continue providing reliability service beyond the currently planned December 2028 date. Lastly, the projected completion date of December 2028 for these transmission solutions is highly uncertain; there could be delays in the project construction and execution, further imposing RMR costs on electric customers. If the transmission projects are not complete by the end of 2028, and/or the continued operation of the RMR units are required beyond December of that year, the RMR costs for electric customers would necessarily increase.

The length of time that PJM, and especially BGE customers, will continue to see elevated prices is also uncertain. The next PJM capacity market auction, for the 2026/2027 delivery year, is set to occur in December 2024, less than 5 months from the recently completed 2025/2026 auction, making it unlikely that there will be any major increases in available supply. Given the long wait times in processing the interconnection queue (delaying the interconnection of new generating resources to the grid to replace the RMR units) and the uncertainty around queue reform, it is unlikely that enough new generation will be under way before December 2024 and online by June 1, 2026 (the start of the 2026/2027 delivery year) to substantially alleviate the very high prices seen for the 2025/2026 BRA. In the case of the BGE LDA, these interconnection queue backlogs make it unlikely that any major generation will be interconnected before the end of 2028, the earliest date for ending the Brandon Shores' and Wagner's RMR arrangements. Thus, the strong price signal sent by the high capacity market prices in the BGE LDA (and the RTO as a whole) may not induce timely new generation into service within the LDA before the completion of the transmission lines that end the need for these RMRs (or to help alleviate prices seen across the region). Instead, the clogged queue could lock in a windfall for the existing generating units continuing to operate in the BGE LDA and across the PJM region generally.

This report and its calculations of prices and bill impacts is based on the best information available at the time of publication. The nature of the report is necessarily forward looking and depends on the assumptions described within. Because PJM is reviewing its market rules and because of changing economic conditions, actual future market prices and bill impacts could be different.

2. PJM'S RELIABILITY MUST-RUN

To understand the impacts to Marylanders of the anticipated RMR arrangements, one needs an understanding of how RMR arrangements work in PJM. This section provides background on the power plant units at issue and describes how RMR costs are allocated to different locational deliverability areas (LDAs).[2] Finally, we describe how, within PJM, RMRs typically interact with wholesale capacity and energy markets.

2.1. Background

Reliability must-run service is a status applied to a generating unit that enters into an arrangement with PJM to remain online beyond its slated retirement date to maintain grid reliability. RMRs are arrangements a generator owner and PJM enter into for continued operation of the generator in exchange for payments outside of the competitive wholesale power market. They are referred to as "Part V Reliability Service" in the PJM tariff.[3] Typically, PJM requests that the RMR unit remain operational beyond the generation plant owner's proposed retirement date, until completion of the transmission upgrades that PJM has deemed

[2] An LDA is an area or zone within the wholesale electric markets administered by PJM, in which local effects of transmission, load and generating resources are separately accounted for in the operation of PJM's markets. In this report, costs described as allocated to or incurred by a LDA mean costs flowed through to the end use customers located within that LDA. Maryland is covered by all or portions of 4 LDAs—the BGE LDA, roughly equal to BGE's retail service area (and entirely within Maryland); DPL-South, inclusive of the Maryland eastern shore and southern Delaware; the Pepco LDA, covering the retail service areas of Pepco (both Maryland and DC) and SMECO; and the APS LDA, including Potomac Edison's Maryland service area and extending to the retail service areas of PE's affiliates in West Virginia and Southwestern Pennsylvania. The cost impacts analyzed in this report focus on those anticipated for Maryland customers, although the increases described impacting the cross-jurisdictional LDAs will also adversely affect customers in the other jurisdictions included in these LDAs.

[3] OATT Part V.

necessary to resolve the grid reliability deficiencies which would be caused when and if the plant is retired. Out-of-market solutions, such as RMR service arrangements, limit the effectiveness of the PJM markets and can lead to high costs for consumers. PJM has engaged in 17 RMR arrangements since they were first introduced in PJM in 2005.[4]

Indian River 4 ("IR4"), a 410-MW coal plant owned by NRG Power Marketing, is the only unit currently providing RMR service in PJM and illustrates RMR arrangements. NRG announced its intent to retire IR4 as of June 1, 2022. Before that planned retirement date, PJM deemed the plant's continued operation necessary for grid reliability. Under PJM's plans, the transmission builds to address reliability issues resulting from the retirement of IR4 require a capital investment of $51 million,[5] while NRG's RMR revenue requirements for IR4, as reflected in a contested settlement agreement currently pending before FERC for approval, are $228 million over the proposed term of the RMR arrangement (June 1, 2022 to Dec. 31, 2026).[6] NRG originally proposed fixed RMR revenue requirements of $357 million; these were contested at FERC by some PJM customer advocates and representatives, including the Maryland Office of People's Counsel. The lower RMR costs, as reflected in the contested settlement pending at FERC, are the result of that litigation and settlement, assuming approval of the settlement by FERC.

This paper focuses on the cost impacts of the future RMR arrangements that PJM is entering into with Talen Energy for its Brandon Shores and Herbert A. Wagner (Wagner) power plants.

- ***Brandon Shores*.** On April 6, 2023, PJM received Talen Energy's deactivation notice for Brandon Shores, a 1,282 MW coal-fired power plant in Maryland's BGE zone, proposing the retirement of the plant on June 1, 2025.[7] PJM assessed the deactivation, and stated that without Brandon Shores, severe voltage drop and thermal violations could occur across seven PJM zones, which could lead to a widespread voltage collapse in Baltimore and the surrounding areas.[8] PJM has said that these reliability issues can only be addressed through needed transmission system upgrades. The Grid Solutions Package addressing these shortcomings was approved by the FERC in November 2023 and is slated to be in service by December 31, 2028.[9] For the interim period until the transmission upgrades are complete, PJM requested that Brandon Shores remain in

[4] Deactivation Enhancements Senior Task Force, February 15, 2024 Meeting, Agenda Item 3 – RMR History. Monitoring Analytics, LLC.

[5] Public Service Commission of Maryland, Order 90950, December 5, 2023. Case No. 9698. The Application of Delmarva Power & Light Company for a Certificate of Public Convenience and Necessity to Rebuild the Vienna-Nelson 138 kV Transmission Line in Dorchester and Wicomico Counties, Maryland.

[6] NRG Power Marketing LLC, Docket No. ER22-1539-002, NRG Business Marketing LLC, Docket No. ER23-2688-002, Settlement Agreement and Offer of Settlement, filed April 2, 2023. The IMM and Maryland Office of People's Counsel are contesting this settlement agreement, and FERC action on the settlement filing is still pending. PJM has indicated that the transmission solutions required to eliminate the need for the IR4 RMR are ahead of schedule, and could be complete by the end of 2024. Devin Leith-Yessian, "PJM OC Briefs: July 11, 2024, Indian River Transmission Upgrades Projected to be Complete One Year Ahead of Schedule July 14, 2024." July 15, 2024, RTO Insider. Available at: https://www.rtoinsider.com/83230-pjm-oc-071124/

[7] Federal Energy Regulatory Commission, November 9, 2023. Order on Cost Allocation Report and Tariff Revisions (ER23-2612-001 and 002), 185 FERC ¶ 61,107 (2023). Available at: https://www.pjm.com/directory/etariff/FercOrders/7022/20231108-er23-2612-001.pdf.

[8] Ibid.

[9] Ibid.

service as an RMR resource to relieve the reliability issues. On April 18, 2024, Talen Energy submitted a tariff filing at FERC for Brandon Shores' RMR Arrangement.[10]

- ***Herbert A. Wagner*.** On October 16, 2023, Talen filed a deactivation notice for the Wagner power plant, an 841 MW generator located in the BGE LDA.[11] Wagner burns coal, gas, oil, and diesel, and has four units: Wagner 1, Wagner CT, Wagner 3, and Wagner 4.[12] It is slated for retirement on June 1, 2025,[13] the same day as Brandon Shores' deactivation date. In January 2024, PJM identified grid reliability violations resulting from the deactivation of Wagner 3 and 4; PJM requested to use those two units as RMR units.[14] On April 18, 2024, Talen Energy submitted a tariff filing at FERC for Wagner's RMR Arrangement.[15]

2.2. RMR Costs

RMR Costs for Brandon Shores and Wagner (Initial Filing)

A unit remaining in service under an RMR arrangement has two options for cost recovery: (1) the Deactivation Avoidable Cost Rate (DACR),[16] and (2) the Cost of Service Recovery Rate (CSRR).[17] Talen Energy has elected to use the CSRR approach for RMR cost recovery for both Brandon Shores and Wagner. This approach is designed to "recover the entire cost of operating the generating unit," during the RMR service period, whereby the generator owner must file a rate schedule with FERC.[18]

[10] FERC Docket No. ER24-1790-000, FERC Generated Tariff Filing. April 18, 2024. Brandon Shores LLC submits tariff filing per 35.13(a)(2)(iii: RMR Arrangement - Continuing Operations Rate Schedule to be effective 6/18/2024 under ER24-1790. Available at: https://elibrary.ferc.gov/eLibrary/docinfo?accession_number=20240418-5176.

[11] Talen Energy. October 16, 2023. Notice of Deactivation Date for H.A. Wagner 1,3,4 & CT under H.A. Wagner LLC. Available at: https://www.pjm.com/-/media/planning/gen-retire/deactivation-notices/wagner-deactiviation-notice.ashx

[12] PJM Generation Deactivations. Available at: https://www.pjm.com/planning/service-requests/gen-deactivations

[13] Talen Energy. October 16, 2023. Notice of Deactivation Date for H.A. Wagner 1,3,4 & CT under H.A. Wagner LLC. Available at: https://www.pjm.com/-/media/planning/gen-retire/deactivation-notices/wagner-deactiviation-notice.ashx

[14] Transmission Expansion Advisory Committee, January 9, 2024. Available at: https://www.pjm.com/-/media/committees-groups/committees/teac/2024/20240109/20240109-item-02---generation-deactivation-notification-update.ashx

[15] FERC Docket No. ER24-1787-000, FERC Generated Tariff Filing. April 18, 2024. H.A. Wagner LLC submits tariff filing per 35.13(a)(2)(iii: RMR Arrangement - Continuing Operations Rate Schedule to be effective 6/18/2024 under ER24-1787. Available at: https://elibrary.ferc.gov/eLibrary/docinfo?accession_number=20240418-5128.

[16] The DACR is a formulaic rate designed to permit the recovery of a unit's avoidable costs of continued operations, plus an incentive adder. These avoidable costs are defined as "incremental expenses directly required for the operation of a generating unit" and include "project investments" (capital expenditures needed to keep the plant operating) of up to $2 million. The incentive adder escalates for each year of service (10 percent of expenses in the first year, 20 percent in the second year, 35 percent in the third year, and 50 percent in the fourth year and beyond). If the owner of an RMR unit decides to continue operations after the RMR arrangement term ends, the tariff requires that project investments that were required for RMR service be repaid to PJM.

[17] More information on the two cost recovery approaches can be found at: Deactivation Enhancements Senior Task Force, October 12, 2023. IMM State of the Market report discussion of Part V (RMR) issues. Available at: https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_DESTF_Memo_re_RMR_20231012.pdf

[18] Deactivation Enhancements Senior Task Force, October 12, 2023. IMM State of the Market report discussion of Part V (RMR) issues. Available at: https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_DESTF_Memo_re_RMR_20231012.pdf

On April 18, 2024, Talen Energy submitted tariff filings at FERC for the RMR Arrangement of Brandon Shores and Wagner, which include provision for the recovery of Talen Energy's requested level of fixed costs for the RMR units, and the units' variable costs of operation. The initial terms of both RMR arrangement tariff filings extend to December 2028, after which PJM anticipates transmission solutions should be in place to eliminate the need for RMR service.[19] However, there is significant uncertainty around this date, as there are numerous factors that could delay the construction and completion of these transmission solutions. Table 3, below, presents the RMR costs as described in the initial Talen Energy filings at FERC.

Table 3. Initially filed costs of Brandon Shores and Wagner RMR Arrangements

Generator	MW	Annual RMR Cost ($ millions)	RMR Cost for Whole Term ($ millions)
For Brandon Shores (units 1 & 2)	1,282	$175	$629
Wagner (units 3 & 4 only)	702	$40	$145
Combined Total for Brandon Shores and Wagner	**1,984**	**$215**	**$774**

Notes: These are total RMR fixed costs, not costs for Maryland only, for June 2025 to December 2028. Cost data from tariff filings, FERC Docket No. ER24-01790-000 (Brandon Shores) and FERC Docket No. ER24-01787-000 (Wagner), April 18, 2024.

The cost recovery under a CSRR approach is subject to litigation by intervening stakeholders in a proceeding before FERC; the final cost recovery amount, approved by FERC, may be lower than the originally requested amount as a result of that litigation (or as determined in a settlement). Historically, final RMR costs are on average 25 percent less than the initial filing for plants using CSRR.[20] For instance, Indian River 4 (or IR4), described above as the only unit currently providing RMR service in PJM, used the CSRR approach. Its owner, NRG Power Marketing, initially proposed an RMR cost of $520/MW-day.[21] As a result of litigation at FERC and as incorporated into a proposed settlement filed at FERC, IR4's revenue requirements for RMR service are $333/MW-day.[22] This revenue requirement remains subject to challenge by the Maryland OPC and PJM's Independent Market Monitor and is pending a FERC decision. The comparison between the initial filing and the litigated outcome over the history of RMRs in PJM is useful, but not dispositive of predicting the particular outcome in any RMR proceeding litigated at FERC, given the widely varying specific circumstances and levels of cost support across each of the RMR proceedings.

In addition, total whole-term costs, as presented in Table 3, depend on timely completion of PJM's planned transmission solutions on or before the planned date of December 31, 2028. The

[19] The end date or Wagner's RMR arrangement is less certain; PJM may require Wagner to continue RMR service beyond December 2028 (even if Brandon Shores' arrangement terminates on that date as currently planned).

[20] Based on a simple average in $/MW-day across all RMR Arrangements that started June 1, 2011 or later. RMR cost data from Deactivation Enhancements Senior Task Force, February 15, 2024 Meeting. Agenda Item 3 – RMR History. Monitoring Analytics, LLC.

[21] Ibid.

[22] NRG Power Marketing LLC, Docket No. ER22-1539-002, NRG Business Marketing LLC, Docket No. ER23-2688-002, Settlement Agreement and Offer of Settlement, filed April 2, 2023.

transmission solutions, totaling $726 million in capital expenditures,[23] may carry potential risks of delay that are beyond the scope of our analysis. If they are not completed on time, however, it is likely PJM would seek to extend the RMR terms beyond 2028, adding further RMR costs for customers. The RMRs could also be extended as a result of changes in load forecasts; if forecasts go up, PJM could determine the RMRs are needed past 2028 to mitigate related reliability impacts.

Cost Allocation to Maryland LDAs

As described in PJM's tariff, RMR costs are allocated to the "load in the Zone(s) of the Transmission Owner(s) that will be assigned financial responsibility for the reliability upgrades necessary to alleviate the reliability impact that would result from the Deactivation of the generating unit."[24] FERC approved the Brandon Shores Grid Solutions Package at the end of 2023. The package includes transmission upgrades PJM deemed necessary to maintain reliability following the deactivation of Brandon Shores.[25] We assumed Brandon Shores RMR costs are allocated proportionally to the cost allocation of that same Grid Solutions Package, which affects all Maryland LDAs (BGE, Pepco, DPL-South, and APS)[26] (Table 4). PJM has not indicated what transmission upgrades are required to alleviate the reliability impact of Wagner. Without more accurate information, we assumed that RMR costs for the Wagner plant would also be allocated according to the approved Brandon Shores Grid Solutions Package.[27]

Table 4. Annual and total Brandon Shores and Wagner RMR costs for Maryland

Maryland LDAs	**Maryland Customers' Share of RMR Costs**	**Annual RMR Cost to Maryland LDAs** ($ millions)	**RMR Cost for Whole Term for Maryland LDAs** (June 2025 – Dec 2028) ($ millions)
APS LDA Customers (Maryland only)	0.1%	$0.3	$1.1
BGE LDA Customers	74%	$159	$569
DPL-South LDA Customers (Maryland only)	1%	$2.5	$9
Pepco LDA Customers (Maryland only)	7%	$14	$50
Maryland Total	**81%**	**$176**	**$630**

Notes: All costs are presented in real 2024 dollars. See description in text for cost allocations.

[23] Transmission costs for the Brandon Shores Deactivation Grid Solutions, provided by Strategen Consulting, Inc. to Synapse on March 7, 2024.

[24] OATT Part V - 120 Cost Allocation.

[25] Federal Energy Regulatory Commission, November 9, 2023. Order on Cost Allocation Report and Tariff Revisions (ER23-2612-001 and 002).

[26] Transmission grid solution cost allocation to LDAs was provided by Strategen Consulting, Inc. to Synapse on March 7, 2024.

[27] To allocate costs, Synapse used the transmission grid solution cost allocation to LDAs provided by Strategen Consulting, Inc. on March 7, 2024.

The BGE LDA is located entirely in Maryland, bearing 74 percent of total costs of the RMR arrangements across PJM. As shown in Table 4, Maryland customers in the Pepco LDA pay for 7 percent of the PJM total, while customers in the remaining two Maryland LDAs (APS, DPL-South) pay less than 1.5 percent of the costs together. In total, Maryland customers pay roughly 81 percent of the total RMR costs for Brandon Shores (Units 1 and 2) and Wagner (Units 3 and 4)—$176 million per year and $630 million over 3.5 years. As discussed, final revenue requirements of these RMR units may be lower as a result of litigation at FERC.

2.3. Treatment of RMRs in the Capacity and Energy Markets

PJM's capacity market is meant to secure capacity commitments—in megawatts (MW)—from generation plant owners, with the intention of securing future reliability. Like any market, prices set by the capacity market depend on buyers and sellers. For example, a smaller number of bidders offering fewer megawatts of capacity into the capacity market lowers supply and could increase prices paid by wholesale buyers—and ultimately by utility retail customers. As further explained below in Section 3.1, PJM's capacity market prices are set in an annual auction and are based on supply (generation plant owner bids)[28] and reliability requirements. The clearing price, or the intercept point between supply and demand, is the price that is paid to all generation plant owners that successfully cleared in the market.

Brandon Shores and Wagner have participated in the capacity market and are committed to provide capacity through to their proposed deactivation dates of June 1, 2025. RMR unit participation in the capacity market, however, depends on the unit's specific RMR arrangement with PJM.[29] Although PJM has designated RMR units to be needed for grid reliability purposes, PJM has not required them to make commitments in the capacity market. PJM and the IMM informed us that nearly all, if not *all*, of the past 17 RMRs have not participated in PJM's capacity market, the Reliability Pricing Model (RPM).[30] Neither Brandon Shores nor Wagner participated in the most recent 2025/2026 capacity market auction and are not expected to participate in future auctions. As discussed in Section 3.3 below, their absence affected the capacity market auction and clearing price for the delivery year 2025/2026 in the BGE LDA, where they are located,[31] and very likely the capacity price for the entire RTO footprint.

For an LDA that is already constrained, such as the BGE LDA—and without additional transmission upgrades or new generation to address constraints—if a unit no longer provides supply in the capacity market, clearing prices are pushed upwards. BGE LDA cleared at its maximum price for the 2025/2026 delivery year, evidence of this upward push on clearing prices. A higher capacity price provides a market signal to generators, incentivizing new generation in that zone. Yet when combined with the out-of-market cost of the RMR itself, the elevated capacity clearing price ultimately costs utility customers in that LDA.

PJM can dispatch and schedule Brandon Shores (Units 1 and 2) and Wagner (Units 3 and 4) for reliability purposes, subject to their specific operational restrictions. As proposed by Talen in its

[28] As well as energy efficiency and demand response resources.

[29] RMR units are modeled in reliability studies and reserve calculations.

[30] Based on conversations with PJM and the IMM at the Deactivation Enhancements Senior Task Force November 9, 2023, meeting.

[31] The presence of the RMR units also impacts the computation of CETO and CETL, and thus has an indirect effect on the parameters influencing the auction outcome.

filings at FERC, the units will be offered into the energy market "with a status of 'unavailable in the Market' but will be available to be dispatched and scheduled by PJM".[32] However, Talen has stated that it does "not guarantee the availability of the Unit(s) in response to a PJM scheduling or dispatch notice."[33,34]

3. PJM'S CAPACITY MARKET

In the most recent PJM capacity auction, for the delivery year 2025/2026, the BGE LDA cleared at its maximum price of $466.35/MW-day. The rest of the RTO (with the exception of Dominion LDA) cleared at $269.92/MW-day, nine times higher than the RTO clearing price for 2024/2025. This section provides an overview of how the capacity market works, particularly around the capacity-constrained zones such as the BGE LDA. We also describe recent reforms to the market and the multiple ways they can affect market prices. Finally, we discuss the impact of the Brandon Shores and Wagner units no longer bidding into PJM's capacity market, even while continuing service under RMR arrangements.

3.1. Capacity Market Mechanisms

PJM's capacity market, known as the Reliability Pricing Model (or RPM), is the market-based mechanism that PJM uses to procure commitments from capacity resources to be available to meet future demand. The capacity market is meant to procure capacity at the lowest possible cost; it includes generation, storage, demand response, and energy efficiency resources. The quantity procured must meet system and local reliability standards, which PJM has historically defined as a loss of load expectation (LOLE) of no more than one day in ten years, or a 1-in-10 LOLE for the system, and a 1-in-25 LOLE for LDAs. In other words, to meet reliability standards, load should not exceed available capacity more than one day in 10 years. In the just completed base residual auction for the 25/26 delivery year (and for future auctions), PJM shifted its measure of resource adequacy risk to an expected unserved energy (EUE) metric,[35] which is

[32] FERC Docket No. ER24-1790-000, Brandon Shores Continuing Operates Rate Schedule (CORS) Transmittal Letter. April 18, 2024. Brandon Shores LLC submits tariff filing per 35.13(a)(2)(iii: RMR Arrangement - Continuing Operations Rate Schedule to be effective 6/18/2024 under ER24-1790. Available at: https://elibrary.ferc.gov/eLibrary/docinfo?accession_number=20240418-5176.

[33] FERC Docket No. ER24-1790-000, Brandon Shores Reliability Must Run Continuing Operations Rate Schedule, Attachment A. April 18, 2024. Brandon Shores LLC submits tariff filing per 35.13(a)(2)(iii: RMR Arrangement - Continuing Operations Rate Schedule to be effective 6/18/2024 under ER24-1790. Available at: https://elibrary.ferc.gov/eLibrary/docinfo?accession_number=20240418-5176.

[34] The units may also be offered based on their cost-based schedule into the Synchronized Reserve market when they are otherwise dispatched for reliability, and they will provide reactive power consistent with their capability and voltage schedules under their interconnection agreements. Any energy and ancillary service market revenues received by RMR units are netted out of the total RMR costs for cost recovery.

[35] "PJM proposes to assess its resource adequacy risk using the EUE metric, keyed to meeting the traditional one day in ten years LOLE metric that PJM has historically employed. PJM states that the current LOLE reliability criterion does not fully represent the three typical reliability dimensions: magnitude (MW), duration (hours), and frequency (numbers of events per time period). In contrast, PJM states that EUE provides a much more granular metric that allows the resource adequacy analysis to clearly differentiate among events of different duration and magnitude, and to better identify the scope of loss of load risk throughout the year. Further, PJM argues that the changing resource

still tied to meeting the one day in ten years (or 25 years) reliability metric. PJM expresses this reliability requirement as forecasted peak load plus a reserve margin. PJM conducts annual auctions to procure capacity and maintain reliability, starting with the Base Residual Auction (BRA) and subsequent incremental auctions. The capacity clearing price is the intercept point between the demand curve and the supply curve; the clearing price is paid to all cleared capacity resources for that delivery year.

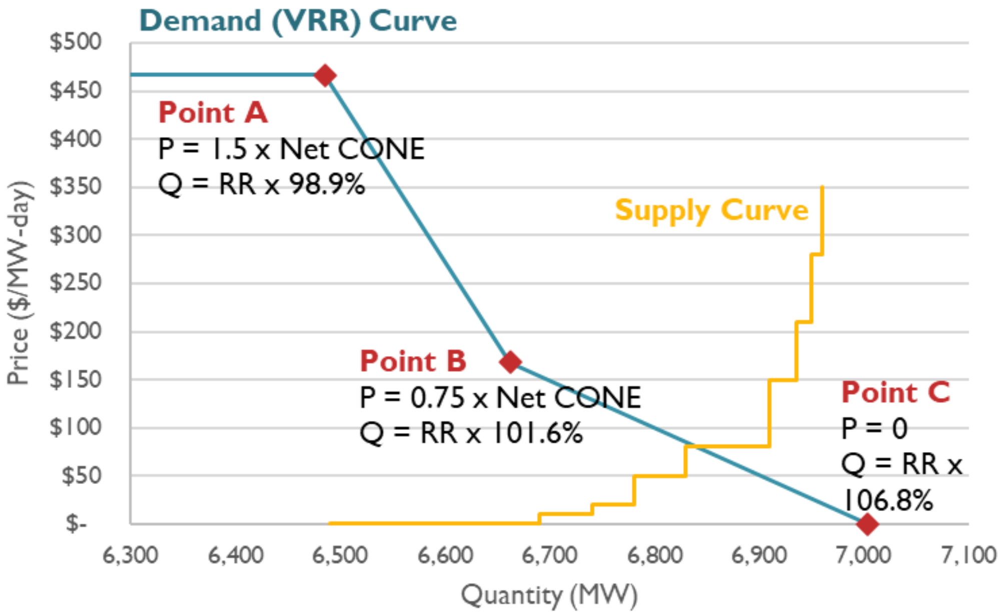
PJM uses a downward sloping demand curve, called the Variable Resource Requirement (VRR) curve, to specify prices and demand relative to the reserve margin requirements. To set the VRR curve, PJM conducts its annual Reserve Requirement Study. The study is a probabilistic risk modeling exercise that incorporates load forecasts, generation capabilities and outage rates, and other factors to determine the Installed Reserve Margin (IRM) necessary to meet the reliability standard (1-in-10 LOLE equivalency). Once approved by the PJM Board, the outputs of the study define the Reliability Requirement, which is used to determine the three points that make up the VRR Curve (points A, B, and C)[36] (Figure 1, with Pepco LDA as an example). The maximum price on the VRR curve is 1.5 times the net Cost of New Entry (CONE);[37] net CONE is the estimated price that a new generation resource would need to enter the market, net of energy market revenues.

mix, which increasingly will be composed of resources with greater hourly performance variability, further supports the need to include EUE in resource adequacy risk modeling." Federal Energy Regulatory Commission, January 30, 2024. Order Accepting Tariff Revisions Subject to Condition. Docket ER24-98, at 62.

[36] Each point on the VRR curve is defined by the reliability requirement and Net CONE (e.g. point B is set at 101.6% times the reliability requirement and 0.75 times Net CONE, and point C is set at 106.8% times the reliability requirement at a price of $0), creating a downward sloping curve. These values that define the curve are determined by PJM probabilistic modeling of reliability, and means that if capacity is more expensive, slightly less of it will be procured, while if capacity is less expensive, more capacity may be procured.

[37] Or Gross CONE, whichever is greatest.

Figure 1. Pepco's 2025/2026 VRR curve, where P is price ($/MW-day), Q is quantity (MW), and RR is reliability requirement, alongside an illustrative example supply curve (which does not reflect 2025/2026 supply offers and the resulting clearing price)



Notes: the supply curve is for illustrative purposes only and is not based on real supply offers. VRR curve for Pepco LDA, 2025/2026 Planning Period Parameters for Base Residual Auction, April 12, 2024. Available at: https://www.pjm.com/markets-and-operations/rpm

The MW of capacity a resource can offer into the market depends on its accreditation value, or its unforced capacity (UCAP). The UCAP is a measure of how much capacity a unit has at peak to contribute to system reliability. PJM has previously used a few capacity accreditation methods, specific to resource types.[38] But starting with the latest capacity auction (2025/2026), PJM shifted to a marginal Effective Load Carrying Capability approach (ELCC). ELCC accredits resources based on their marginal contribution to system resource adequacy across simulated scenarios.[39] Existing market participants are required to offer their UCAP at a price that reflects the costs they would avoid by not operating. This price is defined by Market Seller Offer Cap (MSOC) rules. New market participants can enter at a price of zero (price takers) or at prices that reflect their net costs of entering. Each supply offer (UCAP quantity and price) makes up the supply curve. The capacity price is set at the intercept point of the supply and demand curves.

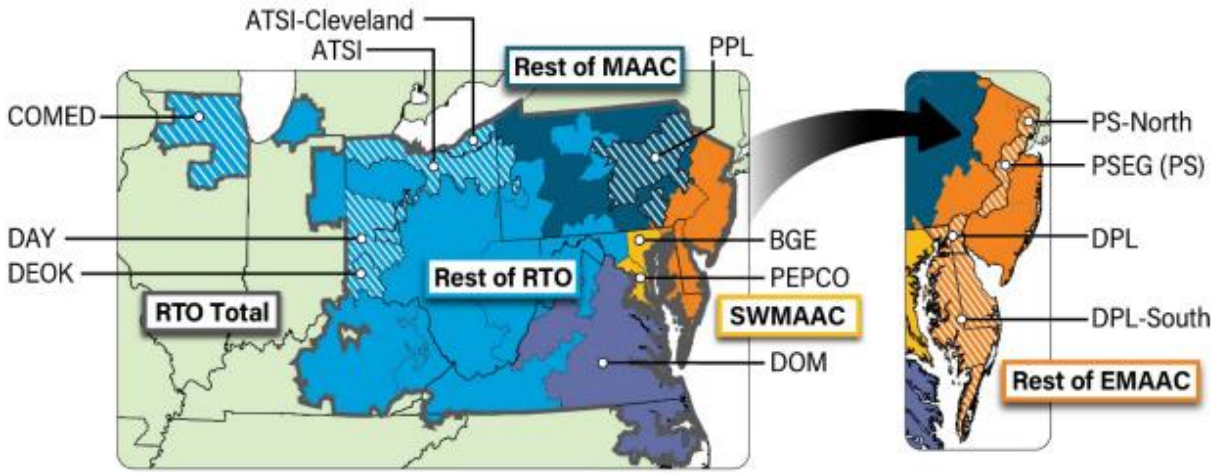
The capacity market clearing price produces a market signal for capacity resources; high prices indicate that supply is scare and encourages entry of new resources, while low prices indicate that there is more supply than the system needs for resource adequacy. The capacity market auction is designed to cost-effectively procure capacity to meet reliability requirements for both the entire RTO region as well as LDAs.

[38] Federal Energy Regulatory Commission, January 30, 2024. Order Accepting Tariff Revisions Subject to Condition. Docket ER24-98, at 3-5.

[39] Federal Energy Regulatory Commission, January 30, 2024. Order Accepting Tariff Revisions Subject to Condition. Docket ER24-98.

LDAs are subregions within PJM that are transmission-constrained and thus have limited import capability; LDAs are modeled in the capacity market separately from the rest of the unconstrained RTO. For purposes of the capacity market auctions, each modeled LDA will have its own reliability requirement and Net CONE value, and if certain criteria are met, its own VRR curve.[40] Figure 2 shows the modeled LDAs alongside the unconstrained RTO ("rest of RTO"), as of 2025/2026.

Figure 2. PJM's modeled LDAs

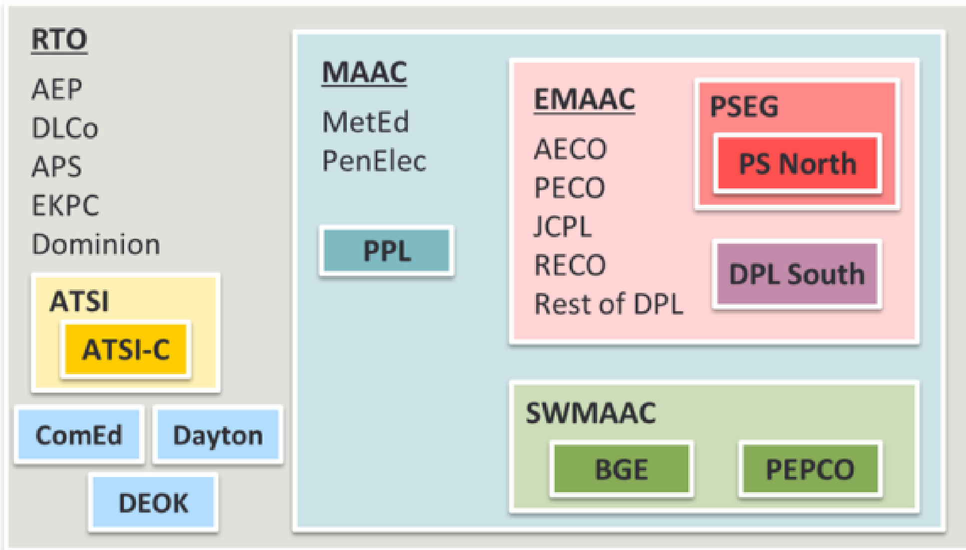


Source: PJM Interconnection, LLC. 2025/2026 Base Residual Auction Report. July 30, 2024. Available at: https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-report.ashx

PJM uses a nested model for determining the capacity market price, where a smaller LDA or a "child" LDA can procure capacity from its own local supply or from a larger "parent" LDA. Each LDA must meet its own local reliability requirement but is able to import capacity to satisfy that requirement up to the import limit that the transmission system can support (or the Capacity Emergency Transfer Limit (CETL)). Figure 3 shows the nested nature of modeled LDAs within PJM. Figure 2, above, also shows the nested structure, where darker colors are a child LDA (e.g., ATSI-C, in dark yellow, is a child of ATSI, in light yellow), and the parent-child relationship is indicated with an arrow.

[40] PJM Interconnection. 2024/2025 RPM Base Residual Auction Planning Period Parameters. Available at: https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2024-2025/2024-2025-planning-period-parameters-for-base-residual-auction-pdf.ashx.

Figure 3. Structure of nested parent and child LDAs in PJM

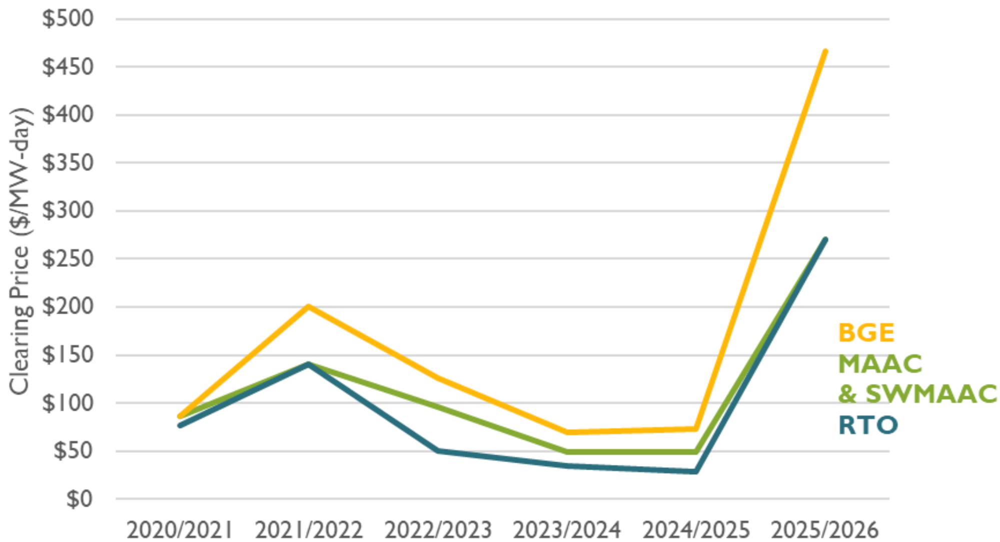


Notes: Each rectangle and bold label represents modeled LDAs while individual energy zones listed in non-bold without boxes are not currently modeled. For example, BGE is the child LDA to SWMAAC, which in turn is a child LDA to MAAC. Source: Modeled LDAs for the 2022/2023 BRA. Newell A., Oates, D., Pfeifenberger, J., Spees, K., Hagerty, J.M., Pedtke, J., Witkin, M., Shorin, E. April 2018. Fourth Review of PJM's Variable Resource Requirement Curve. Prepared for PJM by The Brattle Group. Available at: https://www.pjm.com/-/media/library/reports-notices/reliability-pricing-model/20180425-pjm-2018-variable-resource-requirement-curve-study.ashx.

PJM's capacity market clearing mechanism is meant to find the lowest-cost solution to meet reliability standards in all LDAs, by optimizing local capacity availability and imports from parent LDAs. When an LDA is import-constrained, it can experience price separation from its parent LDA(s). Within the nested structure of the market, a clearing price in a child LDA is never lower than its parent LDA's clearing price.[41] If a child LDA does not have sufficient local capacity to meet its local peak, and transmission constraints prevent the LDA from importing enough capacity to make up the difference, a higher-cost resource might set the price for the child LDA at a higher clearing price than its parent LDA. In other words, instead of the child LDA clearing with its parent LDA at the parent LDA clearing price, it clears at a higher price. This has occurred in recent years in BGE LDA, relative to its parent LDA, SWMAAC. BGE LDA separated and experienced a higher price than its parent LDA over the last six auctions. On the other hand, the Pepco LDA, which is also part of SWMAAC, did not experience price separation. SWMAAC LDA itself cleared with its own parent, MAAC LDA, or the RTO as a whole (Figure 4).

[41] Newell A., Oates, D., Pfeifenberger, J., Spees, K., Hagerty, J.M., Pedtke, J., Witkin, M., Shorin, E. April 2018. Fourth Review of PJM's Variable Resource Requirement Curve. Prepared for PJM by The Brattle Group. Available at: https://www.pjm.com/-/media/library/reports-notices/reliability-pricing-model/20180425-pjm-2018-variable-resource-requirement-curve-study.ashx

Figure 4. Clearing prices for BGE, MAAC and SWMAAC, and RTO from 2020/2021 to 2025/2026



Source: Clearing prices in nominal dollars from RPM Base Residual Auction Results 2020/2021, 2021/2022, 2022/2023, 2023/2024, 2024/2025, and 2025/2026. PJM Interconnection LLC. Available at: https://www.pjm.com/markets-and-operations/rpm.

As further discussed in Section 3.3 below, the conversion of the Brandon Shores and Wagner plants to RMR service was the major driver in the very high prices for the BGE LDA in the 2025/2026 delivery year, and possibly contributed to higher capacity prices seen across the RTO as whole.

3.2. Recent Capacity Market Reforms in PJM

On January 30, 2024, FERC approved major reforms to PJM's capacity market, which were implemented in the most recent BRA (2025/2026) which occurred in July 2024.[42] Although these changes are wide-ranging and impact many components of the market, the three main reforms relevant here are: (1) replacement of the current accreditation approach with a marginal ELCC accreditation approach for all generation capacity resources, (2) enhancement of PJM's resource adequacy risk modeling to evaluate risk on a more granular, hourly level, and (3) adjustments to how Net CONE is calculated.

Market Reform Impact on UCAP

Capacity accreditation is the process of determining a given resource's UCAP, or the amount of capacity a resource can provide after accounting for factors like forced outages and intermittency. Starting in the delivery year 2025/2026 (and implemented with the just completed auction for that delivery year), PJM shifts to a marginal ELCC approach for capacity accreditation, which accredits these resources based on their marginal contribution to system resource adequacy across a number of simulated scenarios (given the anticipated resource mix). PJM's new accreditation

[42] Federal Energy Regulatory Commission, January 30, 2024. Order Accepting Tariff Revisions Subject to Condition. Docket No. ER24-98.

methodology will reduce most generators' UCAP, with some generators affected more than others (each unit has its own accreditation rating). Table 5 shows the class ratings by resource type for the 2025/2026 BRA, under the historical capacity accreditation approach and the new marginal ELCC approach (expressed as a share of total nameplate capacity).

Table 5. PJM's average ELCC class ratings for the 2025/2026 BRA, using historical and marginal ELCC capacity accreditation

Resource Type	2025/2026 Class Rating (Historical Method)	2025/2026 Class Rating (Marginal ELCC method)
Fixed-Tilt Solar	30%	9%
Tracking Solar	50%	14%
Coal	87%	84%
Gas Combined Cycle	96%	79%
Gas Combustion Turbine	90%	62%
Diesel (Oil)	91%	92%

Source: Class ratings for 2025/2026 using historical capacity accreditation method from: PJM Interconnection, December 1, 2023. Docket ER24-99-001. Responses to Deficiency Letter – Capacity Market Reforms to Accommodate the Energy Transition, at 27. Updated 2025/2026 Class Ratings from: PJM Interconnection, ELCC Class Ratings for the 2025/2026 Base Residual Auction, March 13, 2024. Available at: https://www2.pjm.com/-/media/planning/res-adeq/elcc/2025-26-bra-elcc-class-ratings.ashx.

The updated capacity accreditation will reduce the total supply of UCAP, with some LDAs affected more than others. The accreditation methodology impacts natural gas plants and solar generators the most. Therefore, LDAs with a large quantity of solar and gas see the largest decrease in their UCAP supply. For example, in the 2024/2025 BRA, natural gas resources made up 81 percent of cleared UCAP in Pepco LDA, but only 13 percent of cleared UCAP capacity in BGE LDA.[43] However, together these two LDAs make up SWMAAC; gas plants represented over 40 percent of cleared UCAP in SWMAAC in the 2024/2025 auction.[44] As a result, the BGE LDA may not see a major difference in supplied UCAP due to the ELCC adjustments (barring additional retirements), while SWMAAC may see a much larger impact on its available UCAP as a result of PJM's new capacity accreditation approach.[45]

Market Reform Impact on Offer Price

Changes in supplied UCAP in turn affect units' offer prices. If a unit's UCAP decreases under the new accreditation approach, its fixed unit costs will not—it still needs to recover the same total dollar amount for the equivalent offer under the new accreditation. For instance, consider an 8 MW UCAP resource that previously bid in at $50/MW-day, reflecting costs of $400/day; if now accredited at 5 MW UCAP, the offer would be adjusted to $80/MW-day resulting in the

[43] Calvert Cliffs is physically located in BGE LDA but is modeled in its parent LDA, SWMAAC LDA. Calvert Cliffs is included in the percentage calculation for SWMAAC LDA but not BGE LDA. Monitoring Analytics. October 30, 2023. Analysis of the 2024/2025 RPM Base Residual Auction. The Independent Market Monitor for PJM. Available at: https://www.monitoringanalytics.com/reports/Reports/2023/IMM_Analysis_of_the_20242025_RPM_Base_Residual_Auction_20231030.pdf.

[44] Ibid.

[45] Offered and cleared MW by resource type is available in the IMM's Analysis of the RPM Base Residual Auction, which will be available for the 2025/2026 delivery year in a few months.

same total $400/day amount.[46] Although the magnitude of change depends on the specifics of each LDA, moving to a marginal ELCC capacity accreditation approach ultimately results in a shift in supply curves up and to the left (i.e., up in price and down in quantity) relative to the supply curves seen under the former capacity construct.[47]

Market Reform Impact on VRR Demand Curve

The VRR demand curve also shifts up and to the left (once again, up in price and down in quantity) in the 2025/2026 capacity market auction. This shift occurs for several reasons. PJM has adopted hourly probabilistic modeling for its Reserve Requirement Study, which ultimately defines the reliability requirements and the VRR curve. PJM states that this change, along with enhanced risk modeling, will improve the accuracy and confidence in the Installed Reserve Margin and Reliability Requirement. In effect, the accredited (UCAP) capacity required for the RTO as a whole, as well as every child LDA, decreases. Since each megawatt of nameplate capacity (ICAP) is being accredited in a more rigorous and accurate manner, each megawatt of firm capacity (UCAP) is worth more. Therefore, PJM will need to procure less firm capacity to meet reliability requirements. For example, the reliability requirement for the 2025/2026 capacity auction decreased by 8 percent for the BGE LDA relative to the 2024/2025 delivery year.[48]

Importantly, reducing the reliability requirement shifts the VRR curve to the left (down in quantity), as the VRR curve of each LDA is based on its reliability requirement. The VRR price points also increase, as Net CONE will be tied to the ELCC of the reference resource, rather than a pool-wide average forced outage rate.[49] Specifically, Net CONE is converted to $/MW-day (UCAP) using the ELCC class rating of the Reference Resource, rather than using the pool-wide average effective forced outage rate (EFORd). This conversion results in a higher Net CONE.[50] The higher Net CONE is important because the maximum capacity market clearing price under PJM rules is 1.5 times the Net CONE value. These changes to the VRR curve were implemented in the 2025/2026 capacity auction.[51]

Finally, PJM has changed how it models reliability import requirements. PJM will adopt hourly probabilistic modeling to model the Capacity Emergency Transfer Objective (CETO). CETO is the required transfer amount to satisfy an LDA's reliability requirements. This change could impact which LDAs are considered constrained and must be modeled separately from the rest of the RTO.

[46] PJM Market Implementation Committee. January 10, 2024. Informational Posting: Simulation Analysis of PJM CIFP-RA Filing. Available at: https://www.pjm.com/-/media/committees-groups/committees/mic/2024/20240110/20240110-informational-only---simulation-analysis-of-pjm-cifp-ra-filing.ashx

[47] Ibid.

[48] Planning Period Parameters for Base Residual Auction. Available at: https://www.pjm.com/markets-and-operations/rpm.

[49] Based on pool-wide average EFORd (effective forced outage) rate.

[50] The ELCC of the reference resource is used to convert Net CONE ICAP to UCAP. PJM Market Implementation Committee. January 10, 2024. Informational Posting: Simulation Analysis of PJM CIFP-RA Filing. Available at: https://www.pjm.com/-/media/committees-groups/committees/mic/2024/20240110/20240110-informational-only---simulation-analysis-of-pjm-cifp-ra-filing.ashx.

[51] Planning Period Parameters for Base Residual Auction, April 12, 2024. Available at: https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-planning-period-parameters-for-base-residual-auction.ashx.

3.3. 2025/2026 Delivery Year Capacity Market Results

Impact of Brandon Shores and Wagner Retirements on BGE LDA's Capacity Price

In the capacity market auction, the capacity price is set at the point where the demand curve and the supply curve intercept. The supply of capacity of any given LDA is made up of three resource types: (1) generation capacity, (2) demand response, and if constrained, then (3) capacity imports.[52] When there are reductions in supply (for example, if a plant retires in a highly constrained zone), the supply curve shifts left. This moves the intercept point with the VRR curve upwards and pushes the capacity price higher. If there is not enough supply (generating capacity, demand response, and imported capacity) for the supply curve to intercept the demand curve, then the capacity price for that LDA will be set at the maximum, 1.5 times Net CONE. In other words, to avoid maximum price, the supply curve has to intercept the demand curve to the right and downward of Point A (the maximum price point on the VRR curve), as displayed in Figure 1 (above).

The BGE LDA has been capacity-constrained in recent years; the BGE LDA's capacity prices were about twice that of the RTO price for the last four years (as presented in Figure 4, above). From 2022/2023 to 2024/2025, only a third of the BGE LDA's cleared capacity came from local resources located within the LDA, the remainder was imported from its parent LDA (SWMAAC).[53] In the latest auction, for 2025/2026, less than 10 percent of the BGE LDA's cleared capacity was from local resources.[54] In 2024/2025, Brandon Shores and Wagner represent roughly 75 percent of generation capacity in BGE LDA,[55] and together they were responsible for over 60 percent of all cleared capacity (inclusive of supply-side generators, demand response, and energy efficiency). With Brandon Shores and Wagner removed from the supply stack, the BGE LDA does not have enough capacity to intercept the demand curve to the right of Point A on its VRR curve. There is not enough capacity to exceed Point A's UCAP Level, and as a result, the BGE LDA clearing price is at its maximum, $466.35/MW-day. This 2025/2026 maximum price is over six times the BGE LDA's clearing price in the 2024/2025 BRA ($73/MW-day); it will begin to affect customers' electric bills in the BGE LDA in June 2025 or soon after (as discussed in Section 4).

Concerningly, not only is the BGE LDA experiencing a record high capacity price in 2025/2026, but there is not enough capacity to meet the BGE LDA's reliability requirement. PJM's reliability requirement is the target level of capacity resources to meet PJM's reliability standards, i.e., a loss of load expectation of no more than one day in 25 years for LDAs (now expressed as an EUE metric). Specifically, the BGE LDA's remaining internal resources, the maximum amount of

[52] Cleared resources have historically also included energy efficiency. However, energy efficiency is not included in the clearing mechanism and therefore cannot set the price; it is added to cleared resources after the clearing price has been established. Monitoring Analytics, LLC. April 3, 2024. EE Addback Education. Available at: https://www.monitoringanalytics.com/reports/Presentations/2024/IMM_MIC_EE_Addback_Education_20240403.pdf.

[53] Based on data from PJM's RPM Base Residual Auction Results and the IMM's Analysis of the RPM Base Residual Auction, for 2022/2023, 2023/2024, and 2024/2025. Available at: https://www.pjm.com/markets-and-operations/rpm.aspx and https://www.monitoringanalytics.com/reports/Reports/2023.shtml.

[54] 2025/2026 Base Residual Auction Results, July 31, 2024. Available at: https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-results.ashx

[55] We assigned class capacity accreditation values to Brandon Shores units 1 and 2, and Wagner units 1, 3, 4 and CT. Total UCAP based on all offered UCAP from the 2024/2025 BRA, from Monitoring Analytics, October 2023. Analysis of the 2024/2025 RPM Base Residual Auction. Available at: https://www.monitoringanalytics.com/reports/Reports/2023/IMM_Analysis_of_the_20242025_RPM_Base_Residual_Auction_20231030.pdf

capacity that can be imported on the existing transmission system, and the cleared price responsive demand totals 6,765 MW, which is 176 MW below the LDA's reliability requirement of 6,941 MW. BGE LDA's capacity shortfall relative to its reliability requirement suggests that the probability of a loss of load event in the LDA is higher than PJM's reliability standard, further impacting electric customers in that zone.

Beyond the 2025/2026 delivery year, the very high prices may incentivize more demand response resources to bid into the market, which could reduce the clearing price if there is enough demand response to exceed the minimum required UCAP. Similarly, the high prices are in theory meant to incentivize new generation in the LDA. However, as discussed in Section 5, the years-long interconnection queue delays in PJM will likely prevent a large amount of resources from interconnecting in the BGE LDA any time soon. Without major changes to transmission import capacity or generation capacity, prices are likely going to remain at very elevated levels (even if not at the maximum of 1.5 times Net CONE, Point A). High prices are especially likely for PJM's next capacity auction (for the 2026/2027 delivery year) because it will occur in December 2024—less than five months following the BRA for 2025/2026 and only 1 ½ years before the beginning of the delivery year for that next auction. Likewise, the possibility of reliability issues in the BGE LDA as a result of the capacity shortfall will likely be an ongoing concern until more capacity becomes available and the reliability requirements are achieved, via new generation, demand response, or upgraded transmission capacity.

RTO and other LDA Capacity Market Prices in 2025/2026

In PJM's BRA for the 2025/2026 delivery year, which was finalized in July 2024, capacity market prices increased substantially in 2025/2026 from the previous delivery year. Specifically, the RTO price increased by over 800 percent, while the price for BGE LDA increased by over 500 percent (Table 7). In 2025/2026, only BGE and DOM LDAs experienced price separation, and both cleared at their maximum. These RTO and LDA prices are record highs, never before seen in PJM. The total RTO-wide cost to electric customers increased from $2.2 billion in 2024/2025 to $14.7 billion in 2025/2026.[56]

[56] PJM 2025/2026 Base Residual Auction Report. July 30, 2024. Available at: https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-report.ashx

Table 6. BRA clearing prices for 2024/2025 and 2025/2026 delivery years, by LDA, with bolded prices showing price separation

LDA	2024/2025 Clearing Price ($/MW-day)	2025/2026 Clearing Price ($/MW-day)
RTO	$28.92	$269.92
MAAC	**$49.49**	$269.92
EMAAC	**$54.95**	$269.92
SWMAAC	**$49.49**	$269.92
PS	**$54.95**	$269.92
PSNORTH	**$54.95**	$269.92
DPLSOUTH	**$426.17**	$269.92
PEPCO	**$49.49**	$269.92
ATSI	$28.92	$269.92
ATSI-CLEVELAND	$28.92	$269.92
COMED	$28.92	$269.92
BGE	**$73.00**	**$466.35**
PL	**$49.49**	$269.92
DAYTON	$28.92	$269.92
DEOK	**$96.24**	$269.92
DOM	$28.92	**$444.26**

Notes: DPL-South 2024/2025 clearing price was originally $90.64/MW-day. It was repriced due to a Third Circuit Court of Appeals reversal of PJM's determination of the original price. The updated $426.17/MW-day clearing price for DPL-South is now approved by FERC, but still the subject of litigation. PJM's RPM Base Residual Auction Results for 2024/2025 and 2025/2026, available at: https://www.pjm.com/markets-and-operations/rpm

PJM points to three key factors driving these unprecedented price spikes:[57]

- Load: forecasted peak load increased by 3,243 MW (e.g. from new data centers).
- Retirements: actual retirements across the PJM footprint, RMR units participating as energy-only resources (i.e., Brandon Shores, Wagner and Indian River), and must-offer exceptions for units preparing to retire.
- Reductions in UCAP supply due to the new capacity accreditation methods: as discussed in 3.2, updated ELCC ratings have reduced the total amount of supply, in UCAP terms.

The capacity shortfall in BGE LDA from the conversion of Brandon Shores and Wagner to RMR service likely had spillover effects into the RTO as a whole, increasing the RTO-wide clearing price and impacting electric customers in PJM beyond those in the BGE LDA. We conducted a counterfactual analysis of clearing prices in PJM, and found that if Brandon Shores and Wagner RMR units had remained as supply-side resources in the capacity market, the RTO as a whole

[57] 2025/2026 Base Residual Auction Report. July 30, 2024. Available at: https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-report.ashx

would have cleared at $163.46/MW-day. This scenario would have shifted the supply curve to the right and moved the demand and supply curve intercept point down and right, resulting in a lower clearing price. In this scenario, BGE, SWMAAC, and MAAC LDAs would not have separated from the RTO. This analysis is based on three assumptions. First, we assume that Brandon Shores (units 1 and 2) and Wagner (units 3 and 4) had offer prices at or below $163.46/MW-day, which is more than double their offer price in 2024/2025.[58] Second, we assume that the resources that were required to meet the RTO reliability requirement and subsequently cleared had offer prices at or below $163.46/MW-day. In other words, we assume that Brandon Shores and Wagner were marginal resources or were towards the top of the stack of cleared resources. Third, with the exception of the Dominion LDA, we assume that other LDAs would not have separated from the RTO and caused other cascading price impacts on the RTO or the MAAC LDA. Given these assumptions, this counterfactual represents the lower bound of clearing prices for the 2025/2026 base residual auction with Brandon Shores and Wagner participating. If the RTO cleared at $163.46/MW-day for the 2025/2026 BRA, electric customers across the RTO would save over $5 billion in that delivery year. Stated otherwise, our counterfactual analysis demonstrates that the removal of 2,000 MW (ELCC adjusted about 1,600 MW) from the resources clearing the auction—the equivalent of less than 1.5 percent of the 135,000 MW that cleared the auction—had a region-wide impact that will benefit generators (and cost customers) over $5 billion.

Under the same assumptions, we also considered the outcome of the RMR and 2025/2026 capacity auction on Talen’s bottom line by comparing Talen’s expected revenues from the outcome of the auction to our counterfactual. We found that Talen’s revenues for the 2025-2026 delivery year increased by $360 million compared to what its revenues would have been had the Talen RMR units participated in the capacity market.[59]

4. CUSTOMER BILL AND RATE IMPACTS OF RMRS IN MARYLAND

Across the PJM footprint, electric utility customers will see rising costs as a result of the increased capacity clearing prices for the 2025/2026 delivery year. For customers in the BGE LDA, the impact of the soaring capacity price is compounded by having to pay for a substantial portion of the out-of-market RMR arrangement costs for Brandon Shores and Wagner. This section describes those impacts for electric utility customers in the BGE LDA, as well as the impacts to customers in other LDAs within Maryland.

4.1. Analytical Approach and Assumptions

Using utility data and billing determinants from the U.S. Energy Information Administration (EIA),[60] we examined the bill and rate impact associated with RMR costs and recent capacity

[58] The capacity price in the BGE LDA in 2024/2025 was $73/MW-day, and most if not all of Brandon Shores and Wagner cleared as capacity resources in that delivery year.

[59] The $360 million benefit includes Talen’s revenue from the RMR arrangement, where Brandon Shores and Wagner capacity market revenue would be netted out from final RMR costs.

[60] Billing determinants from U.S. Energy Information Administration form 861.

market results for all four Maryland LDAs: BGE, Pepco, DPL-South, and APS.[61] We focused specifically on Maryland's share of each LDA, rather than the LDAs as a whole. BGE's Maryland share is the same as its entire LDA because the BGE LDA is located entirely within Maryland. Because EIA billing determinant data was only available up to 2022, we assumed that energy, transmission, distribution, and other costs have remained unchanged since 2022 and will continue to be stable through the end of the study period. Capacity market costs for the 2025/2026 delivery year are compared against capacity market results from 2024/2025. This rate and bill impact analysis does not include the cost of the transmission solutions approved for the BGE LDA and the surrounding areas that aim to address the reliability impact associated with Brandon Shores' and Wagner's retirement.

Capacity Market Costs Paid by Customers

When an LDA is constrained, such as the BGE LDA, Capacity Transfer Rights (CTRs) are allocated to loads within that LDA. CTRs essentially represent the value of the transmission system's ability to "transfer" capacity resources to the LDA zone and offset "capacity congestion" effects. These are rights for load (i.e. customers) to receive payments that offset, in whole or in part, the charges attributable to the locational price adder. The locational price adder is the component of the clearing price that represents the price-separated clearing price relative to its parent LDA clearing price. The CTRs are payments equal to the locational price adder times the load's pro rata share of the lower-priced capacity imported into the LDA. [62] CTRs serve to offset a portion of the higher capacity prices for customers in that constrained LDA. We used the CTR allocation and annual capacity market costs for customers provided in PJM's 2025/2026 Base Residual Auction Results (Excel workbook).[63]

Timing of Bill and Rate Impacts

The rate and bill impacts will be felt starting in mid-2025 and beyond, and different customers could feel the impacts at different times. For retail customers taking standard offer service, electric utilities procure energy and capacity from wholesale suppliers through a competitive bidding process that occurs twice a year.[64] These wholesale suppliers are the entities that directly pay for increased capacity costs; their bid price in the competitive bidding process reflects capacity market costs. The winning wholesale supplier of that bidding process then supplies electricity to the utilities at an agreed-upon rate, for six months, who then pass on those costs to their customers. Standard offer service power procurement uses a proxy price for capacity costs because of the delays in running PJM capacity auctions. The proxy price will be adjusted based on the actual capacity market results. This adjustment will raise the wholesale supply contract prices for service starting June 1, 2025, and standard offer service customers will see the impact in the bills starting on that date. Electric customers may choose to procure their own electricity supply from alternative electricity suppliers, who also work with wholesale

[61] This analysis does not account for the transmission solutions approved for Maryland and the surrounding areas, in response to Brandon Shore's planned retirement.

[62] Allocation of CTR MWs to LSEs, April 7, 2021. Available at: https://www2.pjm.com/-/media/committees-groups/committees/mic/2021/20210407/20210407-item-05a-rpm-capacity-transfer-rights-pjm-education.ashx

[63] 2025/2026 Base Residual Auction Results, July 31, 2024. Available at: https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-results.ashx

[64] Residential and small commercial customers standard offer service bids occur twice a year, and large commercial bids occur quarterly. Maryland Public Service Commission. Standard Offer Service. Available at: https://www.psc.state.md.us/electricity/standard-offer-service/

suppliers to procure energy and capacity. The impact of higher capacity prices on those customers will depend on the terms of the retail supply contract.

4.2. RMR Costs and Capacity Market Impacts for Customers in BGE LDA

Talen Energy filed initial fixed RMR costs for Brandon Shores and Wagner that together total $215.7 million per year. Although these RMR arrangement costs are expected to be litigated at FERC, we expect that BGE LDA customers will bear 74 percent of these RMR costs. As a result, BGE LDA customers could see their bills increase by 5 percent, resulting in an average residential bill increase of $5 per month. Commercial customers[65] could see their bills increase by $54 per month (Table 7). These RMR costs are expected to last until at least December 2028, when PJM currently plans to have the transmission solutions in place. The RMR arrangements could be extended if these transmission projects are delayed or if the region continues to face reliability issues beyond 2028, which would mean continued rate and bill impacts for BGE LDA electric customers.

Second, Brandon Shores' and Wagner's removal from the capacity market has significantly impacted the BGE LDA clearing price. Those impacts will, in turn, be passed on to electric customers in that zone. Specifically, we expect the capacity price spike to increase bills by 14 percent In the BGE LDA[66]—in addition to the 5 percent from RMR arrangement costs (Table 7). From the capacity price increase alone, average residential and commercial customers could see their bills increase by $16 per month and $170 per month, respectively (excluding RMR costs).

When considering both the capacity market impact and the RMR service arrangement costs together, total bills are likely to increase by 19 percent—an extra $21 on the average residential customer bill and $224 on the average commercial monthly bill (Table 7). Over the course of a year, that could result in residential electric customers paying an additional $247 annually, and commercial customers paying $2,685 of additional costs. Customers will likely feel these costs impacts until at least December 2028, when PJM has planned for the transmission solutions to be in place (but the timeline for transmission solution completion is highly uncertain). Once the transmission projects are complete (assuming no other reliability issues), the RMRs will no longer be needed for reliability, and the BGE LDA will be able to mitigate high capacity prices by importing lower-priced capacity from neighboring LDAs. In addition, before 2028, additional demand response or generating resources may offer into the market, partially mitigating capacity price increases in the BGE LDA. However, given that the next auction (for 2026/2027) is less than five months from the latest auction (2025/2026) and the beginning of that auction's delivery year is only 1 ½ years following its completion, it is unlikely that there will be any change to BGE LDA capacity price until at least 2027/2028.

[65] Industrial customers are excluded from this analysis, due to the wide variation in energy use and monthly bills.

[66] Capacity costs are only a small portion of a customer's electric bill.

Table 7. Bill and Rate Impacts for BGE LDA of the Brandon Shores and Wagner RMRs (capacity market impacts and RMR cost impacts)

Cost Category	Monthly Bill Change (%)	Additional Costs on Monthly Bills ($)	
	All	Residential	Commercial
Total Cost	**19%**	**$21**	**$224**
Capacity Market Impact	*14%*	*$16*	*$170*
RMR Costs	*5%*	*$5*	*$54*

Source: See description in text. Due to the wide variability in industrial customer types, they were not included in this rate impact analysis.

4.3. Costs Impacts for Maryland Customers in Pepco, DPL-South, and APS LDAs

Capacity market prices for the 2025/2026 delivery year in PJM have surged, with the RTO experiencing a nine-fold increase in clearing prices compared to the previous BRA. These unprecedented costs will ultimately be passed onto customers, with major impacts felt in Maryland. Specifically, Maryland customers in APS, DPL-South, and Pepco zones could see their monthly bills increasing by 24 percent, 2 percent, and 11 percent, respectively (Table 8). On average, this translates into a monthly increase of $18, $4, and $14 for the average residential customer in APS, DPL-South, and Pepco zones, respectively (Table 8).

These bill impacts represent the incremental change from the 2024/2025 to 2025/2026 delivery years. APS LDA generally clears with the RTO, meaning that in the previous auction the clearing price was $29/MW-day, while Pepco LDA cleared with MAAC at $49/MW-day. In the 2024/2025 BRA, DPL-South LDA separated at $426/MW-day,[67] but cleared with the RTO in the 2025/2026 BRA at $270/MW-day. The fact that the APS LDA historically has cleared at the lowest price—and has benefitted from the lowest past capacity prices—helps explain why the APS LDA has the largest bill impact relative to the other Maryland LDAs, including BGE's LDA. In addition, CTRs are used to help mitigate the customer impact of higher-priced capacity in constrained LDAs (e.g. BGE's), which also helps to explain why the BGE bill impact is not magnitudes higher than that of the APS and Pepco LDAs, despite the extreme capacity clearing price in the BGE LDA. CTRs also insulated electric customers from the high clearing prices in DPL-South LDA in 2024/2025, which results in only a small bill increase for DPL-South LDA customers between 2024/2025 and 2025/2026.

We also assessed the bill impact of the RMR costs for the Maryland portion of the Pepco, DPL-South, and APS LDAs, using the same methods described above. We find that residential electric customers in the Maryland portion of the Pepco LDA will experience a small increase (roughly $1 per month) in their bills from Brandon Shores and Wagner RMR costs, starting in June 2025 (Table 8). The Maryland portion of the APS and DPL-South LDAs will pay for 0.1 and 1 percent of the Brandon Shores and Wagner RMR costs, respectively, and thus residential customers will not see any noticeable impact on their bills as a result of these RMRs (Table 8).

[67] DPL-South 2024/2025 clearing price was originally $90.64/MW-day. It was repriced due to a Third Circuit Court of Appeals reversal of PJM's determination of the original price. The updated $426.17/MW-day clearing price for DPL-South is now approved by FERC, but still the subject of litigation.

Table 8. Bill and Rate Impacts for the Maryland portion of APS, DPL-South, and Pepco LDAs, of the 2025/2026 capacity market and the RMR costs for Brandon Shores and Wagner

Maryland LDAs	Cost Category	Monthly Bill Change (%)	Additional Costs on Monthly Bills ($)	
		All	Residential	Commercial
APS LDA Customers (Maryland only)	**Total Cost**	**24%**	**$18**	**$81**
	Capacity Price	*24%*	*$18*	*$81*
	RMR Cost	*< 1%*	*< $1*	*< $1*
DPL-South LDA Customers (Maryland only)	**Total Cost**	**2%**	**$4**	**$18**
	Capacity Price	*2%*	*$4*	*$16*
	RMR Cost	*< 1%*	*< $1*	*$2*
Pepco LDA Customers (Maryland only)	**Total Cost**	**11%**	**$15**	**$172**
	Capacity Price	*10%*	*$14*	*$163*
	RMR Cost	*1%*	*$1*	*$9*

Source: See description in text. Due to the wide variability in industrial customer types, they were not included in this rate impact analysis

5. LOOKING FORWARD BEYOND THE 2025/2026 DELIVERY YEAR

For the BGE LDA, PJM suggests that the reliability issues and transmission constraints associated with Brandon Shores and Wagner will be mitigated by the end of 2028 once transmission solutions are in place. That outcome is by no means a certainty. Project delays related to these factors may very well mean the BGE LDA could face reliability constraints after 2028, thus incurring even more costs for customers. In addition, PJM has been struggling with a massive backlog of new project interconnections, while at the same time working towards compliance with new and anticipated FERC reforms. These factors complicate the development of new generation within the BGE LDA and throughout PJM, which would help alleviate the very high capacity prices seen in the latest auction for the BGE LDA and across the RTO. Unfortunately, we are unlikely to see any major relief by 2026/2027, as that delivery year's capacity auction is scheduled for December 2024, less than five months after the completion of the July 2024 auction for 2025/2026 and only 1 ½ years before the beginning of the delivery year for that auction (leaving a very tight timeline for constructing a new plant).

According to PJM, if there are no delays, it will take a customer in the interconnection queue about 10 months from queue entry for an impact study to be tendered. The full timeline from queue entry to final agreement is between 2.25 and 2.54 years as reported by PJM.[68] However, that timeline has not been accurate for at least the past few years.

[68] PJM Learning Center, "Connecting to the Grid FAQs." Available at: https://learn.pjm.com/three-priorities/planning-for-the-future/connecting-grid/how-long-does-the-interconnection-process-take

In 2020, PJM initiated a stakeholder process to explore interconnection reforms that ultimately led to a pause or closure of the queue in 2022 to allow PJM to address backlogs and implement reforms. PJM determined that it would not review new projects until the fourth quarter of 2025—meaning final decisions on those projects could come as late as 2027.[69]

PJM's reforms include a move from a serial first-come, first-served process of reviewing interconnection requests to a first-ready, first-served cluster study process. The cluster study process would enable PJM to study more projects in a shorter amount of time. Addressing ready projects first also reduces the risk of speculative projects withdrawing from the interconnection queue. As many as 33 percent of projects were withdrawing from the queue after initial feasibility studies, and project withdrawals impact other projects as they often trigger re-studies for other resources.[70] FERC approved PJM's proposed reforms in November 2022.[71] Under PJM's original plans, the transition period to clear the existing backlog began in July 2023 and is intended to be complete by 2026, after which PJM could begin processing all requests submitted after October 2021.[72]

Then in late July 2023, FERC announced Order 2023. This order required RTOs, including PJM, to overhaul their interconnection processes. Order 2023 has raised questions about whether PJM's initial reforms and timelines for its regionally planned transition will be impacted, and if so, how. Order 2023 has some language about not interfering with in-progress cluster studies and transmission processes, but the Commission has also rejected any presumption of compliance for recently approved interconnection process reforms such as PJM's.[73] PJM has asked for a re-hearing and for clarification from FERC on Order 2023, as have other RTOs. On March 21, 2024, FERC issued Order 2023-A, which responds to those requests for re-hearing and clarification and requires incremental upgrades from the initial order. As PJM continues to litigate these questions, it has made progress implementing its reforms by kicking off the transition cycle of its reformed interconnection process on January 22, 2024.[74]

Currently, the BGE LDA has 13 interconnection requests in the PJM queue, equal to roughly 1,200 MW of capacity. Storage represents about 75 percent and solar makes up 25 percent of the 13 requests.[75] Some of these projects have been in the queue since 2020, and over half since 2021, yet they are still not interconnected. Although these 13 projects combined are roughly equal to the UCAP of Brandon Shores, based on historical queue conversion rates, it is extremely unlikely that they will all be constructed. However, as the current "fast-lane" transition cycle gets underway, PJM expects that projects sorted in this cycle will be complete in mid-2025. This means 46,000 MW of new generation across PJM could be cleared and moved to

[69] Bruggers, James. 2022. "Largest US grid operator puts 1,200 mostly solar projects on hold for 2 years." *Courier Journal*, April 30, 2022. https://www.courier-journal.com/story/news/local/science/environment/2022/04/30/solar-projects-put-pause-largest-us-power-grid-operator/9587074002/

[70] PJM Interconnection, L.L.C., Docket No. ER22-2110, Tariff Revisions for Interconnection Process Reform, Request for Commission Action by October 3, 2022, and Request for 30-Day Comment Period.

[71] PJM Inside Lines, "FERC Approves Interconnection Process Reform Plan." Available at: https://insidelines.pjm.com/ferc-approves-interconnection-process-reform-plan/

[72] PJM Inside Lines, "Transition to New Interconnection Process Begins July 10." Available at: https://insidelines.pjm.com/transition-to-new-interconnection-process-begins-july-10/

[73] PJM Request for Clarification and Rehearing of PJM Interconnection, 179 FERC ¶ 61,194 p. 8-10 (2023).

[74] PJM Inside Lines, "Transition Cycle 1 of New Interconnection Process Begins Jan. 22." Available at: https://insidelines.pjm.com/transition-cycle-1-of-new-interconnection-process-begins-jan-22/.

[75] PJM Services Request Status. Available at: https://www.pjm.com/planning/service-requests/services-request-status

construction starting in mid-2025,[76] some of which could mitigate high capacity prices in 2026/2027 and beyond, including in the BGE LDA (though given the short time period until the next BRA (December 2024) and the start of its delivery year (June 1, 2026), it is unlikely that there will be major changes to supply before then).

If the capacity market is well designed and is working efficiently, it should send a clear price signal and incentivize the building of more capacity in the BGE LDA. Nonetheless, the transmission solutions will not be in service until the end of 2028, roughly 3.5 years from the start of RMR arrangements for Brandon Shores and Wagner. Given the high uncertainty around queue waiting times, the current backlog, and interconnection reforms, it appears likely that wait times for new entrants to the queue could be longer than 3.5 years, if not more, so that their entry into the market will not help to address the anticipated RMRs and the related capacity market disruptions. This is far longer than the five months until the next capacity market auction, set to occur in December 2024. Without rapid and significant improvements to the interconnection process in PJM, reliability issues, RMRs, and high capacity prices could continue escalating costs for Marylanders for years to come.

[76] RTO Insider, "PJM Initiates Transitional Interconnection Queue." Available at: https://www.rtoinsider.com/69131-pjm-initiates-transitional-interconnection-queue/.

ATTACHMENT 3:

Affidavit of James F. Wilson

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Sierra Club et al	)	Docket No. EL24-
v.	)	
PJM Interconnection, L.L.C.	)	
	)	
	)	

AFFIDAVIT OF JAMES F. WILSON IN SUPPORT OF THE COMPLAINT OF THE PUBLIC INTEREST ORGANIZATIONS

Contents

AFFIDAVIT OF JAMES F. WILSON
IN SUPPORT OF THE COMPLAINT OF
THE PUBLIC INTEREST ORGANIZATIONS

I. Introduction

1. My name is James F. Wilson. I am an economist and independent consultant doing business as Wilson Energy Economics. My business address is 4800 Hampden Lane Suite 200, Bethesda, MD 20814.

2. I have forty years of consulting experience in the electric power and natural gas industries. Many of my past assignments have focused on the economic and policy issues arising from the introduction of competition into these industries, including restructuring policies, market design, market analysis and market power. Other recent engagements have included resource adequacy and capacity markets, contract litigation and damages, forecasting and market evaluation, pipeline rate cases and evaluating allegations of market manipulation. I have submitted affidavits and presented testimony in proceedings of the Federal Energy Regulatory Commission, state regulatory agencies, and U.S. district courts. I hold a B.A. in Mathematics from Oberlin College and an M.S. in Engineering-Economic Systems from Stanford University. My curriculum vitae, summarizing my experience and listing past testimony, is Attachment JFW-1 attached hereto.

3. This affidavit was prepared at the request of Sierra Club, Natural Resources Defense Council, and Union of Concerned Scientists. My assignment was to explain how generating units that operate for some period of time under cost-based contracts for reliability reasons ("Reliability Must Run" or "RMR" units) should be treated in organized capacity markets, and, in particular, in PJM Interconnection, LLC's ("PJM") Reliability Pricing Model ("RPM") capacity construct.

II. Summary and Recommendations

4. The Federal Energy Regulatory Commission ("FERC" or "Commission") has a clear policy in this regard – an RMR unit, which has been determined by the RTO to be needed for reliability, should be offered into the RTO's capacity market as a price taker for the duration of the need and RMR contract. I have concluded in the past,[1] and again conclude, that the Commission's policy is supported by economic theory and economically efficient. I also find that FERC's policy, which is applicable and in force in New York and New England, is also fully applicable to RMRs in the PJM region. While RMRs in the PJM region have generally not participated in RPM in recent years, this resulted from negotiations between the owners and PJM, and in some instances RMRs have offered into RPM.[2]

5. To hold an RMR unit out of the RPM capacity market, as current rules allow and some parties desire,[3] is economically inefficient and harms markets and consumers:

a. Holding the RMR unit out of RPM misrepresents the true state of supply, because the RMR unit, which is needed and has been retained for other reliability needs,

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[1] Wilson, James F., *Affidavit in Support of the Protest of the New England States Committee on Electricity*, filed June 6, 2018 in FERC Docket No. EL18-154, pp. 4-5 (finding the FERC policy sound and concluding that the Mystic units should be offered as price takers into the ISO New England capacity market).

[2] *See, e.g.,* FirstEnergy Service Company, Informational Filing regarding Deactivation Avoidable Cost (DAC) Rate under Section 116 of the PJM Interconnection, L.L.C.'s Open Access Transmission Tariff (July 10, 2012), Docket No. ER12-2710, at Section IV ("To the extent that Eastlake #1 does not already have a capacity commitment, FE Genco agrees to offer Eastlake #1's capacity into every Reliability Pricing Model Incremental Auction at a price of zero dollars."). Attachment 4 to this filing is a written agreement between FirstEnergy Service Company and Monitoring Analytics documenting agreement that FirstEnergy would offer the capacity from all of units receiving RMR arrangements—Eastlake Units 1-4, Lake Shore Unit 18, and Ashtabula Unit 5—into the incremental auction as price takers if the units did not already have a capacity commitment.

[3] See, for instance, letter from Electric Power Supply Association and PJM Power Providers Group to the PJM Board of Managers, *RE: Opposition to Critical Issue Fast Path Request on Reliability Must Run Arrangements in Capacity Markets and Possible Auction Delay,* p. 2 (opposing efforts to bring RMR units back into the capacity market), available at https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/2024/20240912-epsa-p3-letter-regarding-consumer-advocates-request-for-urgent-reforms-to-the-pjm-capacity-market-regarding-rmr-units.ashx.

does indeed contribute to resource adequacy. To ignore the unit distorts the supply-demand balance in RPM.

b. The distorted supply-demand balance in RPM is economically inefficient because it will lead to price signals that falsely signal a degree of scarcity that does not exist. The inaccurate price signals harm markets by encouraging inefficient decisions with respect to existing and potential new resources by market participants on the supply side and demand side.

c. Holding the RMR unit out of RPM also harms consumers by forcing them to "pay twice" for resource adequacy; first, under the cost-based RMR contract for the RMR capacity, and then through RPM for the additional capacity procured to meet the part of the Reliability Requirement that the RMR unit could and should have satisfied. Indeed, consumers pay more than twice, because holding the RMR out of RPM also artificially raises the RPM clearing prices paid by consumers to all other resources.

6. Some will argue that additional resources are urgently needed on the PJM system at this time so any policy that could moderate capacity prices should be rejected. However, RPM is designed to set high prices when resources are needed, as they are at present due to anticipated load growth and retirements, among other factors. It is not necessary or appropriate to distort the RPM supply-demand balance to send a strong price signal. And market participants are unlikely to respond much to a price signal known to misrepresent the supply-demand balance and to likely be short-lived, since RMR units only serve for the period until PJM builds transmission to solve the reliability problem created by the retiring generation.

7. While it is appropriate and consistent with FERC policy for current RMRs to participate in RPM as price takers, I will also describe an alternative approach that is roughly as efficient, and allows the RMR unit to avoid taking on an RPM capacity obligation. The RMR unit's contribution to resource adequacy can alternatively be captured by accurately modeling its performance as an RMR unit within the resource adequacy analysis that determines the Reliability Requirements to be acquired through RPM. This approach would reduce the locational Reliability Requirement by roughly the resource adequacy value of the RMR unit, which would shift the RPM capacity demand curves and lead to similar RPM price results as including the RMR unit as a supply in RPM.

8. To summarize: RMR units should participate in PJM's RPM capacity construct as price takers, to accurately and efficiently represent their contribution to resource adequacy and avoid the inefficiency and harm that result from misrepresenting true resource adequacy within RPM. Alternatively and roughly equivalently, the reliability contributions of RMR units could be reflected in the resource adequacy analyses that determine the Reliability Requirements acquired through RPM.

9. The remainder of my affidavit is organized as follows. The next section explains, by way of background, why and how RMR units occur on the PJM system, and the typical nature of an RMR contract. Section IV explains FERC's policy with respect to RMRs in capacity markets and the rationale behind the policy, and why this logic is fully applicable to the PJM region and markets. Section V describes the inefficiency and harm that results from holding RMR units out of RPM. Section VI notes that RPM would send a strong price signal without withholding RMRs from it, and explains that the artificial signal resulting from withholding RMRs likely does not have the desired impact. Section VII further explains how RMR units should participate in RPM,

and also describes the alternative solution of representing RMR units within the resource adequacy analysis that determines the RPM reliability requirements.

III. RMRs in PJM: Why and How They Happen

10. When a PJM generator announces its intention to retire, PJM's generator deactivation process[4] is initiated, under which PJM performs a comprehensive reliability analysis.[5] PJM may find that the retirement would lead to reliability violations that cannot quickly be addressed through transmission upgrades or other approaches. To maintain reliability, PJM may request that the owner keep the unit in service until the necessary transmission enhancements can be constructed.

11. PJM negotiates the RMR contract with the unit's owner. Two recent examples are the RMR contracts with Talen Energy for the continued operation of the Brandon Shores coal-fired power plant and the Herbert A. Wagner oil-fired power plant,[6] both plants located in Maryland.

12. There is no template or pro forma agreement for RMR contracts in PJM, and the PJM tariff does not substantially restrict the content or provide much guidance.[7] The owner may

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[4] See, for instance, PJM Manual 14D: *Generator Operational Requirements*, Revision: 65, Effective Date: December 20, 2023, Section 9, Generator Deactivations, available at https://learn.pjm.com/-/media/documents/manuals/m14d.ashx.

[5] See, for instance, PJM, Generation Deactivation Notification Update, Transmission Expansion Advisory Committee (Jun 6, 2023), at slides 4-8 (detailing results of reliability analysis for Brandon Shores deactivation), https://www.pjm.com/-/media/committees-groups/committees/teac/2023/20230606/20230606-item-02---generation-deactivation-notification-update.ashx.

[6] *See, e.g.*, Brandon Shores LLC, RMR Arrangement – Continuing Operations Rate Schedule, Docket No. ER24-1790 (Apr. 18, 2024), Accession No. 20240418-5176 (effective date June 1, 2025 through December 31, 2028); H.A. Wagner LLC, RMR Arrangement – Continuing Operations Rate Schedule, Docket No. ER24-1787 (Apr. 18, 2024), Accession No. 20240418 (effective date June 1, 2025 through December 31, 2028).

[7] PJM Open Access Transmission Tariff, Part V.

choose a Deactivation Avoidable Cost Rate, or full cost-of-service.[8] An RMR contract in PJM will typically call for the RMR unit to operate only as needed and requested by PJM.[9] The RMR contract may include some performance incentives if the owner and PJM can agree to this.[10]

13. One peculiarity of RMR contracts in PJM is that they have generally not called for RMR units to offer their capacity into RPM. This is in contrast to other RTOs where, as discussed further below, RMR units are required under the tariff to offer their capacity into the capacity market as price takers.

14. The non-participation of RMR units in RPM is enabled by the PJM Tariff that allows a generating resource to qualify for an exception to the RPM must-offer rule if, as shown by appropriate documentation, the capacity resource is "reasonably expected to be physically unable to participate in the relevant Delivery Year;" and it can receive the excusal from the must-offer rule if it can show this "without regard" to whether PJM has requested the resource to operate in the delivery year under an RMR contract, and the owner has agreed to do so.[11] Of course, if the owner can demonstrate that the resource is "reasonably expected to be unable to participate" in the delivery year (perhaps due to some major problems at the facility) the resource is unlikely to be of much value under the RMR contract and is understandably excused from RPM. But apparently

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[8] OATT, Part V, at sections 114-16, 119.

[9] Brandon Shores LLC, BSH - Attachment A - Brandon Shores CORS with Cover, Docket No. ER24-1790 (Apr. 18, 2024), Accession No. 20240418-5176 ("Brandon Shores CORS") at § 3.3(a) ("PJM may schedule and dispatch either or both Units solely to address 1) an identified transmission reliability need…; 2) a PJM transmission reliability need…; 3) a capacity emergency…).

[10] See, for instance, NRG Power Marketing LLC, NRG-BML Settlement Agreement, Docket No. ER22-1539 (April 2, 2024), Accession No. 20240402-5138, at Attachment B, 1 (PDF 51) (describing a Transmission Performance Adjustment and a Reliability Performance Adjustment, penalties for failure to perform).

[11] PJM Tariff Attachment DD Section 6.6(g).

this tariff language has been interpreted as offering a broad excusal from RPM participation for RMR units even if they are expected to continue to perform as they have in the recent past.

15. It is, of course, an undesirable result when a resource that is needed for reliability is revenue inadequate, and is requested to continue operation under a cost-based RMR contract. PJM agrees with the goal that its markets should produce results that align with the reliability needs of the system, adequately compensating all resources for their reliability contributions, which would obviate the need for RMRs:[12]

> As a general matter, PJM supports aligning the structure and parameters used in the markets with the criteria and actions taken to maintain reliability in planning and operations. This alignment is essential to producing market results that align with the reliability needs of the system and send incentives that promote cost-effective actions to maintain reliability.

16. However, PJM also recognizes that creating the complete set of markets that would eliminate RMRs is not feasible:[13]

> Additionally, the interactions between system elements, particularly in voltage-related constraints, make it challenging to directly translate the detailed reliability standards used in transmission planning into the capacity market framework. For instance, the impact of a single unit's deactivation can affect hundreds of reliability tests, some in ways only observable in non-linear AC power flow simulations, which are not readily captured in the current LDA-based resource adequacy assessments.

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[12] PJM, *PJM Response to the 2023 State of the Market Report* ("PJM Response to 2023 SOM") p. 2, available at https://www.pjm.com/-/media/library/reports-notices/state-of-the-market/20240822-pjm-response-to-the-2023-state-of-the-market-report.ashx.

[13] PJM Response to 2023 SOM, p. 2.

17. This means that RMRs will from time to time be necessary in RTO markets, so it is important that RTO policies in this regard are economically efficient and do not unduly harm markets or consumers.

IV. FERC Policy re: RMRs in Capacity Markets

18. FERC's policy with respect to the treatment of RMR units in organized capacity markets was established in a New York ISO case in 2016[14] and affirmed in a more recent ISO New England case:[15] RMR resources are offered into these capacity markets as price takers. The logic and rationale for this policy, as explained by the Commission and by Potomac Economics, the market monitor for the New York and New England ISOs, is as follows:[16]

a. The RMR unit has announced plans to retire, meaning it is revenue inadequate – it does not earn enough compensation under the RTO's current markets.

b. However, the RTO has determined that the unit is needed for reliability for some period of time until transmission upgrades are completed. This means that if the RTO had had a complete set of markets to acquire all the services needed for reliability, this unit would have been acquired and fully compensated, and would not have requested retirement. Put another way, the RMR occurs because the RTO's market design is incomplete and has "missing markets" that would have acquired the needed RMR unit and compensated it adequately.

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[14] See New York Independent System Operator, Inc., 155 FERC ¶ 61,076 (2016), at P 82 (finding that RMR units should participate in the capacity market as price takers).

[15] See, ISO New England, 165 FERC ¶ 61,202 (2018) at P 82 (accepting ISO New England's proposal to enter fuel security resources into the capacity market as price takers).

[16] *Id*; see also Comments of ISO New England's External Market Monitoring Unit, filed September 21, 2018 in FERC Docket No. EL18-182, pp. 12-13 (concluding that including Mystic as a price-taker in the upcoming FCA will ensure that capacity prices are efficient.)

c. Accordingly, while the unit is apparently *revenue inadequate* under the RTO's *current* (incomplete) market design, the unit is in fact economic because it is for now necessary for reliability. A complete market design that does not have missing markets would have acquired the unit and compensated it sufficiently, and it would not have announced an intention to retire. The RMR contract fills the gap in the current market design and maintains reliability.

d. Because the unit is needed and therefore economic, it should offer into the capacity market that acquires capacity for resource adequacy at its net going forward cost, as do all other existing resources. Because the unit's net going forward cost is covered through the RMR contract, its net going forward cost needed from the capacity market is zero, so it should offer into the capacity market at zero.

19. Note that if the RTO were to create a complete set of markets, the unit would be compensated for its reliability contribution by the additional markets that are presently apparently missing, so the result would be roughly the same – the unit would be acquired in one of the new markets, its going forward cost would be covered in the new markets, and its net cost that must be recovered from the capacity market would be zero or very low.

20. Note also that even if the missing market that leads to the RMR is essentially a very local capacity zone, creating that locational market within RPM would also lead to the same result – the unit would be acquired through RPM to meet the locational need (possibly at a high price that only it receives in the very local capacity zone), and, since acquired, the unit would be on the supply side for matching supply and demand for resource adequacy in all "parent" (surrounding) zones, moderating capacity prices in those zones and at the RTO level.

21. This policy – RMR units participate in the capacity market as price takers -- has recently been confirmed by ISO New England.[17] The ISO is planning a broad-based review of its capacity market rules, and notes that under its current rules, "Resources retained for local transmission security are treated as price takers in the capacity market." The ISO states that it "finds that this treatment continues to be appropriate" and proposes to exclude any consideration of the treatment of RMR units in the capacity market from the scope of the work.[18]

22. The rationale described above is applicable to the PJM RTO just as it is to the New York and New England ISOs. All three operate wholesale markets that include locational capacity markets, and their market rules can result in resources that are needed for reliability becoming revenue deficient at times. And the rationale is applicable to the circumstances that are causing the current RMRs in PJM in the same way as at applied in the past in New York and New England – the RTO's markets are imperfect and incomplete, resulting in some needed resources finding themselves revenue inadequate.

23. At first glance it may seem that since the unit wished to retire, retaining it and including it "out of market" in the capacity market distorts the capacity market. But again, the unit wished to retire not because it was uneconomic, but because the RTO's markets were incomplete and failed to adequately compensate it for its reliability services. Had the RTO's markets been complete, they would have acquired and compensated the unit, it would not be seeking to retire, and it would be in the capacity market for resource adequacy.

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[17] Presentation by Chris Geissler, Director, Economic Analysis, ISO New England, NEPOOL Markets Committee meeting September 10, 2024, Item 3: *Capacity Auction Reforms: Continued Discussion of Project Scope,* slide 20, available at https://www.iso-ne.com/static-assets/documents/100015/a03a_mc_2024_09-10_capacity_auction_reforms_iso_presentation.pdf.

[18] *Id.*

V. The Inefficiency and Harm if an RMR Unit is Held Out of RPM

24. To hold an RMR unit out of the RPM capacity market – and to not reflect its contribution to resource adequacy in another manner – is economically inefficient and harms markets and consumers.

25. First, holding the unit out of RPM misrepresents the true state of supply, because the RMR unit, which is needed and has been retained for other reliability needs, does indeed contribute to resource adequacy. To remove the RMR unit from RPM distorts the supply-demand balance represented there.

26. The distorted supply-demand balance in RPM is economically inefficient because it will lead to price signals that falsely signal a degree of scarcity that does not exist, and it may also lead to clearing resources that are not needed. The inaccurate price signal harms the market by encouraging inefficient decisions with respect to existing and potential new resources by market participants on the supply side and demand side.

27. Holding the unit out of RPM also harms consumers by forcing them to "pay twice" for resource adequacy; first, consumers bear the unit's cost under the RMR contract, and then they also pay through RPM for the capacity procured to meet the part of the Reliability Requirement that the RMR could and should have satisfied. Indeed, consumers pay more than twice, because holding the RMR out of RPM also artificially raises the RPM clearing prices paid by consumers to all other cleared resources.

28. PJM also recognizes the importance of modeling RMR units within its reliability analyses to accurately represent the true state of the system, and the inefficiency that results if RMR units are excluded. In discussing the reliability requirements and import capacity needs

(Capacity Emergency Transfer Objective, or "CETO") for locational deliverability areas ("LDAs"), PJM has stated as follows:[19]

> Under the current process, PJM believes that including RMR units in the assessment of local reliability requirements and CETO calculations is important. First, note that the physical presence of an RMR unit can (sometimes significantly) alter the patterns of risk within an LDA. Excluding these units from the analysis could result in an incomplete and potentially inaccurate assessment of local reliability needs… Therefore, our reliability analysis must assess the total quantity of system-accredited capacity necessary to meet local reliability needs based on local risks, which inherently includes considering all physical resources expected in the area, including RMR units.
>
> … Including RMR units in the analysis also ensures that we determine the appropriate total reliability requirement and CETO for each LDA. In some cases, excluding these units could lead to an overestimation of the capacity needed from the market, potentially resulting in over-procurement and inefficient market outcomes. In other cases, excluding RMR units from the analysis could lead to under-procurement of local capacity, potentially creating greater local reliability risks.

29. PJM also recognizes the market distortion that can occur if RMR units are excluded from its analyses:[20]

> Additionally, it is important to be consistent in the modeling of the necessary transmission upgrades associated with an RMR unit. The RMR units are included in the assessment of local reliability requirements, CETO and CETL calculations, but the necessary transmission upgrades are appropriately not included. This consistency removes the potential for distorted price signals that would incent generation where transmission upgrades could have replaced that need.

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[19] PJM Response to 2023 SOM, p. 4.

[20] PJM Response to 2023 SOM, p. 4.

30. An example of the harm when RMR units are held out of the capacity market occurred in the July 2024 RPM Base Residual Auction for the 2025/2026 delivery year.[21] While the Brandon Shores and Wagner plants will be operating under RMR contracts in that delivery year, neither plant was offered into RPM, nor was the reliability value of these plants reflected in RPM in any other manner. The result was a price spike in the BG&E zone where the plants are located, causing an estimated $4 or $5 billion transfer of wealth from consumers to capacity sellers across the RTO.[22]

31. The excessive prices and resulting harm are likely to continue in the next auction, scheduled for December 2024, for the following delivery year, 2026-2027.[23]

VI. RPM Sends a Strong Price Signal Without Artificially Raising It; and the Artificial Signal Would In Any Case Not Have the Desired Impact

32. While additional resources are needed on the PJM system at this time, RPM is designed to set appropriately high prices when resources are needed, so it is not necessary or appropriate to distort the supply-demand balance to send a stronger price signal. While including

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[21] See PJM, *2025/2026 Base Residual Auction Report*, July 30, 2024 p. 3 (showing that the price in the BG&E zone was at the price cap, $444.26/MW-day).

[22] See IMM 2025/26 BRA Report p. 9 (estimating the impact at $4.3 billion), or Synapse Energy Economics, Inc. *Bill and Rate Impacts of PJM's 2025/2026 Capacity Market Results & Reliability Must-Run Units in Maryland*, report prepared for the Maryland Office of People's Counsel, August, 2024 ("Synapse Report") p. 8 (estimating the impact at $5 billion).

[23] See, for instance, BofA Power and Utilities*, PJM capacity prices will be higher in the near term, volatile in the long term;* September 4, 2024 (expecting higher prices in the next auction, with a "distinct possibility" that the entire market will clear at the ceiling price of $695.83/MW-day); Aurora Energy Research, *PJM Capacity Market – 2025/2026 results & outlook for upcoming auctions,* September, 2024 (price expectations $100 to $700/MW-day, with central expectation $200- $300/MW-day); Synapse Report, p. 31 (unlikely to see any major relief for 2026/2027).

the RMRs in RPM would have saved consumers billions, it would still have resulted in a very high RTO level capacity price, sending one of the strongest price signals ever sent by RPM.[24]

33. The PJM Board of Managers suggests that including RMRs in RPM would "distort the price signal;" [25] but as explained above, RPM is distorted by removing the RMRs, not by including them. The PJM Board of Managers also asserts that including RMRs in RPM would "fail to incent the new build needed in Maryland and in the rest of the RTO" and is "likely to result in greater reserve shortfalls in the future."[26] However, market participants are unlikely to respond much to a price signal that 1) they know misrepresents the true near-term and longer-term supply-demand balance, and 2) they also know is likely to be short-lived. Investors base their decisions to invest capital on longer-term price expectations, not short-term prices.[27] The extra price signal that results from excluding an RMR unit from RPM is known to be a distortion of the actual conditions on the system. Investors know that transmission to relieve the constraints that the retirement would cause are under construction. And investors also know the RMR contract is a temporary bridge for the period until PJM builds transmission to allow the generator to retire without causing reliability problems.

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[24] The Synapse Report estimates the RTO price would have been $163.46/MW-day, a level only exceeded in 2018-2019 ($164.77/MW-day) and 2010-2011 ($174.29/MW-day). The IMM 2025/26 BRA Report did not state the price underlying its estimate cost impact, but since its cost impact estimate was smaller, the price was likely higher than in the Synapse Report. Past RPM prices are from Monitoring Analytics, PJM State of the Markets reports.

[25] PJM Board Response to Consumer Advocates' Letter Regarding Urgent Reforms to the PJM Capacity Market Regarding Reliability Must Run Units, September 19 2024, p. 4.

[26] *Id*.

[27] See Wilson, James F., *Forward Capacity Market CONEfusion*, Electricity Journal, November 2010 (explaining that investments in fixed, long-term assets are based on longer-term price expectations, and why hopes that capacity sellers would offer at Net CONE were misguided).

34. PJM's Independent Market Monitor, Monitoring Analytics, also recognizes that a price signal is pointless under these circumstances:[28]

> 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.

VII. Two Economically Efficient Solutions

35. This section first elaborates on how RMR units should participate in RPM as supply. This section also proposes an alternative economically efficient approach to recognizing the reliability value of RMR units in RTO capacity markets.

36. For these approaches to be non-discriminatory, any other units that provide equivalent service to the RMR unit should be compensated in a manner commensurate with the RMR unit's compensation. However, typically the RMR unit is providing unique reliability services at its specific location, and there are few if any other resources providing comparable reliability services.

A. Alternative 1: The RMR Unit Participates in the RPM Capacity Market

37. The preferred alternative is for RMR units to be offered into RTO capacity markets as price takers, consistent with economic theory and FERC policy, discussed above and established in the New York ISO and ISO New England markets.

38. If an RMR unit clears in RPM it will face potential penalties and bonuses under PJM's Capacity Performance capacity market framework. It is appropriate for the RMR contract to specify to what extent these penalties and incentives flow through to consumers or are partially

[28] Monitoring Analytics, *Analysis of the 2025/2026 RPM Base Residual Auction Part A,* September 20, 2024 ("IMM 2025/26 BRA Report"), p. 7.

borne by the owner in order to create performance incentives. To the extent the owner faces some potential penalties and other costs that are specifically related to serving as a capacity resource, PJM's tariff allows including those costs in RPM offers even if all other costs are fully covered.[29] Thus, if and to the extent the owner would face any Capacity Performance Quantified Risk ("CPQR") under its RMR contract, it would offer into RPM not at zero as a complete price taker, but at a non-zero level that reflects this risk.

B. Alternative 2: The RMR Unit's Resource Adequacy Contribution is Reflected in the RPM Reliability Requirements

39. While it is appropriate and consistent with FERC policy for RMR units to participate in RPM as price takers, as described above as Alternative 1, there is an alternative, economically efficient approach that would continue to allow RMR units to avoid taking on RPM capacity obligations: the RMR unit's contribution to resource adequacy could be modeled within the resource adequacy analysis that determines the locational and RTO-level Reliability Requirements that will be acquired through RPM.

40. The RMR unit would be represented as a resource with capacity injection rights that is called by PJM when needed for reliability at its location (consistent with the RMR agreement) within the resource adequacy modeling. The unit's anticipated performance characteristics, including outage rate, would be modeled. RMR agreements typically allow necessary investments to remain in operation over the required period, so it would be reasonable to assume future performance would be consistent with historical performance.

41. This approach can be expected to reduce the Reliability Requirements in the unit's locational delivery area by roughly the resource adequacy value of the RMR unit in that zone, and

[29] PJM Tariff Attachment DD section 6.4 Market Seller Offer Caps.

also in parent zones.[30] Reducing the Reliability Requirements in this manner should lead to roughly the same RPM clearing prices, in the unit's local zone and in parent zones, as including the RMR unit as a supply resource in RPM, offering its Effective Load Carrying Capability ("ELCC")[31] into RPM. This is because it reduces the Reliability Requirements, and shifts the sloped Variable Resource Requirements capacity demand curves, by roughly the capacity value of the RMR unit. Including the RMR unit in the RPM supply curve as a price taker shifts the RPM supply curve by roughly the reliability value of the RMR unit. Because the supply and demand curves are generally rather steep, these two shifts should have roughly the same impact on prices in the local zone and parent zones.

42. An RMR unit typically provides capacity in a constrained zone while ELCC in PJM is established at the RTO level. For some types of resources, this could result in substantial differences between the resource's calculated RTO-level ELCC, its modeled reliability value within the zone, and its modeled reliability value at the RTO level; Alternative 1 and 2 could give quite different results for such resources. However, for the types of resources that typically operate under RMR contracts (older thermal resources) and assuming they are called by PJM when needed for reliability, the differences are likely to be minor.

43. This concludes my affidavit.

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[30] See Patricio Rocha-Garrido and Michael Herman, PJM, *PJM CETO/CETL & Load Deliverability*, presentation to the Deactivation Enhancements Senior Task Force, August 19, 2024, pp. 6-8 (explaining that removing a resource from the CETO analysis changes the locational Reliability Requirement only if and to the extent the locational reliability value of the resource in the zone differs substantially from its accreditation at RTO level).

[31] ELCC values quantify the resource adequacy value of groups of similar resources based on simulation. See PJM Manual 20A: Resource Adequacy Analysis, Revision: 0, Effective Date: June 27, 2024.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Sierra Club et al	)	Docket No. EL24-
v.	)	
PJM Interconnection, L.L.C.	)	
	)	
	)	

VERIFICATION

I, James F. Wilson, pursuant to 28 U.S.C. § 1746, state, under penalty of perjury, that I am the same James F. Wilson referred to in the foregoing document entitled "Affidavit of James F. Wilson in Support of the Protest of the Public Interest Entities," that I have read the same and am familiar with the contents thereof, and that the facts set forth therein are true and correct to the best of my knowledge, information, and belief.

James F. Wilson

James F. Wilson

Dated: September 26, 2024

James F. Wilson
Principal, Wilson Energy Economics

4800 Hampden Lane Suite 200
Bethesda, Maryland 20814 USA

Phone: (240) 482-3737
Cell: (301) 535-6571
Email: jwilson@wilsonenec.com
www.wilsonenec.com

SUMMARY

James F. Wilson is an economist with over 40 years of consulting experience, primarily in the electric power and natural gas industries. Many of his assignments have pertained to the economic and policy issues arising from the interplay of competition and regulation in these industries, including restructuring policies, market design, market analysis and market power. Other recent engagements have involved resource adequacy and capacity markets, contract litigation and damages, forecasting and market evaluation, pipeline rate cases and evaluating allegations of market manipulation. Mr. Wilson has been involved in electricity restructuring and wholesale market design for over twenty years in California, PJM, New England, Russia and other regions. He also spent five years in Russia in the early 1990s advising on the reform, restructuring and development of the Russian electricity and natural gas industries.

Mr. Wilson has submitted affidavits and testified in Federal Energy Regulatory Commission and state regulatory proceedings. His papers have appeared in the *Energy Journal*, *Electricity Journal*, *Public Utilities Fortnightly* and other publications, and he often presents at industry conferences.

Prior to founding Wilson Energy Economics, Mr. Wilson was a Principal at LECG, LLC. He has also worked for ICF Resources, Decision Focus Inc., and as an independent consultant.

EDUCATION

MS, Engineering-Economic Systems, Stanford University, 1982

BA, Mathematics, Oberlin College, 1977

RECENT ENGAGEMENTS

- Analysis of provisions to enhance resource fuel security in day-ahead and real-time wholesale electricity markets.
- Evaluated peak electric load forecasts and enhancements to load forecasting methodologies.
- Evaluated a probabilistic analysis to determine the electric generating capacity reserve margin to satisfy resource adequacy criteria.
- Evaluated the potential impact of an electricity generation operating reserve demand curve on a wholesale electricity market with a capacity construct.
- Developed wholesale capacity market enhancements to accommodate seasonal resources and resource adequacy requirements.
- Evaluation of wholesale electricity market design enhancements to accommodate state initiatives to promote state environmental and other policy objectives.
- Evaluation of proposals for natural gas distribution system expansions.
- Various consulting assignments on wholesale electric capacity market design issues in PJM, New England, the Midwest, Texas, and California.
- Cost-benefit analysis of a new natural gas pipeline.
- Evaluation of the impacts of demand response on electric generation capacity mix and emissions.

- Panelist on a FERC technical conference on capacity markets.
- Affidavit on the potential for market power over natural gas storage.
- Executive briefing on wind integration and linkages to short-term and longer-term resource adequacy approaches.
- Affidavit on the impact of a centralized capacity market on the potential benefits of participation in a Regional Transmission Organization (RTO).
- Participated in a panel teleseminar on resource adequacy policy and modeling.
- Affidavit on opt-out rules for centralized capacity markets.
- Affidavits on minimum offer price rules for RTO centralized capacity markets.
- Evaluated electric utility avoided cost in a tax dispute.
- Advised on pricing approaches for RTO backstop short-term capacity procurement.
- Affidavit evaluating the potential impact on reliability of demand response products limited in the number or duration of calls.
- Evaluated changing patterns of natural gas production and pipeline flows, developed approaches for pipeline tolls and cost recovery.
- Evaluated an electricity peak load forecasting methodology and forecast; evaluated regional transmission needs for resource adequacy.
- Participated on a panel teleseminar on natural gas price forecasting.
- Affidavit evaluating a shortage pricing mechanism and recommending changes.
- Testimony in support of proposed changes to a forward capacity market mechanism.
- Reviewed and critiqued an analysis of the economic impacts of restrictions on oil and gas development.
- Advised on the development of metrics for evaluating the performance of Regional Transmission Organizations and their markets.
- Prepared affidavit on the efficiency benefits of excess capacity sales in readjustment auctions for installed capacity.
- Prepared affidavit on the potential impacts of long lead time and multiple uncertainties on clearing prices in an auction for standard offer electric generation service.

EARLIER PROFESSIONAL EXPERIENCE

LECG, LLC, Washington, DC 1998–2009.
<u>Principal</u>

- Reviewed and commented on an analysis of the target installed capacity reserve margin for the Mid Atlantic region; recommended improvements to the analysis and assumptions.
- Evaluated an electric generating capacity mechanism and the price levels to support adequate capacity; recommended changes to improve efficiency.
- Analyzed and critiqued the methodology and assumptions used in preparation of a long run electricity peak load forecast.
- Evaluated results of an electric generating capacity incentive mechanism and critiqued the mechanism’s design; prepared a detailed report. Evaluated the impacts of the mechanism’s flaws on prices and costs and prepared testimony in support of a formal complaint.
- Analyzed impacts and potential damages of natural gas migration from a storage field.
- Evaluated allegations of manipulation of natural gas prices and assessed the potential impacts of natural gas trading strategies.
- Prepared affidavit evaluating a pipeline’s application for market-based rates for interruptible transportation and the potential for market power.
- Prepared testimony on natural gas industry contracting practices and damages in a contract dispute.
- Prepared affidavits on design issues for an electric generating capacity mechanism for an eastern US regional transmission organization; participated in extensive settlement discussions.

- Prepared testimony on the appropriateness of zonal rates for a natural gas pipeline.
- Evaluated market power issues raised by a possible gas-electric merger.
- Prepared testimony on whether rates for a pipeline extension should be rolled-in or incremental under Federal Energy Regulatory Commission ("FERC") policy.
- Prepared an expert report on damages in a natural gas contract dispute.
- Prepared testimony regarding the incentive impacts of a ratemaking method for natural gas pipelines.
- Prepared testimony evaluating natural gas procurement incentive mechanisms.
- Analyzed the need for and value of additional natural gas storage in the southwestern US.
- Evaluated market issues in the restructured Russian electric power market, including the need to introduce financial transmission rights, and policies for evaluating mergers.
- Affidavit on market conditions in western US natural gas markets and the potential for a new merchant gas storage facility to exercise market power.
- Testimony on the advantages of a system of firm, tradable natural gas transmission and storage rights, and the performance of a market structure based on such policies.
- Testimony on the potential benefits of new independent natural gas storage and policies for providing transmission access to storage users.
- Testimony on the causes of California natural gas price increases during 2000-2001 and the possible exercise of market power to raise natural gas prices at the California border.
- Advised a major US utility with regard to the Federal Energy Regulatory Commission's proposed Standard Market Design and its potential impacts on the company.
- Reviewed and critiqued draft legislation and detailed market rules for reforming the Russian electricity industry, for a major investor in the sector.
- Analyzed the causes of high prices in California wholesale electric markets during 2000 and developed recommendations, including alternatives for price mitigation. Testimony on price mitigation measures.
- Summarized and critiqued wholesale and retail restructuring and competition policies for electric power and natural gas in select US states, for a Pacific Rim government contemplating energy reforms.
- Presented testimony regarding divestiture of hydroelectric generation assets, potential market power issues, and mitigation approaches to the California Public Utilities Commission.
- Reviewed the reasonableness of an electric utility's wholesale power purchases and sales in a restructured power market during a period of high prices.
- Presented an expert report on failure to perform and liquidated damages in a natural gas contract dispute.
- Presented a workshop on Market Monitoring to a group of electric utilities in the process of forming an RTO.
- Authored a report on the screening approaches used by market monitors for assessing exercise of market power, material impacts of conduct, and workable competition.
- Developed recommendations for mitigating locational market power, as part of a package of congestion management reforms.
- Provided analysis in support of a transmission owner involved in a contract dispute with generators providing services related to local grid reliability.
- Authored a report on the role of regional transmission organizations in market monitoring.
- Prepared market power analyses in support of electric generators' applications to FERC for market-based rates for energy and ancillary services.
- Analyzed western electricity markets and the potential market power of a large producer under various asset acquisition or divestiture strategies.
- Testified before a state commission regarding the potential benefits of retail electric competition and issues that must be addressed to implement it.

- Prepared a market power analysis in support of an acquisition of generating capacity in the New England market.
- Advised a California utility regarding reform strategies for the California natural gas industry, addressing market power issues and policy options for providing system balancing services.

ICF RESOURCES, INC., Fairfax, VA, 1997–1998.
Project Manager

- Reviewed, critiqued and submitted testimony on a New Jersey electric utility's restructuring proposal, as part of a management audit for the state regulatory commission.
- Assisted a group of US utilities in developing a proposal to form a regional Independent System Operator (ISO).
- Researched and reported on the emergence of Independent System Operators and their role in reliability, for the Department of Energy.
- Provided analytical support to the Secretary of Energy's Task Force on Electric System Reliability on various topics, including ISOs. Wrote white papers on the potential role of markets in ensuring reliability.
- Recommended near-term strategies for addressing the potential stranded costs of non-utility generator contracts for an eastern utility; analyzed and evaluated the potential benefits of various contract modifications, including buyout and buydown options; designed a reverse auction approach to stimulating competition in the renegotiation process.
- Designed an auction process for divestiture of a Northeastern electric utility's generation assets and entitlements (power purchase agreements).
- Participated in several projects involving analysis of regional power markets and valuation of existing or proposed generation assets.

IRIS MARKET ENVIRONMENT PROJECT, 1994–1996.
Project Director, Moscow, Russia

Established and led a policy analysis group advising the Russian Federal Energy Commission and Ministry of Economy on economic policies for the electric power, natural gas, oil pipeline, telecommunications, and rail transport industries (*the Program on Natural Monopolies,* a project of the IRIS Center of the University of Maryland Department of Economics, funded by USAID):

- Advised on industry reforms and the establishment of federal regulatory institutions.
- Advised the Russian Federal Energy Commission on electricity restructuring, development of a competitive wholesale market for electric power, tariff improvements, and other issues of electric power and natural gas industry reform.
- Developed policy conditions for the IMF's $10 billion Extended Funding Facility.
- Performed industry diagnostic analyses with detailed policy recommendations for electric power (1994), natural gas, rail transport and telecommunications (1995), oil transport (1996).

Independent Consultant stationed in Moscow, Russia, 1991–1996

Projects for the WORLD BANK, 1992-1996:

- Bank Strategy for the Russian Electricity Sector. Developed a policy paper outlining current industry problems and necessary policies, and recommending World Bank strategy.
- Russian Electric Power Industry Restructuring. Participated in work to develop recommendations to the Russian Government on electric power industry restructuring.
- Russian Electric Power Sector Update. Led project to review developments in sector restructuring, regulation, demand, supply, tariffs, and investment.
- Russian Coal Industry Restructuring. Analyzed Russian and export coal markets and developed forecasts of future demand for Russian coal.
- World Bank/IEA Electricity Options Study for the G-7. Analyzed mid- and long-term electric power demand and efficiency prospects and developed forecasts.

- Russian Energy Pricing and Taxation. Developed recommendations for liberalizing energy markets, eliminating subsidies and restructuring tariffs for all energy resources.

Other consulting assignments in Russia, 1991–1994:

- Advised on projects pertaining to Russian energy policy and the transition to a market economy in the energy industries, for the Institute for Energy Research of the Russian Academy of Sciences.
- Presented seminars on the structure, economics, planning, and regulation of the energy and electric power industries in the US, for various Russian clients.

DECISION FOCUS INC., Mountain View, CA, 1983–1992
Senior Associate, 1985-1992.

- For the Electric Power Research Institute, led projects to develop decision-analytic methodologies and models for evaluating long term fuel and electric power contracting and procurement strategies. Applied the methodologies and models in numerous case studies, and presented several workshops and training sessions on the approaches.
- Analyzed long-term and short-term natural gas supply decisions for a large California gas distribution company following gas industry unbundling and restructuring.
- Analyzed long term coal and rail alternatives for a midwest electric utility.
- Evaluated bulk power purchase alternatives and strategies for a New Jersey electric utility.
- Performed a financial and economic analysis of a proposed hydroelectric project.
- For a natural gas pipeline company serving the Northeastern US, forecasted long-term natural gas supply and transportation volumes. Developed a forecasting system for staff use.
- Analyzed potential benefits of diversification of suppliers for a natural gas pipeline company.
- Evaluated uranium contracting strategies for an electric utility.
- Analyzed telecommunications services markets under deregulation, developed and implemented a pricing strategy model. Evaluated potential responses of residential and business customers to changes in the client's and competitors' telecommunications services and prices.
- Analyzed coal contract terms and supplier diversification strategies for an eastern electric utility.
- Analyzed oil and natural gas contracting strategies for an electric utility.

TESTIMONY AND AFFIDAVITS

In the Matter of the Application of Ohio Power Company for New Tariffs Related to Data Centers and Mobile Data Centers, Public Utilities Commission of Ohio Case No. 24-508-EL-ATA, Direct Testimony on behalf of the Ohio Consumers' Counsel, August 29, 2024.

Mark McEvoy et al, Plaintiffs, v. Diversified Energy Company PLC, EQT Corporation, et. al, Defendants, United States District Court for the Northern District of West Virginia, Civil Action No. 5:22-CV-171, Expert Report prepared for Appalachian Mountain Advocates, June 19, 2024.

In the Matter of the Biennial Consolidated Carbon Plan and Integrated Resource Plans of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, North Carolina Utilities Commission Docket No. E-100, SUB 190, Direct Testimony on behalf of Southern Alliance for Clean Energy, Sierra Club, Natural Resources Defense Council, and North Carolina Sustainable Energy Association, May 28, 2024; testimony at hearings, August 1, 2024.

PJM Interconnection, L.L.C., FERC Docket No. ER24-98 (Market Seller Offer Cap), Affidavit in Support of the Protest of the Public Interest Organizations, November 9, 2023; Supplemental Affidavit, December 22, 2023.

PJM Interconnection, L.L.C., FERC Docket No. ER24-99 (Resource Adequacy), Affidavit in Support of the Protest of the Public Interest Entities, November 9, 2023.

Midcontinent Independent System Operator, Inc.'s Reliability Based Demand Curve, FERC Docket No. ER23-2977, Affidavit in Support of the Comments of Public Interest Organizations, November 3, 2023;

Supplemental Affidavit in Support of the Comments and Reply of Public Interest Organizations, January 11, 2024.

In the Matter of the Application of Ohio Edison Company, the Cleveland Electric Illuminating Company, and the Toledo Edison Company for Authority to Establish a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan, Public Utilities Commission of Ohio Case No. 23-301-EL-SSO, Direct Testimony on behalf of the Office of the Ohio Consumers' Counsel, October 23, 2023; testimony at hearings, November 29, 2023.

In the Matter of the Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2024 Energy Resource Recovery Account, California Public Utilities Commission Application 23-05-012, Direct Testimony on behalf of Small Business Utility Advocates, September 6, 2023.

Virginia Electric and Power Company's 2023 Integrated Resource Plan filing, Virginia State Corporation Commission Case No. PUR-2023-00066, Direct Testimony on behalf of Appalachian Voices, August 8, 2023; testimony at hearings, September 19, 2023.

In the Matter of the Application of Ohio Power Company for Authority to Establish a Standard Service Offer in the Form of an Electric Security Plan, Public Utilities Commission of Ohio Case No. 23-23-EL-SSO, Direct Testimony on Behalf of the Office of the Ohio Consumers' Counsel, June 9, 2023; Testimony Recommending Modification of the Stipulation, September 20, 2023; testimony at hearings, October 11, 2023.

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August 2024

ATTACHMENT 4:

Declaration of Justin Vickers

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Sierra Club et al	)	Docket No. EL24-
v.	)	
PJM Interconnection, L.L.C.	)	
	)	
	)	

DECLARATION OF JUSTIN VICKERS

1. My name is Justin Vickers. I am a senior attorney at the Sierra Club, where I have been employed since June 2022. Through my work, I am familiar with the history of Sierra Club's advocacy surrounding Talen Energy's Brandon Shores and H.A. Wagner plants in Maryland, and in particular, an agreement that Sierra Club and Talen signed in November 2020 pertaining to the continued combustion of coal at those plants.
2. The purpose of this declaration is to describe the content of that agreement and its relationship to the issues in this complaint. In brief, my conclusion is that the relief from PJM sought in the complaint does not conflict with the Sierra Club-Talen agreement.
3. As memorialized in the 2020 agreement, Sierra Club believed that it had claims against Talen under environmental laws relating to coal combustion at Talen's Montour facility in Pennsylvania, as well as the Brandon Shores and Wagner plants in Maryland. In consideration for Talen's commitment to cease combustion of coal by December 31, 2025 at Montour, Brandon Shores, and Wagner, Sierra Club agreed not to initiate or participate in any judicial proceeding concerning the (1) closure of coal ash basins at Montour, (2) coal-related groundwater or surface water conditions at any of the facilities, and (3) Talen's compliance with EPA regulations concerning coal combustion waste and water at any of the facilities. Sierra Club also agreed not to initiate or participate in any proceeding challenging permits needed for Talen to effectuate its commitment to cease combustion of coal, including specifically permits needed to convert to combustion of oil at these facilities.
4. Talen converted all units at the Wagner plant to oil as of December 2023, and pursued an oil conversion at Brandon Shores until changing course in early 2023 for reasons it has

explained in a December 7, 2023 letter from Talen's Chief Executive Officer to the PJM Board of Managers.[1]

5. In April and November 2023, Talen filed deactivation notices for the Brandon Shores and Wagner plants, respectively. PJM responded in each case with a request that Talen enter into reliability-must-run arrangements beginning June 1, 2025 and extending through the end of 2028, when transmission upgrades to enable the deactivations were expected to be in service.
6. Sierra Club has not contested the need for the reliability-must-run arrangements that Talen filed at FERC in April 2024 in Dockets ER24-1787 and ER24-1790. Sierra Club intervened in those proceedings and filed protests regarding various terms of the agreement, but not the need for them.[2] As stated in that protest, Sierra Club has engaged in negotiations with Talen regarding the 2020 agreement in light of the need for the RMR arrangement, and remains willing to negotiate to reach reasonable terms regarding continued coal combustion under an RMR arrangement.[3] In short, while Sierra Club supports the cessation of coal combustion at the Brandon Shores plants, Sierra Club recognizes that PJM may need to rely on Brandon Shores to maintain reliability and is willing to negotiate necessary modifications to its agreement with Talen to enable PJM to do so.
7. The instant complaint relates to PJM's rules for reflecting the availability of RMR resources in the capacity market clearing results. It seeks to modify the terms of PJM's generally applicable rules for administering the capacity auction when a resource will be operating under an RMR arrangement during a delivery year applicable to a particular auction.
8. Whether or not the deactivation of a particular resource should trigger the need for an RMR arrangement, or whether that resource will choose to accept the RMR, are issues outside the scope of this complaint. Sierra Club's agreement with Talen is irrelevant to the general question of how PJM should account for the presence of RMR resources once a generator has accepted an RMR arrangement. Talen has also noted other factors affecting its ability to accept an RMR arrangement, including a wastewater permit issued by the Maryland Department of the Environment prohibiting the discharge of coal combustion wastewater after the end of 2025.[4]
9. Under the agreement, Sierra Club's remedy against Talen for continuing to burn coal at Brandon Shores beyond 2025 would be to renew its efforts to enforce certain

[1] *See* Mac MacFarland, Talen Energy, Letter to Manu Asthana (Dec. 7, 2023), available at https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20231207-talen-letter-re-sierra-club-letter-re-pjms-role-in-md-energy-transition.ashx.
[2] *See* Brandon Shores LLC, Docket No. ER24-1790-000, and H.A. Wagner LLC, Docket No. ER24-1787-000 (May 16, 2024), Accession No. 20240516-5186, Protest of Sierra Club
[3] *Id.* at 3.
[4] *See* Brandon Shores CORS Transmittal Letter, Docket No. ER24-1790 (Apr. 18, 2024), Accession No. 20240418-5176, at 4.

environmental laws at Talen's facilities. Those remedies would not prohibit Talen from operating plants under RMR arrangements or operating as a capacity resource.

10. Moreover, as noted above and in comments filed in prior Commission proceedings, Sierra Club remains committed to renegotiating the terms of the 2020 agreement with Talen. There is precedent for Sierra Club amending this same agreement to reflect reliability concerns. In 2023, Sierra Club and Talen agreed to an amendment of the agreement to permit Talen to continue burning coal at Brandon Shores and Wagner if the Department of Energy required those plants' operation under a Federal Power Act Section 202(c) order, so long as Talen provided notice to PJM of its deactivation as soon as possible.
11. This complaint addresses tariff provisions generally applicable to all instances in which RMR arrangements may be needed, and as explained in the complaint, the chances of future RMRs are material and extend far beyond the RMR arrangements that the system currently anticipates at Brandon Shores and Wagner.
12. This concludes my declaration.

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Sierra Club et al v. PJM Interconnection, L.L.C.	))))))	Docket No. EL24-

VERIFICATION

I, Justin Vickers, pursuant to 28 U.S.C. § 1746, state, under penalty of perjury, that I am the same Justin Vickers referred to in the foregoing document entitled "Declaration of Justin Vickers," that I have read the same and am familiar with the contents thereof, and that the facts set forth therein are true and correct to the best of my knowledge, information, and belief.

Justin Vickers
Senior Attorney
Sierra Club Environmental Law Program
1229 W Glenlake Ave.
Chicago, IL 60660
(224) 420-0614
justin.vickers@sierraclub.org

Dated: September 26, 2024

ATTACHMENT 5:

PJM Board Communications

September 6, 2024

Via email

PJM Board of Managers
Mark Takahashi, Chair
Manu Asthana, President and CEO
PJM Interconnection, L.L.C.
2750 Monroe Blvd.
Audubon, PA 19403

Re: Support for Urgent Reforms Regarding Reliability Must Run Units and the PJM Capacity Market

We write to voice our strong support for consumer advocates' August 30, 2024 request that the PJM Board immediately begin a Critical Issue Fast Path process to reform the PJM capacity market to address unreasonable prices driven by the market's failure to logically account for generators operating under Reliability Must Run arrangements (RMR). The Maryland Office of Peoples' Counsel recently commissioned a report from Synapse Energy Economics, which demonstrates that the capacity market's failure to account for RMR units increased the market's overall cost by a whopping $5 billion. For consumers in the constrained BGE Locational Deliverability Area (LDA), price impacts were especially unreasonable; not only did prices in that LDA spiked to the price cap, but the same consumers are already being forced to pay multiple RMR units to stay online. PJM must act swiftly to prevent similar unjust and unreasonable outcomes from upcoming capacity auctions in December 2024 and June 2025, which will, in the absence of urgent reform, likely create another $10 billion in unreasonable costs. Because preventing $10 billion in excessive costs is more important than bringing the capacity auction back to a 3-year-forward schedule, PJM should delay the next auctions if necessary to put critical reforms in place.

The Synapse report illustrates that PJM's capacity market is extremely vulnerable to unjust and unreasonable prices associated with the failure to account for RMR units. For example, in the most recent capacity auction, the non-participation of just two power plants caused prices to spike to their upper limit in the BGE LDA and increased costs throughout the entire region by $5 billion. We are especially troubled by the Synapse report's finding that the owner of these plants earned $360 million more from the capacity market under these record-high prices than they would have if the RMR units had participated in the market. Moreover, those two units' nameplate capacity of only 1,282 MW and 841 MW is less than 1.5% of the total 135,684 MW of unforced capacity procured in the most recent auction. The fact that just two power plants representing less than 1.5% of the region's capacity supply had such dramatic impacts on the market's clearing price—and the overall prices borne by consumers—underscores the importance of reform. Further, since PJM anticipates as much as 40 GW of additional retirements by 2030—which may lead to additional RMR arrangements—the time to act is now.

We agree with the consumer advocates' letter, which explained numerous reasons why failing to account for RMR units in the capacity market is unjust and unreasonable, including that this approach forces consumers to pay twice for reliability and sends inaccurate price signals. Additionally, we note that PJM's current approach to accounting for RMR units in the capacity market is logically inconsistent. On the one hand, PJM accounts for RMR units when calculating how much capacity an LDA can import or export, because as PJM explained, "[e]xcluding these units from the analysis could result in incomplete and potentially inaccurate assessment of local reliability needs."[1] On the other hand, PJM ignores the existence of those units when it is clearing the auction unless those units choose to participate, which PJM acknowledges typically does not happen. It is unreasonable to treat these units as operating for the reliability of the transmission system and calculation of an accurate locational reliability requirement, and then turn around and pretend the units do not exist when determining the appropriate clearing price.

As the consumer advocates' letter noted, other RTO/ISOs have rules in place that prevent these unreasonable outcomes. The fact that New York ISO, ISO New England, and the California ISO have all adopted approaches that allow their resource adequacy mechanisms to more effectively account for RMR units indicates that a similar reform is attainable in PJM. We also believe that the existence of these better approaches in other RTO/ISOs reinforces that PJM's failure to protect consumers in this region is unjust and unreasonable.

We strongly urge the PJM Board to take immediate action to reform the capacity market to prevent unjust and unreasonable outcomes in upcoming auctions. There are multiple ways that PJM may remedy this issue, including requiring RMR units to participate in the capacity market as supply (as is required in other RTO/ISOs), or by accounting for the capacity provided by RMR units by adjusting the demand curve to procure less capacity overall. PJM should work with its stakeholders to identify the best reforms on an expedited basis, with the aim of correcting the unjust and unreasonable status quo prior to the next auction.

Sincerely,

Nick Lawton, Senior Attorney, Earthjustice
Casey Roberts, Senior Attorney, Sierra Club
Michael B. Jacobs, Senior Energy Analyst, Union of Concerned Scientists
Tom Rutigliano, Senior Advocate, Natural Resources Defense Council
Tyson Slocum, Energy Program Director, Public Citizen

CC: Evelyn Robinson

[1] PJM, *PJM Response to the 2023 State of the Market Report* at 4 (Aug. 2024), available at https://www.pjm.com/-/media/library/reports-notices/state-of-the-market/20240822-pjm-response-to-the-2023-state-of-the-market-report.ashx.

Mark Takahashi
Chair, PJM Board of Managers

PJM Interconnection
2750 Monroe Blvd.
Audubon, PA 19403

Via Electronic Delivery

September 19, 2024

David S. Lapp
People's Counsel
Maryland Office of People's Counsel

Sandra Mattavous-Frye
People's Counsel
Office of the People's Counsel for the District of Columbia

Brian O. Lipman
Director
New Jersey Division of Rate Counsel

Ruth Ann Price
Acting Public Advocate
Delaware Division of the Public Advocate

Sarah Moskowitz
Executive Director
Citizens Utility Board of Illinois

Maureen R. Willis
Consumers' Counsel
Office of the Ohio Consumers' Counsel

Dear Advocates,

Thank you for your correspondence dated Aug. 30, 2024, wherein you express concern about the most recent Base Residual Auction (BRA or capacity auction) results and request that the PJM Board of Managers (PJM Board) take immediate action to require the participation of Reliability Must Run (RMR) units in capacity auctions.

At PJM, we work hard to balance concerns around affordability with our obligation to ensure reliability for the 65 million consumers in the PJM footprint, all while trying to assist states and the federal government in the advancement of their policy objectives.

We understand that many consumers are financially stressed right now, and we appreciate you raising questions around appropriate price signals for capacity given the current supply-demand balance on our system. As we consider these questions, it is important to first understand how we arrived here.

As PJM has been warning[1] for some time now, our region is experiencing a combination of trends that have served to rapidly tighten the supply-demand balance on our system. These trends include:

- Electrification coupled with the proliferation of high-demand data centers in the region that will result in material load growth

[1] *See* Energy Transition in PJM: Resource Retirements, Replacements & Risk (4R Report).

- Retirement of thermal generators at a rapid pace due to policy pressure as well as economics
- Slow new entry of replacement generation resources due to a combination of industry forces, including siting, permitting and supply chain constraints
- The high proportion of our interconnection queue that is composed of intermittent and limited-duration resources, many of which are valuable energy resources but are much less effective providers of capacity than the thermal resources they are replacing

Given these trends, it has become very clear that our region will require the buildout of a significant quantity of new generation, including a material amount of natural gas-fueled generation, in order to maintain the reliable electricity supply our consumers expect. It is in this context that the BRA for the 2025/2026 Delivery Year, in conjunction with the forward energy market, sent a new-build investment price signal. This signal is consistent with market fundamentals.

It is also important to note that these reliability concerns associated with reducing supply and increasing demand are not limited to PJM; the North American Electric Reliability Corporation (NERC) has identified elevated risk to the reliability of the electrical grid for much of the country outside of PJM. In fact, PJM is currently situated with a stronger reserve position than several other regions in the U.S.

In addressing the acute issue of Brandon Shores mentioned in your letter, the facts of what has occurred with these units are not in dispute:

- In November 2020 the units' owner, Talen, announced a "strategic repositioning of its power generation fleet that will eliminate the use of coal at all Talen wholly owned facilities." Talen's press release identified the Brandon Shores units in particular and stated that Talen "will cease coal-fired operations by the end of 2025 and repower pending approvals by state agencies."
- Subsequently, in December 2021, Raven Power Fort Smallwood LLC, a subsidiary of Talen and the owner/operator of the Brandon Shores units, filed a request for a determination from the Maryland Public Service Commission (PSC) that the proposed fuel-switching from coal to oil at the Brandon Shores units would not constitute a modification to the generation stations, signaling Talen's intent to move forward with the repowering of the facility.
- In January 2022, the Maryland PSC issued a decision confirming that the "proposed fuel-switching would not be considered a 'modification' under the *Public Utilities Article* § 7-205 …" and approved the proposed fuel-switching from coal to oil, subject to certain conditions.
- Additionally, in parallel with Talen's press release and the Maryland PSC's proceeding described above, Talen contacted PJM in May 2021 to inquire about Brandon Shores' proposed fuel-switching from coal to oil. Talen also had subsequent discussions and meetings with PJM's transmission planning group on several occasions between May 2021 and August 2022 regarding whether any studies would be necessary to support the fuel conversion and to obtain information from PJM about requirements for PJM's upcoming capacity auction. Talen clearly communicated it was on a path to convert Brandon Shores to oil.

- PJM did not become aware that Talen had decided to pivot from its fuel conversion plan until April 6, 2023, when PJM received a deactivation notice for Brandon Shores. In that notice (which was provided in compliance with the PJM Tariff), Talen explained, for the first time, that although it had previously been working toward a conversion of the Brandon Shores units to fuel-oil combustion, it had determined that such a conversion would be uneconomic.
- Further, as you may be aware, Talen entered into a private agreement with the Sierra Club that prevents Brandon Shores from continuing to run without conversion beyond Dec. 31, 2025. PJM was not consulted on this agreement nor was PJM a party to the agreement.
- Shortly after receiving Talen's deactivation notice, PJM conducted a generator deactivation analysis, finding that the Brandon Shores retirement would result in over 600 reliability violations. PJM then acted quickly to initiate the process to find transmission solutions to resolve these violations. The PJM Board acted swiftly in approving these projects, as did the Federal Energy Regulatory Commission (FERC).

The sheer number of reliability violations resulting from the retirement of Brandon Shores indicates Maryland's urgent need for additional energy infrastructure. Brandon Shores (and Wagner) will be needed to preserve electric reliability for consumers in Maryland beyond their stated retirement dates and until required transmission is built. PJM's federally approved rules contemplate this scenario, and the rules provide the opportunity for retiring generation needed for grid reliability to operate under an RMR framework, pursuant to the PJM Tariff, until required transmission upgrades have been completed. There is a proceeding underway at FERC to discuss a possible RMR framework for Brandon Shores and Wagner (see FERC Docket No. ER24-1790). Further, there are currently discussions underway in the PJM stakeholder process that would allow for a more holistic planning effort in response to a generator deactivation notice submission.

As you note, PJM's current market rules (as approved by the FERC) do not require a deactivating resource to participate in a capacity auction, and PJM cannot require such participation if the resource is the subject of a valid must-offer exception. More particularly, Tariff, Attachment DD, section 6.6(g) explicitly provides that a resource qualifies for an exception to the capacity market must-offer requirement if it has a "documented plan in place to retire the resource prior to or during the delivery year, and has submitted a notice of Deactivation regardless of whether PJM has asked the unit to continue to operate beyond its requested deactivation date." These market rules make sense for several reasons:

- First, requiring participation of a deactivating unit in the capacity auction under the existing RMR agreements could distort the price signal and fail to incent the new build needed in Maryland and in the rest of the regional transmission organization (RTO). With Maryland already importing ~40% of its annual electricity needs from other states and the RTO needing new generation build to keep up with the combined effects of demand growth and generator retirements, suppressing this price signal now is likely to result in greater reserve shortfalls in the future. Additionally, suppressing this price signal now could discourage other forms of resources, such as Demand Response and other resources that may be available on shorter notice from increasing their market participation precisely at the time they are most needed.
- Second, requiring such market participation from a resource following a deactivation notice could have unintended market consequences for existing resources. For example, a generator that had the opportunity to

continue operating by investing in technologies meant to lower emissions may decide to retire instead of investing in those technologies due to the lower price signal, thereby exacerbating reliability problems down the road.

- Third, a resource that intends to retire but is being forced to offer into the capacity market is likely to be more reluctant to agree to an RMR arrangement. This will be deleterious to maintaining system reliability. The obligations of being a capacity resource and any associated performance penalty risks may be a bridge too far for that unit owner. PJM views RMR arrangements as a last resort but a necessary action to keep units temporarily operational in order to maintain system reliability.

- Finally, in this instance it is our understanding that Talen's agreement with the Sierra Club precludes Brandon Shores from operating as a capacity resource beyond Dec. 31, 2025, unless the units convert to oil.

Further, these are the market rules that have been in place for many years and have been approved by the FERC. You make reference to rules currently in place for other Independent System Operators (ISOs). Each ISO/RTO has different market constructs and thus different rules for how RMR arrangements should be accounted for in those markets. NYISO, for example, has a significantly different market construct than PJM. In the case you cite related to NYISO, FERC did not definitively address this idea of "double counting" for RMR resources that are deemed needed for resource adequacy. In fact, the NYISO Orders cited by you were limited to a determination of the required offer price that RMR units are required to offer into NYISO auctions. On rehearing, FERC merely noted that it was unable to discern under what circumstances NYISO would need an RMR unit for resource adequacy, and thus, under NYISO's proposal, the unit should not be subjected to an offer floor.[2] On the other hand, PJM's treatment of RMR units' participation in ongoing capacity auctions is similar to those of the Midcontinent Independent System Operator (MISO).

For all of these reasons, we believe it would be counterproductive to try to change our market rules prior to the next BRA to force RMR units to offer into capacity auctions.

However, there are other actions we believe are important to pursue to try to ensure that market prices correctly reflect the supply-demand challenge we are experiencing. There are also actions we can pursue to enable the fastest possible supply response to these market signals.

1) Certain resource types, such as wind, solar, batteries and hydro, don't currently have a must-offer requirement. Many of these resources did in fact offer in the previous auction. However, several generators did not. Given how tight the supply-demand balance could be for the next auction, PJM will work with our Independent Market Monitor (IMM) to request information from these generators to ensure each decision to not offer a resource is economically justified on a stand-alone basis based upon current market conditions. Resources without a must-offer requirement generally should be evaluated to ensure that their decision not to offer is justified on a stand-alone basis and is not being done for the purposes of benefiting other units in the resource owner's portfolio. PJM should be given the ability to mandate participation in the capacity auction if there is found to be an exercise of market power.

[2] New York Independent System Operator, Inc., 161 FERC P 61,189 (2017).

2) There are several resources that have requested a must-offer exception for the 2026/2027 BRA because they intend to retire. PJM will work with our IMM to request information from these generators to ensure that these decisions to retire are still justified on a stand-alone basis.

PJM will work with the IMM to address any issues that may arise prior to the next auction. Further:

1) We intend to advance a proposed expedited framework to "fast-track" some incremental generation interconnection projects for consideration by our members in the near future.

2) We believe it is appropriate to review the choice of reference unit and shape of the demand curve, and we have launched an expedited quadrennial review to do this.

Additionally, PJM is certainly willing to have a more fulsome discussion on the issues you raise related to deactivating units and their positioning within our markets. There is currently a Deactivation Enhancements Senior Task Force (DESTF) that is convening to discuss particulars around deactivating units, and this discussion is perhaps best suited for that task force. The PJM Board respectfully requests that the Members focus attention on the DESTF and accomplish the tasks set out in the Task Force's issue charge. The DESTF has been meeting for some time now and should complete its work as soon as practicable.

Again, we thank you for your correspondence and your focus on these important issues. To note, this PJM Board correspondence is meant to be responsive to the additional correspondences received on this topic.[3]

Sincerely,

Mark Takahashi

Mark Takahashi
Chair, PJM Board of Managers

[3] Public Interest Organizations' Correspondence; PSA/P3 Correspondence.

ATTACHMENT 6:

Excerpts from RMR Arrangements

Attachment 6 – Documents supporting Table 1: Provisions for PJM Dispatch in Reliability Must Run Arrangements

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Vinson&Elkins

Bill Scherman wscherman@velaw.com
Tel +1.202.639.6550 **Fax** +1.202.879.8950

VIA ETARIFF FILING

April 18, 2024

Debbie-Anne A. Reese, Acting Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: *Brandon Shores LLC*
Docket No. ER24- -000
RMR Arrangement Continuing Operations Rate Schedule
Request for Expedited Consideration

Dear Acting Secretary Reese:

Pursuant to Section 205 of the Federal Power Act[1] and Part 35 of the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"),[2] Brandon Shores LLC ("Brandon Shores") hereby submits for filing its Continuing Operations Rate Schedule ("CORS"), for the continued Reliability Must Run ("RMR") operation and provision of service from Brandon Shores Generating Station Units 1 and 2 ("Units 1 and 2"). Brandon Shores also requests expedited consideration of the CORS (enclosed as Attachment A hereto).

PJM Interconnection, L.L.C. ("PJM")[3] has determined that Units 1 and 2 will be needed past the date of their proposed deactivation date of June 1, 2025, to maintain transmission system reliability pending completion of significant upgrades to PJM's transmission system. The CORS sets forth the terms, conditions, and cost-based rates under which Brandon Shores will agree to continue to operate Units 1 and 2 for reliability purposes from June 1, 2025 through December 31, 2028 (the "CORS Term").

Brandon Shores respectfully requests that the Commission issue an order approving the CORS for filing no later than June 18, 2024, and an effective date for the CORS of June 1, 2025. To effectuate these dates, Brandon Shores has provided for a June 1, 2025 effective date in

[1] 16 U.S.C. § 824d (2024)

[2] 18 C.F.R. Pt. 35 (2023).

[3] Capitalized terms used but not defined herein shall have the meaning set forth in the PJM Open Access Transmission Tariff ("PJM Tariff"), Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("PJM Operating Agreement"), or the CORS, as applicable.

BRANDON SHORES LLC
RELIABILITY MUST RUN CONTINUING OPERATIONS RATE SCHEDULE

BRANDON SHORES LLC
RELIABILITY MUST RUN CONTINUING OPERATIONS RATE SCHEDULE

Pursuant to the rates, terms, and conditions of this Reliability Must Run Continuing Operations Rate Schedule ("Rate Schedule"), Brandon Shores LLC ("Brandon Shores") will continue to own, operate, and maintain Brandon Shores Units 1 and 2 for the purpose of facilitating the reliable operation of the PJM Transmission System.

1. DEFINITIONS

1.1. "Brandon Shores Generating Station" shall mean Brandon Shores Unit 1 and Brandon Shores Unit 2.

1.2. "Brandon Shores Unit 1" shall mean Unit 1 of the Brandon Shores Generating Station.

1.3. "Brandon Shores Unit 2" shall mean Unit 2 of the Brandon Shores Generating Station.

1.4. "Effective Date" shall mean the effective date given to this Rate Schedule by FERC in response to a filing of this Rate Schedule pursuant to Section 205 of the Federal Power Act.

1.5. "FERC" shall mean the Federal Energy Regulatory Commission or its successor.

1.6. "Force Majeure" means an event or circumstance which prevents Brandon Shores from performing its obligations under this Rate Schedule, which event or circumstance was not anticipated as of the date of filing this Rate Schedule with FERC, which is not within the reasonable control of, or the result of the negligence of, Brandon Shores, and which, by the exercise of due diligence, Brandon Shores is unable to overcome or avoid or cause to be avoided.

1.7. "Markets Gateway" means PJM's tool for market participants to use to submit resource energy offers, ancillary services markets offers, demand bids, resource intra-day/intra-hour status and parameter updates in the Day-Ahead, Real-Time and Ancillary Services markets, as well as review the results of the Day-Ahead and Ancillary Services markets.

1.8. "Monthly Fixed-Cost Charge" has the meaning set forth in Section 5.1.

1.9. "Outage" shall mean a Forecasted Planned, Maintenance Outage, Unplanned Forced Outage, or a Partial Outage/Derate as such terms are defined in the PJM Governing Documents.

1.10. "PJM" shall mean PJM Interconnection, L.L.C. or its successor.

1.11. "PJM Governing Documents" shall mean the PJM Tariff, the PJM Operating Agreement, the Reliability Assurance Agreement Among Load Serving Entities in the PJM Region, and the PJM Manuals.

1.12. "PJM Manuals" shall mean PJM's manuals that document PJM's administrative, planning, operating, and accounting procedures.

1.13. "PJM Operating Agreement" shall mean the Amended and Restated Operating Agreement of PJM.

1.14. "PJM Tariff" shall mean the PJM Open Access Transmission Tariff.

1.15. "Project Investment" or "PI" shall mean an investment made by Brandon Shores after September 30, 2023, to enable either or both of Brandon Shores Unit 1 and Brandon Shores Unit 2 to continue operating for the period of time during which PJM has identified a reliability need for the Units. A Project Investment may include repairs, replacements, actions required for North American Electric Reliability Corporation or other regulatory compliance, and maintenance of Unit facilities and equipment and associated parts, supplies, labor (including overtime if consistent with Good Utility Practice), and overheads.

1.16. "Settlement Agreement" shall mean that certain Settlement Agreement by and among Sierra Club and Talen Energy Corporation, Montour, LLC, Brandon Shores, LLC, and H.A. Wagner LLC, dated November 23, 2020 as amended April 6, 2023.

1.17. "Term" shall mean the term of this Rate Schedule as established under Section 2.2.

1.18. "Unit" or "Units" shall mean either or both of Brandon Shores Unit 1 or Brandon Shores Unit 2, as applicable.

2. TERM

2.1. Effective Date

This Rate Schedule shall become effective June 1, 2025, or such other date as made effective by FERC.

2.2. Term of Rate Schedule

Unless terminated as provided in Sections 2.3, 2.4, or 2.5, this Rate Schedule shall have a term (the "Term") through December 31, 2028.

2.3. Brandon Shores Termination Rights

Brandon Shores may terminate this Rate Schedule consistent with the requirements of Section 113.3 of the PJM Tariff.

2.4. PJM Termination Rights

Brandon Shores shall terminate this Rate Schedule upon PJM giving at least one hundred eighty (180) days' written notice to Brandon Shores of such a request.

2.5. Other Events of Termination

a) In the event operation of a Unit would violate any applicable law, regulation, or ordinance, Brandon Shores may notify PJM that it will no longer perform under this Rate Schedule. Upon providing PJM such notice, all obligations of Brandon Shores and PJM under this Rate Schedule shall be suspended and shall remain suspended unless and until such time as Brandon Shores notifies PJM that it will perform again under this Rate Schedule.

b) This Rate Schedule shall terminate ninety (90) days after any Unit becomes inoperable if PJM provides, or is deemed to have provided pursuant to Section 5.2.E, Brandon Shores with a notice declining to approve a Project Investment and such Unit is unable to continue operating without such Project Investment. Within ten (10) days after Brandon Shores receives, or is deemed to have received, notice that PJM has declined to approve a Project Investment pursuant to Section 5.2(E), Brandon Shores shall provide written notice to PJM and FERC of the termination of this Rate Schedule and shall explain why such Unit is inoperable without the Project Investment.

3. OBLIGATIONS

3.1. Application of PJM Governing Documents

Brandon Shores' operation of the Units consistent with the terms and conditions of this Rate Schedule shall not be deemed inconsistent with the performance obligations identified in Section 121 of the PJM Tariff.

3.2. Scheduling and Dispatch of the Units

PJM may schedule and dispatch the Units subject to the operating limitations identified in Section 3.4 and the availability of coal, equipment, parts, and the other inputs to energy production, consisting of, but not limited to, lime and oil.

3.3. Operation of the Units

a) Subject to the terms of this Section 3.3, PJM may schedule and dispatch either or both Units solely to address (i) an identified transmission reliability need in support of the requirement to operate such transmission facilities within established thermal, voltage and stability limits under Sections 2 and 3 of PJM Manual 3 and when such transmission reliability needs cannot otherwise be met with available economically dispatched generating resources; (ii) a PJM transmission reliability need caused by a system restoration need as described in PJM Manual 36; (iii) a capacity emergency (as described in PJM Manual 13) during which PJM determines that the resources scheduled for an operating day are not sufficient to maintain the appropriate reserve levels for PJM and (iv) any required testing for either or both Units as set forth in Section 3.3(e).

b) Subject to the Unit operating limitations identified in Section 3.4, Brandon Shores shall operate either or both Units upon receipt of, and consistent with, a scheduling or dispatch notice issued by PJM. Brandon Shores does not guarantee that such Unit(s) will start or operate at rated capacity, and Brandon Shores does not guarantee the availability of the Unit(s) in response to a PJM scheduling or dispatch notice.

c) Brandon Shores shall not be obligated to cause either Unit to be operated in a manner that will cause Brandon Shores to violate the terms of any law or regulation, including but not limited to any environmental restrictions or any operating permit limitations or the Settlement Agreement.

d) PJM shall not issue a scheduling or dispatch notice to Brandon Shores for operation of a Unit during periods when such Unit is unavailable due to an Outage, provided that Brandon Shores shall notify PJM of Unit Outages consistent with the PJM Governing Documents.

e) Brandon Shores, with advance notice of at least one (1) day to, and prior approval by, PJM, may self-schedule a Unit under limited circumstances when PJM's scheduling or dispatch of such Unit is not expected to allow necessary operational activities to occur. These activities generally include, but are not limited to, scheduling a Unit to conduct mandatory compliance testing or diagnostic evaluations performed to maintain a Unit's ability to operate. PJM shall provide compensation pursuant to this Rate Schedule consistent with that provided during a PJM scheduling or dispatch relating to such periods of operation.

f) If a Unit has not run for the prior thirty (30) days consecutively, then at the discretion of Brandon Shores, and with prior notice to PJM, Brandon Shores may self-schedule such Unit to operate for up to forty-eight (48) hours. If such Unit has not run for the prior thirty (30) days consecutively, PJM may, with prior notice to Brandon Shores, schedule such Unit to operate for up to forty-eight (48) hours. PJM shall provide compensation pursuant to this Rate Schedule consistent with that provided during a PJM scheduling or dispatch relating to such periods of operation.

3.4. Operating Limitations

The Units shall be coded in PJM's Markets Gateway as Maximum-Emergency units and shall be subject to the following pre-determined limits on the offer parameters for their cost-based schedules unless different limits are approved in Markets Gateway:

Parameters	**Brandon Shores Unit 1**	**Brandon Shores Unit 2**
Minimum Down Time	24 hours	24 hours
Minimum Run Time	24 hours	24 hours
Maximum Daily Starts	1	1
Maximum Weekly Starts	3	3

Brandon Shores Unit 1:

Operating Parameters:

Max Capacity 635 MW
Economic Max 635 MW
Economic Min 220 MW
Emergency Min 220 MW
Start-up + Notification Cold 24 Hours
Start-up + Notification Intermediate 10 Hours
Start-up + Notification Hot 8 Hours
PJM Node Name BRANDONS24 KV GEN 01
PJM Pnode Number 50659

Brandon Shores Unit 2

Operating Parameters:

Max Capacity 638 MW
Economic Max 638 MW
Economic Min 220 MW
Emergency Min 220 MW
Start-up + Notification Cold 24 Hours
Start-up + Notification Intermediate 10 Hours
Start-up + Notification Hot 8 Hours
PJM Node Name BRANDONS24 KV GEN 02
PJM Pnode Number 50660

To the extent a Unit experiences a physical operational limitation that prevents it from meeting the parameters listed above, Brandon Shores shall modify the parameters to reflect the limitations and shall notify PJM via email and via PJM's Electronic Dispatcher Application and Reporting Tool ("eDart") as soon as the need for the change is recognized. Notwithstanding any operating limitations set forth in this section, Brandon Shores shall respond to PJM scheduling and dispatch notices on a best efforts basis when consistent with law and regulation.

3.5. Obligation to Offer Units into Markets

a) Brandon Shores will submit cost-based offers of energy from the Units in the PJM Interchange Energy Market in accordance with PJM Operating Agreement, Schedule 2 and PJM Manual 15. The Units will be offered with a status of 'unavailable' in the PJM Interchange Energy Market but will be available to be scheduled pursuant to Section 3.3. The cost-based offer of energy also applies to scheduling and dispatch pursuant to Section 3.3(e). Costs included in the Monthly Fixed-Cost Charge pursuant to Section 5.1 and recovered for Project Investment pursuant to Section 5.2 will not be included in the Maintenance Adder (as defined in the PJM Operating Agreement) of Brandon Shore's cost-based offers for the Units during the Term.

b) Except when the Units are unavailable due to an Outage, the Units may be offered based on its cost-based schedule into the Synchronized Reserve market when the Units are otherwise scheduled or dispatched for reliability. Such cost-based bids shall be calculated in accordance with Section 1.10.1A(j) of the PJM Operating Agreement.

c) Except when the Units are unavailable due to an Outage, the Units will, when otherwise scheduled or dispatched for reliability, provide reactive power consistent with the available capability of the Unit and voltage schedules provided for in the relevant interconnection agreement.

4. SURVIVAL OF OPERATIONS AND COST RECOVERY

If this Rate Schedule is terminated prior to the termination date identified in Section 2.2 and Brandon Shores has not yet recovered all its costs of operating the Units as specified herein, which costs were incurred, or obligated to be incurred, before the termination date of this Rate Schedule, Brandon Shores shall be entitled to recover all such unrecovered costs in accordance with this Rate Schedule. Expiration or termination of this Rate Schedule shall not affect Brandon Shores' or PJM's accrued rights and obligations arising during the Term, including either party's obligation to make all payments to the other.

5. COST OF SERVICE RECOVERY RATE

Pursuant to Section 119 of the PJM Tariff, Brandon Shores shall recover its costs of operating Brandon Shores Unit 1 and Brandon Shores Unit 2 during the Term through the Cost of Service Recovery Rate identified in this Article 5.

5.1. Monthly Fixed-Cost Charges

a) Each month during the Term, PJM shall pay to Brandon Shores a Monthly Fixed-Cost Charge of $14,619,407; provided, however, that in the event the H.A. Wagner Generating Station fully deactivates, and effective as of such date of deactivation, PJM shall pay to Brandon Shores a Monthly Fixed-Cost Charge of $14,980,033 (as appropriate, the "Monthly Fixed-Cost Charge").

b) Brandon Shores shall submit an informational filing to the Commission, in the docket in which this Rate Schedule was initially filed, no later than 10 days following the full deactivation of the H.A. Wagner Generating Station, notifying the Commission of such deactivation.

5.2. Reimbursement of Project Investment Costs

Each month during the Term, PJM shall pay to Brandon Shores a monthly payment to reimburse its costs of Project Investments undertaken pursuant to this Rate Schedule ("Monthly Project Investment Tracker Payment"). Monthly Project Investment payments for Project Investments incurred in a single month shall be calculated as follows:

$$Monthly\ Project\ Investment\ Tracker\ Payment =$$

$$\frac{r/_{12}}{1-\left(1+r/_{12}\right)^{-n}} \times (PI\ Incurred\ during\ month)$$

Where "r" is the carrying charge rate per annum and "n" is the number of months remaining in the Term.

Monthly Project Investment Payments for Project Investments incurred in any specific month shall remain fixed for the number of months remaining in the Term.

Where:

A. "Project Investment" shall have the meaning set forth in Article 1.

B. "Project Investment Costs" shall mean costs for a Project Investment. As of January 1, 2024, anticipated Project Investment costs include the following:

i. Units 1 and 2 Regenerate SCR Catalyst,

ii Units 1 and 2 Baghouse Rebagging,

iii. Units 1 and 2 Ovation/Windows Hardware and Software Upgrade,

iv. Units 1 and 2 Generator Inspections and Repairs, and

v. Units 1 and 2 LP Turbine Inspections and Repairs.

C. "Unamortized Project Investment Costs" shall mean Project Investment Costs incurred but not yet fully recovered.

D. The balance in Unamortized Project Investment Costs shall accrue carrying charges at 13% per annum and shall be increased for actual Project Investment costs incurred in each month.

E. If Brandon Shores determines it necessary to make a Project Investment to enable one or both Units to continue to operate during the remaining Term, and Brandon Shores expects the cost of such Project Investment will exceed $500,000, Brandon Shores shall notify and consult with PJM in writing and identify the nature of the Project Investment and the expected duration and cost of the Project Investment. Within five (5) days of receipt of Brandon Shores' notice, PJM shall notify Brandon Shores in writing of the need for Brandon Shores to undertake the Project Investment to support the reliable operation of the PJM Transmission System. If PJM notifies Brandon Shores that it declines to approve such Project Investment, then Brandon Shores will not undertake the Project Investment. If within ten (10) days of receipt of Brandon Shores' written notice with respect to a Project Investment, PJM fails to notify Brandon Shores in writing whether it approves or declines to approve such Project Investment, PJM will be deemed to have provided Brandon Shores notice declining to approve such Project Investment. Brandon Shores shall not be required to notify PJM in advance of any Project Investment with a cost Brandon Shores expects will not exceed $500,000, but, as soon as practicable after deciding to initiate such project, will provide notice to PJM of any Project Investment being undertaken that Brandon Shores expects will exceed $100,000. Such notice will include the estimated cost of the Project Investment and an explanation of the reason such Project Investment is needed. Until the date the settlement in this proceeding is made effective, Project Investments in accordance with this Paragraph E undertaken by Brandon Shores shall be added to the Unamortized Project Investment Costs when incurred and shall accrue the carrying charges identified in Paragraph D of this section.

F. Project Investment Costs shall be recovered on the basis of actual costs incurred, with carrying charges as identified in Paragraph D of this section. Not later than ninety (90) days after the end of the Term, Brandon Shores shall report to PJM the actual amounts expended for the projects pursuant to this Rate Schedule, with associated carrying charges. Not later than sixty (60) days after submission of such report to PJM, Brandon Shores will refund any amount by which the Project Investment Costs, including carrying charges, reimbursed to Brandon Shores exceed actual expenditures or will charge PJM any amount by which actual expenditures exceed the amount of the Project Investment Costs previously paid to Brandon Shores.

G. Project Investment Costs will be billed monthly and paid in full by PJM in the month after invoicing as set forth in Section 5.6 herein.

5.3. Reimbursement of Fuel and Variable Operations and Maintenance Costs

For each month during the Term, PJM shall reimburse Brandon Shores any costs incurred in the operation of the Units not otherwise recovered in an amount calculated in accordance with the following methodologies.

a) Fuel Costs. Fuel costs will be determined based on actual costs, using a weighted average inventory methodology. Fuel costs will include all necessary costs associated with securing fuel, including but not limited to delivery costs, taxes, fees, and costs associated with any letters of credit needed to purchase fuel. No later than sixty (60) days prior to the expiration of this Rate Schedule, Brandon Shores shall inform PJM of fuel inventory levels; if remaining fuel is not burned by the end of the Term, PJM will reimburse Brandon Shores its actual costs of the fuel and removal costs less the sales price of the remaining fuel. Brandon Shores shall invoice PJM for removal costs monthly as incurred. If the inventory costs exceed the resale proceeds received by Brandon Shores, then Brandon Shores shall invoice PJM for the difference in the month after any such resale occurs. Relevant fuels include:

A. No. 2 Fuel Oil – Start-up, warming and flame stabilization fuel for both Units, and

B. Coal – Primary fuel for both Units.

b) Emissions and Environmental Costs. Emissions costs will be determined based on actual costs, using the monthly average price of emissions, in \$/ton as published in the Argus Air Daily. The emissions with respect to which Brandon Shores may recover its costs include, but are not limited to, the following:

A. NOx emissions allowances,

B. SO_2 emissions allowances,

C. CO_2 emissions allowances,

D. Nitrogen discharge allowances,

E. Maryland State Renewable Energy Credits, and

F. Any additional items required by changes in law, regulation, or permit conditions.

c) Chemicals and Coal Combustion By-Products Disposal Costs. Chemicals costs will be determined based on actual costs. Coal combustion by-products disposal costs will be determined based on actual costs. At the end of the Term, PJM will pay for actual costs and removal costs less the sales price of the remaining chemicals, bulk lubricating oils, and coal combustion by-products. Chemicals costs shall include, but are not limited to:

A. Urea (SCR NOx Control Chemical),

B. Sorbent/Hydrated Lime Injection (for SO_3 Control),

C. Carbon Injection (for Mercury Control),

D. Limestone (used in flue-gas desulfurization for SO_2 control),

E. Sulfuric Acid, Caustic(Boiler Water Control),

F. Sulfuric Acid, Hydrochloric Acid, Hydrated Lime (WWTP Chemicals),

G. Gypsum Disposal,

H. Slag/Bottom Ash Disposal,

I. Fly Ash Disposal, and

J. Bulk Lubricating Oils and disposal.

d) Auxiliary Power. To the extent that Brandon Shores is charged for auxiliary or standby (i.e., station) power for either Unit, the auxiliary power costs will be equal to the actual costs incurred pursuant to PJM Tariff, Attachment K-Appendix.

e) Coal Combustion By-Products Disposal. Coal combustion by-products disposal costs will include, but not be limited to, costs associated with the removal, handling, transportation, and disposal costs for ash, sludge, filter cake and gypsum.

f) Regulatory and Administrative Costs. Regulatory and administrative costs will include, but not be limited to, the costs of obtaining a final FERC order, and any associated appeals, accepting this Rate Schedule for filing.

5.4. Monthly Fixed-Cost Charge in Event of Early Termination

If this Rate Schedule is terminated early in accordance with Sections 2.3, 2.4, or 2.5, except as provided in Section 4, Brandon Shores shall recover Monthly Fixed-Cost Charges until the earlier of the decommissioning of such Unit commences or the end of the original Term as set forth in Section 2.2.

5.5. Revenue Credits

For service provided during the Term, Brandon Shores will credit monthly net revenues (total credits net of total charges), identified on the applicable PJM bill, above variable operations and maintenance ("O&M") and fuel costs, earned from any sales of wholesale energy, capacity and ancillary services from a Unit or other revenues earned with respect to a Unit during the Term, each as earned in PJM's markets or pursuant to other rate schedules on file with the Commission, against the charges under Section 5.3 above and will provide an invoice reflecting this credit pursuant to Section 5.6 below.

5.6. Invoices

Brandon Shores will invoice PJM monthly for amounts due under Sections 5.1 through 5.4. Such invoice shall reflect as a separate line item the revenue credits for each Unit provided for in Section 5.5. Brandon Shores will issue the invoice no later than the fifteenth (15th) calendar day of the month following the month in which service is provided, unless extenuating circumstances exist, in which case it will issue the invoice no later than the last day of the month. PJM shall include the charges billed by Brandon Shores in the PJM monthly billing statement for the month in which PJM received the invoice from Brandon Shores (for example: April invoice is received in May and goes out in the PJM monthly bill for May). PJM shall remit payment to Brandon Shores according to the standard financial settlement timeline for such PJM monthly billing statement. Such invoices shall also include as separate line items any adjustments to previously billed amounts. Upon request, Brandon Shores will provide supporting data for such invoice. Except as otherwise provided in Section 5.7, not later than ninety (90) days from the end of the Term, Brandon Shores will issue final invoices for amounts due by PJM under this Rate Schedule. However, notwithstanding any provision of this Rate Schedule to the contrary, should costs relating to this Rate Schedule continue to be incurred after the end of the Term, or should fuel inventory take longer to liquidate, the final invoices shall be due within ninety (90) days from the date cost incurrence ceases or fuel is fully liquidated.

5.7. Miscellaneous Provisions

a) PJM and Brandon Shores may by mutual agreement waive any of the time periods set forth herein.

b) References to PJM Governing Documents included herein shall be to the versions in effect as of the Effective Date, as they may be amended from time to time.

c) To the extent Brandon Shores is prevented by Force Majeure from carrying out, in whole or part, its obligations under this Rate Schedule and it gives notice and details of the Force Majeure to PJM as soon as practicable, then Brandon Shores shall be excused from the performance of its obligations with respect to this Rate Schedule. Brandon Shores shall remedy the Force Majeure with all reasonable dispatch.

5.8. Designated Representatives

For purposes of any notices required to be provided pursuant hereto, notice shall be provided by electronic mail and the designated representatives to receive such notices shall be:

For Brandon Shores:

Debra Raggio
Debra.Raggio@talenenergy.com

For PJM:

Thomas DeVita
Thomas.DeVita@pjm.com

Either Brandon Shores or PJM may change their respective designated representatives by written notice to all other designated representatives.

5.9. Standard of Review

The standard of review for changes to any rate, charge, classification, term or condition of this Rate Schedule, whether proposed by PJM, any party with standing under Federal Power Act

Section 206, or FERC acting *sua sponte*, shall solely be the most stringent standard of review set forth in *United Gas Pipe Line Co. v. Mobile Gas Service Corp.,* 350 U.S. 332 (1956) and *Federal Power Commission v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956) and clarified by *Morgan Stanley Capital Group, Inc. v. Public Util. Dist. No. 1 of Snohomish*, 554 U.S. 527, 128 S. Ct. 2733 (2008) and *NRG Power Marketing, LLC, et al. v. Maine Public Utilities Commission*, 558 U.S. 165 (2010).

Vinson&Elkins

Bill Scherman wscherman@velaw.com
Tel +1.202.639.6550 **Fax** +1.202.879.8950

VIA ETARIFF FILING

April 18, 2024

Debbie-Anne A. Reese, Acting Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: *H.A. Wagner LLC*
Docket No. ER24-   -000
RMR Arrangement   Continuing Operations Rate Schedule
Request for Expedited Consideration

Dear Acting Secretary Reese:

Pursuant to Section 205 of the Federal Power Act[1] and Part 35 of the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"),[2] H.A. Wagner LLC ("Wagner") hereby submits for filing its Continuing Operations Rate Schedule ("CORS"), for the continued Reliability Must Run ("RMR") operation and provision of service from Wagner Generating Station Units 3 and 4 ("Units 3 and 4"). Wagner also requests expedited consideration of the CORS (enclosed as Attachment A hereto).

PJM Interconnection, L.L.C. ("PJM")[3] has determined that Units 3 and 4 will be needed past the date of their proposed deactivation date of June 1, 2025, to maintain transmission system reliability pending completion of significant upgrades to PJM's transmission system. The CORS sets forth the terms, conditions, and cost-based rates under which Wagner will agree to continue to operate Units 3 and 4 for reliability purposes from June 1, 2025 through December 31, 2028 (the "CORS Term").

Wagner respectfully requests that the Commission issue an order approving the CORS for filing no later than June 18, 2024, and an effective date for the CORS of June 1, 2025. To effectuate these dates, Wagner has provided for a June 1, 2025 effective date in the

[1] 16 U.S.C. § 824d (2024)

[2] 18 C.F.R. Pt. 35 (2023).

[3] Capitalized terms used but not defined herein shall have the meaning set forth in the PJM Open Access Transmission Tariff ("PJM Tariff"), Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("PJM Operating Agreement"), or the CORS, as applicable.

H.A. WAGNER LLC
RELIABILITY MUST RUN CONTINUING OPERATIONS RATE SCHEDULE

H.A. WAGNER LLC
RELIABILITY MUST RUN CONTINUING OPERATIONS RATE SCHEDULE

Pursuant to the rates, terms, and conditions of this Reliability Must Run Continuing Operations Rate Schedule ("Rate Schedule"), H.A. Wagner LLC ("H.A. Wagner") will continue to own, operate, and maintain H.A. Wagner Units 3 and 4 for the purpose of facilitating the reliable operation of the PJM Transmission System.

1. DEFINITIONS

1.1. "H.A. Wagner Generating Station" shall mean H.A. Wagner Unit 3 and H.A. Wagner Unit 4.

1.2. "H.A. Wagner Unit 3" shall mean Unit 3 of the H.A. Wagner Generating Station.

1.3. "H.A. Wagner Unit 4" shall mean Unit 4 of the H.A. Wagner Generating Station.

1.4. "Effective Date" shall mean the effective date given to this Rate Schedule by FERC in response to a filing of this Rate Schedule pursuant to Section 205 of the Federal Power Act.

1.5. "FERC" shall mean the Federal Energy Regulatory Commission or its successor.

1.6. "Force Majeure" means an event or circumstance which prevents H.A. Wagner from performing its obligations under this Rate Schedule, which event or circumstance was not anticipated as of the date of filing this Rate Schedule with FERC, which is not within the reasonable control of, or the result of the negligence of, H.A. Wagner, and which, by the exercise of due diligence, H.A. Wagner is unable to overcome or avoid or cause to be avoided.

1.7. "Markets Gateway" means PJM's tool for market participants to use to submit resource energy offers, ancillary services markets offers, demand bids, resource intra-day/intra-hour status and parameter updates in the Day-Ahead, Real-Time and Ancillary Services markets, as well as review the results of the Day-Ahead and Ancillary Services markets.

1.8. "Monthly Fixed-Cost Charge" has the meaning set forth in Section 5.1.

1.9. "Outage" shall mean a Forecasted Planned, Maintenance Outage, Unplanned Forced Outage, or a Partial Outage/Derate as such terms are defined in the PJM Governing Documents.

1.10. "PJM" shall mean PJM Interconnection, L.L.C. or its successor.

1.11. "PJM Governing Documents" shall mean the PJM Tariff, the PJM Operating Agreement, the Reliability Assurance Agreement Among Load Serving Entities in the PJM Region, and the PJM Manuals.

1.12. "PJM Manuals" shall mean PJM's manuals that document PJM's administrative, planning, operating, and accounting procedures.

1.13. "PJM Operating Agreement" shall mean the Amended and Restated Operating Agreement of PJM.

1.14. "PJM Tariff" shall mean the PJM Open Access Transmission Tariff.

1.15. "Project Investment" or "PI" shall mean an investment made by H.A. Wagner after December 31, 2023, to enable either or both of H.A. Wagner Unit 3 and H.A. Wagner Unit 4 to continue operating for the period of time during which PJM has identified a reliability need for the Units. A Project Investment may include repairs, replacements, actions required for North American Electric Reliability Corporation or other regulatory compliance, and maintenance of Unit facilities and equipment and associated parts, supplies, labor (including overtime if consistent with Good Utility Practice), and overheads.

1.16. "Settlement Agreement" shall mean that certain Settlement Agreement by and among Sierra Club and Talen Energy Corporation, Montour, LLC, Brandon Shores LLC, and H.A. Wagner LLC, dated November 23, 2020 as amended April 6, 2023.

1.17. "Term" shall mean the term of this Rate Schedule as established under Section 2.2.

1.18. "Unit" or "Units" shall mean either or both of H.A. Wagner Unit 3 or H.A. Wagner Unit 4, as applicable.

2. TERM

2.1. Effective Date

This Rate Schedule shall become effective June 1, 2025, or such other date as made effective by FERC.

2.2. Term of Rate Schedule

Unless terminated as provided in Sections 2.3, 2.4, or 2.5, this Rate Schedule shall have a term (the "Term") through December 31, 2028.

2.3. H.A. Wagner Termination Rights

H.A. Wagner may terminate this Rate Schedule consistent with the requirements of Section 113.3 of the PJM Tariff.

2.4. PJM Termination Rights

H.A. Wagner shall terminate this Rate Schedule upon PJM giving at least one hundred eighty (180) days' written notice to H.A. Wagner of such a request.

2.5. Other Events of Termination

a) In the event operation of a Unit would violate any applicable law, regulation, or ordinance, H.A. Wagner may notify PJM that it will no longer perform under this Rate Schedule. Upon providing PJM such notice, all obligations of H.A. Wagner and PJM under this Rate Schedule shall be suspended and shall remain suspended unless and until such time as H.A. Wagner notifies PJM that it will perform again under this Rate Schedule.

b) This Rate Schedule shall terminate ninety (90) days after any Unit becomes inoperable if PJM provides, or is deemed to have provided pursuant to Section 5.2.E, H.A. Wagner with a notice declining to approve a Project Investment and such Unit is unable to continue operating without such Project Investment. Within ten (10) days after H.A. Wagner receives, or is deemed to have received, notice that PJM has declined to approve a Project Investment pursuant to Section 5.2(E), H.A. Wagner shall provide written notice to PJM and FERC of the termination of this Rate Schedule and shall explain why such Unit is inoperable without the Project Investment.

3. OBLIGATIONS

3.1. Application of PJM Governing Documents

H.A. Wagner's operation of the Units consistent with the terms and conditions of this Rate Schedule shall not be deemed inconsistent with the performance obligations identified in Section 121 of the PJM Tariff.

3.2. Scheduling and Dispatch of the Units

PJM may schedule and dispatch the Units subject to the operating limitations identified in Section 3.4 and the availability of fuel, equipment, parts, and the other inputs to energy production, consisting of, but not limited to, lime and oil.

3.3. Operation of the Units

a) Subject to the terms of this Section 3.3, PJM may schedule and dispatch either or both Units solely to address (i) an identified transmission reliability need in support of the requirement to operate such transmission facilities within established thermal, voltage and stability limits under Sections 2 and 3 of PJM Manual 3 and when such transmission reliability needs cannot otherwise be met with available economically dispatched generating resources; (ii) a PJM transmission reliability need caused by a system restoration need as described in PJM Manual 36; (iii) a capacity emergency (as described in PJM Manual 13) during which PJM determines that the resources scheduled for an operating day are not sufficient to maintain the appropriate reserve levels for PJM and (iv) any required testing for either or both Units as set forth in Section 3.3(e).

b) Subject to the Unit operating limitations identified in Section 3.4, H.A. Wagner shall operate either or both Units upon receipt of, and consistent with, a scheduling or dispatch notice issued by PJM. H.A. Wagner does not guarantee that such Unit(s) will start or operate at rated capacity, and H.A. Wagner does not guarantee the availability of the Unit(s) in response to a PJM scheduling or dispatch notice.

c) H.A. Wagner shall not be obligated to cause either Unit to be operated in a manner that will cause H.A. Wagner to violate the terms of any law or regulation, including but not limited to any environmental restrictions or any operating permit limitations or the Settlement Agreement.

d) PJM shall not issue a scheduling or dispatch notice to H.A. Wagner for operation of a Unit during periods when such Unit is unavailable due to an Outage, provided that H.A. Wagner shall notify PJM of Unit Outages consistent with the PJM Governing Documents.

e) H.A. Wagner, with advance notice of at least one (1) day to, and prior approval by, PJM, may self-schedule a Unit under limited circumstances when PJM's scheduling or dispatch of such Unit is not expected to allow necessary operational activities to occur. These activities generally include, but are not limited to, scheduling a Unit to conduct mandatory compliance testing or diagnostic evaluations performed to maintain a Unit's ability to operate. PJM shall provide compensation pursuant to this Rate Schedule consistent with that provided during a PJM scheduling or dispatch relating to such periods of operation.

f) If a Unit has not run for the prior thirty (30) days consecutively, then at the discretion of H.A. Wagner, and with prior notice to PJM, H.A. Wagner may self-schedule such Unit to operate for up to forty-eight (48) hours. If such Unit has not run for the prior thirty (30) days consecutively, PJM may, with prior notice to H.A. Wagner, schedule such Unit to operate for up to forty-eight (48) hours. PJM shall provide compensation pursuant to this Rate Schedule consistent with that provided during a PJM scheduling or dispatch relating to such periods of operation.

3.4. Operating Limitations

The Units shall be coded in PJM's Markets Gateway as Maximum-Emergency units and shall be subject to the following pre-determined limits on the offer parameters for their cost-based schedules unless different limits are approved in Markets Gateway:

Parameters	**H.A. Wagner Unit 3**	**H.A. Wagner Unit 4**
Minimum Down Time	24 hours	24 hours
Minimum Run Time	24 hours	24 hours
Maximum Daily Starts	1	1
Maximum Weekly Starts	3	3

H.A. Wagner Unit 3:

Operating Parameters:

Max Capacity 305 MW

Economic Max 305 MW
Economic Min 105 MW
Emergency Min 105 MW
Start-up + Notification Cold 24 Hours
Start-up + Notification Intermediate 16 Hours
Start-up + Notification Hot 10 Hours
PJM Node Name WAGNER 13 KV GEN 03
PJM Pnode Number 50691

H.A. Wagner Unit 4

Operating Parameters:

Max Capacity 397 MW
Economic Max 397 MW
Economic Min 60 MW
Emergency Min 60 MW
Start-up + Notification Cold 20 Hours
Start-up + Notification Intermediate 12 Hours
Start-up + Notification Hot 8 Hours
PJM Node Name WAGNER 13 KV GEN 04
PJM Pnode Number 50692

To the extent a Unit experiences a physical operational limitation that prevents it from meeting the parameters listed above, H.A. Wagner shall modify the parameters to reflect the limitations and shall notify PJM via email and via PJM's Electronic Dispatcher Application and Reporting Tool ("eDart") as soon as the need for the change is recognized. Notwithstanding any operating limitations set forth in this section, H.A. Wagner shall respond to PJM scheduling and dispatch notices on a best efforts basis when consistent with law and regulation.

3.5. Obligation to Offer Units into Markets

a) H.A. Wagner will submit cost-based offers of energy from the Units in the PJM Interchange Energy Market in accordance with PJM Operating Agreement, Schedule 2 and PJM Manual 15. The Units will be offered with a status of 'unavailable' in the PJM Interchange Energy Market but will be available to be scheduled pursuant to Section 3.3. The cost-based offer of energy also applies to scheduling and dispatch pursuant to Section 3.3(e). Costs included in the Monthly Fixed-Cost Charge pursuant to Section 5.1 and recovered for Project Investment pursuant to Section 5.2 will not be included in the Maintenance Adder (as defined in the PJM Operating Agreement) of H.A. Wagner's cost-based offers for the Units during the Term.

b) Except when the Units are unavailable due to an Outage, the Units may be offered based on its cost-based schedule into the Synchronized Reserve market when the Units are otherwise scheduled or dispatched for reliability. Such cost-based bids shall be calculated in accordance with Section 1.10.1A(j) of the PJM Operating Agreement.

c) Except when the Units are unavailable due to an Outage, the Units will, when otherwise scheduled or dispatched for reliability, provide reactive power consistent with the available capability of the Unit and voltage schedules provided for in the relevant interconnection agreement.

4. SURVIVAL OF OPERATIONS AND COST RECOVERY

If this Rate Schedule is terminated prior to the termination date identified in Section 2.2 and H.A. Wagner has not yet recovered all its costs of operating the Units as specified herein, which costs were incurred, or obligated to be incurred, before the termination date of this Rate Schedule, H.A. Wagner shall be entitled to recover all such unrecovered costs in accordance with this Rate Schedule. Expiration or termination of this Rate Schedule shall not affect H.A. Wagner's or PJM's accrued rights and obligations arising during the Term, including either party's obligation to make all payments to the other.

5. COST OF SERVICE RECOVERY RATE

Pursuant to Section 119 of the PJM Tariff, H.A. Wagner shall recover its costs of operating H.A. Wagner Unit 3 and H.A. Wagner Unit 4 during the Term through the Cost of Service Recovery Rate identified in this Article 5.

5.1. <u>Monthly Fixed-Cost Charges</u>

a) Each month during the Term, PJM shall pay to H.A. Wagner a Monthly Fixed-Cost Charge of $3,361,926; provided, however, that in the event the Brandon Shores Generating Station fully deactivates, and effective as of such date of deactivation, PJM shall pay to H.A. Wagner a Monthly Fixed-Cost Charge of $4,015,882 (as appropriate, the "Monthly Fixed-Cost Charge").

b) H.A. Wagner shall submit an informational filing to the Commission, in the docket in which this Rate Schedule was initially filed, no later than 10 days following the full deactivation of the Brandon Shores Generating Station, notifying the Commission of such deactivation.

5.2. <u>Reimbursement of Project Investment Costs</u>

Each month during the Term, PJM shall pay to H.A. Wagner a monthly payment to reimburse its costs of Project Investments undertaken pursuant to this Rate Schedule ("Monthly Project Investment Tracker Payment"). Monthly Project Investment payments for Project Investments incurred in a single month shall be calculated as follows:

$$\mathit{Monthly\ Project\ Investment\ Tracker\ Payment} = \frac{r/_{12}}{1-\left(1+r/_{12}\right)^{-n}} \times (\mathit{PI\ Incurred\ during\ month})$$

Where "r" is the carrying charge rate per annum and "n" is the number of months remaining in the Term.

Monthly Project Investment Payments for Project Investments incurred in any specific month shall remain fixed for the number of months remaining in the Term.

Where:

A. "Project Investment" shall have the meaning set forth in Article 1.

B. "Project Investment Costs" shall mean costs for a Project Investment. As of January 1, 2024, anticipated Project Investment costs include the following:

   i. Units 3 and 4 Critical 4 kV Bus/Breakers Overhaul;

   ii. Replacement of Unit 3 Rear Wall OFA Panels 1 & 5;

   iii. Replacement of Unit 3 Boiler Tube Dissimilar Metal Welds;

   iv. Selective Replacement of Unit 3 Underground Service Water System Piping;

   v. Selective Replacement of Unit 4 Water Wall Tubes;

   vi. Structural Repairs to Unit 4 Ductwork and Hoppers;

   vii. Rebuild of Units 3 and 4 Bay Intake Screens and Trash Rake;

   viii. Units 3 and 4 Fuel Oil Tank Inspections and Repairs; and

   ix. Units 3 and 4 Boiler Tube and High Energy Piping Inspections and Repairs.

C. "Unamortized Project Investment Costs" shall mean Project Investment Costs incurred but not yet fully recovered.

D. The balance in Unamortized Project Investment Costs shall accrue carrying charges at 13% per annum and shall be increased for actual Project Investment costs incurred in each month.

E. If H.A. Wagner determines it necessary to make a Project Investment to enable one or both Units to continue to operate during the remaining Term, and H.A. Wagner expects the cost of such Project Investment will exceed $500,000, H.A. Wagner shall notify and consult with PJM in writing and identify the nature of the Project Investment and the expected duration and cost of the Project Investment. Within five (5) days of receipt of H.A. Wagner's notice, PJM shall notify H.A. Wagner in writing of the need for H.A. Wagner to undertake the Project Investment to support the reliable operation of the PJM Transmission System. If PJM notifies H.A. Wagner that it declines to approve such Project Investment, then H.A. Wagner will not undertake the Project Investment. If within ten (10) days of receipt of H.A. Wagner's written notice with respect to a Project Investment, PJM fails to notify H.A. Wagner in writing whether it approves or declines to approve such Project Investment, PJM will be deemed to have provided H.A. Wagner notice declining to approve such Project Investment. H.A. Wagner shall not be required to notify PJM in advance of any Project Investment with a cost H.A. Wagner expects will not exceed $500,000, but, as soon as practicable after deciding to initiate such project, will provide notice to PJM of any Project Investment being undertaken that H.A. Wagner expects will exceed $100,000. Such notice will include the estimated cost of the Project Investment and an explanation of the reason such Project Investment is needed. Until the date the settlement in this proceeding is made effective, Project Investments in accordance with this Paragraph E undertaken by H.A. Wagner shall be added to the Unamortized Project Investment Costs when incurred and shall accrue the carrying charges identified in Paragraph D of this section.

F. Project Investment Costs shall be recovered on the basis of actual costs incurred, with carrying charges as identified in Paragraph D of this section. Not later than ninety (90) days after the end of the Term, H.A. Wagner shall report to PJM the actual amounts expended for the projects pursuant to this Rate Schedule, with associated carrying charges. Not later than sixty (60) days after submission of such report to PJM, H.A. Wagner will refund any amount by which the Project Investment Costs, including carrying charges, reimbursed to H.A. Wagner exceed actual expenditures or will charge PJM any amount by which actual expenditures exceed the amount of the Project Investment Costs previously paid to H.A. Wagner.

G. Project Investment Costs will be billed monthly and paid in full by PJM in the month after invoicing as set forth in Section 5.6 herein.

5.3. Reimbursement of Fuel and Variable Operations and Maintenance Costs

For each month during the Term, PJM shall reimburse H.A. Wagner any costs incurred in the operation of the Units not otherwise recovered in an amount calculated in accordance with the following methodologies.

a) Fuel Costs. Fuel costs will be determined based on actual costs, using a weighted average inventory methodology. Fuel costs will include all necessary costs associated with securing fuel, including but not limited to delivery costs, taxes, fees, and costs associated with any letters of credit needed to purchase fuel, including startup fuel and fuel used to operate auxiliary boilers to provide steam necessary to start the Units 3 and 4, as well as fuel for the H.A. Wagner Combustion Turbine necessary to provide emergency station power. No later than sixty (60) days prior to the expiration of this Rate Schedule, H.A. Wagner shall inform PJM of fuel inventory levels; if remaining fuel is not burned by the end of the Term, PJM will reimburse H.A. Wagner its actual costs of the fuel and removal costs less the sales price of the remaining fuel. H.A. Wagner shall invoice PJM for removal costs monthly as incurred. If the inventory costs exceed the resale proceeds received by H.A. Wagner, then H.A. Wagner shall invoice PJM for the difference in the month after any such resale occurs. Relevant fuels include (i) No. 4 Fuel Oil – Primary fuel for Unit 3 and Unit 4 and (ii) Natural Gas – Start-up fuel used for ignition in Units 3 and 4 and for operating auxiliary boilers to provide steam for starting Units 3 and 4.

b) Emissions and Environmental Costs. Emissions costs will be determined based on actual costs, using the monthly average price of emissions, in $/ton as published in the Argus Air Daily. The emissions with respect to which H.A. Wagner may recover its costs include, but are not limited to, the following:

A. NOx emissions allowances,

B. SO_2 emissions allowances,

C. CO_2 emissions allowances,

D. Nitrogen discharge allowances,

E. Maryland State Renewable Energy Credits, and

F. Any additional items required by changes in law, regulation, or permit conditions.

c) Chemicals Costs. Chemicals costs will be determined based on actual costs. At the end of the Term, PJM will pay for actual costs and removal costs less the sales price of the remaining chemicals and bulk lubricating oils. Chemicals costs shall include, but are not limited to:

A. Urea (SCR NOx Control Chemical),

B. Sulfuric Acid, Caustic (Boiler Water Control),

C. Sulfuric Acid, Hydrochloric Acid, Hydrated Lime (WWTP Chemicals), and

D. Bulk Lubricating Oils and disposal.

d) Auxiliary Power. To the extent that H.A. Wagner is charged for auxiliary or standby (i.e., station) power for either Unit, the auxiliary power costs will be equal to the actual costs incurred pursuant to PJM Tariff, Attachment K-Appendix.

e) Regulatory and Administrative Costs. Regulatory and administrative costs will include, but not be limited to, the costs of obtaining a final FERC order, and any associated appeals, accepting this Rate Schedule for filing.

5.4. Monthly Fixed-Cost Charge in Event of Early Termination

If this Rate Schedule is terminated early in accordance with Sections 2.3, 2.4, or 2.5, except as provided in Section 4, H.A. Wagner shall recover Monthly Fixed-Cost Charges until the earlier of the decommissioning of such Unit commences or the end of the original Term as set forth in Section 2.2.

5.5. Revenue Credits

For service provided during the Term, H.A. Wagner will credit monthly net revenues (total credits net of total charges), identified on the applicable PJM bill, above variable operations and maintenance ("O&M") and fuel costs, earned from any sales of wholesale energy, capacity and ancillary services from a Unit or other revenues earned with respect to a Unit during the Term, each as earned in PJM's markets or pursuant to other rate schedules on file with the Commission, against the charges under Section 5.3 above and will provide an invoice reflecting this credit pursuant to Section 5.6 below.

5.6. Invoices

H.A. Wagner will invoice PJM monthly for amounts due under Sections 5.1 through 5.4. Such invoice shall reflect as a separate line item the revenue credits for each Unit provided for in Section 5.5. H.A. Wagner will issue the invoice no later than the fifteenth (15th) calendar day of the month following the month in which service is provided, unless extenuating circumstances exist, in which case it will issue the invoice no later than the last day of the month. PJM shall include the charges billed by H.A. Wagner in the PJM monthly billing statement for the month in which PJM received the invoice from H.A. Wagner (for example: April invoice is received in May and goes out in the PJM monthly bill for May). PJM shall remit payment to H.A. Wagner according to the standard financial settlement timeline for such PJM monthly billing statement. Such invoices shall also include as separate line items any adjustments to previously billed amounts. Upon request, H.A. Wagner will provide supporting data for such invoice. Except as otherwise provided in Section 5.7, not later than ninety (90) days from the end of the Term, H.A. Wagner will issue final invoices for amounts due by PJM under this Rate Schedule. However, notwithstanding any provision of this Rate Schedule to the contrary, should costs relating to this Rate Schedule continue to be incurred after the end of the Term, or should fuel inventory take longer to liquidate, the final invoices shall be due within ninety (90) days from the date cost incurrence ceases or fuel is fully liquidated.

5.7. Miscellaneous Provisions

a) PJM and H.A. Wagner may by mutual agreement waive any of the time periods set forth herein.

b) References to PJM Governing Documents included herein shall be to the versions in effect as of the Effective Date, as they may be amended from time to time.

c) To the extent H.A. Wagner is prevented by Force Majeure from carrying out, in whole or part, its obligations under this Rate Schedule and it gives notice and details of the Force Majeure to PJM as soon as practicable, then H.A. Wagner shall be excused from the performance of its obligations with respect to this Rate Schedule. H.A. Wagner shall remedy the Force Majeure with all reasonable dispatch.

5.8. Designated Representatives

For purposes of any notices required to be provided pursuant hereto, notice shall be provided by electronic mail and the designated representatives to receive such notices shall be:

For H.A. Wagner:

Debra Raggio
Debra.Raggio@talenenergy.com

For PJM:

Thomas DeVita
Thomas.DeVita@pjm.com

Either H.A. Wagner or PJM may change their respective designated representatives by written notice to all other designated representatives.

5.9. Standard of Review

The standard of review for changes to any rate, charge, classification, term or condition of this Rate Schedule, whether proposed by PJM, any party with standing under Federal Power Act Section 206, or FERC acting *sua sponte*, shall solely be the most stringent standard of review set forth in *United Gas Pipe Line Co. v. Mobile Gas Service Corp.,* 350 U.S. 332 (1956) and *Federal Power Commission v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956) and clarified by *Morgan Stanley Capital Group, Inc. v. Public Util. Dist. No. 1 of Snohomish*, 554 U.S. 527, 128 S. Ct. 2733 (2008) and *NRG Power Marketing, LLC, et al. v. Maine Public Utilities Commission*, 558 U.S. 165 (2010).

April 2, 2024

<u>VIA ETARIFF FILING</u>

Debbie-Anne A. Reese
Acting Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: NRG Power Marketing LLC, Docket No. ER22-1539-002
NRG Business Marketing LLC, Docket No. ER23-2688-002
<u>Settlement Agreement and Offer of Settlement</u>

Dear Secretary Reese:

Pursuant to Rule 602 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission (the "Commission"),[1] NRG Business Marketing LLC ("NRG-BML"), on behalf of Indian River Power LLC, Delaware Public Service Commission, Old Dominion Electric Cooperative, Delaware Municipal Electric Corporation, Inc., the City of Dover Delaware, and PJM Interconnection, L.L.C. (collectively, the "Settling Parties) hereby submits for filing the Settlement Agreement and Offer of Settlement (the "Settlement Agreement") and the settlement materials described below.[2] NRG-BML respectfully requests that the Settlement Agreement be transmitted,

[1] 18 C.F.R. § 385.602 (2023).

[2] On August 23, 2023, NRG-BML filed with the Commission, in Docket No. ER23-2688-000, its notice of succession ("Notice") and related, non-substantive revisions to the NRG Power Marketing LLC ("NRG-PML") Electric, Rate Schedule FERC No. 3 filed in Docket No. ER22-1539-000, in connection with the merger of NRG-PML into NRG-BML with NRG-BML being the surviving entity (the "Merger") and with the Notice stating the filed rate schedule would be subject to the outcome of the proceeding in Docket No. ER22-1539-000. *See* Notice of Succession and Request for Waiver, Docket No. ER23-2688-000 (filed Aug. 23, 2023). On March 4, 2024, NRG-BML filed with the Commission, in Docket No. ER23-2688-001, a substitute tariff record ("Substitute Rate Schedule") to the Notice. *See* Revised Tariff Record to Notice of Succession and Requests for Consolidation, Shortened Notice Period, Expedited Treatment, and Waiver, Docket No. ER23-2688-001 (filed Mar. 4, 2024). On March 26, 2024, the Commission issued the order accepting the Notice and Substitute Rate Schedule, granting the August 1, 2023, effective date as requested, subject to refund, and consolidating the proceeding with Docket No. ER22-1539-000. *See NRG Power Marketing LLC*, 186 FERC ¶ 61,215 (2024) ("Notice Order"). As a result of the Merger and the

2.7 Survival of Obligations

(a) If the provision of RMR service pursuant to this Rate Schedule is terminated prior to the date identified in Section 2.2 and Utility has not yet recovered costs of operating Unit 4 under the Cost of Service Recovery Rate, which costs were Incurred, Utility shall be entitled to recover all such unrecovered costs with respect to Unit 4, in accordance with this Rate Schedule.

(b) If the provision of RMR service pursuant to this Rate Schedule is terminated prior to the date identified in Section 2.2 and Utility has not yet recovered Project Investment Costs, which costs were Incurred, Utility shall be entitled to recover all such costs in accordance with this Rate Schedule.

(c) If Unit 4 continues to operate beyond the Term, this Rate Schedule shall not terminate until the obligations established in Section 5.3 of this Rate Schedule have been fully satisfied.

(d) Expiration or termination of the RMR service pursuant to this Rate Schedule shall not affect Utility's or PJM's accrued rights and obligations arising during the Term, including either party's obligation to make all payments to the other, and this Rate Schedule shall not terminate until all such obligations have been fully satisfied.

2.8 FERC Filings

(a) Pursuant to Section 119 of the PJM Tariff, Utility shall file this Rate Schedule with FERC.

(b) If the Term of this Rate Schedule is extended pursuant to Section 2.6, Utility shall file an amendment to this Rate Schedule, reflecting such extension and any changes to the rates, terms, and conditions for such extension, with FERC pursuant to Federal Power Act § 205.

(c) Subject to the conditions precedent in Section 2.7, Utility shall file a notice of termination pursuant to 18 C.F.R. § 35.15(c).

III. OBLIGATIONS

3.1 Application of PJM Governing Documents

The operation of Unit 4 consistent with the terms and conditions of this Rate Schedule shall not be deemed inconsistent with the performance obligations identified in Section 121 of the PJM Tariff.

3.2 Scheduling and Dispatch of Unit 4

PJM may schedule and dispatch Unit 4 subject to the operating limitations identified in Section 3.4 and the availability of coal, equipment, parts, and the other inputs to energy production, consisting of, but not limited to, lime, and oil. Utility will endeavor to maintain inventories of the foregoing, consistent with good utility practice, to provide the RMR service pursuant to this Rate Schedule.

3.3 Operation of Unit 4

(a) Subject to the terms of this Section 3.3, PJM may schedule and dispatch Unit 4 solely to address (i) an identified transmission reliability need, including transmission reliability needs that are the result of transmission maintenance or transmission work to support upgrades, in support of the requirement to operate such transmission facilities within established thermal, voltage and stability limits under Sections 2 and 3 of PJM Manual 3 and when such transmission reliability needs cannot otherwise be met with available economically dispatched generating resources; (ii) a PJM transmission reliability need caused by a system restoration need as described in PJM Manual 36; (iii) a capacity emergency (as described in PJM Manual 13) during which PJM determines that the resources scheduled for an operating day are not sufficient to maintain the appropriate reserve levels for PJM; (iv) any required testing of Unit 4 as set forth in Section 3.3(e); and (v) as described in Section 6.3(a).

(b) Subject to the Unit 4 operating limitations identified in Section 3.4, Utility shall operate Unit 4 upon receipt of, and consistent with, a scheduling notice and subsequent dispatch notice issued by PJM. Utility does not guarantee that Unit 4 will start or operate at its rated capacity, and Utility does not guarantee the availability of Unit 4 in response to a PJM scheduling or dispatch notice.

(c) In its sole discretion, Utility shall not be obligated to cause Unit 4 to be operated in a manner that will cause it to violate the terms of any environmental restrictions or any operating permit limitations.

(d) PJM shall not issue a scheduling or dispatch notice to Utility for operation of Unit 4 during periods when Unit 4 is unavailable due to an Outage, provided that Utility shall notify PJM of Unit Outages consistent with the PJM Governing Documents.

(e) Utility, with advance notice of at least one (1) day to, and prior approval by, PJM, may self-schedule Unit 4 under limited circumstances where PJM's dispatch of Unit 4 is not expected to allow necessary operational activities to occur. These activities generally include, but are not limited to, scheduling Unit 4 to conduct mandatory compliance testing, diagnostic evaluations performed to maintain Unit 4's ability to operate, and addressing the coal inventory requirements and coal inventory reduction obligations set forth in this Rate Schedule. PJM shall provide compensation pursuant to this Rate Schedule consistent with that provided during a PJM dispatch relating to such periods of operation.

(f) Utility shall maintain weather preparation measures for Unit 4 for winter and summer seasons consistent with good utility practice. Upon request and with ten (10) Business Days' notice, PJM may conduct an on-site summer and/or winter readiness inspection of Unit 4 up to two times per year to determine compliance with winter and/or summer performance preparation criteria consistent with good utility practice and, in the case of winter preparation criteria, consistent with PJM Manual 14D. PJM may, at its discretion, develop an inspection report. Should the inspection report identify any discrepancies with the criteria, Utility shall develop a plan to cure such discrepancy within thirty (30) Business Days of the report. If Utility's efforts to cure the discrepancy are declared deficient by PJM, Utility may provide notice pursuant to Section 2.3.

(g) If Unit 4 has not run for the prior thirty (30) days consecutively, then at the discretion of Utility, and with prior notice to PJM, Unit 4 may self-schedule to operate for up to forty-eight (48) hours. If Unit 4 has not run for the prior thirty (30) days consecutively, PJM may, with prior notice to Utility, schedule Unit 4 to operate for up to forty-eight (48) hours. PJM shall provide compensation pursuant to this Rate Schedule consistent with that provided during a PJM dispatch relating to such periods of operation.

3.4 Operating Restrictions

(a) Unit 4 shall be subject to its Parameter-Limited Schedule in place with PJM as of the Effective Date; provided, however, to the extent Unit 4 experiences a physical operational limitation that prevents it from meeting such Parameter-Limited Schedule, Utility will modify the parameters to reflect the limitation and will notify PJM via email and eDart as soon as the need for the change is recognized.

(b) To the extent that Unit 4 offers Synchronized Reserve Service, the parameters for those offers will comply with the PJM Governing Documents.

IV. MARKET OPERATIONS

4.1 Obligation to Offer Unit 4 into Markets

(a) Unit 4 shall not be subject to any must-offer obligation in the PJM capacity market. Unit 4 will submit cost-based offers of energy in the PJM Interchange Energy Market in accordance with the PJM Operating Agreement, Schedule 2, Section 1, and PJM Manual 15; provided, however, such offers shall exclude (i) replacement and opportunity costs and (ii) Emissions Costs, as defined in Section 5.4. Unit 4 will be offered with a status of 'unavailable' in the Market but will be available to be scheduled pursuant to Section 3.3. The cost-based offer of energy also applies to dispatch pursuant to Section 3.3(e). From FERC's approval of a Settlement Agreement without modification pertaining to this Rate Schedule, or if parties to the Settlement Agreement agree to accept FERC-proposed modifications, Utility will not include the Maintenance Adder (as defined in the PJM Operating Agreement) in Utility's cost-based offers for Unit 4 during the Term.

(b) Except when Unit 4 is unavailable due to an Outage, Unit 4 may be offered based on its cost-based schedule into the Synchronized Reserve market when Unit 4 is otherwise dispatched for reliability. Such cost-based bids shall be calculated in accordance with Section 1.10.1A(j) of the PJM Operating Agreement.

(c) Except when Unit 4 is unavailable due to an Outage, Unit 4 will provide reactive power consistent with the available capability of the unit and voltage schedules provided for in the relevant interconnection agreement.

McGuireWoods LLP
2001 K Street N.W.
Suite 400
Washington, DC 20006-1040
Phone: 202.857.1700
Fax: 202.857.1737
www.mcguirewoods.com

Noel Symons
Direct: 202.857.2929

nsymons@mcguirewoods.com
Fax: 202.857.1737

January 5, 2017

Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: Deactivation Avoidable Cost Rate Informational Filing under Section 116 of the PJM Interconnection, L.L.C. Open Access Transmission Tariff

Dear Secretary Bose:

Dominion Resources Services, Inc. ("Dominion"), on behalf of Dominion Virginia Power ("DVP"), submits to the Federal Energy Regulatory Commission (the "Commission") DVP's Deactivation Avoidable Cost ("DAC") Rate for Yorktown generating unit 2, located in Yorktown, Virginia, with a nameplate capacity of 164 MW ("Yorktown Unit 2").[1] This filing is being submitted for informational purposes under Section 116 of the PJM Interconnection, L.L.C. ("PJM") Open Access Transmission Tariff ("Tariff").

I. BACKGROUND

DVP owns and operates Yorktown Unit 2. On October 9, 2012, Dominion Generation, an operating segment of Dominion Resources, Inc. ("DRI"), submitted a letter to PJM under Section 113.1 of the Tariff notifying PJM of DVP's intent to deactivate Yorktown Unit 2 effective as of December 31, 2014 ("Deactivation Notice").[2] DRI is also the parent company of DVP. The Deactivation Notice is attached as Attachment 1.

By letter dated April 11, 2014, PJM notified Dominion Generation under Section 113.2 of the Tariff that the deactivation of Yorktown Unit 2 would adversely affect the PJM transmission system absent the installation of certain transmission upgrades ("Reliability Impact Letter," attached as Attachment 2). In the Reliability Impact Letter, PJM described the reliability impacts resulting from the proposed Deactivation in the Reliability Impact Letter and provided

[1] Dominion is contemporaneously submitting to the Commission a DAC Rate informational filing for Yorktown generating unit 1 with a nameplate capacity of 159 MW.
[2] DVP is also obligated to make an information filing with the Commission under Schedule 2 of the PJM Tariff to report the retirement of Yorktown Unit 2 ninety days prior to deactivation.

AME (Avoidable Maintenance Expenses)

The AME component comprises avoidable maintenance expenses, except those included in AOML, including chemicals and materials consumed during maintenance of the generating unit and rented maintenance equipment used to maintain the generating unit. As shown in Schedule 3 (AME-Yorktown Unit 2), the total AME component for Yorktown Unit 2 effective January 6, 2017, is $4.85/MW-day.

AVE (Avoidable Variable Expenses)

The AVE component comprises avoidable variable expenses, including: (1) water treatment chemicals and lubricants; (2) water, gas and electric service (not for power generation); and (3) waste water treatment. As shown in Schedule 4 (AVE-Yorktown Unit 2), the total AVE component for Yorktown Unit 2 effective January 6, 2017, is $0/MW-day; effective January 1, 2018, it is $7.82/MW-day.

ATFI (Avoidable Taxes, Fees and Insurance)

The ATFI component comprises the following avoidable expenses: (1) insurance; (2) permits and licensing fees; (3) site security and utilities for maintaining security at the site; and (4) property taxes. As shown in Schedule 5 (ATFI-Yorktown Unit 2), the total ATFI component for Yorktown Unit 2 effective January 6, 2017, is $6.79/MW-day.

ACC (Avoidable Carrying Charges)

The ACC component comprises avoidable short term carrying charges for maintaining reasonable levels of inventories of fuel and spare parts that result from short-term operational unit decisions as measured by industry best practice standards. For the purpose of determining ACC, short term is the time period in which a reasonable replacement of inventory for normal, expected operations can occur. The ACC component for Yorktown Unit 2 is $0; thus, no cost support schedule is attached for this component.

ACLE (Avoidable Corporate Level Expenses)

The ACLE component comprises avoidable corporate level expenses, including only such expenses that are directly linked to providing tangible services required for the operation of the generating unit, such as legal services, environmental reporting and procurement expenses. The ACLE component for Yorktown Unit 2 is $0; thus, no cost support schedule is attached for this component.

APIR (Avoidable Project Investment Recovery Rate)

The APIR component is calculated by dividing the project investment costs necessary to keep the generating unit operating beyond its deactivation dates by the number of months beyond the deactivation date that the generating unit will be required to operate. The amount recovered under the APIR cannot exceed the actual project investment and is limited to $2 million. The

APIR component for Yorktown Unit 2 is $0; thus, no cost support schedule is attached for this component.

Applicable Adder

Section 114 of the Tariff provides for an adder to the DAC rate (Applicable Adder"), an annually increasing percentage of the DAC Rate. Because Dominion Generation's proposed Deactivation Date for Yorktown Unit 2 was December 31, 2014, the Third Year Adder applies as of January 1, 2017. Thus, in accordance with Section 114, Yorktown Unit 2 will receive a 35% Applicable Adder effective January 6, 2017, through December 31, 2017. As set forth in Section 114, the Applicable Adder for the fourth year shall be 50% of the DAC Rate. As shown in the attached Schedule 6 (Adder-Yorktown Unit 2), the total Applicable Adder for Yorktown Unit 2 effective January 6, 2017, through December 31, 2017, is equal to $20.61/MW-day.

Total DAC Rate

As shown in the attached Schedule 7 (DAC Rate-Yorktown Unit 2), the total DAC Rate for Yorktown Unit 2 effective January 6, 2017, is $58.88/MW-day. Schedule 7 (DAC Rate-Yorktown Unit 2) also shows that the total DAC Rate for Yorktown Unit 2, including the Applicable Adder, effective January 6, 2017, is $79.49/MW-day.

IV. MARKET COMMITMENTS

DVP will continue to make Yorktown Unit 2 available to PJM pursuant to the existing procedures that PJM developed to address the restrictions placed on the unit by the Environmental Protection Agency's April 16, 2016 Administrative Compliance Order issued under Section 113(g) of the Clean Air Act. Yorktown Unit 2 does not have any capacity market commitments.

V. CONCLUSION

Pursuant to Section 116 of the Tariff, Dominion has provided a copy of this informational filing to PJM. Please contact me with any questions.

Respectfully submitted,

/s/ *Noel Symons*

Noel Symons
Nelli Doroshkin
McGuireWoods LLP
2001 K St NW, Suite 400
Washington, DC, 20006
(202) 857-2929
nsymons@mcguirewoods.com
ndoroshkin@mcguirewoods.com

Attorneys for Dominion Resources Services, Inc.

CC: PJM Interconnection, L.L.C.

Enclosures

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR ENFORCEMENT DIVISION, OFFICE OF ENFORCEMENT AND COMPLIANCE ASSURANCE
BEFORE THE ADMINISTRATOR

In the Matter of: Virginia Electric and Power Company, Respondent.	Administrative Compliance Order on Consent AED-CAA-113(a)-2016-0005

ADMINISTRATIVE COMPLIANCE ORDER

A. PRELIMINARY STATEMENT

1. This Administrative Compliance Order ("Order") is issued under the authority vested in the Administrator of the U.S. Environmental Protection Agency ("EPA") by Section 113(a) of the Clean Air Act ("CAA" or the "Act"), 42 U.S.C. § 7413(a)(3) and (4).
2. On the EPA's behalf, Phillip A. Brooks, Division Director of the Air Enforcement Division, Office of Civil Enforcement, Office of Enforcement and Compliance Assurance, U.S. Environmental Protection Agency, is delegated the authority to issue this Order under Section 113(a) of the Act.
3. Respondent is Virginia Electric and Power Company, doing business as Dominion Virginia Power (hereinafter, "Respondent" or "Dominion"), a corporation doing business in the Commonwealth of Virginia. Respondent is a "person" as defined in Section 302(e) of the Act, 42 U.S.C. § 7602(e). Respondent owns and/or operates Yorktown Power Station (hereafter, the "Facility"), located in the Commonwealth of Virginia. The Facility includes two coal-fired units (Units 1&2) and an oil-fired unit (Unit 3).
4. Respondent signs this Order on consent.

related project components are completed and in service (collectively, "Skiffes Creek Project"[2]), which is expected no earlier than the second quarter of 2017. *See* Order Request at 17 and 21. In the Order Request, Respondent claims that construction of the Skiffles Creek Project was delayed due to factors outside of its control, including appeals of the Certificate of Convenience and Necessity for the Skiffles Creek Project and other approvals. *Id.* at 1 – 2, 4, 11 - 15.

25. More specifically, the Order Request states that Respondent will be unable to avoid violations of Reliability Standards developed by the North American Electric Reliability Corporation ("NERC") if Units 1 and 2 are deactivated prior to the Skiffes Creek Project being put into service unless Respondent resorts to load shedding. *Id.* at 17. Specifically, Respondent maintains that the retirement of Units 1 and 2 before completion of the Skiffes Creek Project would result in Category B, C and D violations under the NERC Transmission Planning Reliability Standards without load shedding. *Id.* at 18-19; *see also,* note 11.

26. In its Order Request, Respondent provided concurrence from its Planning Authority with the reliability assessment. *See id.*, Attachment C (Written Concurrence of Planning Coordinator) at 2. In its concurrence, the Planning Authority states that "the Deactivation of both Yorktown Unit Nos. 1 and 2 will adversely affect the reliability of the PJM Transmission System, and that updates to the system were required." *Id.*, Attachment K (PJM April 11, 2014 Letter) at 1.

27. FERC reviewed the reliability risk presented in the Order Request in accordance with the FERC Policy Statement and on December 2, 2015 found that "the loss of Dominion's Yorktown Unit Nos. 1 and 2 prior to the completion of the Skiffes Creek Project might result in violations of NERC Reliability Standards in the absence of load shedding," and "Dominion's Yorktown Unit

[2] The Skiffes Creek Project consists of construction of the Surry-Skiffes Creek 500 kV transmission line, the Skiffes Creek-Whealton 230 kV transmission line, and the Skiffes Creek 500 kV-230 kV-115 kV Switching Station ("Skiffes Station"), and work at Dominion Virginia Power's existing Surry and Whealton Stations. *Id.* at 10 and note 4. The Skiffes Creek Project will be located in the Counties of James City, Surrey, and York and the Cities of Hampton and Newport News within Virginia.

Nos. 1 and 2 are needed during the administrative order period, as requested by Dominion, to maintain electric reliability and to avoid possible NERC Reliability Standard violations." *See* Commission Comments On Requests For EPA Administrative Order (December 2, 2015), at Paragraph 5, Docket No. AD16-11-000.

28. Respondent proposes to minimize emissions by operating Units 1 and 2 only as needed in order to meet the NERC Reliability Standards discussed in Paragraphs 25 - 27 of this Order. In order to do so, Respondent asserts that it will work with its Planning Authority to establish a dispatch methodology that operates Units 1 and 2 "only when called upon for reliability issues associated with the Skiffes Creek construction project, as well as for other expected and actual local area transmission issues or generation emergencies from April 16, 2016 to April 15, 1017." *Id.* at 22-23.[3] Respondent expects the required combined operation of Units 1 and 2 "to be in an estimated monthly range between 30% and 50% in any month during which the [] units are required to operate to support the Skiffes Creek project and up to 10% in months without Skiffes Creek support but requiring support for generation or local transmission reasons;" however, "the units could be required to operate above or below the estimates provided above, depending on system operating requirements." *Id.*

D. ORDER

29. Respondent is ordered to take the actions described in this section of this Order.

30. Between April 16, 2016 and April 15, 2017, Respondent shall operate Units 1 and 2 only as needed in order to meet the NERC Reliability Standards discussed in Paragraphs 25 - 27 of this Order. In order to do so, from April 16, 2016 to April 15, 1017, Respondent shall implement a

[3] Respondent indicates that "in order to maintain compliance with NERC Reliability Standards, if the [] Units must be retired before the Skiffes Creek Project is completed and operational, the Company will implement special protection schemes to shed load under certain system conditions." Order Request at note 17.

dispatch methodology with PJM that operates Units 1 and 2 only when called upon for reliability issues associated with the Skiffes Creek Project or for other local area transmission issues or generation emergencies. Respondent expects the required combined operation of Units 1 and 2 to be between 30% and 50% in any month during which the units are required to operate to support the Skiffes Creek Project and up to 10% in months requiring support for generation or local transmission reasons in the absence of support for the Skiffes Creek Projects; however, the units may be required to operate above or below the estimates provided above, depending on system operating requirements.

31. By 11:59 pm April 15, 2017, Respondent shall achieve full compliance with the MATS at Units 1 and 2 at the Facility.

32. Within 30 days of achieving full compliance with the MATS at the Facility, Respondent shall provide written notice to the EPA indicating that compliance has been achieved and the date by which is it was achieved, pursuant to the process specified in paragraph 39 of this Order.

E. OTHER TERMS AND CONDITIONS

33. Respondent admits the jurisdictional allegations contained in Sections A (Preliminary Statement) and B (Statutory and Regulatory Background) of this Order.

34. Respondent neither admits nor denies the findings in Section C (Findings) of this Order.

F. GENERAL PROVISIONS

35. Any violation of this Order may result in a civil administrative or judicial action for an injunction or civil penalties of up to $37,500 per day per violation, or both, as provided in Sections 113(b)(2) and 113(d)(1) of the Act, 42 U.S.C. §§ 7413(b)(2) and 7413(d)(1), as well as criminal sanctions as provided in Section 113(c) of the Act, 42 U.S.C. § 7413(c). The EPA may use any information submitted under this Order in an administrative, civil judicial, or criminal action.

ARNOLD & PORTER KAYE SCHOLER

Sandra Rizzo
+1 202.942.5826 Direct
Sandra.Rizzo@apks.com

January 5, 2018

Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: *RC Cape May Holdings, LLC*, Docket No. ER17-1083-
Joint Offer of Settlement

Dear Secretary Bose:

Pursuant to Rule 602 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission"), 18 C.F.R. § 385.602 (2017), RC Cape May Holdings, LLC ("RCCM"), PJM Interconnection, L.L.C., Monitoring Analytics, LLC, and Atlantic City Electric Company, an Exelon Corporation subsidiary, hereby submit for filing a Joint Offer of Settlement ("Settlement"). If approved, this Settlement will resolve all issues set for settlement and hearing regarding RCCM's Reliability Must-Run Rate Schedule, Electric Rate Schedule FERC No. 3 ("RMR Rate Schedule"), submitted pursuant to Part V and Section 119 of the PJM Interconnection, L.L.C. Open Access Transmission Tariff.

The Settlement package is comprised of:

1. The Settlement;
2. Explanatory Statement; and
3. RCCM Rate Schedule revised in accordance with the Settlement (both a clean version and a redline against the rate schedule currently on file with the Commission).

Copies of this filing have been served on all parties in this proceeding.

Initial comments on the Settlement are due 20 days after the filing of the Settlement, and reply comments are due 30 days after the filing of the Settlement.

Please contact the undersigned if you have any questions.

2.4 PJM Termination Rights

To the extent that PJM determines that its need for Unit 2 no longer exists, PJM shall provide at least 90 days' advance notice to RCCM after which time the agreement shall terminate.

2.5 Other Events of Termination

a) Consistent with Section 113.3 of the PJM Tariff, this Rate Schedule shall terminate with respect to a Unit ninety (90) days after the Unit becomes inoperable if PJM provides, or is deemed to have provided, RCCM with a notice declining to approve a Project Investment and the Unit is unable to continue operating without such Project Investment. Within ten (10) days after RCCM receives, or is deemed to have received, notice that PJM has declined to approve a Project Investment pursuant to Section 5.2I, RCCM shall provide written notice to PJM and FERC of the termination of this Rate Schedule with respect to the inoperable Unit and shall explain why the Unit is inoperable without the Project Investment.

b) If this Rate Schedule terminates with respect to either Unit, it shall remain in effect with respect to the other Unit. If this Rate Schedule terminates with respect to both Units, then it shall terminate in its entirety.

2.6 Extension by Mutual Agreement

If PJM wishes to extend the Term of this Rate Schedule for Unit 2 beyond April 30, 2019, PJM will endeavor to provide at least 120 days' notice to RCCM prior to the date upon which this Rate Schedule otherwise would terminate. RCCM will reply within 30 days indicating whether it is willing to continue operating if permitted to do so. If it is so willing, it will provide PJM with a status update with regard to its potential ability to extend the operation of Unit 2 with its reply. RCCM will thereafter provide periodic status updates to PJM, and will notify PJM of its ability to continue operation and the duration of such operation no later than 90 days after the receipt of PJM's notice, or as soon thereafter as possible.

3. OBLIGATIONS

3.1 Application of PJM Governing Documents

RCCM's operation of the Units consistent with the terms and conditions of this Rate Schedule shall not be deemed inconsistent with the performance obligations identified in Section 121 of the PJM Tariff.

3.2 Dispatch of the Units

Subject to the Unit operating limitations identified in Section 3.4 below, PJM may dispatch either or both Units.

3.3 Operation of the Units

a) Subject to the Unit operating limitations identified in Section 3.4 below, RCCM shall operate either or both Units upon receipt of a dispatch notice issued by PJM. RCCM does not guarantee that such Unit(s) will start or operate at rated capacity, and RCCM does not guarantee the availability of the Unit(s) in response to a PJM dispatch notice.

b) In its sole discretion, RCCM shall not be obligated to cause either Unit to be operated in a manner that will cause RCCM to violate the terms of any environmental restrictions or any operating permit limitations.

c) PJM shall not issue a dispatch notice to RCCM for operation of a Unit during periods when a Unit is unavailable due to an Outage, provided that RCCM shall notify PJM of Unit Outages consistent with the PJM Governing Documents.

d) RCCM, with advance notice of at least one day to, and prior approval by, PJM, may self-schedule a Unit under limited circumstances when PJM's dispatch of a Unit is not expected to allow necessary operational activities to occur. These activities generally include, but are not limited to, scheduling a Unit to conduct mandatory compliance testing or diagnostic evaluations performed to maintain a Unit's ability to operate. PJM shall provide compensation pursuant to this rate schedule consistent with that provided during a PJM dispatch relating to such periods of operation.

3.4 Operating Restrictions

The Units shall be coded in Markets Gateway as Maximum-Emergency units and shall be subject to the following pre-determined limits on the offer parameters for their cost-based schedules unless different limits are approved in Markets Gateway:

Parameters	**BL England Unit 2**	**BL England Unit 3**
Minimum Down Time (Hrs)	24 hours	24 hours
Minimum Run Time (Hrs)	15 hours	8 hours
Maximum Daily Starts	1	1
Maximum Weekly Starts	3	3

BL England Unit 2:

Operating Parameters:

Max Capacity = 146 MW
Economic Max = 146 MW
Economic Min = 80 MW
Emergency Min = 72 MW
Start-up Notification Cold (Scrubber ready) = 14 Hours
Start-up Notification Cold (Scrubber secured) = 32 Hours
Start-up Notification Intermediate = 12 Hours
Start-up Notification Hot = 8 Hours
PJM Node Name = ENGLAND 18KV UNIT02
PJM Pnode Number = 50854

Environmental Limitations

Environmental limitations for BL England Unit 2 include, but are not limited to, the following:

BL England Unit 2 is limited to Hours of Operation <= 4,300 hours from May 1 to April 30 each calendar year.

BL England Unit 2 is limited to a boiler heat input restriction of 1,600 MMBtu/HR.

Title V Operating Permit and NJPDES Permit limits and conditions.

BL England Unit 3

Operating Parameters:

Max Capacity = 146 MW
Economic Max = 146 MW
Economic Min = 80 MW
Emergency Min = 25 MW

Start-up Notification Cold (No. 6 Fuel Oil secured) = 42 Hours
Start-up Notification Cold (No. 6 Fuel Oil circulating) = 16 Hours
Start-up Notification Intermediate = 12 Hours
Start-up Notification Hot = 8 hours
PJM Node Name = ENGLAND 20KV UNIT03
PJM Pnode Number 50855

Environmental Limitations

Environmental limitations for BL England Unit 3 include, but are not limited to, the following:

BL England Unit 3 has a 16 hour “Start-Up” limitation such that the first fire to 40 MW <= 16 hours.

Title V Operating Permit and NJPDES Permit limits and conditions.

Unit 3 is a limited use liquid oil-fired boiler as per subcategory 40 C.F.R. § 63.10042 for MATS compliance purposes. Annual heat input to the boiler, based on the Maximum Gross Heat Input, is 1,205,376 MMBtu (HHV) for any consecutive 365 days. This equates to a unit net MW capacity factor of approximately 8%.

BL England Unit 3 is limited to a boiler heat input restriction of 1,720 MMBtu/HR.

Pursuant to the Stack Test ACO, RCCM may be required to conduct comprehensive stack testing within 15 days of BL England Unit 3 operating.

To the extent a Unit experiences a physical operational limitation that prevents it from meeting the parameters listed above, RCCM will modify the parameters to reflect the limitations and will notify PJM via email and via eDart as soon as the need for the change is recognized. Notwithstanding any operating limitations set forth in this section, RCCM will respond to PJM dispatch notices on a best efforts basis when consistent with law and regulation.

3.5 Continued Operations

Unless a successor reliability rate schedule is made effective, RCCM plans to retire each of Unit 2 and Unit 3 upon termination of the RMR Rate Schedule as to the respective unit. However, Unit 2 may eventually repower as a natural gas unit. If the repowering of Unit 2 proceeds and RCCM reuses any equipment subject to a Project Investment and such reuse offsets a cost that RCCM otherwise would have been required to incur, RCCM shall reimburse a portion of the cost based on the prorated period of time the equipment may be used for repowered unit commercial operation relative to the extended life of the equipment resulting from the Project Investment plus one year. At the time of the repowered unit commercial operation date, RCCM shall identify such reused equipment, the amount of time by which the Project Investment extended the life of the equipment, and the expected useful life of the equipment during repowering, and will calculate the proposed amount to be refunded based on those factors in a report provided to PJM and the IMM within 3 months after the commercial operation date of the repowered Unit 2. Any such refund will be divided by 2 if the Project Investment was made to benefit both Units 2 and 3. RCCM will provide PJM with a credit equal to such amount within 30 days after the date of the report.

For example, if the Project Investment is to overhaul and rewind a pump motor for Unit 2 at a cost of $100, extending the pump motor expected life for 8 years, and the pump motor was used to provide RMR service for 2 years, and will be used by Unit 2 for repowering for 4 years after the commercial operation date, RCCM will credit PJM for 4 years of use plus one year such that the credit to PJM is 5/8 x $100 equals $62.50.

July 10, 2012

Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: Informational Filing regarding Deactivation Avoidable Cost (DAC) Rate under Section 116 of the PJM Interconnection, L.L.C.'s Open Access Transmission Tariff

Dear Secretary Bose:

Pursuant to Section 116 of the PJM Interconnection, L.L.C. ("PJM") Open Access Transmission Tariff ("Tariff"), FirstEnergy Service Company ("FirstEnergy") hereby submits to the Federal Energy Regulatory Commission ("FERC" or the "Commission"), on behalf of FirstEnergy Generation Corporation ("FE Genco"), for informational purposes, FE Genco's Deactivation Avoidable Cost ("DAC") Rate with respect to Eastlake generating unit number 1 located in Eastlake, Ohio with an installed nameplate capacity of 132 MW ("Eastlake #1").

I. BACKGROUND

FE Genco is the owner of Eastlake #1. In accordance with Section 113.1 of the Tariff, on January 26, 2012, FirstEnergy, on behalf of FE Genco, submitted a letter to PJM notifying PJM of FE Genco's intent to deactivate Eastlake #1 (as well as certain other generating units owned by FE Genco), effective as of September 1, 2012 ("Deactivation Notice"), which is attached hereto as Attachment 1.

Pursuant to Section 113.2 of the Tariff, PJM notified FirstEnergy, by letter dated February 24, 2012, that the deactivation of Eastlake #1 (as well as the certain other generating units referenced in the Deactivation Notice) would adversely affect the PJM transmission system absent the installation of certain transmission upgrades ("Reliability Impact Letter"), which is attached hereto as Attachment 2. In the Reliability Impact Letter, PJM provided FirstEnergy with a list of specific reliability impacts and an initial estimated date of June 2016 to complete the necessary transmission system reliability upgrades necessary to alleviate those reliability impacts.

component for Eastlake #1 effective September 1, 2012 is $1,862,331, which corresponds to $46.81/MW-day.

AVE

The AVE component of the DAC Rate consists of avoidable variable expenses, including: (1) water treatment chemicals and lubricants; (2) water, gas and electric service (not for power generation); and (3) waste water treatment. As demonstrated in the attached Schedule 4 (AVE-Eastlake #1), the total AVE component for Eastlake #1 effective September 1, 2012 is $241,160, which corresponds to $6.06/MW-day.

ATFI

The ATFI component of the DAC Rate consists of the following avoidable expenses: (1) insurance; (2) permits and licensing fees; (3) site security and utilities for maintaining security at the site; and (4) property taxes. As demonstrated in the attached Schedule 5 (ATFI-Eastlake #1), the total ATFI component for Eastlake #1 effective September 1, 2012 is $625,671, which corresponds to $15.73/MW-day.

ACC

The ACC component of the DAC Rate consists of avoidable short term carrying charges for maintaining reasonable levels of inventories of fuel and spare parts that result from short-term operational unit decisions as measured by industry best practice standards. For the purpose of determining ACC, short term is the time period in which a reasonable replacement of inventory for normal, expected operations can occur. As demonstrated in the attached Schedule 6 (ACC-Eastlake #1), the total ACC component for Eastlake #1 effective September 1, 2012 is $61,194, which corresponds to $1.54/MW-day.

ACLE

The ACLE component of the DAC Rate consists of avoidable corporate level expenses, including only such expenses that are directly linked to providing tangible services required for the operation of the generating unit, such as legal services, environmental reporting and procurement expenses. As demonstrated in the attached Schedule 7 (ACLE-Eastlake #1), the total ACLE component for Eastlake #1 effective September 1, 2012 is $80,531, which corresponds to $2.02/MW-day.

APIR

The APIR component of the DAC Rate is calculated by dividing the project investment costs necessary to keep the generating unit operating beyond its deactivation dates by the number of months beyond the deactivation date that the generating unit will be required to operate. The amount recovered under the APIR cannot exceed the actual project investment and is limited to $2 million. As demonstrated in the attached Schedule 8 (APIR-Eastlake #1), the APIR

component for Eastlake #1 is $6,563. The APIR component effective from September 1, 2012 through August 31, 2013 is $0.39/MW-day.[2]

Applicable Adder

Pursuant to Section 114 of the Tariff, a generating unit also receives an adder to the DAC Rate (the "Applicable Adder"), which is intended to increase compensation for the generating unit the longer it is required to run, thus providing additional return if the operating period is extended. The Applicable Adder also serves as an incentive to loads to take actions to avoid the need for the generating unit. In accordance with Section 114, Eastlake #1 will receive a 15% Applicable Adder effective September 1, 2012 for the 12 months thereafter for providing PJM with 219 days' notice of deactivation. As set forth in Section 114, the Applicable Adder for the second year shall be 20% of the DAC Rate, the Applicable Adder for the third year shall be 35% of the DAC Rate and the Applicable Adder for the fourth year shall be 50% of the DAC Rate. As demonstrated in the attached Schedule 9 (Adder-Eastlake #1), the total Applicable Adder for Eastlake #1 effective September 1, 2012 and for the 12 months thereafter is equal to $24.57/MW-day.

Total DAC Rate

As demonstrated in the attached Schedule 10 (DAC Rate-Eastlake #1), the total DAC Rate for Eastlake #1 effective September 1, 2012 is $163.78/MW-day. Also as demonstrated in the attached Schedule 10 (DAC Rate-Eastlake #1), the total DAC Rate for Eastlake #1, including the Applicable Adder, effective September 1, 2012 is $188.34/MW-day.

IV. MARKET COMMITMENTS

FE Genco agrees to offer Eastlake #1 every day in which the unit is available into the day-ahead energy market at its cost-based offer price. To the extent that Eastlake #1 does not already have a capacity commitment, FE Genco agrees to offer Eastlake #1's capacity into every Reliability Pricing Model Incremental Auction at a price of zero dollars.

[2] The APIR component varies for each year that Lake Shore continues to be in service. *See* Schedule 8 (APIR-Eastlake #1).

V. CONCLUSION

Pursuant to Section 116 of the Tariff, FirstEnergy has provided a copy of this informational filing to PJM. Please do not hesitate to contact the undersigned if you have any questions regarding this informational filing.

Respectfully submitted,

/s/ Natasha Gianvecchio

David L. Schwartz
Natasha Gianvecchio
Tyler Brown
Latham & Watkins LLP
555 Eleventh Street, NW
Suite 1000
Washington, DC 20004
Tel: (202) 637-2200

cc: PJM Interconnection, L.L.C.

Enclosures

July 10, 2012

Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: Informational Filing regarding Deactivation Avoidable Cost (DAC) Rate under Section 116 of the PJM Interconnection, L.L.C.'s Open Access Transmission Tariff

Dear Secretary Bose:

Pursuant to Section 116 of the PJM Interconnection, L.L.C. ("PJM") Open Access Transmission Tariff ("Tariff"), FirstEnergy Service Company ("FirstEnergy") hereby submits to the Federal Energy Regulatory Commission ("FERC" or the "Commission"), on behalf of FirstEnergy Generation Corporation ("FE Genco"), for informational purposes, FE Genco's Deactivation Avoidable Cost ("DAC") Rate with respect to Eastlake generating unit number 2 located in Eastlake, Ohio with an installed nameplate capacity of 132 MW ("Eastlake #2").

I. BACKGROUND

FE Genco is the owner of Eastlake #2. In accordance with Section 113.1 of the Tariff, on January 26, 2012, FirstEnergy, on behalf of FE Genco, submitted a letter to PJM notifying PJM of FE Genco's intent to deactivate Eastlake #2 (as well as certain other generating units owned by FE Genco), effective as of September 1, 2012 ("Deactivation Notice"), which is attached hereto as Attachment 1.

Pursuant to Section 113.2 of the Tariff, PJM notified FirstEnergy, by letter dated February 24, 2012, that the deactivation of Eastlake #2 (as well as the certain other generating units referenced in the Deactivation Notice) would adversely affect the PJM transmission system absent the installation of certain transmission upgrades ("Reliability Impact Letter"), which is attached hereto as Attachment 2. In the Reliability Impact Letter, PJM provided FirstEnergy with a list of specific reliability impacts and an initial estimated date of June 2016 to complete the necessary transmission system reliability upgrades necessary to alleviate those reliability impacts.

component for Eastlake #2 effective September 1, 2012 is $1,666,994, which corresponds to $41.90/MW-day.

AVE

The AVE component of the DAC Rate consists of avoidable variable expenses, including: (1) water treatment chemicals and lubricants; (2) water, gas and electric service (not for power generation); and (3) waste water treatment. As demonstrated in the attached Schedule 4 (AVE-Eastlake #2), the total AVE component for Eastlake #2 effective September 1, 2012 is $241,160, which corresponds to $6.06/MW-day.

ATFI

The ATFI component of the DAC Rate consists of the following avoidable expenses: (1) insurance; (2) permits and licensing fees; (3) site security and utilities for maintaining security at the site; and (4) property taxes. As demonstrated in the attached Schedule 5 (ATFI-Eastlake #2), the total ATFI component for Eastlake #2 effective September 1, 2012 is $613,746, which corresponds to $15.43/MW-day.

ACC

The ACC component of the DAC Rate consists of avoidable short term carrying charges for maintaining reasonable levels of inventories of fuel and spare parts that result from short-term operational unit decisions as measured by industry best practice standards. For the purpose of determining ACC, short term is the time period in which a reasonable replacement of inventory for normal, expected operations can occur. As demonstrated in the attached Schedule 6 (ACC-Eastlake #2), the total ACC component for Eastlake #2 effective September 1, 2012 is $61,194, which corresponds to $1.54/MW-day.

ACLE

The ACLE component of the DAC Rate consists of avoidable corporate level expenses, including only such expenses that are directly linked to providing tangible services required for the operation of the generating unit, such as legal services, environmental reporting and procurement expenses. As demonstrated in the attached Schedule 7 (ACLE-Eastlake #2), the total ACLE component for Eastlake #2 effective September 1, 2012 is $80,531, which corresponds to $2.02/MW-day.

APIR

The APIR component of the DAC Rate is calculated by dividing the project investment costs necessary to keep the generating unit operating beyond its deactivation dates by the number of months beyond the deactivation date that the generating unit will be required to operate. The amount recovered under the APIR cannot exceed the actual project investment and is limited to $2 million. As demonstrated in the attached Schedule 8 (APIR-Eastlake #2), the APIR

component for Eastlake #2 effective September 1, 2012 is $6,563. The APIR component effective from September 1, 2012 through August 31, 2013 is $0.39/MW-day.[2]

Applicable Adder

Pursuant to Section 114 of the Tariff, a generating unit also receives an adder to the DAC Rate (the "Applicable Adder"), which is intended to increase compensation for the generating unit the longer it is required to run, thus providing additional return if the operating period is extended. The Applicable Adder also serves as an incentive to loads to take actions to avoid the need for the generating unit. In accordance with Section 114, Eastlake #2 will receive a 15% Applicable Adder effective September 1, 2012 for the 12 months thereafter for providing PJM with 219 days' notice of deactivation. As set forth in Section 114, the Applicable Adder for the second year shall be 20% of the DAC Rate, the Applicable Adder for the third year shall be 35% of the DAC Rate and the Applicable Adder for the fourth year shall be 50% of the DAC Rate. As demonstrated in the attached Schedule 9 (Adder-Eastlake #2), the total Applicable Adder for Eastlake #2 effective September 1, 2012 and for the 12 months thereafter is equal to $23.79/MW-day.

Total DAC Rate

As demonstrated in the attached Schedule 10 (DAC Rate-Eastlake #2), the total DAC Rate for Eastlake #2 effective September 1, 2012 is $158.57/MW-day. Also as demonstrated in the attached Schedule 10 (DAC Rate-Eastlake #2), the total DAC Rate for Eastlake #2, including the Applicable Adder, effective September 1, 2012 is $182.35/MW-day.

IV. MARKET COMMITMENTS

FE Genco agrees to offer Eastlake #2 every day in which the unit is available into the day-ahead energy market at its cost-based offer price. To the extent that Eastlake #2 does not already have a capacity commitment, FE Genco agrees to offer Eastlake #2's capacity into every Reliability Pricing Model Incremental Auction at a price of zero dollars.

[2] The APIR component varies for each year that Lake Shore continues to be in service. *See* Schedule 8 (APIR-Eastlake #2).

V. CONCLUSION

Pursuant to Section 116 of the Tariff, FirstEnergy has provided a copy of this informational filing to PJM. Please do not hesitate to contact the undersigned if you have any questions regarding this informational filing.

Respectfully submitted,

/s/ Natasha Gianvecchio

David L. Schwartz
Natasha Gianvecchio
Tyler Brown
Latham & Watkins LLP
555 Eleventh Street, NW
Suite 1000
Washington, DC 20004
Tel: (202) 637-2200

cc: PJM Interconnection, L.L.C.

Enclosures

July 10, 2012

Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: Informational Filing regarding Deactivation Avoidable Cost (DAC) Rate under Section 116 of the PJM Interconnection, L.L.C.'s Open Access Transmission Tariff

Dear Secretary Bose:

Pursuant to Section 116 of the PJM Interconnection, L.L.C. ("PJM") Open Access Transmission Tariff ("Tariff"), FirstEnergy Service Company ("FirstEnergy") hereby submits to the Federal Energy Regulatory Commission ("FERC" or the "Commission"), on behalf of FirstEnergy Generation Corporation ("FE Genco"), for informational purposes, FE Genco's Deactivation Avoidable Cost ("DAC") Rate with respect to Eastlake generating unit number 3 located in Eastlake, Ohio with an installed nameplate capacity of 132 MW ("Eastlake #3").

I. BACKGROUND

FE Genco is the owner of Eastlake #3. In accordance with Section 113.1 of the Tariff, on January 26, 2012, FirstEnergy, on behalf of FE Genco, submitted a letter to PJM notifying PJM of FE Genco's intent to deactivate Eastlake #3 (as well as certain other generating units owned by FE Genco), effective as of September 1, 2012 ("Deactivation Notice"), which is attached hereto as Attachment 1.

Pursuant to Section 113.2 of the Tariff, PJM notified FirstEnergy, by letter dated February 24, 2012, that the deactivation of Eastlake #3 (as well as the certain other generating units referenced in the Deactivation Notice) would adversely affect the PJM transmission system absent the installation of certain transmission upgrades ("Reliability Impact Letter"), which is attached hereto as Attachment 2. In the Reliability Impact Letter, PJM provided FirstEnergy with a list of specific reliability impacts and an initial estimated date of June 2016 to complete the necessary transmission system reliability upgrades necessary to alleviate those reliability impacts.

component for Eastlake #3 effective September 1, 2012 is $1,678,794, which corresponds to $42.20/MW-day.

AVE

The AVE component of the DAC Rate consists of avoidable variable expenses, including: (1) water treatment chemicals and lubricants; (2) water, gas and electric service (not for power generation); and (3) waste water treatment. As demonstrated in the attached Schedule 4 (AVE-Eastlake #3), the total AVE component for Eastlake #3 effective September 1, 2012 is $241,160, which corresponds to $6.06/MW-day.

ATFI

The ATFI component of the DAC Rate consists of the following avoidable expenses: (1) insurance; (2) permits and licensing fees; (3) site security and utilities for maintaining security at the site; and (4) property taxes. As demonstrated in the attached Schedule 5 (ATFI-Eastlake #3), the total ATFI component for Eastlake #3 effective September 1, 2012 is $605,359, which corresponds to $15.22/MW-day.

ACC

The ACC component of the DAC Rate consists of avoidable short term carrying charges for maintaining reasonable levels of inventories of fuel and spare parts that result from short-term operational unit decisions as measured by industry best practice standards. For the purpose of determining ACC, short term is the time period in which a reasonable replacement of inventory for normal, expected operations can occur. As demonstrated in the attached Schedule 6 (ACC-Eastlake #3), the total ACC component for Eastlake #3 effective September 1, 2012 is $61,194, which corresponds to $1.54/MW-day.

ACLE

The ACLE component of the DAC Rate consists of avoidable corporate level expenses, including only such expenses that are directly linked to providing tangible services required for the operation of the generating unit, such as legal services, environmental reporting and procurement expenses. As demonstrated in the attached Schedule 7 (ACLE-Eastlake #3), the total ACLE component for Eastlake #3 effective September 1, 2012 is $80,531, which corresponds to $2.02/MW-day.

APIR

The APIR component of the DAC Rate is calculated by dividing the project investment costs necessary to keep the generating unit operating beyond its deactivation dates by the number of months beyond the deactivation date that the generating unit will be required to operate. The amount recovered under the APIR cannot exceed the actual project investment and is limited to $2 million. As demonstrated in the attached Schedule 8 (APIR-Eastlake #3), the APIR

component for Eastlake #3 effective September 1, 2012 is $6,563. The APIR component effective from September 1, 2012 through August 31, 2013 is $0.39/MW-day.[2]

Applicable Adder

Pursuant to Section 114 of the Tariff, a generating unit also receives an adder to the DAC Rate (the "Applicable Adder"), which is intended to increase compensation for the generating unit the longer it is required to run, thus providing additional return if the operating period is extended. The Applicable Adder also serves as an incentive to loads to take actions to avoid the need for the generating unit. In accordance with Section 114, Eastlake #3 will receive a 15% Applicable Adder effective September 1, 2012 for the 12 months thereafter for providing PJM with 219 days' notice of deactivation. As set forth in Section 114, the Applicable Adder for the second year shall be 20% of the DAC Rate, the Applicable Adder for the third year shall be 35% of the DAC Rate and the Applicable Adder for the fourth year shall be 50% of the DAC Rate. As demonstrated in the attached Schedule 9 (Adder-Eastlake #3), the total Applicable Adder for Eastlake #3 effective September 1, 2012 and for the 12 months thereafter is equal to $23.80/MW-day.

Total DAC Rate

As demonstrated in the attached Schedule 10 (DAC Rate-Eastlake #3), the total DAC Rate for Eastlake #3 effective September 1, 2012 is $158.65/MW-day. Also as demonstrated in the attached Schedule 10 (DAC Rate-Eastlake #3), the total DAC Rate for Eastlake #3, including the Applicable Adder, effective September 1, 2012 is $182.45/MW-day.

IV. MARKET COMMITMENTS

FE Genco agrees to offer Eastlake #3 every day in which the unit is available into the day-ahead energy market at its cost-based offer price. To the extent that Eastlake #3 does not already have a capacity commitment, FE Genco agrees to offer Eastlake #3's capacity into every Reliability Pricing Model Incremental Auction at a price of zero dollars.

[2] The APIR component varies for each year that Lake Shore continues to be in service. *See* Schedule 8 (APIR-Eastlake #3).

V. CONCLUSION

Pursuant to Section 116 of the Tariff, FirstEnergy has provided a copy of this informational filing to PJM. Please do not hesitate to contact the undersigned if you have any questions regarding this informational filing.

Respectfully submitted,

/s/ Natasha Gianvecchio

David L. Schwartz
Natasha Gianvecchio
Tyler Brown
Latham & Watkins LLP
555 Eleventh Street, NW
Suite 1000
Washington, DC 20004
Tel: (202) 637-2200

cc: PJM Interconnection, L.L.C.

Enclosures

July 10, 2012

Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: Informational Filing regarding Deactivation Avoidable Cost (DAC) Rate under Section 116 of the PJM Interconnection, L.L.C.'s Open Access Transmission Tariff

Dear Secretary Bose:

Pursuant to Section 116 of the PJM Interconnection, L.L.C. ("PJM") Open Access Transmission Tariff ("Tariff"), FirstEnergy Service Company ("FirstEnergy") hereby submits to the Federal Energy Regulatory Commission ("FERC" or the "Commission"), on behalf of FirstEnergy Generation Corporation ("FE Genco"), for informational purposes, FE Genco's Deactivation Avoidable Cost ("DAC") Rate with respect to Ashtabula generating unit number 5 located in Ashtabula, Ohio with an installed nameplate capacity of 244 MW ("Ashtabula").

I. BACKGROUND

FE Genco is the owner of Ashtabula. In accordance with Section 113.1 of the Tariff, on January 26, 2012, FirstEnergy, on behalf of FE Genco, submitted a letter to PJM notifying PJM of FE Genco's intent to deactivate Ashtabula (as well as certain other generating units owned by FE Genco), effective as of September 1, 2012 ("Deactivation Notice"), which is attached hereto as Attachment 1.

Pursuant to Section 113.2 of the Tariff, PJM notified FirstEnergy, by letter dated February 24, 2012, that the deactivation of Ashtabula (as well as the certain other generating units referenced in the Deactivation Notice) would adversely affect the PJM transmission system absent the installation of certain transmission upgrades ("Reliability Impact Letter"), which is attached hereto as Attachment 2. In the Reliability Impact Letter, PJM provided FirstEnergy with a list of specific reliability impacts and an initial estimated date of June 2016 to complete the necessary transmission system reliability upgrades necessary to alleviate those reliability impacts.

component for Ashtabula effective September 1, 2012 is $1,816,021, which corresponds to $23.69/MW-day.

AVE

The AVE component of the DAC Rate consists of avoidable variable expenses, including: (1) water treatment chemicals and lubricants; (2) water, gas and electric service (not for power generation); and (3) waste water treatment. As demonstrated in the attached Schedule 4 (AVE-Ashtabula), the total AVE component for Ashtabula effective September 1, 2012 is $663,198, which corresponds to $8.65/MW-day.

ATFI

The ATFI component of the DAC Rate consists of the following avoidable expenses: (1) insurance; (2) permits and licensing fees; (3) site security and utilities for maintaining security at the site; and (4) property taxes. As demonstrated in the attached Schedule 5 (ATFI-Ashtabula), the total ATFI component for Ashtabula effective September 1, 2012 is $1,137,267, which corresponds to $14.84/MW-day.

ACC

The ACC component of the DAC Rate consists of avoidable short term carrying charges for maintaining reasonable levels of inventories of fuel and spare parts that result from short-term operational unit decisions as measured by industry best practice standards. For the purpose of determining ACC, short term is the time period in which a reasonable replacement of inventory for normal, expected operations can occur. As demonstrated in the attached Schedule 6 (ACC-Ashtabula), the total ACC component for Ashtabula effective September 1, 2012 is $161,915, which corresponds to $2.11/MW-day.

ACLE

The ACLE component of the DAC Rate consists of avoidable corporate level expenses, including only such expenses that are directly linked to providing tangible services required for the operation of the generating unit, such as legal services, environmental reporting and procurement expenses. As demonstrated in the attached Schedule 7 (ACLE-Ashtabula), the total ACLE component for Ashtabula effective September 1, 2012 is $98,799, which corresponds to $1.29/MW-day.

APIR

The APIR component of the DAC Rate is calculated by dividing the project investment costs necessary to keep the generating unit operating beyond its deactivation dates by the number of months beyond the deactivation date that the generating unit will be required to operate. The amount recovered under the APIR cannot exceed the actual project investment and is limited to $2 million. As demonstrated in the attached Schedule 8 (APIR-Ashtabula), the APIR component for Ashtabula effective September 1, 2012 is $24,375. The APIR component effective from September 1, 2012 through August 31, 2013 is $1.91/MW-day.[2]

Applicable Adder

Pursuant to Section 114 of the Tariff, a generating unit also receives an adder to the DAC Rate (the "Applicable Adder"), which is intended to increase compensation for the generating unit the longer it is required to run, thus providing additional return if the operating period is extended. The Applicable Adder also serves as an incentive to loads to take actions to avoid the need for the generating unit. In accordance with Section 114, Ashtabula will receive a 15% Applicable Adder effective September 1, 2012 for the 12 months thereafter for providing PJM with 219 days' notice of deactivation. As set forth in Section 114, the Applicable Adder for the second year shall be 20% of the DAC Rate, the Applicable Adder for the third year shall be 35% of the DAC Rate and the Applicable Adder for the fourth year shall be 50% of the DAC Rate. As demonstrated in the attached Schedule 9 (Adder-Ashtabula), the total Applicable Adder for Ashtabula effective September 1, 2012 and for the 12 months thereafter is equal to $21.65/MW-day.

Total DAC Rate

As demonstrated in the attached Schedule 10 (DAC Rate-Ashtabula), the total DAC Rate for Ashtabula effective September 1, 2012 is $144.32/MW-day. Also as demonstrated in the attached Schedule 10 (DAC Rate-Ashtabula), the total DAC Rate for Ashtabula, including the Applicable Adder, effective September 1, 2012 is $165.96/MW-day.

IV. MARKET COMMITMENTS

FE Genco agrees to offer Ashtabula every day in which the unit is available into the day-ahead energy market at its cost-based offer price. To the extent that Ashtabula does not already have a capacity commitment, FE Genco agrees to offer Ashtabula's capacity into every Reliability Pricing Model Incremental Auction at a price of zero dollars

[2] The APIR component varies for each year that Ashtabula continues to be in service. *See* Schedule 8 (APIR-Ashtabula).

V. CONCLUSION

Pursuant to Section 116 of the Tariff, FirstEnergy has provided a copy of this informational filing to PJM. Please do not hesitate to contact the undersigned if you have any questions regarding this informational filing.

Respectfully submitted,

/s/ Natasha Gianvecchio

David L. Schwartz
Natasha Gianvecchio
Tyler Brown
Latham & Watkins LLP
555 Eleventh Street, NW
Suite 1000
Washington, DC 20004
Tel: (202) 637-2200

cc: PJM Interconnection, L.L.C.

Enclosures

July 10, 2012

Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: Informational Filing regarding Deactivation Avoidable Cost (DAC) Rate under Section 116 of the PJM Interconnection, L.L.C.'s Open Access Transmission Tariff

Dear Secretary Bose:

Pursuant to Section 116 of the PJM Interconnection, L.L.C. ("PJM") Open Access Transmission Tariff ("Tariff"), FirstEnergy Service Company ("FirstEnergy") hereby submits to the Federal Energy Regulatory Commission ("FERC" or the "Commission"), on behalf of FirstEnergy Generation Corporation ("FE Genco"), for informational purposes, FE Genco's Deactivation Avoidable Cost ("DAC") Rate with respect to Lake Shore generating unit number 18 located in Cleveland, Ohio with an installed nameplate capacity of 245 MW ("Lake Shore").

I. BACKGROUND

FE Genco is the owner of Lake Shore. In accordance with Section 113.1 of the Tariff, on January 26, 2012, FirstEnergy, on behalf of FE Genco, submitted a letter to PJM notifying PJM of FE Genco's intent to deactivate Lake Shore (as well as certain other generating units owned by FE Genco), effective as of September 1, 2012 ("Deactivation Notice"), which is attached hereto as Attachment 1.

Pursuant to Section 113.2 of the Tariff, PJM notified FirstEnergy, by letter dated February 24, 2012, that the deactivation of Lake Shore (as well as the certain other generating units referenced in the Deactivation Notice) would adversely affect the PJM transmission system absent the installation of certain transmission upgrades ("Reliability Impact Letter"), which is attached hereto as Attachment 2. In the Reliability Impact Letter, PJM provided FirstEnergy with a list of specific reliability impacts and an initial estimated date of June 2016 to complete the necessary transmission system reliability upgrades necessary to alleviate those reliability impacts.

component for Lake Shore effective September 1, 2012 is $2,497,135, which corresponds to $36.01/MW-day.

AVE

The AVE component of the DAC Rate consists of avoidable variable expenses, including: (1) water treatment chemicals and lubricants; (2) water, gas and electric service (not for power generation); and (3) waste water treatment. As demonstrated in the attached Schedule 4 (AVE-Lake Shore), the total AVE component for Lake Shore effective September 1, 2012 is $680,120, which corresponds to $9.81/MW-day.

ATFI

The ATFI component of the DAC Rate consists of the following avoidable expenses: (1) insurance; (2) permits and licensing fees; (3) site security and utilities for maintaining security at the site; and (4) property taxes. As demonstrated in the attached Schedule 5 (ATFI-Lake Shore), the total ATFI component for Lake Shore effective September 1, 2012 is $1,322,842, which corresponds to $19.07/MW-day.

ACC

The ACC component of the DAC Rate consists of avoidable short term carrying charges for maintaining reasonable levels of inventories of fuel and spare parts that result from short-term operational unit decisions as measured by industry best practice standards. For the purpose of determining ACC, short term is the time period in which a reasonable replacement of inventory for normal, expected operations can occur. As demonstrated in the attached Schedule 6 (ACC-Lake Shore), the total ACC component for Lake Shore effective September 1, 2012 is $122,323, which corresponds to $1.76/MW-day.

ACLE

The ACLE component of the DAC Rate consists of avoidable corporate level expenses, including only such expenses that are directly linked to providing tangible services required for the operation of the generating unit, such as legal services, environmental reporting and procurement expenses. As demonstrated in the attached Schedule 7 (ACLE-Lake Shore), the total ACLE component for Lake Shore effective September 1, 2012 is $82,511, which corresponds to $1.19/MW-day.

APIR

The APIR component of the DAC Rate is calculated by dividing the project investment costs necessary to keep the generating unit operating beyond its deactivation dates by the number of months beyond the deactivation date that the generating unit will be required to operate. The amount recovered under the APIR cannot exceed the actual project investment and is limited to $2 million. As demonstrated in the attached Schedule 8 (APIR-Lake Shore), the APIR component for Lake Shore is $17,188. The APIR component effective from September 1, 2012 through August 31, 2013 is $0.54/MW-day.[2]

Applicable Adder

Pursuant to Section 114 of the Tariff, a generating unit also receives an adder to the DAC Rate (the "Applicable Adder"), which is intended to increase compensation for the generating unit the longer it is required to run, thus providing additional return if the operating period is extended. The Applicable Adder also serves as an incentive to loads to take actions to avoid the need for the generating unit. In accordance with Section 114, Lake Shore will receive a 15% Applicable Adder effective September 1, 2012 for the 12 months thereafter for providing PJM with 219 days' notice of deactivation. As set forth in Section 114, the Applicable Adder for the second year shall be 20% of the DAC Rate, the Applicable Adder for the third year shall be 35% of the DAC Rate and the Applicable Adder for the fourth year shall be 50% of the DAC Rate. As demonstrated in the attached Schedule 9 (Adder-Lake Shore), the total Applicable Adder for Lake Shore effective September 1, 2012 and for the 12 months thereafter is equal to $22.95/MW-day.

Total DAC Rate

As demonstrated in the attached Schedule 10 (DAC Rate-Lake Shore), the total DAC Rate for Lake Shore effective September 1, 2012 is $152.99/MW-day. Also as demonstrated in the attached Schedule 10 (DAC Rate-Lake Shore), the total DAC Rate for Lake Shore, including the Applicable Adder, effective September 1, 2012 is $175.94/MW-day.

IV. MARKET COMMITMENTS

FE Genco agrees to offer Lake Shore every day in which the unit is available into the day-ahead energy market at its cost-based offer price. To the extent that Lake Shore does not already have a capacity commitment, FE Genco agrees to offer Lake Shore's capacity into every Reliability Pricing Model Incremental Auction at a price of zero dollars.

[2] The APIR component varies for each year that Lake Shore continues to be in service. *See* Schedule 8 (APIR-Lake Shore).

V. CONCLUSION

Pursuant to Section 116 of the Tariff, FirstEnergy has provided a copy of this informational filing to PJM. Please do not hesitate to contact the undersigned if you have any questions regarding this informational filing.

Respectfully submitted,

/s/ Natasha Gianvecchio

David L. Schwartz
Natasha Gianvecchio
Tyler Brown
Latham & Watkins LLP
555 Eleventh Street, NW
Suite 1000
Washington, DC 20004

cc: PJM Interconnection, L.L.C.

Enclosures

KING & SPALDING

King & Spalding LLP
1700 Pennsylvania Avenue, N.W.
Washington, D.C. 20006 4706
www.kslaw.com

Bruce L. Richardson
Direct Dial: (202) 626 5510
Direct Fax : (202) 626 3737
brichardson@kslaw.com

May 8, 2013

VIA EFILING

Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

RE: GenOn Power Midwest, LP, Docket No. ER12-1901-000
Settlement Agreement and Offer of Settlement

Dear Secretary Bose:

Pursuant to Rule 602 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission (the "Commission"), 18 C.F.R. § 385.602 (2012), enclosed are a Settlement Agreement and Offer of Settlement ("Settlement Agreement") and accompanying documents, which are proposed to resolve all issues set for hearing in the above-referenced docket. This Settlement Agreement is submitted on behalf of: GenOn Power Midwest, LP ("GenOn Midwest"), Duquesne Light Company, Duquesne Light Energy, LLC, FirstEnergy Solutions Corp., Duquesne Industrial Intervenors, PJM Industrial Customer Coalition, West Penn Power Industrial Intervenors, and Old Dominion Electric Cooperative (collectively, "Settling Parties"). As set forth in the accompanying documents, additional parties have advised that they do not oppose resolution of this proceeding on the terms set forth in the Settlement Agreement.

The Settling Parties submit that the Settlement Agreement resolves all issues relating to Docket No. ER12-1901-000 without the need for an evidentiary hearing or any further proceedings regarding those issues. The Settling Parties further assert that the Settlement Agreement is in the public interest, and respectfully request that the Commission approve the Settlement Agreement without material change or condition and accept for filing GenOn Midwest's revised Reliability Must-Run Rate Schedule, Electric Rate Schedule FERC No. 3 ("Revised RMR Rate Schedule") effective as of June 1, 2012.

Pursuant to Rule 602(f)(2), 18 C.F.R. § 385.602(f)(2) (2012), initial comments on the Settlement Agreement must be filed with the Secretary no later than May 28, 2013, twenty (20) days after this filing, with reply comments to be filed with the Secretary no later than June 7, 2013, thirty (30) days after the filing of the Settlement Agreement.

GENON POWER MIDWEST, LP

Electric Rate Schedule FERC No. 3

Reliability Must-Run Rate Schedule

Pursuant to the rates, terms, and conditions of this Reliability Must-Run Rate Schedule ("Rate Schedule"), GenOn Power Midwest, LP ("GenOn Midwest"), will own, operate, and maintain Elrama Unit 4 and Niles Unit 1 for the purpose of facilitating the reliable operation of the PJM Transmission System.

I. DEFINITIONS

1.1 "Elrama Unit 4" shall mean Unit 4 of the Elrama Generating Station.

1.2 "FERC" shall mean the Federal Energy Regulatory Commission or its successor.

1.3 "Niles Unit 1" shall mean Unit 1 of the Niles Generating Station.

1.4 "PJM" shall mean PJM Interconnection, L.L.C.

1.5 "PJM Tariff" shall mean the Open Access Transmission Tariff of PJM Interconnection, L.L.C.

1.6 "Settlement Agreement and Offer of Settlement" shall mean that Settlement Agreement and Offer of Settlement filed with the FERC in *GenOn Power Midwest, LP,* Docket No. ER12-1901-000, on May 8, 2013, to resolve all issues that had been set for hearing in that proceeding.

II. TERM

2.1. Effective Date

This Rate Schedule shall become effective June 1, 2012.

2.2. Term of Rate Schedule

This Rate Schedule shall terminate with respect to Elrama Unit 4 on September 30, 2012, and shall terminate with respect to Niles Unit 1 on September 30, 2012.

III. OBLIGATIONS

3.1. Application of PJM Governing Documents

(a) Subject to the Unit operating limitations identified in Section 3.4, PJM shall dispatch the Units, and GenOn Midwest shall operate and maintain the Units, in a manner consistent with their respective obligations under the PJM Governing Documents with respect to the dispatch, ownership, operation, and maintenance of generating facilities.

(b) GenOn Midwest's operation of the Units consistent with the terms and conditions of this Rate Schedule shall not be deemed inconsistent with the performance obligations identified in Section 121 of the PJM Tariff.

3.2. Dispatch of the Units

Subject to the Unit operating limitations identified in Section 3.4, PJM may dispatch either or both Units.

3.3. Operation of the Units

(a) Subject to the Unit operating limitations identified in Section 3.4, GenOn Midwest shall operate either or both Units upon receipt of a dispatch notice issued by PJM. GenOn Midwest does not guarantee that such Unit(s) will start or operate at its rated capacity, and GenOn Midwest does not guarantee the availability of the Units in response to a PJM dispatch notice.

(b) In its sole discretion, GenOn Midwest shall not be obligated to cause Elrama Unit 4 and/or Niles Unit 1 to be operated in a manner that will cause GenOn Midwest to violate the terms of any environmental restrictions or any operating permit limitations.

(c) PJM shall not issue a dispatch notice to GenOn Midwest for operation of a Unit during periods when a Unit is unavailable due to an Outage, provided that GenOn Midwest shall notify PJM of Unit Outages consistent with the PJM Governing Documents.

(d) GenOn Midwest, with advance notice to PJM, may self-schedule a Unit under limited circumstances where PJM's dispatch of a Unit will not allow necessary operational activities to occur. These activities generally include, but are not limited to, scheduling a Unit to conduct mandatory compliance testing or diagnostic evaluations performed to maintain a Unit's ability to operate.

3.4 Operating Restrictions

(a) Cost-Based Parameter Limited Schedules:

The Units shall be subject to the following pre-determined limits on the offer parameters for their cost-based schedules:

Parameters	**Elrama Unit 4**	**Niles Unit 1**
Minimum Down Time (Hrs)	9	5
Minimum Run Time (Hrs)	15	14

Maximum Daily Starts	1	2
Maximum Weekly Starts	5	5
Turn Down Ratio = Economic Maximum MW / Economic Minimum MW	3.2	2.16

To the extent a Unit experiences a physical operational limitation that prevents the resource from meeting the parameters listed above, GenOn Midwest will modify the parameters to reflect the limitations. To the extent that the Unit is not able to comply with the minimum parameters set forth in Section 6.6 of Schedule 1 of the PJM Operating Agreement, GenOn Midwest will seek an exception to those minimum parameters consistent with the process set forth in Section 6.6 of Schedule 1 of the PJM Operating Agreement.

(b) To the extent that Niles Unit 1 offers Regulation and/or Synchronized Reserve Service, the parameters for those offers will comply with the PJM Governing Documents.

(c) For the avoidance of doubt, both Elrama Unit 4 and Niles Unit 1 will continue to comply with the operating requirements of their currently effective Interconnection Agreements with PJM and their respective Interconnecting Transmission Owner, Duquesne Light and FirstEnergy/American Transmission Systems, Inc.

IV. RATE

4.1 Charges

Pursuant to the Settlement Agreement and Offer of Settlement, the rate for RMR Service during the Term shall be $13,200,000.

V. STANDARD OF REVIEW

5.1 Standard of Review

The standard of review for changes to any rate, charge, classification, term or condition of this Rate Schedule, whether proposed by PJM, any party with standing under Federal Power Act § 206, or FERC acting *sua sponte,* shall solely be the most stringent standard of review set forth in United Gas Pipe Line Co. v. Mobile Gas Service Corp., 350 U.S. 332 (1956) and Federal Power Commission v. Sierra Pacific Power Co., 350 U.S. 348 (1956) and clarified by Morgan Stanley Capital Group, Inc. v. Public Util. Dist. No. 1 of Snohomish, 554 U.S. 527, 128 S. Ct. 2733 (2008) and NRG Power Marketing, LLC, et al. v. Maine Public Utilities Commission, 558 U.S. _____, 130 S.Ct. 693 (2010).

Morgan, Lewis & Bockius LLP
1111 Pennsylvania Avenue, NW
Washington, DC 20004
Tel. 202.739.3000
Fax: 202.739.3001
www.morganlewis.com

Morgan Lewis
COUNSELORS AT LAW

Michael C. Griffen
(202) 739 5257
mgriffen@morganlewis.com

February 11, 2010

VIA eFILING

Hon. Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

RE: Exelon Generation Company, LLC
Docket No. ER10-1418-

Dear Ms. Bose:

Exelon Generation Company, LLC ("Exelon Generation"), submits for filing with the Federal Energy Regulatory Commission ("FERC") in the captioned docket a Settlement Agreement and Explanatory Statement in Support of Settlement Agreement.[1] The unopposed Settlement Agreement resolves all issues raised in response to Exelon Generation's rate filing in this proceeding. Exelon Generation requests FERC to approve the Settlement Agreement.

On June 10, 2010, Exelon Generation submitted for filing with FERC a proposed Reliability Must Run Rate Schedule ("RMR Rate Schedule") that will govern the operation of two generating units in southeastern Pennsylvania for reliability must-run purposes: Cromby Unit No. 2 (which includes the Cromby Diesel) and Eddystone Unit No. 2 ("RMR Units"). PJM Interconnection, L.L.C. ("PJM") has determined that the RMR Units will be needed past the date of their planned deactivation to maintain transmission system reliability pending the completion of scheduled upgrades to the transmission system. The RMR Rate Schedule sets forth the terms, conditions, and rates under which Exelon Generation will continue to operate the RMR Units for reliability purposes beyond their planned May 31, 2011, deactivation date.

Motions to intervene were filed by Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor for PJM ("Market Monitor"); New Jersey Division of Rate Counsel ("NJ Rate Counsel"); Philadelphia Area Industrial Energy Users Group ("PAIEUG");

1. Exelon Generation submits the Settlement Agreement pursuant to Rule 602 of FERC's Rules of Practice and Procedure, 18 C.F.R. § 385.602.

2.2. Term of Rate Schedule

Unless terminated early by Exelon Generation as provided in this Article 2 or extended, this Rate Schedule shall terminate with respect to Cromby Unit No. 2 on December 31, 2011, and shall terminate with respect to Eddystone Unit No. 2 on May 31, 2012.

2.3. Termination

(a) Exelon Generation may terminate this Rate Schedule with respect to either or both Units consistent with the requirements of Section 113.3 of the PJM Tariff if any of the following events or circumstances materially and adversely affects Exelon Generation's ability to recover its costs of operating a Unit or the Units, as identified in this Rate Schedule, during the Term: (1) a change in law or regulation; (2) a change to the PJM Tariff or other PJM policy or rule; or (3) an order of FERC or a court on a complaint or other action initiated by a third party.

(b) Exelon Generation shall terminate this Rate Schedule upon request by PJM, with respect to either or both Units, upon PJM giving at least ninety (90) days written notice to Exelon Generation of such a request. Exelon Generation shall notify the parties in Docket No. ER10-1418 and the FERC of any new or updated request of PJM, with respect to either or both Units, within five (5) business days of receiving such written notice from PJM.

(c) This Rate Schedule shall terminate with respect to a Unit ninety (90) days after the Unit becomes inoperable if PJM provides, or is deemed to have provided, Exelon Generation with the notice required under Section 5.2(J) declining to approve a Project Investment and the Unit is unable to continue operating without such Project Investment. Within five (5) days after Exelon Generation receives, or is deemed to have received, notice that PJM has declined to approve a Project Investment under Section 5.2(J), Exelon Generation shall provide written notice to PJM, the parties in Docket No. ER10-1418, and FERC of the termination of this Rate Schedule with respect to the inoperable Unit.

(d) If this Rate Schedule terminates with respect to either Unit, it shall remain in effect with respect to the other Unit. If this Rate Schedule terminates with respect to both Units, then it shall terminate in its entirety.

(e) Notwithstanding the above provisions, if a Unit continues to operate after the completion date of the necessary Transmission System reliability upgrades that would alleviate the reliability impact resulting from the deactivation of such Unit, as determined by PJM, or the date that PJM otherwise determines, in accordance with established reliability criteria, that the continued operation of such Unit is no longer necessary for the reliability of the Transmission System, this Rate Schedule shall not terminate until the obligations established in Section 5.3 of this Rate Schedule have been fully satisfied.

2.4. Survival of Obligations

(a) If this Rate Schedule is terminated early with respect to one or both Units prior to the termination dates identified in Section 2.2 and Exelon Generation has not yet recovered all its costs of operating such Unit or Units under the Cost of Service Recovery Rate, which costs were incurred before the termination date of this Rate Schedule with respect to the Unit or Units, Exelon Generation shall be entitled to recover all such unrecovered costs in accordance with this Rate Schedule with respect to the relevant Unit or Units.

(b) Expiration or termination of this Rate Schedule shall not affect Exelon Generation's or PJM's accrued rights and obligations arising during the Term, including either party's obligation to make all payments to the other.

2.5. FERC Filings

(a) Pursuant to Section 119 of the PJM Tariff, Exelon Generation shall file this Rate Schedule with FERC. Exelon Generation shall request FERC to accept the Rate Schedule effective as of June 1, 2011.

(b) If this Rate Schedule terminates with respect to a Unit pursuant to Section 2.3, Exelon Generation shall file appropriate amendments to this Rate Schedule with FERC reflecting its termination with respect to that Unit.

III. OBLIGATIONS

3.1. Application of PJM Governing Documents

(a) Subject to the Unit operating limitations identified in the Consent Decree and the PJM Operating Procedures, PJM shall dispatch the Units, and Exelon Generation shall operate and maintain the Units, in a manner consistent with their respective obligations under the PJM Governing Documents with respect to the dispatch, ownership, operation, and maintenance of generating facilities.

(b) Exelon Generation's operation of the Units consistent with the terms and conditions of this Rate Schedule shall not be deemed inconsistent with the performance obligations identified in Section 121 of the PJM Tariff.

3.2. Dispatch of the Units

(a) Subject to the Unit operating limitations identified in the Consent Decree and the PJM Operating Procedures, PJM may dispatch either or both Units in accordance with the PJM Operating Procedures. At no time may PJM dispatch either Unit on the basis of economic considerations.

(b) PJM shall designate Cromby Unit No. 2 and Eddystone Unit No. 2 in its dispatch tools and resources as unavailable for economic dispatch.

3.3. Operation of the Units

(a) Subject to the Unit operating limitations identified in the Consent Decree and the PJM Operating Procedures, Exelon Generation shall operate either or both Units upon receipt of a dispatch notice issued by PJM consistent with the PJM Operating Procedures. Exelon Generation does not guarantee that such Unit(s) will start or operate at its rated capacity, and Exelon Generation does not guarantee the availability of the Units in response to a PJM dispatch notice.

(b) In its sole discretion, Exelon Generation shall not be obligated to cause Cromby Unit No. 2 and/or Eddystone Unit No. 2 to be operated in a manner that will cause Exelon Generation to violate the terms of the Consent Decree with respect to either Unit. Exelon Generation's operation of a Unit in response to a PJM dispatch notice that causes it to violate the Consent Decree shall not serve as a waiver of any of Exelon Generation's rights under this Rate Schedule, including but not limited to its indemnification rights, or the PJM Governing Documents.

(c) PJM shall not issue a dispatch notice to Exelon Generation for operation of a Unit during periods when a Unit is unavailable due to an outage, provided that Exelon Generation shall notify PJM of scheduled and unscheduled outages of the Units consistent with the PJM Governing Documents.

IV. MARKET OPERATIONS

4.1. No Obligation to Offer Units into Markets

(a) The Units shall not be subject to an offer requirement under Attachment DD of the PJM Tariff. Pursuant to Attachment DD and Attachment M-Appendix, of the PJM Tariff, the Units shall be deemed to be physically unable to participate in PJM Reliability Pricing Model auctions for base or incremental capacity and therefore shall not be qualified as Capacity Resources or Generating Capacity Resources under the PJM Reliability Assurance Agreement or Attachment DD of the PJM Tariff because (a) Exelon Generation has notified PJM that it intended to retire the Units but agreed to continue to operate the units for reliability purposes at PJM's request, and (b) they are subject to the Consent Decree.

(b) Exelon Generation shall not offer either Unit into any market administered by PJM, including, but not limited to, PJM markets for the sale of capacity, energy, ancillary services, or any other product. For the avoidance of doubt, the Units have not cleared in a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff, and therefore consistent with Section 1.10.1A(d) of Schedule 1 of the PJM Operating Agreement and the parallel provisions of Attachment K-Appendix of the PJM Tariff, Exelon Generation shall not be obligated to offer the Units into the PJM markets.

V. COST OF SERVICE RECOVERY RATE

Pursuant to Section 119 of the PJM Tariff, Exelon Generation shall recover its costs of operating Cromby Unit No. 2 and Eddystone Unit No. 2 during the Term through the Cost of Service Recovery Rate identified in this Article. Exelon Generation shall recover the charges identified in Sections 5.1 and 5.5 and be reimbursed for its costs as identified in Sections 5.2 and 5.4.

Morgan, Lewis & Bockius LLP
1111 Pennsylvania Avenue, NW
Washington, DC 20004
Tel. 202.739.3000
Fax: 202.739.3001
www.morganlewis.com

Michael C. Griffen
(202) 739 5257
mgriffen@morganlewis.com

June 9, 2010

VIA eTARIFF FILING

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

RE: Exelon Generation Company, LLC
Docket No. ER10-

Dear Ms. Bose:

Exelon Corporation, on behalf of Exelon Generation Company, LLC ("Exelon Generation"), its wholly owned subsidiary, submits for filing with the Federal Energy Regulatory Commission ("FERC") its proposed Reliability Must-Run Rate Schedule ("RMR Rate Schedule").[1]

The RMR Rate Schedule will govern the operation of two generating units in southeastern Pennsylvania for reliability must-run purposes: Cromby Unit No. 2 and Eddystone Unit No. 2 ("RMR Units"). PJM Interconnection, L.L.C. ("PJM"), has determined that the RMR Units will be needed past the date of their planned deactivation to maintain transmission system reliability pending the completion of scheduled upgrades to the transmission system. The RMR Rate Schedule sets forth the terms, conditions, and cost-based rates under which Exelon Generation will continue to operate the RMR Units for reliability purposes beyond their planned May 31, 2011, deactivation date.

Exelon Generation respectfully requests FERC to accept the RMR Rate Schedule for filing effective June 1, 2011.

---

1. Exelon Generation provides the RMR Rate Schedule as Attachment A. Exelon Generation files the RMR Rate Schedule pursuant to Section 205 of the Federal Power Act and Part 35 of FERC's regulations, 18 C.F.R. Part 35.

ATTACHMENT C

PJM Operating Procedures

EXECUTION VERSION

PJM Interconnection, L.L.C.
Exelon Generation Company, LLC

Operating Procedures for

Cromby Generating Station Unit No. 2

and

Eddystone Generating Station Unit No. 2

as Required for Reliability Purposes

May 27, 2010

Operating Procedures for Cromby Generating Station Unit No. 2 and
Eddystone Generating Station Unit No. 2 as Required for Reliability Purposes

Pursuant to Part V of the Open Access Transmission Tariff ("Tariff") of PJM Interconnection, L.L.C. ("PJM"), and subject to the terms and conditions of its Reliability Must-Run Rate Schedule on file with the Federal Energy Regulatory Commission ("FERC"), Exelon Generation Company, LLC ("Exelon Generation"), has agreed to continue to operate Unit No. 2 of its Cromby Generating Station ("Cromby Unit No. 2") and Unit No. 2 of its Eddystone Generating Station ("Eddystone Unit No. 2") after their planned deactivation date of May 31, 2011, solely for the purpose of facilitating the reliable operation of the PJM Transmission System. Exelon Generation will operate Cromby Unit No. 2 and Eddystone Unit No. 2 during the term of the Reliability Must-Run Rate Schedule as dispatched by PJM consistent with the following operating procedures developed by PJM and Exelon Generation (the "PJM Operating Procedures"). The PJM Operating Procedures (a) identify the reliability-related circumstances under which PJM may call upon Exelon Generation to operate Cromby Unit No. 2 and Eddystone Unit No. 2 during the term of the Reliability Must-Run Rate Schedule for purposes of maintaining the reliability of the PJM Transmission System, and (b) delineate the operating characteristics and parameters under which Exelon Generation may be requested to operate those Units.

1. Definitions

a. "Consent Decree" shall mean the Consent Decree entered by the Commonwealth Court of Pennsylvania on April 16, 2010, in the Matter of Commonwealth of Pennsylvania Department of Environmental Protection v. Exelon Generation Company, LLC, in Docket No. 382 M.D. 2010. A copy of the Consent Decree is attached as Appendix 1 to these PJM Operating Procedures.

b. "Deactivation Study" shall mean the Cromby Units Nos. 1 and 2 and Eddystone Units Nos. 1 and 2 Deactivation Study prepared by PJM and posted to the Generation Retirements page of PJM's website (www.pjm.com) on March 2, 2010, as updated on May 10, 2010. A copy of the May 10, 2010, Updated Deactivation Study is attached as Appendix 2 to these PJM Operating Procedures.

c. "Operating Parameters" shall mean the Unit operating parameters identified in Section 2.g of these Operating Procedures.

d. "Operating Procedures" shall mean these Operating Procedures for Cromby Generating Station Unit No. 2 and Eddystone Generating Station Unit No. 2 as required for Reliability Purposes.

e. "PJM Manuals" shall mean PJM's manuals that document PJM's administrative, planning, operating, and accounting procedures.

f. "PJM Operating Agreement" shall mean the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C.

g. "PJM RAA" shall mean the Reliability Assurance Agreement Among Load Serving Entities in the PJM Region.

h. "PJM Transmission System" shall have the meaning set forth in section 1.49 of the PJM Tariff.

i. "Reliability Must-Run Rate Schedule" shall mean the Exelon Generation rate schedule filed with FERC pursuant to which Exelon Generation will own, operate, and maintain Cromby Unit No. 2 and Eddystone Unit No. 2 for the purpose of facilitating the reliable operation of the PJM Transmission System.

j. "Reliability Purpose" shall mean the commitment of a Unit or the Units after all resources have already been committed and additional units are required to help alleviate a Transmission Security Emergency that arises from the reliability impacts identified in the Deactivation Study.

k. "Transmission Security Emergency" shall mean an event addressed in PJM Manual 13, "Emergency Operations," at Section 5, "Transmission Security Emergencies."

l. "Unit" or "Units" shall mean Cromby Unit No. 2 and/or Eddystone Unit No. 2.

m. All other capitalized terms used and not otherwise defined in these Operating Procedures have the meaning set forth in the PJM Tariff, PJM Operating Agreement and the PJM RAA.

2. Operating Procedures

a. PJM may designate Eddystone Unit No. 2 and Cromby Unit No. 2 as generating units that may be dispatched to operate subject to the Operating Parameters during periods when operation of either Unit or both Units is necessary for Reliability Purposes.

b. The Units shall not be subject to an offer requirement under Attachment DD of the PJM Tariff. Pursuant to Attachment DD and Attachment M-Appendix, of the PJM Tariff, the Units shall be deemed to be physically unable to participate in PJM Reliability Pricing Model auctions for base or incremental capacity and therefore shall not be qualified as Capacity Resources or Generating Capacity Resources under the PJM RAA or Attachment DD of the PJM Tariff because (a) Exelon Generation has notified PJM that it intended to retire the Units but agreed to continue to operate the units for Reliability Purposes at PJM's request, and (b) the Units are subject to the Consent Decree.

c. Exelon Generation shall not offer either Unit into any market administered by PJM, including, but not limited to, PJM markets for the sale of capacity, energy, ancillary services, or any other product. For the avoidance of doubt, the Units have not cleared in a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff, and therefore consistent with Section 1.10.1A(d) of Schedule 1 of the PJM Operating Agreement and the parallel provisions of Attachment K-Appendix of the PJM Tariff, Exelon Generation shall not be obligated to offer the Units into the PJM markets.

d. PJM may dispatch a Unit **only** under the following circumstances:

i. PJM may dispatch a Unit for a Reliability Purpose to facilitate the reliable operation of the PJM Transmission System when PJM anticipates that the reliability impacts identified in the Deactivation Study will exist if the Unit or Units are not operated.

ii. PJM may dispatch a Unit for a purpose other than a Reliability Purpose to facilitate the reliable operation of the PJM Transmission System when PJM anticipates such operation will help alleviate a Transmission Security Emergency that does not arise from the reliability impacts identified in the Deactivation Study and when PJM already has dispatched all other units that may help alleviate such Transmission Security Emergency, provided that PJM provides Exelon Generation written explanation of such need not later than five (5) business days after the request.

iii. PJM may dispatch a Unit when operation of the Unit is needed to help maintain the reliability of the PJM Transmission System during a generation or transmission outage scheduled in connection with the construction of the PJM Transmission System upgrades identified in the Deactivation Study.

iv. For the avoidance of doubt, PJM may not dispatch either Unit solely on the basis of economic considerations.

e. When PJM dispatches a Unit or the Units to help alleviate a Transmission Security Emergency, PJM must do so subject to the Operating Parameters. PJM will notify Exelon Generation when the Unit or Units are no longer required to help alleviate a Transmission Security Emergency. Based on such notification, Exelon Generation will discontinue operation of the Unit or Units consistent with the Operating Parameters.

f. PJM will not require Eddystone Unit No. 2 to provide Regulation service or run on Automatic Generation Control ("AGC") (Cromby Unit No. 2 is not capable of running on AGC). If PJM requests Eddystone Unit No. 2 to run on AGC and Exelon Generation agrees to operate Eddystone Unit No. 2 on AGC, PJM will cause the AGC to be set in a manner that dispatches the Unit only for a Reliability Purpose.

g. PJM will observe the following Operating Parameters for the Units:

Operating Parameters

Operating Parameter	Cromby Unit No. 2	Eddystone Unit No. 2
Type of Unit	Single Boiler	Single Boiler
Fuel Type	Nat Gas/Petroleum #6 Oil 1.0 S	Coal/Bituminous 0.5 S
Node	CROMBY 20 KV UNIT 02	EDDYSTON 20 KV UNIT 02
Operating Company	EXGNPT	EXGNPT
Capacity Resource	No	No
Regulating Resource	No	No
Default Status	Reliability	Reliability
Default Ramp Rate	2.0	2.0
Fixed Gen	Yes, unless otherwise agreed	Yes, unless otherwise agreed
Min MW	46	118
Max MW	201	309
Parameter Limits Description	Petroleum and Natural Gas Steam Units - Pre-1985	Super-Critical Coal Plants
Turndown Ratio Limit	3	1.5
Maximum Successful Daily Starts Limit	1	1
Maximum Successful Weekly Starts Limit	7	2
Minimum Runtime Limit	8 hours	72 hours
Minimum Downtime Limit	7 hours	72 hours
Hot to Cold Time	60 hours	60 hours
Hot to Inter Time	12 hours	5 hours
Hot Notification Time	2 hours	2 hours
Inter Notification Time	2 hours	2 hours
Cold Notification Time	6 hours	2 hours
Hot Startup Time	4 hours	5 hours
Inter Startup Time	4 hours	13 hours
Cold Startup Time	6 hours	13 hours
Capable of AGC Operation	No	Yes

3. Term

PJM's and Exelon Generation's respective rights and obligations under these Operating Procedures will become effective on June 1, 2011, or such later date as FERC accepts Exelon Generation's Reliability Must-Run Rate Schedule for filing without material modification. These Operating Procedures will terminate with respect to each Unit on the date the Reliability Must-Run Rate Schedule terminates with respect to the Unit and will terminate in its entirety on the date the Reliability Must-Run Rate Schedule terminates in its entirety.

4. Posting

PJM will post these PJM Operating Procedures on its Web site at http://www.pjm.com/planning/generation-retirements.aspx.

5. Amendment

No amendment to the PJM Operating Procedures will be effective unless agreed to in writing by the Parties.

ER06-993-004
Orion Pwr. Midwest
Rate
11
1/3/07
Effective Date: 5/16/06

ORION POWER MIDWEST, L.P.
RATE SCHEDULE NO. 11
COST OF SERVICE RECOVERY TARIFF

I. GENERAL

1. This tariff sets forth the terms, conditions of service and rates for reliability services to be supplied by Orion Power MidWest, L.P. ("OPMW") to PJM Interconnection, L.L.C. ("PJM") pursuant to Sections 119 and 121 of the PJM Open Access Transmission Tariff ("PJM Tariff").

2. Definitions: Unless otherwise defined, capitalized terms used herein shall have the meaning set forth in the PJM Tariff.

II. NATURE OF SERVICE

1. During the Term of this tariff, OPMW shall continue operating the following units ("the Units") located in the PJM region:

   i. Brunot Island CT2A
   ii. Brunot Island CT2B
   iii. Brunot Island CT3
   iv. Brunot Island CC4

2. The Units will be operated in accordance with the Performance Standards set forth in Section 121 of the PJM Tariff. PJM's sole remedies against OPMW for any default under this tariff shall be as specified in such provision.

3. Except when the Units are unavailable due to a Forced Outage or Planned Outage, the Units will be bid into the day-ahead and real-time PJM Energy Interchange Markets by OPMW at rates equal to the Unit offer caps for energy sales into the PJM Interchange Energy Market determined in accordance with the methodology specified in Section 6.4.2(a)(ii) of the PJM Tariff.

4. The Units will not be de-listed as Capacity Resources for PJM.

5. PJM shall pay OPMW the amounts set forth in Article IV hereof as Cost of Service Recovery Rates.

III. TERM

1. Subject to Paragraph 1 and Paragraph 2 of this Section III, this tariff shall remain in effect for as long as PJM determines that the Units are needed for reliability purposes. PJM has determined that the Units will be needed until September 1, 2008 upon which date the Term will end. OPMW will provide reliability services beyond this date (or any other date to which this tariff is subsequently extended) provided that PJM provides at least one hundred and twenty (120) days advance written notice prior to such termination date advising that the Units will continue to be needed for reliability purposes and setting forth a new date of termination. In the event that PJM provides written notice to OPMW that the Units will be needed for reliability purposes for any period beyond September 1, 2008 (or any other date of extension), OPMW shall, within sixty (60) days of the receipt of such written notice, file an amendment to this tariff reflecting the modified Term.

2. This tariff shall terminate upon PJM's determination that the Units are no longer needed for reliability purposes following one hundred and twenty (120) days written notice to OPMW of such determination; provided however, that to the extent that OPMW is recovering Project Investment costs with respect to the Units which are the subject of the PJM notice, OPMW shall be entitled to recover, over the remaining Term of this tariff, all of such Project Investment costs that have been incurred as of the date OPMW receives such written notice. OPMW shall be entitled but shall not be obligated, without seeking or receiving any further approvals from PJM, to deactivate any Unit(s) if PJM determines that the Units are no longer needed for reliability purposes.

ORIGINAL

FULBRIGHT & JAWORSKI L.L.P.
A REGISTERED LIMITED LIABILITY PARTNERSHIP
801 PENNSYLVANIA AVENUE, N.W.
WASHINGTON, D.C. 20004-2623
WWW.FULBRIGHT.COM

WWILLIAMS@FULBRIGHT.COM
DIRECT DIAL: (202) 662-4673

TELEPHONE: (202) 662-0200
FACSIMILE: (202) 662-4643

September 23, 2005

Hand Delivery

Magalie R. Salas, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Room #72-33
Washington, DC 20426

Re: PSEG Energy Resources & Trade LLC and PSEG Fossil LLC
Docket No. ER05-644-000

Dear Ms. Salas:

Pursuant to Rule 602 of the Federal Energy Regulatory Commission's ("Commission") Rules of Practice and Procedure, 18 C.F.R. §385.602, PSEG Energy Resources & Trade LLC and PSEG Fossil LLC (hereinafter the "PSEG Power Companies") hereby submit an original and fourteen copies of a Stipulation and Agreement ("Agreement") for approval by the Commission in the above-captioned docket.

The Agreement, if approved and implemented pursuant to its terms, provides for a resolution of all issues in the above-captioned docket. Prompt consideration and approval of this Agreement by the Commission will aid the PSEG Power Companies and all parties by providing rate certainty and eliminating the need to dedicate resources to the litigation of the issues resolved herein.

The Agreement is the result of negotiations among the participants in this proceeding, reflects a fair and reasonable resolution of the issues, and is in the public interest. The PSEG Power Companies are authorized to state that the Commission's Trial Staff and the parties identified below either support or do not oppose the Agreement.[1] Pursuant to Rule 602(f), initial

[1] These parties include the Public Power Association of New Jersey, the Maryland Office of People's Counsel, Gerdau Ameristeel Corporation , Mirant Americas Energy Marketing, LP, Mirant Chalk Point, LLC, Mirant Mid-Atlantic, LLC, Mirant Peaker, LLC, Mirant Potomac River, LLC, Consolidated Edison Energy, Inc., Public Service Electric and Gas Company, PPL EnergyPlus, LLC, PPL Electric Utilities Corporation, PPL Brunner

This Agreement shall become effective as of the date of a final and unappealable Commission order which approves the Agreement in its entirety without condition or modification.

Respectfully submitted,

By: William A. Williams

William A. Williams
Fulbright & Jaworski L.L.P.
801 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2623
Tel: (202) 662-4673
Fax: 202-662-4643
wwilliams@fulbright.com

Shawn P. Leyden, Esq.
Vice President and General Counsel
PSEG Energy Resources & Trade LLC
80 Park Plaza, T19
Newark, NJ 07102
Tel: 973-430-7698
Fax: 973-643-8385
shawn.leyden@pseg.com

Kenneth R. Carretta, Esq.
PSEG Services Corporation
80 Park Plaza, T5G
Newark, NJ 07102
Tel: 973-430-6462
Tel: 973-430-6409
Fax: 973-430-5983
kenneth.carretta@pseg.com

Attorneys for PSEG Energy
Resources & Trade LLC and
PSEG Fossil LLC

DATED: September 23, 2005

APPENDIX A
Docket No. ER05-644

PRO FORMA TARIFF SHEETS

COST OF SERVICE RECOVERY RATE TARIFF

I. GENERAL

1. This tariff sets forth the terms, conditions of service and rates for reliability services to be supplied by PSEG Energy Resources & Trade LLC ("PSEG ER&T") to PJM Interconnection, L.L.C. ("PJM") pursuant to Sections 119 and 121 of the PJM Open Access Transmission Tariff ("PJM Tariff").
2. Definitions: Unless otherwise defined, capitalized terms used herein shall have the meaning set forth in the PJM Tariff.

II. NATURE OF SERVICE

1. During the Term of this tariff, PSEG ER&T shall cause PSEG Fossil LLC to continue operating the following units ("the Units") located in the PJM region:
   i. Sewaren, Unit No. 1
   ii. Sewaren, Unit No. 2
   iii. Sewaren, Unit No. 3
   iv. Sewaren, Unit No. 4
   v. Hudson, Unit No. 1.
2. The Units will be operated in accordance with the Performance Standards set forth in Section 121 of the PJM Tariff. PJM's sole remedies against PSEG ER&T for any default under this tariff shall be as specified in such provision.
3. Except when the Units are unavailable due to a Forced Outage or Planned Outage, each Unit will be bid into the day-ahead and real-time PJM Energy Interchange Markets by PSEG ER&T at rates equal to the Unit offer caps for energy sales into the PJM Interchange Energy Market determined in accordance with the methodology specified in Section 6.4.2(a)(ii) of the PJM Tariff.
4. The Units will not be de-listed as Capacity Resources for PJM.
5. PJM shall pay PSEG ER&T the amounts set forth in Article IV hereof as Cost of Service Recovery Rates.