UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Exelon Corporation,	)	
	)	
Complainant	)	
	)	
v.	)	**Docket No. EL27-11-000**
	)	
PJM Interconnection, L.L.C.,	)	
	)	
Respondent	)	
	)	

COMPLAINT REQUESTING FAST TRACK PROCESSING OF EXELON CORPORATION

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Dated: November 3, 2026

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COMPLAINT REQUESTING FAST TRACK PROCESSING OF EXELON CORPORATION

Pursuant to sections 206, 306, and 309 of the Federal Power Act ("FPA"),[1] and Rule 206 of the Federal Energy Regulatory Commission's ("FERC" or the "Commission") Rules of Practice and Procedure,[2] Exelon Corporation ("Exelon") hereby submits this complaint against PJM Interconnection, L.L.C. ("PJM"). For the reasons stated herein and in the attached Affidavits of Dr. Emma Nicholson and Deborah Sears,[3] Exelon respectfully requests that the Commission: (i) find under FPA section 206 that the current three-year forward period of PJM's Reliability Pricing Model[4] ("RPM") is no longer just and reasonable; and (ii) adopt as

[1] 16 U.S.C. §§ 824e, 825e, 825h.

[2] 18 C.F.R. § 385.206.

[3] The Nicholson Affidavit is included as Attachment A to this complaint, and the Sears Affidavit is included as Attachment B.

[4] Terms not otherwise defined herein shall have the same meaning as in the PJM Open Access Transmission Tariff ("Tariff"), the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("Operating Agreement"), and the Reliability Assurance Agreement Among Load Serving Entities in the PJM Region ("RAA"). The Tariff, Operating Agreement, and RAA are currently located under PJM's "Intra-PJM Tariffs" eTariff Title, available here: https://etariff.ferc.gov/TariffBrowser.aspx?tid=1731.

the just and reasonable replacement rate a "prompt" auction schedule, to run two months[5] before a given Delivery Year, starting with the 2030/2031 Delivery Year and continuing beyond.[6]

Exelon respectfully requests that the Commission establish a refund effective date of January 1, 2027, and permit Fast Track processing under Rule 206(h) to facilitate a Commission order by no later than January 31, 2027—currently the last day before the scheduled posting date of the planning parameters for the 2030/31 Delivery Year Base Residual Auction ("BRA"). To be clear, nothing in this complaint is intended to apply to, or otherwise disrupt the implementation of, the 2029/2030 Delivery Year BRA, which is scheduled to run in December 2026, nor any Reliability Backstop Procurement ("RBP")[7] auction.[8]

Granting the relief requested herein will have three important outcomes. First, it will remedy an unjust and unreasonable aspect of RPM (the three-year forward period) by better aligning the parameters used in each BRA with actual system conditions, resulting in an auction that relies on more accurate load forecasts, resource availability data, and capacity accreditation, and that facilitates more efficient resource entry and exit through improved

[5] As discussed herein, Exelon acknowledges that the Commission has wide legal discretion under FPA section 206 in establishing the just and reasonable replacement rate, but recommends two months as a reasonable period between when PJM publishes its load forecast information in late January and the start of the Delivery Year on June 1. Two months also provides time for pre-auction activities to take place following the publication of the load forecast in January, gives Market Participants and PJM sufficient notice of the applicable auction parameters, and provides supply resources more than one month to make final operating arrangements if they clear the auction.

[6] Exelon acknowledges that conforming changes to other PJM Governing Agreements may be needed, should the Commission grant the relief requested herein.

[7] *See generally* Docket Nos. ER26-3380-000, EL26-108-000.

[8] Out of an abundance of caution, Exelon is not proposing to apply the "prompt" auction remedy sought herein to the 2029/2030 Delivery Year BRA, in light of the fact that the applicable planning parameters for the 2029/2030 Delivery Year BRA have already been posted. *See PJM Power Providers Group v. FERC,* 96 F.4th 390 (3d Cir. 2024).

market signals.[9] Second, it will functionally push out the date of the BRA for the 2030/31 Delivery Year, currently scheduled for May 2027, to approximately March 2030, thereby preventing Exelon's customers, and PJM customers at large, from being exposed to the uncapped surge in capacity prices expected this coming spring under the current three-year forward RPM period while there is significant uncertainty about supply and demand fundamentals and PJM's resource adequacy structure over this time horizon. Third, it will provide PJM and its stakeholder community, operating under the Commission's oversight, critical time to develop—and timely transition to—the comprehensive resource adequacy reforms that the Trump Administration, PJM Governors, and PJM itself recognize are critical to ensuring a long-term, enduring, and just and reasonable capacity construct in the PJM Region.[10]

I. INTRODUCTION

Customers are, and always have been, at the center of Exelon's core mission and values. Exelon is committed to addressing the mounting affordability pressures experienced every day by its more than 10.7 million customers in the PJM Region.[11] In furtherance of this

[9] *See* Nicholson Affidavit, at ¶¶ 54-59.

[10] *See, e.g., Statement of Principles Regarding PJM* (Jan. 16, 2026) (hereafter, the "Statement of Principles") ("PJM should immediately embark on a stakeholder process to reform the capacity market to ensure long-term viability and prevent consumers from bearing excessive ongoing costs, with the expectation that these reforms be implemented in time for the BRA currently scheduled for May 2027."); *Powering Reliability Through Market Design* at 4 (May 6, 2026) (hereafter, the "PJM White Paper") ("On Jan. 16, 2026, the PJM Board of Managers directed PJM staff to undertake a holistic review of the capacity market design and investment incentives. The Board recognized that the market's current price volatility—while economically rational—is placing unsustainable stress on the governmental compact that allows the market to function, and that the foundational assumptions of the Reliability Pricing Model design must be reexamined in a resource-constrained world. This white paper is PJM's response to that directive."). The Statement of Principles is available here: https://www.energy.gov/documents/statement-principles-regarding-pjm. The PJM White Paper is available here: https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2026/20260506-powering-reliability-through-market-design.pdf.

[11] More information about the Exelon Promise is available here: https://www.exeloncorp.com/company/exelon-promise.

commitment, Exelon submits this complaint against the RPM three-year forward period, to ensure the people and businesses it serves, and the customers of the PJM Region more broadly, receive what they are entitled to—market outcomes predicated on accurate information.

The auction schedule of RPM that has successfully driven efficient outcomes for Exelon customers in the past has proven incapable of meeting the needs of the PJM Region today and into the future. Customers in all six Exelon service territories are directly impacted by the extraordinary prices produced by RPM in recent years, beginning with the 2025/2026 Delivery Year BRA that cleared at several multiples of the historical average capacity price in PJM, and at roughly ten times the prior year's clearing price.[12] The crisis has only deepened since then, with the 2027/2028 and 2028/2029 Delivery Year BRAs clearing at the temporary Commission-approved price cap and simultaneously falling thousands of MWs *short* of PJM's target Installed Reserve Margin.[13] While PJM's staff, management, and Board of Managers ("Board") have diligently and competently administered RPM Auctions over the last two decades, it is self-evident that RPM in its current structure is fundamentally broken. Not only are PJM customers at large being forced to pay unprecedented prices for capacity, they are not getting sufficient capacity in return, and are paying for a widening gap between supply and demand as a reliability deficit looms.

As the Commission correctly observed on September 30, 2026, "[w]e think it clear that PJM's ordinary instrument for procuring sufficient capacity to meet PJM's reliability requirement, the RPM, has failed to keep pace with the unprecedented influx of large load into

[12] *See, e.g.*, *PJM Capacity Prices Spike 10-Fold in 2025/2026 Auction*, RTO Insider, Devin Leith-Yessian (Jul. 30, 2024), https://www.rtoinsider.com/84356-pjm-capacity-prices-spike-2025-26-auction/.

[13] PJM's 2027/2028 BRA report is available here: https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2027-2028/2027-2028-bra-report.pdf. PJM's 2028/2029 BRA report is available here: https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2028-2029/2028-2029-bra-results-report.pdf.

the PJM Region in recent years."[14] Exelon agrees with the Commission's assessment and is taking action. In this complaint, Exelon demonstrates that an integral component of RPM—the three-year forward period—is no longer just and reasonable, because it produces market outcomes that charge customers on the basis of parameters estimated four years in advance of delivery completion, thereby structuralizing uncertainty and inaccuracy with no proportional benefit. While Exelon, like other PJM Transmission Owners and PJM itself, has taken steps to proactively enhance the accuracy of its own load forecast and to eliminate speculative demand (including through its pioneering use of Transmission Security Agreements ("TSAs")),[15] it is still fundamentally bound by RPM's mandate to predict reality years in advance—a challenge exacerbated by the distinct nature, characteristics, and volatile development schedules of today's large loads, as well as the changing nature of market dynamics and federal, state, and local environmental, permitting, and tax policies.

The market outcomes produced under this paradigm create an unjustifiable chasm between the costs customers pay and the capacity they receive, while simultaneously failing to accurately portray the underlying supply and demand dynamics of the PJM Region in a manner that inhibits efficient resource exit, and fails to incentivize efficient resource entry. Accordingly, Exelon respectfully requests the Commission exercise its authority under FPA section 206 to find the existing three-year forward period of RPM unjust and unreasonable, and direct PJM to establish a just and reasonable "prompt" auction schedule, to run two months before a given Delivery Year, starting with the 2030/2031 Delivery Year and continuing

[14] *PJM Interconnection, L.L.C.*, 196 FERC ¶ 61,245, at P 29 (2026).

[15] A TSA is a customer protection mechanism that requires large new power users like data centers to make firm financial commitments for the transmission service that the grid must be ready to provide. More information about TSAs is available here: https://www.exeloncorp.com/grid/exelons-transmission-security-agreements-a-pioneering-model-for-customer-protection1

beyond. Exelon acknowledges that the Commission has wide legal discretion under FPA section 206 in establishing the just and reasonable replacement rate,[16] but recommends two months as a reasonable period between when PJM publishes its load forecast information in late January and the start of the Delivery Year on June 1. Two months also provides time for pre-auction activities to take place following the publication of the load forecast in January, gives Market Participants and PJM sufficient notice of the applicable auction parameters, and provides Capacity Resource owners more than one month to make final operating arrangements if they clear the auction.

While this particular complaint is narrowly focused on the three-year forward period of RPM, and the prompt auction remedy proposed herein is just and reasonable on its own, Exelon acknowledges the targeted surgery requested in this complaint will not heal all that ails RPM. Developments in recent years have exposed broad structural shortcomings inherent in the PJM resource adequacy paradigm and capacity market framework that have led to the crisis the PJM Region faces today. These include (i) the explosive growth of data center load, (ii) a historic procurement crisis for components essential to the development of new capacity, (iii) challenges in the permitting and financing of new generation, (iv) frequent market rule changes, and (v) reactive interventions aimed at promoting just, reasonable, and affordable rates for customers. There is accordingly a considerable amount of work still to be completed by PJM and its stakeholder community to identify a more durable resource adequacy construct that can reliably support the efficient entry and exit of Capacity Resources from the PJM

[16] *See, e.g., Niagara Mohawk Power Corp. v. FPC*, 379 F.2d 153, 159 (D.C. Cir. 1967) ("[T]he breadth of agency discretion is, if anything, at zenith when the action assailed relates primarily . . . to the fashioning of policies, remedies and sanctions . . . in order to arrive at maximum effectuation of Congressional objectives.").

Region, while simultaneously protecting consumers from the extreme price and reliability outcomes that have become the unjust and unreasonable norm.

In the interim, through this complaint, Exelon is providing the Commission with a legal pathway and evidentiary record to *immediately* address one significant defect of RPM (the three-year forward period), and in doing so ensure both customers and suppliers in the PJM Region benefit from an auction schedule that better reflects actual supply and demand fundamentals, and sends more accurate investment signals. Such action directly aligns with the Commission's core responsibilities under the FPA, as the Commission's "first and foremost duty" under the statute is "to protect consumers from unjust and unreasonable rates,"[17] and the Commission has long viewed efficient, accurate, and competitive markets as a vehicle to achieve that end.[18] As an ancillary but not insignificant benefit, granting the instant complaint would provide much-needed time for PJM, States, and the PJM stakeholder community to thoughtfully develop comprehensive and durable reforms to the capacity construct in the PJM Region and submit a proposal to the Commission, without the unnecessary specter of extreme

[17] *Morgan Stanley Cap. Grp. Inc. v. Pub. Util. Dist. No. 1 of Snohomish Cnty*., 554 U.S. 527, 551 (2008) (quotations and citations omitted). *See also Atl. Refin. Co. v. Pub. Serv. Comm'n of N.Y*., 360 U.S. 378, 388 (1959) (The FPA's sister, the Natural Gas Act, was "framed as to afford consumers a complete, permanent and effective bond of protection from excessive rates and charges."); *NAACP v. FPC*, 520 F.2d 432, 438 (D.C. Cir. 1975) ("The Commission's primary task . . . is to guard the consumer from exploitation . . . ."), *aff'd*, 425 U.S. 662 (1976).

[18] *See Fed. Energy Regulatory Comm'n v. Elec. Power Supply Ass'n,* 577 U.S. 260, 267-68 (2016) [hereinafter *FERC v. EPSA*] ("The Commission instead undertakes to ensure 'just and reasonable' wholesale rates by enhancing competition—attempting, as we recently explained, 'to break down regulatory and economic barriers that hinder a free market in wholesale electricity.'") (citing *Morgan Stanley Capital Group Inc. v. Public Util. Dist. No. 1 of Snohomish Cty.,* 554 U.S. 527, 536 (2008)); *Public Citizen, Inc. v. FERC*, 7 F.4th 1177, 1194 (D.C. Cir. 2021) (explaining that "the whole premise of the Commission's market-based system is that a properly competitive market will necessarily produce just and reasonable prices," and that the Commission satisfies its statutory obligations by ensuring that markets are fair, competitive, and unmanipulated); *Calpine Corp. et. al.,* 171 FERC ¶ 61035, at P 139 (2020) (upholding determination on rehearing that the relevant replacement rate will enable PJM's capacity market to send price signals on which both investors and consumers can rely to guide the entry and exit of economically-efficient capacity resources, will support the capacity market's ability to attract investments, and "supports the capacity market's core objective of maintaining resource adequacy at just and reasonable rates, particularly during periods when entry is needed."); *Wholesale Competition in Regions with Organized Electric Markets* , Order No. 719, 125 FERC ¶ 61,071, at P 13 (tying reforms to wholesale competition to its responsibilities under FPA §§ 205 and 206).

pricing outcomes with each passing BRA. Additionally, remedying this defect by moving to a prompt auction schedule now, while this broader market redesign takes place, will have several immediate benefits for the PJM Region:

- It will allow the PJM Region to transition more quickly to the new resource adequacy structure once such a construct is ultimately established. Maintaining the three-year forward period would push the completion of *any* transition ahead to, at best, four years (the current forward period plus the Delivery Year) after those reforms are accepted. In the current fast-moving energy environment, that is simply too long, and customers should not be expected to keep taking on long-term commitments to this current broken model.

- Similarly, it will allow future market reforms to "sink in" more quickly should future adjustments be needed. If history is any guide, there will likely be a need, even after this round of reforms, to adjust rules to address lingering shortcomings. A prompt structure allows PJM customers to benefit from future market improvements more quickly than the existing three-year forward period.

- It will relieve the challenges and administrative burden on PJM and stakeholders associated with constantly running and participating in Incremental Auctions ("IAs").

- It will improve alignment of participation timing for non-conventional resources like demand response, which are challenged by long forward commitments in the context of capacity obligations, and eliminate concerns regarding speculative price arbitrage.

Critically, the discrete remedy sought by Exelon through this complaint is not new. The Commission *already found* prompt auction schedules to be just and reasonable in ISO-NE Inc. ("ISO-NE"),[19] the New York Independent System Operator, Inc. ("NYISO"),[20] and the Midcontinent Independent System Operator, Inc. ("MISO"),[21] even though these three regions have diverse approaches to resource adequacy, ranging from utility-owned generation under

[19] *See* ISO New England Inc., 194 FERC ¶ 61,249 (2026) ("ISO-NE Order").

[20] *See* New York Independent System Operator, Inc., Market Administration and Control Area Services Tariff, §§ 5.13, 5.14.1.1.

[21] *See Midcontinent Indep. Sys. Operator, Inc.,* 162 FERC ¶ 61,176, at PP 70, 74 (2018) ("MISO Order"), *reh'g denied,* 170 FERC ¶ 61,215, at PP 125-26 (2020) ("MISO Rehearing Order").

state commission Integrated Resource Plans ("IRP") to fully restructured, market-based frameworks. Action by the Commission in this proceeding will align PJM's capacity auction schedule with all other Regional Transmission Organizations and Independent System Operators ("RTOs/ISOs") that have centralized capacity market constructs.

Exelon presents its legal case under FPA section 206 in Part IV of this complaint, which is divided into two subparts. In Part IV.A, Exelon demonstrates that the three-year forward period of RPM has become unjust, unreasonable, unduly discriminatory or preferential under FPA section 206, for the following five reasons:

1. The risk balancing analysis the Commission relied on in 2006 to accept the load forecast inaccuracies inherent in RPM's multi-year forward period has fundamentally collapsed in 2026.

2. The prospective assumptions in 2006 regarding the ability of RPM's multi-year forward period to incentivize Load-Serving Entity ("LSE") bilateral contracting and risk hedging have been disproven over the course of 20 years.

3. The current three-year forward period inhibits efficient resource exit and Deactivation, as it requires generator owners to invest in the absence of reasonable predictability in future operational capability and environmental policy.

4. PJM's current capacity accreditation methodology, Effective Load Carrying Capability ("ELCC") bears no resemblance to the Equivalent Forced Outage Rate - demand ("eFORd") model considered by the Commission in 2006, and the three-year forward period forces PJM to integrate speculative assumptions into its ELCC modeling.

5. The current three-year forward period undermines the accuracy of other BRA planning parameters, including the assumed resource mix in each Locational Deliverability Area ("LDA") used to calculate Capacity Emergency Transfer Objective ("CETO") and Capacity Emergency Transfer Limit ("CETL") values, leading to unjust and unreasonable results.

In Part IV.B, Exelon requests that the Commission replace the three-year forward period of RPM with a prompt auction, starting with the 2030/2031 Delivery Year and continuing beyond. Exelon explains that a prompt auction is just and reasonable for the following four reasons:

1. A prompt auction will significantly improve the accuracy of key BRA auction parameters, resulting in capacity prices that better reflect actual supply and demand fundamentals and system conditions in the Delivery Year.

2. A prompt auction will significantly enhance the quality of information and the accuracy of the price signal used in generator Deactivation decisions.

3. A prompt auction will significantly enhance the quality of data used in PJM's ELCC capacity accreditation, thereby better aligning both price and payments with resource contributions to resource adequacy.

4. A prompt auction will significantly reduce the risks to new resources seeking to enter the market by creating more certainty regarding their expected availability for the Delivery Year.

II. PARTIES AND COMMUNICATIONS

A. Complainant Exelon

Exelon is one of the nation's largest utility holding companies, providing transmission and distribution service to nearly 11 million customers in the PJM Region through its regulated subsidiaries Atlantic City Electric Company ("ACE"), Baltimore Gas and Electric Company ("BGE"), Commonwealth Edison Company ("ComEd"), Delmarva Power & Light Company ("DPL"), PECO Energy Company ("PECO"), and Potomac Electric Power Company ("Pepco") (together, the "Exelon Companies"). Exelon's more than 20,000 employees dedicate their time and expertise to supporting the communities they live in and serve through reliable, affordable, and efficient energy delivery, workforce development, economic development, and volunteerism.

The Exelon Companies are public utilities under the FPA, and signatories to both the PJM Consolidated Transmission Owners Agreement ("CTOA") in their capacity as PJM Transmission Owners, and the RAA in their capacity as PJM LSEs.

B. Respondent PJM

PJM is the nation's largest RTO, coordinating the movement of wholesale electricity in all or parts of 13 states and the District of Columbia.[22] As an RTO, PJM is responsible for the reliability of the high-voltage transmission system serving 68 million people 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. PJM also administers the PJM wholesale electricity markets, including the Day-ahead Energy Market, the Real-time Energy Market, ancillary services markets, and, as relevant here, the RPM.

C. Communications

All correspondence and communications to Exelon in this docket should be addressed to the following individuals, whose names should be entered on the official service list maintained by the Secretary in connection with these proceedings:[23]

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[22] *See* PJM Interconnection, *About PJM* (last visited Sept. 27, 2026), https://www.pjm.com/about-pjm.

[23] Exelon respectfully requests a waiver of Rule 203(b)(3), 18 C.F.R. § 385.203(b)(3), to allow the inclusion of more than two persons on the official service list.

III. BACKGROUND

The concept of a multi-year forward period for RPM first emerged in PJM's August 2005 Initial RPM Proposal,[24] and was designed to address one of several core deficiencies with PJM's then-existing capacity construct—namely that, as PJM explained, the construct did "not look far enough into the future to secure capacity in time to meet reliability needs."[25] In 2005, this defect was glaring. At the time, PJM's capacity construct only required that Capacity Resources be committed for one day, and there was little incentive to commit for longer periods. Moreover, Capacity Resources were permitted to "opt out" of their Capacity Resource status with as little as 36 hours' notice. PJM administered capacity credit markets only twelve months at a time, which were designed to accommodate short-term competitive load-switching under retail choice, and were incapable of sustaining long-term generation investment. As PJM described it, "[s]imply put, the short-term nature of the current PJM capacity construct is fundamentally inconsistent with the need to preserve system reliability in the longer term."[26] To remedy these shortcomings, PJM proposed a four-year forward period for RPM.

On April 20, 2006, the Commission issued its Initial RPM Order, finding that PJM's existing capacity construct was unjust and unreasonable and establishing additional procedures to resolve several remaining issues regarding the just and reasonable replacement rate.[27] As relevant here, the Commission accepted the four-year forward period of RPM, finding that

[24] *PJM Interconnection, L.L.C.*, PJM Section 205 and 206 Filing of PJM Interconnection, L.L.C., Docket Nos. ER05-1410-000 and EL05-148-000 (Aug. 31, 2005) ("August 2005 Initial RPM Proposal").

[25] *Id*., at 5.

[26] *Id*., at 9.

[27] *PJM Interconnection, L.L.C.*, 115 FERC ¶ 61,079, at P 1 (2006) ("April 2006 Initial RPM Order").

"four years is a reasonable period in which solutions can be placed in operation in response to the RPM's base residual auction."[28]

On September 29, 2006, PJM submitted the RPM Settlement, which proposed to resolve all outstanding issues in the proceeding regarding RPM.[29] Among other things, the RPM Settlement retained a multi-year forward period accepted by the Commission in the April 2006 Initial RPM Order, but shortened the period between the BRA and the start of the Delivery Year from four to three years. As explained in the RPM Settlement, the parties determined three years was sufficient to meet the essential purpose of a forward commitment, namely to provide a credible prospect for new entry via the construction of new resources.[30] To this point, the settlement noted that PJM previously presented witness testimony indicating a typical 33-month period between signing of an Incremental Facilities Study Agreement for a new plant and the plant's commercial operation date.[31]

On December 22, 2006,[32] the Commission approved the RPM Settlement, subject to certain conditions, including the proposed three-year-forward period of RPM. Over the last twenty years, many of the RPM market design components from the original RPM Settlement have evolved and been improved upon, including capacity accreditation, performance obligations, and interface with PJM's planning and operations regime. Notably, however, with

[28] *Id*., at P 72.

[29] *PJM Interconnection, L.L.C.*, Settlement Agreement and Explanatory Statement of the Settling Parties Resolving All Issues, Docket Nos. ER05-1410-000 and -001, EL05-148-000 and -001 (Sept. 29, 2006) ("RPM Settlement").

[30] *See* RPM Settlement, at 11-12.

[31] *Id.*

[32] *See PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331, at P 28 (2006) ("December Order Approving Settlement").

the exception of the BRA delays starting in 2019, the three-year forward period auction schedule has remained unchanged since 2006.

IV. LEGAL ARGUMENT

A. The Current Three-Year Forward Period of RPM is No Longer Just and Reasonable.

i. The risk balancing analysis the Commission relied on in 2006 to accept the load forecast inaccuracies inherent in RPM's multi-year forward period has fundamentally collapsed in 2026.

As described above, the concept of a multi-year forward period was integral to PJM's original RPM filing in 2005. In the August 2005 Initial RPM Proposal, PJM predicated RPM on a four-year forward period (later revised down to three years via the RPM Settlement), which aligned with what was at the time the expected development schedule for a new combustion turbine (an estimated 33 months, as discussed above), according to PJM's affiant Mr. Pasteris.[33] From the outset, PJM acknowledged that RPM's proposed multi-year forward period, by definition, contained an inherent risk of load forecast inaccuracies. PJM explained that "the choice of the forward period represents a balance among many factors, including the risk of estimation error . . . and the ease of participation by resources with relatively long lead times."[34] In applying this "balancing" of factors, PJM reasoned that "what is crucial is a market that is sufficiently forward to provide the opportunity for additional competition and a greater degree of forward price certainty, while not being so long that the estimation errors create a substantial risk of too much construction should the expected load fail[] to materialize."[35]

[33] *See* August 2005 Initial RPM Proposal, at 75-76.

[34] *Id*., at 77-78.

[35] *Id*., at 78.

In its April 2006 Initial RPM Order approving RPM's multi-year forward period, the Commission recognized what several protesters argued in the record—namely that "RPM may expose customers to greater risks than they now face," including "the inherent risk that a four-year-forward estimate of how much capacity will be needed five years later will prove to be unreliable."[36] The Commission acknowledged these concerns were valid, but engaged in a risk balancing analysis to justify acceptance of the risk of inaccuracy inherent in RPM's multi-year forward period.

> *We agree, in part, with Morgan Stanley that RPM may cause customers to bear risks such as the risk that a four-year forward estimate of needed capacity may turn out to be inaccurate. However, we think that the risk is reasonable when it is compared to the risks of the current construct, namely that sufficient capacity resources may not be constructed to ensure the preservation of reliability.*[37]

Twenty years later, this risk-balancing analysis the Commission relied on in 2006 has fundamentally collapsed, and the resulting RPM framework that was explicitly predicated on it has become unjust and unreasonable. As demonstrated below, not only have the load forecast inaccuracies inherent in RPM's three-year forward period *increased* since 2006, but Capacity Resources—and in particular the RPM Reference Resource[38]—are now functionally incapable of being constructed in the PJM Region within the current three-year cycle, leaving *only* the downside pricing risk of those load forecast inaccuracies to be borne by customers. Put another way, the very outcome the Commission sought to avoid in accepting the load forecast

[36] April 2006 Initial RPM Order, at P 66. It is worth noting that the three-year forward period of RPM is functionally a "three year + one year" estimate and commitment by customers.

[37] *Id*., at P 71 (emphasis added).

[38] *See* Tariff, Definitions R-S ("Reference Resource" shall mean a combustion turbine generating station, configured with a single General Electric Frame 7HA turbine with evaporative cooling, Selective Catalytic Reduction technology all CONE Areas, dual fuel capability, and a heat rate of 9.134 Mmbtu/ MWh.").

inaccuracies inherent in RPM's multi-year forward period—"that sufficient capacity resources may not be constructed to ensure the preservation of reliability"—is today the lived reality of the PJM Region. This conclusion is supported by several key pieces of evidence, which are described below in subsections IV.A.i.a and IV.A.i.b.

a. Evidence that PJM Load Forecast Inaccuracies Have Increased Since 2006.

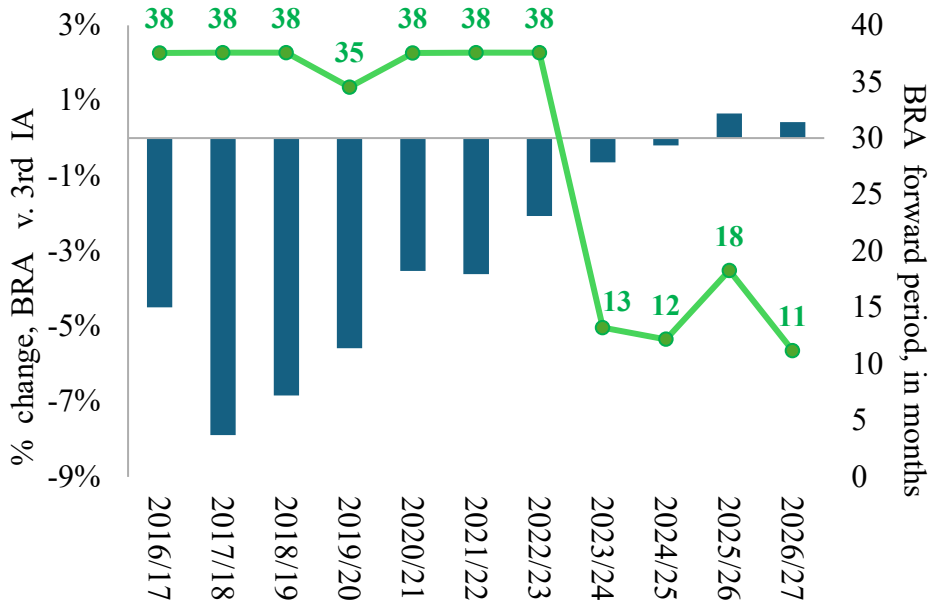
As noted above, Exelon has taken concrete steps to improve the accuracy of its load forecast and eliminate speculative demand, including through its pioneering use of TSAs, which require firm financial commitments from large load customers.[39] Notwithstanding these efforts, Exelon, the other Transmission Owners of the PJM Region, and PJM itself are nonetheless bound by RPM's requirement to predict reality years into the future—a task made more difficult by the nature, characteristics, and volatile development schedules of today's large loads. Beyond this, a forward period of this magnitude will, by definition, fail to capture changes in business economics, federal and state environmental and regulatory policy, and local siting and permitting regulations, all of which play a vital role in the market outcomes of RPM.

Irrespective of the efforts of Exelon, the PJM Transmission Owners, and PJM to enhance the accuracy of their load forecasts, RPM's mandate to predict reality so far into the future creates uncertainty in PJM's near-term load forecast that is persistent, consistent in direction, and has increased in magnitude since 2006 when the Commission initially accepted RPM's three-year forward period. There are multiple data sets that support this conclusion. First, Figure 2 of the Nicholson Affidavit illustrates the change in the peak load forecast

[39] More information about TSAs is available here: https://www.exeloncorp.com/grid/exelons-transmission-security-agreements-a-pioneering-model-for-customer-protection1.

between the BRA, which has historically been held thirty-eight (38) months prior to the start of the Delivery Year, and the third IA, which is held approximately four months before the start of the Delivery Year. The magnitude of the load forecast inaccuracies (blue bars) between the 2016/2017 BRA and the 2022/2023 BRA is significant, reveals a clear trend toward overestimation of load, and notably the need for forecast adjustments *decreased* in instances where the BRA forward period was shortened as a result of auction delays. As Dr. Nicholson explains, the increase in BRA load forecast precision shown in Figure 2 of the Nicholson Affidavit is positively correlated with the shorter forecast horizon, as the 2023/24 through 2026/27 BRAs had a shorter forward period due to auction delays.[40]

Nicholson Affidavit - Figure 2
BRA Forward Period (Green, Right Axis) and Load Forecast Change between BRA and Third IA (Blue, Left Axis)



Second, the increase in magnitude in recent years of PJM load forecast inaccuracies can also be observed in the growing size (in MW) of the Load Adjustments PJM makes to its

[40] Nicholson Affidavit, at ¶¶ 15-16.

load forecast model, which Dr. Nicholson describes in Table 2 of her Affidavit. Where such adjustments historically represented no more than 2% of the projected summer peak load four to five years out as recently as the 2017 through 2021 forecasts, PJM's 2026 forecast reflects adjustments of 18.4% and 21.7% of the summer peak for those same time horizons.[41] Indeed, projected year-over-year growth in summer peak tells the same story, rising from well under 1% annually as recently as 2022 to a range of 3.1% to 4.4% in PJM's 2025 load forecast and 2.6% to 6.7% in the 2026 forecast.[42] This trend in year-over-year growth is illustrated in Table 3 of the Nicholson Affidavit.

Nicholson Affidavit - Table 2
Load Adjustments as a Percent of the Summer Peak Load Forecasts, 2017 - 2026

Historical PJM Load Forecasts by Year

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Y_0	0.6%	0.8%	1.1%	0.0%	-0.2%	0.6%	1.9%	1.8%	2.3%	4.1%
Y_0 +1	0.7%	1.0%	1.3%	0.1%	-0.1%	1.1%	2.2%	3.0%	5.3%	6.7%
Y_0 +2	0.8%	1.2%	1.5%	0.3%	-0.1%	1.6%	2.4%	4.8%	8.3%	9.8%
Y_0 +3	1.0%	1.4%	1.6%	0.4%	0.0%	2.0%	2.5%	6.3%	11.4%	13.0%
Y_0 +4	1.2%	1.6%	1.8%	0.5%	0.1%	2.6%	2.6%	7.8%	14.4%	18.4%
Y_0 +5	1.4%	1.7%	1.9%	0.4%	0.0%	2.7%	2.7%	8.9%	17.8%	21.7%

Nicholson Affidavit - Table 3
Year-Over-Year Growth in Summer Peak Load Forecasts, 2017 - 2026

Historical PJM Load Forecasts by Year

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Y_0+1	0.6%	0.2%	-0.3%	1.0%	0.5%	0.3%	0.5%	1.5%	3.1%	2.6%
Y_0+2	0.2%	-0.3%	0.4%	1.0%	0.6%	0.6%	0.8%	2.2%	3.3%	3.2%
Y_0+3	-0.4%	0.3%	0.5%	0.6%	0.4%	0.6%	1.2%	1.9%	3.5%	3.6%
Y_0+4	-0.2%	0.3%	0.4%	0.4%	0.3%	0.7%	1.0%	1.9%	3.6%	6.7%
Y_0+5	0.0%	0.5%	0.4%	0.6%	0.2%	0.0%	0.9%	1.7%	4.4%	4.4%

As Dr. Nicholson notes, this is not a modeling failure; it reflects a structural shift in forecast uncertainty driven almost entirely by the nature and size of data center load growth in

[41] *Id.*, at ¶¶ 20-21.

[42] *Id.*, at ¶ 22.

the PJM Region. Not only is such uncertainty larger in magnitude given the size of the underlying customers, but the forecasting challenges are also amplified by recent and ongoing siting, permitting, and supply chain challenges nationwide, as well as the fast-changing business environment and evolving regulatory constructs with which data center developers need to contend with.[43] These load forecast inaccuracies have real impacts on market outcomes. As Dr. Nicholson explains, the three-year RPM forward period and assumptions about large load growth, principally from data centers, are likely to overstate the peak load forecast that PJM uses to determine the Reliability Requirement and the amount of capacity that PJM must procure in the BRA.[44] This can lead to unjust and unreasonable outcomes. Procuring too much capacity in the BRA unnecessarily increases costs for PJM Market Participants, because if a portion of the large loads included in the load forecast used in the BRA do not materialize, capacity costs will increase for all customers. This outcome is also economically inefficient, because when it occurs the PJM Region purchases more capacity than is necessary to ensure target levels of resource adequacy.

Dr. Nicholson provides an illustrative example to demonstrate just how much load forecast inaccuracies can impact market prices, even in small percentages. Figure 3 of the Nicholson Affidavit is based on a VRR Curve constructed using PJM's 2029/30 BRA parameters, the VRR Curve formulation the Commission accepted in Docket No. ER26-455, and no price collar. As Dr. Nicholson explains, the blue plot shows an estimate of what the VRR Curve would be with the Reliability Requirement for the 2029/30 BRA, and the orange

[43] *Id.*, at ¶¶ 14, 21-23, 27.

[44] *Id.*, at ¶ 14. Note that the PJM Region Reliability Requirement is defined as the Forecast Pool Requirement multiplied by the Preliminary PJM Region Peak Load Forecast, less the sum of all Preliminary Unforced Capacity Obligations of FRR Entities in the PJM Region; and, for purposes of the Incremental Auctions, the Forecast Pool Requirement multiplied by the updated PJM Region Peak Load Forecast, less the sum of all updated Unforced Capacity Obligations of FRR Entities in the PJM Region."

and green plots show what the VRR Curve would have been if the Reliability Requirement were 1% or 2% lower, respectively.[45] Both 1% and 2% are reasonable load forecast sensitivities to explore because they are consistent with historically observed forecast errors within a three-year forecast horizon in the 2016/17 through 2022/23 BRAs (*see* Figure 3 of the Nicholson Affidavit), which occurred before the uncertainty inherent in large load growth seen today. Additionally, when comparing the PJM load forecasts published in January 2025 and January 2026, the Summer Peak forecasts for 2027 through 2029 fell by between 2.3% and 2.6%.[46]

Nicholson Affidavit - Figure 3
Illustrative Example of Cost Implications of the Reliability Requirement on the BRA Clearing Price



[45] *Id.*, at ¶ 29.

[46] *Id.*

If one were to assume that, as may happen in a tight market, the BRA were to clear on the sloped portion of the VRR Curve, Figure 3 of the Nicholson Affidavit shows that a 1% shift in the Reliability Requirement could reduce the capacity price by approximately $120/UCAP-MW-day, and a 2% reduction could lead to a price reduction of approximately $120-220/UCAP MW-day, depending on the capacity the auction clears. This translates to approximately $6 to $12 billion in change in total capacity costs to customers resulting from a historically "normal" level of load forecast error associated with a three-year forward period.[47]

b. Evidence that Capacity Resources cannot be constructed in the PJM Region within the current three-year cycle.

There are multiple pieces of evidence supporting the conclusion that, in 2026, Capacity Resources cannot be constructed in the PJM Region within the current three-year forward period, thereby undermining the key 'counterweight' the Commission used in its balancing analysis in 2006 to justify being willing to accept the load forecast inaccuracies inherent in a multi-year forward period of RPM.

First, as a threshold matter, it is worth noting that PJM itself has reached this conclusion. In the PJM White Paper, PJM explained that while "[t]he three-year forward timeline was originally established because it aligned with the construction schedule of many of the resources that could be built to meet the system's resource adequacy needs, including both combustion turbine and combined cycle gas turbine resources," this "foundational assumption of the RPM design has been physically broken."[48] PJM concluded that "[t]oday, due to compounding frictions in siting, permitting, supply chains and interconnection, it can

[47] *Id*. at Table 5, ¶¶30-31.

[48] PJM White Paper, at 18.

take two or three times as long to build a gas resource as it does to build a hyperscale data center."[49]

Second, despite notable reforms to PJM's interconnection queue that are designed to make the standard Cycle study one to two years in duration, data indicates that Capacity Resources are still experiencing significant difficulty entering service *at all*, let alone within the three-year forward period of RPM. For example, since 2020, approximately 24 GW of planned generation with fully executed interconnection agreements have terminated their agreements before reaching commercial operation, including 13.5 GW of natural gas capacity.[50] These terminations have largely been caused by matters external to PJM, and continue to inhibit the deployment of new capacity to the PJM Region. Indeed, in May 2026 PJM reported that "~53 GW of interconnection projects – enough to power 40 million homes at full output – currently have signed agreements to connect to the grid, but many are being stymied by issues beyond PJM's control, like federal, state and local permitting, siting, and supply chain challenges."[51] Additionally, as Dr. Nicholson explains, a recent analysis of PJM's interconnection queue between 2015 and 2024 found that new large natural gas-fired generation projects that completed the interconnection process had an average timeline of 10.8 years between initial submission into the queue and commercial operation.[52] This study also

[49] *Id*.

[50] Nicholson Affidavit, at ¶ 34.

[51] *See* PJM, *New, Faster Generation Interconnection Process Fact Sheet* (Updated May 21, 2026), https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/interconnection-reform-progress-fact-sheet.pdf.

[52] Nicholson Affidavit, at ¶ 34 (citing Ralph O'Connor Sustainable Energy Inst., Johns Hopkins Univ., *Natural Gas Generator and Energy Storage Timelines in PJM*, at 2-3 (May 18, 2026)).

found that, since 2015, of 102 gas-fired generators over 100 MW that entered into the PJM queue, only thirteen were online by early 2026 (eleven years later).[53]

Third, recent evidence indicates that the global shortage of gas turbines—the technology underlying RPM's reference resource (and combined cycle gas turbine resources as well)—has made three-year entry functionally impossible. As Dr. Nicholson explains, major manufacturers have reported backlogs stretching years into the future. For example, Siemens Energy disclosed an approximately 69 GW order backlog as of August 2026, with new orders now quoting lead times of three years or more. GE Vernova similarly reported a 116 GW backlog it expected to exceed 125 GW by year-end 2026, and Mitsubishi's gas turbine lead times have grown from roughly two years just after the pandemic to five years or more today, with the company now booking deliveries as far out as 2031 to 2034.[54]

Fourth, recent markets data and rule changes indicate the current market environment is no longer conducive to new resource entry within the three-year forward period of RPM. This is perhaps most clearly illustrated by the recent BRA results, which conclusively demonstrate the current construct is failing to procure adequate capacity, even as prices have reached their regulatory ceiling.[55] In particular, the 2027/2028 and 2028/2029 BRAs each cleared at the Commission-approved price cap (most recently $325.00/MW-day in the Rest of RTO zone for the 2028/2029 BRA) while simultaneously failing to procure the full Reliability Requirement, falling short by 6,517 MW UCAP and 6,831 MW UCAP, respectively.[56] Notably, the 2029/2030 BRA, scheduled for December 2026, will again be subject to a price

[53] *Id*.

[54] *Id.*, at ¶ 35.

[55] *Id.*, at ¶ 7.

[56] *Id.*

cap, set at $337.83/UCAP MW-day.[57] It is also worth noting that future auctions, beyond the 2029/2030 Delivery Year, are slated to be run on an uncapped basis, a factor that will allow prices to further rise to the regulatory maximum price and that generation developers would naturally incorporate into their commercial outlooks for new generation revenue.

At the same time, PJM recently pursued *alternative* procurement mechanisms that offer long-term investment certainty superior to the three-year forward period of RPM.[58] Specifically, the RBP, which the Commission accepted and suspended for further briefing on September 30, 2026, would procure capacity from new resources on a pay-as-bid basis for terms of up to fifteen years, subject to a weighted-average price cap of $555/MW-day, for resources expected to be in service by June 1, 2032.[59] Because a Capacity Resource that clears an RPM Auction is ineligible for an RBP auction, these long-term procurement mechanisms compete directly with (and, given their superior revenue certainty, are likely to draw developers away from) the three-year forward BRA, which offers only a single-year commitment.[60] The scale of that pull is already evident, with PJM reporting that roughly 136 GW of potential new capacity, spanning 397 projects and 87 entities, have expressed interest in RBP auctions or in facilitated bilateral matching in response to its request for interest.[61] As Dr. Nicholson explains, it is highly unlikely that a rational investor would forgo a long-term commitment of up to fifteen years under an RBP auction or potentially similar certainty under a contract directly with a large load, in favor of a single Delivery Year's worth of revenue

[57] *Id.*, at ¶ 9.

[58] *Id.*, at ¶ 67.

[59] *Id.*

[60] *See id.*

[61] *Id.*

certainty under the BRA, particularly now that lenders financing new merchant generation generally insist on exactly the kind of long-term offtake commitment that only those alternative multi-year mechanisms can offer.[62]

In summary, there is ample evidence that the risk balancing analysis the Commission relied on in 2006 has collapsed in 2026. Not only have the load forecast inaccuracies inherent in RPM's three-year forward period *increased* considerably since 2006, but Capacity Resources are now functionally incapable of being constructed in the PJM Region within the current three-year cycle, leaving *only* the downside pricing risk of those load forecast inaccuracies to be borne by customers.

ii. The prospective assumptions in 2006 regarding the ability of RPM's multi-year forward period to incentivize LSE bilateral contracting and risk hedging have been disproven over the course of 20 years.

One of the key ideas put forward in the August 2005 Initial RPM Filing was that RPM's multi-year forward period would help facilitate LSE bilateral contracting and risk hedging. PJM explained that "[l]onger term price signals [] should incent longer term bilateral contracts, as an effective means of hedging the reliability charges assessed under RPM."[63] In support of this proposition, PJM included testimony from Andrew Ott, then PJM's Vice President of Market Services. Mr. Ott explained that this anticipated enhanced incentive for LSE bilateral contracting and risk hedging would "help orient market participant objectives with the system's reliability needs, and help ensure the long-term viability of the competitive market model in the electric industry."[64]

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[62] *See id.*

[63] August 2005 Initial RPM Proposal, at 77.

[64] *Id*. at Ott Affidavit ¶ 15.

Several protesters raised concerns with PJM's prognostications regarding RPM's positive impact on LSE bilateral contracting and risk hedging, arguing that, contrary to PJM's predictions, "RPM will impair parties' willingness and ability to manage risk: since all parties will be fully hedged prior to each Delivery Year, there will be no incentive for parties to manage their own risk by entering into additional bilateral contracts."[65] Protesters further argued that "if the market becomes less volatile, parties will be less motivated to enter into bilateral agreements even before entering the capacity markets."[66]

In response, PJM acknowledged that "RPM will affect bilateral contracting in the PJM region, just as LMP affected bilateral contracting," but argued that "the impact will be beneficial from the standpoint of system reliability, as it will encourage contracts of four years or more."[67] PJM argued that, under the current structure, "LSEs that have an orientation towards short time horizons are not entering into long-term contracts" and that "[t]o the extent RPM begins to induce a change in contracting towards agreements that come closer to reflecting those costs and supporting those investments [necessary to maintain a reliable system], then it is a change worth making, and one the Commission should support as a matter of policy."[68]

In its April 2006 Initial Order approving RPM's multi-year commitment period, the Commission accepted PJM's assumptions and predictions regarding the incentivization of LSE bilateral contracting and risk hedging, stating:

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[65] April 2006 Initial Order, at P 65.

[66] *Id.*

[67] *PJM Interconnection, L.L.C.*, Motion for Leave to Answer and Answer of PJM Interconnection, L.L.C, at 35 (Sept. 16, 2005).

[68] *Id.*, at 35-36.

> ***The Commission does not consider it likely that RPM will lessen parties' motivation to purchase more of their forward-looking capacity needs through bilateral contracts, or to manage their risk in other ways****, such as releasing or purchasing additional capacity in the auctions following the Residual Base Auction during the four years prior to each Delivery Year. First, those states or LSEs who wish to maintain maximum flexibility to manage their own risk will be able to fulfill their own capacity needs by providing their own fixed resource requirement.* ***Second, as PJM has alleged, parties are not engaging in significant amounts of forward contracting now: RPM will provide more information to all market participants, and all parties will be able to use this information to manage their risk more effectively, whether through bilateral contracting or otherwise.*** *Moreover, the series of follow-on auctions for each Delivery Year will enable LSEs to adjust the amounts of capacity they hold, or to seek to obtain capacity at a better price, until four months before the Delivery Year.*[69]

These prospective predictions and assumptions made in 2006 regarding the impact of RPM's multi-year forward period on LSE bilateral contracting and risk hedging have been comprehensively disproven over the course of 20 years. The anticipations of PJM and the Commission, that RPM would lead to a broad propagation of bilateral contracting and hedging, and the associated reasoning used in support of accepting the three-year forward period, have not come to pass. This conclusion is supported by several pieces of evidence.

First, PJM itself identified that a significant portion of PJM load is presently served by entities that rely on short-term procurement rather than long-term bilateral contracts to meet their capacity needs, leaving those entities (and the retail customers they serve) directly exposed to RPM price volatility, rather than hedged against it. And, as a corollary, opportunities for long-term contracting between those entities and Capacity Resources have been equally limited. In the PJM White Paper, PJM explained that:

[69] April 2006 Initial Order, at P 70 (emphasis added).

> *A significant portion of PJM load is served by default service providers – state-regulated entities that are often constrained by statute or regulatory practice from entering long-term bilateral contracts. These entities procure capacity primarily through short-term default service auctions calibrated to the annual Base Residual Auction cycle. During PJM's prolonged surplus era, this approach was rational: short-term procurement captured low market prices without paying a long-term hedge premium. But it also left these entities – and their retail customers – exposed to capacity price volatility when the market transitioned into scarcity. This effect was exacerbated by the persistent capacity auction delays experienced in PJM.*[70]

Similarly, in PJM's February 2025 filing to establish a revised price cap and price floor for the 2026/2027 and 2027/2028 Delivery Years, PJM's Executive Vice President for Market Services and Strategy Stu Bresler explained that although the RPM was initially expected to be a residual market, with the majority of capacity contracted bilaterally, that contracting has not occurred. Instead, Mr. Bresler explained that "[r]ather, it appears that substantial load in the states that have expressed concern are *directly exposed* to Base Residual Auction prices for the *entirety* of their capacity obligations."[71] It was precisely because of this absence of long-term contracting that PJM presented "Path A" in the PJM White Paper, which envisions enhanced requirements for LSEs to sign long-term capacity contracts to support investment in new capacity resources and to act as a hedge against volatility in capacity market prices.[72]

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[70] PJM Whitepaper, at 29-36.

[71] *PJM Interconnection, L.L.C.*, Affidavit of Mr. Frederick S. Bresler III on Behalf of PJM Interconnection, L.L.C., at 6, Docket No. ER25-1357-000 (Feb. 20, 2025), emphasis added ("The original vision of the RPM was for it to function primarily as a residual market, with the majority of capacity procured through bilateral contracts and only a small portion needed to cover remaining needs from the market. Participation in this way as originally intended would serve to substantially hedge market participants on both the supply and demand sides from uncertain and potentially volatile Base Residual Auction clearing prices. The historic and existing capacity market design and results do not appear to have sufficiently stimulated this type of activity. Rather, it appears that substantial load in the states that have expressed concern are directly exposed to Base Residual Auction prices for the entirety of their capacity obligations.").

[72] PJM Whitepaper, at 32-34.

Second, in many PJM jurisdictions, LSEs are restricted by state law from engaging in the kinds of long-term bilateral contracting and hedging that the Commission envisioned in 2006 when approving the three-year forward period of RPM. Exelon Affiant Deborah Sears submits direct testimony on this point into the record, describing in detail the range of restrictions on long-term bilateral contracting and hedging in the District of Columbia, Maryland, New Jersey, and Delaware. As Ms. Sears notes, "[t]he SOS/BGS auction structures are highly prescriptive and any changes to the annual auction process are reviewed through a stakeholder meeting called the Procurement Improvement Process, and the final changes to the Request for Proposal and Full Requirements Service Agreement require approval by the applicable state utility regulatory commission."[73] As Ms. Sears puts plainly, "Pepco, DPL, and ACE are not permitted to enter into any bilateral transactions including hedging agreements without approval from the applicable state utility regulatory commission."[74]

Third, beyond restrictions in state law, restrictions in federal law have also been identified by certain states as an obstacle to long-term bilateral contracting and hedging. To this point, and as further referenced by Dr. Nicholson, a New Jersey Board of Public Utilities ("NJBPU") examination of the PJM capacity market explained that federal legal restrictions limit the types of bilateral contracting the state of New Jersey can engage in to procure capacity bilaterally on a long-term basis outside of the RPM.[75] The NJBPU assessment found that "[t]he only way an LSE can use capacity procured wholly outside the RPM to meet its capacity needs is by electing to use the Fixed Resource Requirement ("FRR") Alternative under which

[73] Sears Affidavit, at ¶ 9.

[74] *Id*.

[75] Nicholson Affidavit, at ¶ 38 (citing New Jersey Board of Public Utilities, *An Investigation of PJM's Capacity Market*, at 6 (Aug. 2026)).

it must meet all of its capacity needs outside of the RPM for the relevant service area. However, the Reliability Assurance Agreement effectively bars LSEs in states like New Jersey that allow full retail choice from electing the FRR Alternative."[76] The Assessment went on to explain that the state of New Jersey attempted to make long-term bilateral capacity procurements through the Long-Term Capacity Pilot Program, but courts found the program was preempted by the Federal Power Act in *PPL v. Hannah*[77] and *PPL v. Solomon*.[78] The NJBPU further explained that *Hughes v. Talen*[79] put further limits on the types of long-term bilateral capacity contracting PJM states can engage in. As a result of these federal legal constraints, NJBPU concluded that "to date New Jersey LSEs have opted to procure the capacity they needed exclusively or nearly exclusively through RPM auctions."[80]

In summary, the prospective assumptions and predictions of PJM and the Commission in 2006 regarding the ability of RPM's multi-year forward period to incentivize LSE bilateral contracting and risk hedging have not come to pass over the last 20 years.

iii. The current three-year forward period inhibits efficient resource exit and Deactivation, as it requires generation owners to invest in the absence of reasonable predictability in future operational capability and environmental policy.

Under PJM's Capacity Performance construct, cleared Capacity Resources with RPM commitments are required to be available to operate throughout the Delivery Year, pursuant to RPM's must-offer requirements. Capacity Resources have particular performance obligations when scheduled and/or dispatched by PJM during a Performance Assessment Interval

[76] *Id*.

[77] *PPL Energyplus, LLC v. Hanna*, 977 F.Supp. 2d 372, 389-390 (D.N.J. 2013).

[78] *PPL EnergyPlus, LLC v. Solomon*, 766 F.3d 241, 246 (3rd Cir. 2014).

[79] *Hughes v. Talen Energy Mktg*., LLC, 578 U.S. 150 (2016).

[80] Nicholson Affidavit, at ¶ 38.

("PAI").[81] Capacity Resources that fail to perform when called upon face severe financial penalties, or as PJM has described it, "[g]enerators assume virtually all financial risks if they do not meet their power supply obligations."[82]

In deciding how to bid their Capacity Resources into RPM and at what price, all resource owners must engage in a business risk balancing analysis that weighs the potential revenues that might be earned in a given RPM Auction against the cost of continuing to operate a given Capacity Resource, including the Capacity Performance risk associated with failing to perform when called upon during a PAI. Indeed, PJM's rules explicitly acknowledge these considerations in the construction of a resource's Avoidable Cost Rate ("ACR"), which represents the ongoing fixed operation and maintenance costs a Capacity Resource can avoid if it does not operate for a given Delivery Year, and in a resource's Capacity Performance Quantifiable Risk ("CPQR"), which measures and values the expected financial risks and potential performance penalties that a Capacity Resource may face during emergency operations.

For the owners of older Capacity Resources that may be trying to ascertain whether it is economic to remain in the market or exit through Deactivation, the three-year forward period of RPM profoundly clouds this balancing analysis. The reason for this is simple—these resource owners cannot see three years (and in practice, four years) into the future. As a result, they are unable to make two important determinations: (i) whether they will be able to physically operate their resource dependably during the future Delivery Year; and (ii) whether

[81] *See* Tariff, Attachment DD, Section 5.5A(a).

[82] *See* PJM Interconnection, *Capacity Performance at a Glance* (last visited Sept. 27, 2026), https://www.pjm.com/-/media/DotCom/library/reports-notices/capacity-performance/20150720-capacity-performance-at-a-glance.ashx?la=en.

applicable environmental policy will legally allow them to operate their resource during the future Delivery Year. Furthermore, given the various uncertainties in play, Capacity Resource owners may also struggle to predict future system conditions and therefore estimate the volume of Capacity Performance exposure. Accordingly, even if it *would be* efficient for the market, economic for the resource owner, and beneficial to reliability as a whole for the Capacity Resource to remain in the market, these resource owners are incapable of conducting an accurate risk assessment and are thus inadvertently incentivized to exit the market earlier than may be appropriate. These operational and environmental policy uncertainties are described below, in the following subsections IV.A.iii.a and IV.A.iii.b.

a. Operational Uncertainties

A key consideration for the owner of a Capacity Resource contemplating Deactivation is whether they will be physically able to dependably operate their resource during the future Delivery Year. By definition, many of the resources contemplating Deactivation are old and nearing the end of their operational life. This reality tends to exacerbate several factors critical to the predictability of future operations. The first is the availability and long-term procurement of fuel. Global instability, supply chain disruptions, transportation and storage bottlenecks, and contractual rigidity in price/volume take, duration, and collateral credit requirements can make accurately forecasting the price and future availability of both the fuel commodity itself and delivery challenging, particularly for resources that may be operating under shorter time horizons due to their vintage.

The second factor that can exacerbate uncertainty around the future ability of an older Capacity Resource to operate is project investment. These facilities tend to need significant investment in their physical plant to continue reliable operations when compared to newer facilities. In PJM, this fact can be seen in the scale of identified project investment for units

that are required to continue operations via Reliability Must-Run ("RMR") arrangements with the RTO. For example, in its April 18, 2024, application for cost recovery for the Brandon Shores facility in Maryland, Talen Energy identified nearly $30,000,000 in anticipated project investment to ensure the availability of the facility for PJM scheduling and dispatch.[83]

Finally, employee retention has remained an ongoing challenge for resource owners, as an aging workforce and the geographic isolation of many power plants limits the availability of skilled personnel needed to operate these facilities, particularly as they near the end of their useful life. Additionally, competition for the labor skill sets required to operate power plants is also increasing from other sectors of the economy. To this point, the Department of Energy in its 2026 United States Energy and Employment Report, ("USEER") found that "energy employers are increasingly competing for workers not only with other energy companies, but also with fast-growing data centers, infrastructure projects, advanced manufacturing facilities, and critical minerals industries" as "[t]hese sectors rely on many of the same skilled occupations, including electricians, electrical engineers and technicians, industrial maintenance workers, construction trades workers, and production workers."[84] These challenges can add to uncertainty regarding the staffing needed to ensure the operational availability of Capacity Resources in the future.

b. Environmental Policy Uncertainties

In addition to the operational uncertainties described above, a key consideration for the owner of a Capacity Resource contemplating Deactivation is whether they will be able to

[83] *Brandon Shores LLC*, Continuing Operations Rate Schedule of Brandon Shores LLC, Docket No. ER24-1790-000, at 18 (Apr. 18, 2024).

[84] U.S. Dep't of Energy, 2026 United States Energy and Employment Report, at 24 (2026), https://www.energy.gov/documents/2026-useer-national-report.

legally operate their resource, and under what environmental regulations, during the future Delivery Year. Environmental regulations at both the federal and state level directly impact the operation of Capacity Resources, and can change significantly from year to year.

For example, federal environmental policy has been particularly volatile in recent years, as reflected in Figure Exelon-1, which illustrates the major changes to federal carbon dioxide regulation policy that have occurred *just* over the last decade.

Figure Exelon-1
Major Changes in Federal Regulation of Carbon Dioxide
2015-2026

Date	Federal Carbon Dioxide Regulation Event
August 3, 2015	The EPA finalizes the Clean Power Plan, which aims to reduce carbon dioxide emissions from the power sector by 32% below 2005 levels by 2030.[85]
February 9, 2016	The United States Supreme Court stays the implementation of the Clean Power Plan, pending further proceedings before the United States Court of Appeals for the District of Columbia Circuit ("D.C. Circuit").[86]
June 19, 2019	The EPA finalizes the Affordable Clean Energy Rule, which repeals the Clean Power Plan.[87]
January 19, 2021	The D.C. Circuit vacates the Affordable Clean Energy Rule.[88]
June 30, 2022	The United States Supreme Court rejects EPA's attempt to revive the Clean Power Plan, and limits EPA's ability to regulate carbon dioxide emissions from power plants under the Clean Air Act.[89]
April 25, 2024	The EPA announces final Carbon Pollution Standards requiring that all long-term coal-fired plants and base load new gas-fired plants control 90% of their carbon emissions.[90]
September 17, 2026	The EPA repeals most of the Carbon Pollution Standards and solicits comment on additional reasons to rescind all greenhouse gas emission requirements for fossil fuel-fired generators.[91]

[85] *See* U.S. Env't Prot. Agency, *Fact Sheet: Overview of the Clean Power Plan* (last updated May 9, 2017), https://archive.epa.gov/epa/cleanpowerplan/fact-sheet-overview-clean-power-plan.html

[86] *See Chamber of Commerce v. EPA,* 136 S. Ct. 999 (2016) (order granting stay), https://www.supremecourt.gov/orders/courtorders/020916zr3_hf5m.pdf.

[87] *See* U.S. Env't Prot. Agency, *Affordable Clean Energy* (last updated Mar. 12, 2026), https://www.epa.gov/stationary-sources-air-pollution/affordable-clean-energy-rule.

[88] *Am. Lung Assoc. v. EPA*, 985 F.3d 914 (D.C. Cir. 2021).

[89] *W. Va. vs. EPA*, 597 U.S. 697 (2022).

[90] *See* U.S. Env't Prot. Agency, *Supporting Information – Final Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants* (last updated May 20, 2026), https://www.epa.gov/stationary-sources-air-pollution/supporting-information-final-greenhouse-gas-standards-and.

[91] *See* Partial Repeal of the Carbon Pollution Standards for Fossil Fuel-Fired Electric Generating Units, 91 Fed Reg. 58,954 (Sept. 17, 2026), https://www.federalregister.gov/documents/2026/09/17/2026-19071/partial-repeal-of-the-carbon-pollution-standards-for-fossil-fuel-fired-electric-generating-units.

The impact of federal environmental policy can also be seen in the words of PJM resource owners themselves, through their Deactivation notices to PJM. For example, in its July 22, 2025, Deactivation notice to PJM for the Kincaid facility, Vistra Corp. explained that "[t]he Kincaid Units will cease operations by this date in order to comply with the U.S. Environmental Protection Agency's (EPA) Coal Combustion Residual (CCR) Rule, 40 C.F.R. Part 257, Subpart D."[92]

Beyond federal environmental policy, uncertainty and future assumptions regarding state environmental policy can also impact Deactivation decisions. Indeed, a review of generator Deactivation notices in PJM from the last three years makes clear that prospective assumptions regarding the future applicability of state environmental regulations are a key driver for Deactivation decisions in the PJM Region, as illustrated in Figure Exelon-2.

Figure Exelon-2
References to State Environmental Regulations in PJM Deactivation Notices
2023-2026

Deactivation Letter	Date	Reason Given in Deactivation Letter
Cumberland CT	August 26, 2024	*"Calpine's Cumberland CT 1 generating facility in its current state will be physically unable to perform in the Delivery Year 2027/2028 as a result of finalized regulations in connection with New Jersey's efforts to limit carbon emissions from power plants."*
Sherman Avenue	August 26, 2024	*"Calpine's Sherman Avenue generating facility in its current state will be physically unable to perform in the Delivery Year 2027/2028 as a result of finalized regulations in connection with New Jersey's efforts to limit carbon emissions from power plants."*

[92] Vistra's July 22, 2025, Deactivation Letter is available on the PJM Website. *See* Deactivation Notice Letter for Kincaid Generation, L.L.C, from Jessica H. Miller, Vice President & Assoc. Gen. Counsel, Vistra Corp., to PJM Generation Manager (July 22, 2025), https://www.pjm.com/-/media/DotCom/planning/gen-retire/deactivation-notices/kincaid-deactivation-letter.pdf.

Elwood	May 28, 2024	*"Given current and expected market conditions and ongoing Illinois regulatory uncertainty, operation of Elwood is expected to continue to be uneconomic."*
Fisk	June 30, 2026	*"Pursuant to the Illinois Climate and Equitable Jobs Act ("CEJA"), the Units are required to "permanently reduce all CO2e and copollutant emissions to zero, including through unit retirement" by January 1, 2030. As such, MWG intends to retire the Units on January 1, 2030."*
Elgin	May 10, 2024	*"MRP Elgin is planning to retire the Units as of June 1, 2025 in light of PJM market conditions and operating restrictions imposed by the stringent emissions limits under the Illinois Climate and Equitable Jobs Act. Given these circumstances, continued operation of the Units is expected to be uneconomic relative to other opportunities."*
Zion	June 22, 2026	*"Constellation intends to retire these units in compliance with the Illinois Climate and Equitable Jobs Act (CEJA), which requires certain electric generation resources to reduce all CO2 and co-pollutant emissions to zero, including through unit retirement, on or before January 1, 2030."*
Sayreville	December 29, 2023	*"The New Jersey Department of Environmental Protection (NJDEP) issued a final regulation on January 3, 2023 establishing CO2 emissions rates limits for in-state electric generating units (EGUS) sized 25 MW and larger. The Sayreville units are unable to operate within the limitation that go into effect on June 1st, 2024, 1,700 lbs CO2/MWh. These new regulations will require New Jersey-located EGUs to retire if they are unable to meet the established CO2 emissions rates limits unless granted a reliability extension by the NJDEP."*
Brandon Shores	April 6, 2023	*"The Brandon Facilities' National Pollution Discharge Elimination System ("NPDES") permit precludes operation using coal on or after January 1, 2026. Brandon had previously been evaluating a conversion of the Brandon Facilities to fuel oil combustion but has determined that, under current capacity market rules, such a conversion is uneconomic and does not justify operating after June 1, 2025. The Brandon Facilities have capacity market obligations through May 31, 2025."*
H.A. Wagner	October 16, 2023	*"The Wagner Facilities' Title V air permit limits operation to capacity factors under 15% when operating on oil. The limited run hours on the Wagner Facilities are not sustainable to continue operations, especially in light of the amount of time the Wagner Facilities have recently been running in the market. The combination of low margin energy market*

		economics, low-capacity prices and significant Capacity Performance penalty risk due to run hour limitations results in the economics being outweighed by the risk associated with continued operation. The Wagner Facilities have capacity market obligations through May 31, 2025."
Cardinal	July 22, 2026	*"[U]nless and until such conditions are satisfied, or waived by Buckeye in its discretion, continued operations past December 31, 2028, will not be possible based on the requirements of the EPA NOPP and the Sierra Club Agreement. Should these conditions be satisfied, or waived by Buckeye in its discretion, Buckeye reserves the right to withdraw its deactivation notice and participate in future PJM capacity auctions for the 2029/2030 Delivery Year and thereafter."*
University Park North Station	June 30, 2026	*"LSPUP is deactivating these units due to uneconomic compliance requirements of the Illinois Climate and Equitable Jobs Act."*
Rocky Road	February 6, 2026	*"Dairyland intends to retire the Unit due to its inability to meet operational restrictions imposed on the Unit by the Clean Air Act Permit Program ("CAAPP") permit issued by the Illinois Environmental Protection Agency ("EPA")."*
Forked River 1	February 24, 2025	*"Forked River's Unit-1 generating facility in its current state will be physically unable to perform in the Delivery Year 2027/2028 as a result of finalized regulations in connection with New Jersey's efforts to limit carbon emissions from power plants. Thus, as affirmed by this submission, Forked River plans to retire the Unit-1 generating facility before the commencement of the 2027/2028 delivery year and provides this Notice of Deactivation."*
Forked River 2	February 24, 2025	*"Forked River's Unit-2 generating facility in its current state will be physically unable to perform in the Delivery Year 2026/2027 because of its inability to meet NJ air permit requirements. Thus, as affirmed by this submission, Forked River plans to retire the Unit-2 generating facility before the commencement of the 2026/2027 delivery year and provides this Notice of Deactivation."*

Given the outsized role that prospective assumptions regarding the future applicability of operational and environmental policy play in Deactivation decisions in the PJM Region, the stability and veracity of those assumptions are, by extension, critical to the determination of whether or not a Deactivation decision is efficient for the market and economic for the resource

owner in the context of RPM's three-year forward period. And therein lies the problem. Given the protean nature of the operational uncertainties and environmental policy considerations described above, a three-year forward period is often too long for resource owners to develop confidence that they will be permitted to continue operation of their Capacity Resources in the future. The decision these resource owners are left with in light of that ambiguity is simple—exit the market to avoid significant and hard-to-predict regulatory risks, even if it might otherwise be efficient for the market and economic for the resource owner to stay.

Importantly, the uncertainty in operational availability and environmental policy described above also incentivizes the owners of Capacity Resources that remain in the market to include a "risk premium" in their RPM offers, especially when the auction is run three years forward. As Dr. Nicholson explains, under PJM's Capacity Performance construct, this uncertainty is reflected in a resource's CPQR component of a capacity sell offer, meaning that the three-year forward period directly inflates the risk premium that owners of resources near the end of their economic life must build into their capacity supply offers, or exit the market rather than attempt to price that risk at all.[93] This dynamic is not unique to PJM. As ISO-NE explained in proposing a prompt capacity auction, "the uncertainty about whether a new or existing resource will be available to perform three years into the future can be reflected in suppliers' capacity offers or bids through higher risk premiums, increasing Capacity Clearing Prices over what those prices would have been had the auction been held closer in time to the Capacity Commitment Period, where sellers would have more certainty about their performance and the costs associated with holding an obligation."[94]

[93] Nicholson Affidavit, at ¶¶ 40-43.

[94] *Id.* at ¶ 41 & n. 63 (citing ISO-NE Transmittal, Docket No. ER26-925, at 24 (December 30, 2025)).

In summary, the current three-year forward period inhibits efficient resource exit and Deactivation, as it requires generation owners to take on capacity commitments and make capital investments in the absence of reasonable predictability in future operational capability and environmental policy. It also leads to higher capacity prices by causing the owners of Capacity Resources to include a "risk premium" in their RPM offers to account for these uncertainties.

iv. PJM's current capacity accreditation methodology (ELCC) bears no resemblance to the eFORd model considered by the Commission in 2006, and the three-year forward period forces PJM to integrate speculative assumptions into its ELCC modeling.

At the time of the Commission's 2006 approval of RPM's multi-year forward period, PJM used a capacity accreditation methodology known as Equivalent Forced Outage Rate - demand, or "eFORd." This methodology focused on historic, unit-specific metrics that measured the percentage of time that a specific unit was forced out of service or unable to run when called upon. For various reasons, including the nature of the then-prevailing generation mix and the types of operational risks faced by the PJM Region, eFORd was supportable when RPM was accepted. Additionally, because eFORd relied on a resource's own historical performance rather than on system-wide, forward-looking modeling of the resource mix, it had a high level of predictability, stability, and replicability for resource owners.

On July 30, 2021, the Commission accepted PJM's proposal to transition from eFORd to a new capacity accreditation methodology, known as Effective Load Carrying Capability ("ELCC").[95] Unlike eFORd, ELCC considers the simultaneous reliability contribution of *all* resources, and recognizes the complementary and antagonistic interactions among the

[95] *PJM Interconnection, L.L.C.*, 176 FERC ¶ 61,056 (2021).

resources expected to be able to provide capacity in a given Delivery Year. In general, a resource that contributes a significant level of capacity during high-risk hours (*i.e.*, hours with very high electricity demand and low resource output) will have a higher capacity value under ELCC than a resource that delivers the same generating capability but only during low-risk hours. These risk hours may vary as the resource mix changes (*e.g.*, more wind and solar resources are installed) and hours of high demand evolve (*e.g.*, wide-scale electric car charging at night).[96]

As explained by Dr. Nicholson, the process by which PJM implements the ELCC model involves an extraordinary amount of data and analysis.[97] Specifically, ELCC class accreditations are derived from sophisticated probabilistic modeling that estimates each resource class's reliability contribution across a wide range of system conditions, placing the greatest weight on the hours of greatest reliability risk, and PJM must update and re-run this analysis as the assumed resource mix and load profile change from year to year.[98]

Given the volume of data and analytical complexity involved in implementing the ELCC model, the accuracy and replicability of PJM's ELCC model has remained an issue of paramount concern within the PJM Region since the model's inception in 2021. These concerns have been expressed directly to the PJM Board by the Organization of PJM States, Inc. ("OPSI"), with OPSI arguing that "[t]he accuracy of the ELCC methodology is essential and necessary to ensure that it reflects the true ability of supply to meet demand and secure the

[96] PJM's current ELCC methodology is set forth in RAA, Schedule 9.2 and implemented through PJM Manuals 21A and 21B.

[97] Nicholson Affidavit, at ¶¶ 44-50.

[98] *Id.*, at ¶ 47.

reliability needs of the region."[99] Indeed, in its August 4, 2025, letter approving the Forecast Pool Requirement ("FPR") and the Installed Reserve Margin ("IRM") for the 2027/2028 Delivery Year BRA, the PJM Board acknowledged that at the Markets and Reliability Committee ("MRC") and Members Committee ("MC") "[a]dditional concerns were expressed about the methodology utilized to determine Effective Load Carrying Capability (ELCC) values that are derived from the same reliability analysis that produces the FPR and IRM."[100] The Board accordingly directed PJM to engage a consultant to examine the ELCC methodology to identify improvements. The consultant's report was published in December 2025,[101] and included multiple recommendations regarding how to enhance transparency and accuracy.

Yet the current three-year forward period of RPM works *against* model accuracy and replicability by forcing PJM to integrate assumptions that are almost certain to change over the course of three years. As explained by Dr. Nicholson, under ELCC PJM must estimate the resource mix that will actually be available during the Delivery Year (including the mix of thermal, intermittent, and storage resources expected to be in service, and the retirements and new entry assumed to occur before that year) approximately three and a half years before the start of the Delivery Year, because capacity suppliers must know their accreditation values

[99] Letter from Emile Thompson, President, Org. of PJM States, Inc., to David Mills, Chair, PJM Bd. of Managers, & Manu Asthana, President & CEO, PJM Interconnection, L.L.C., at 2 (Aug. 28, 2025), https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/2025/20250828-opsi-letter-re-consultant-review-of-elcc-methodology.pdf.

[100] Letter from David E. Mills, Chair, PJM Bd. of Managers, to PJM Stakeholders, at 1 (Aug. 4, 2025), https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/2025/20250804-board-correspondence-re-irm-and-fpr.pdf.

[101] Energy+Environmental Economics, *PJM ELCC/ RRS Model Evaluation: Prepared for PJM* (Dec. 2025), https://www.pjm.com/-/media/DotCom/committees-groups/task-forces/elccstf/2025/20251209/20251209-item-02---pjm-elcc-rrs-model-evaluation---e3-report.pdf.

before the BRA.[102] These assumptions are far from static: PJM's own preliminary ELCC estimates show that accreditation values for a given resource class can shift materially from one year's estimate to the next, with storage resource ELCC values in particular projected to decline significantly across upcoming Delivery Years as PJM's assumptions about extended cold-weather charging constraints evolve, and with the gas combustion turbine reference class also experiencing meaningful changes. This dynamic can be seen in Figure 4 of the Nicholson Affidavit, which shows the final ELCC values for Delivery Years 2028/2029 and 2029/2030 along with PJM's preliminary estimate for Delivery Years 2030/2031 and 2031/2032.

Nicholson Affidavit - Figure 4
Actual and Preliminary ELCC Values, Delivery Years 2028/29 Through 2032/33

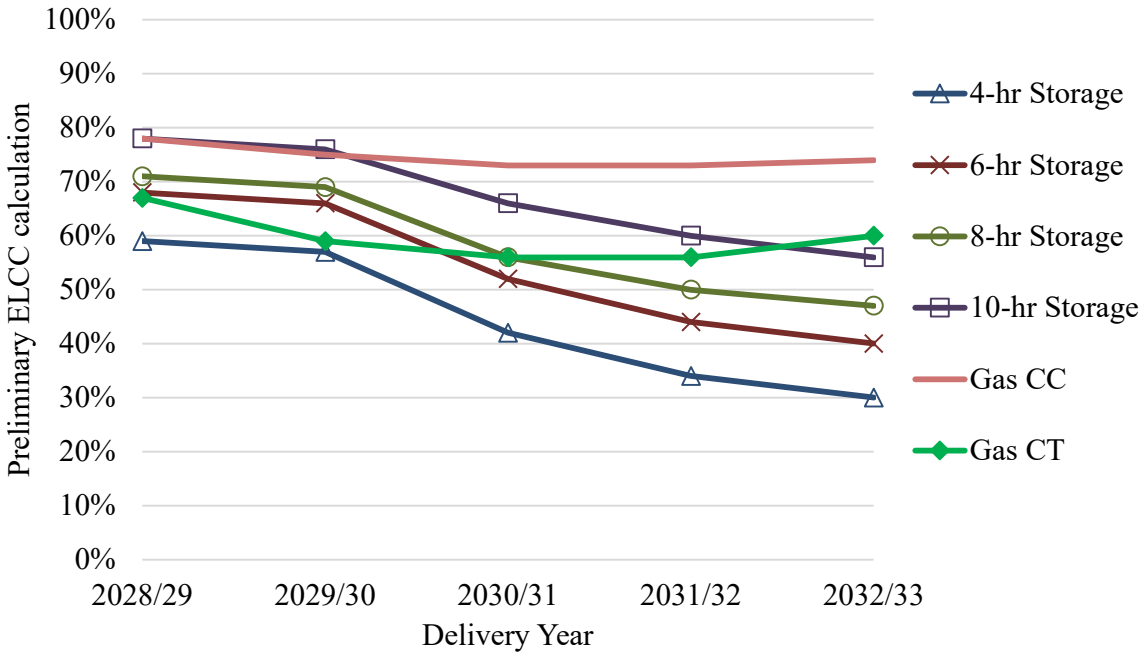


Figure 4 of the Nicholson Affidavit illustrates just how much projected and actual ELCC values can change over the three-year forward period of RPM depending on the

[102] Nicholson Affidavit, at ¶ 46.

assumptions used, such as the assumed resource mix and system loads. Because even modest shifts in ELCC accreditation can translate into substantial swings in a resource's qualifying capacity, and, in the aggregate, in the auction's supply curve and clearing price, basing those accreditation values on three-and-a-half-year-old assumptions introduces significant inaccuracy into the BRA that a shorter forward period would not.[103] Owing to the resulting inaccuracies, BRA prices can diverge from what underlying supply and demand fundamentals would otherwise produce, rendering the current three-year forward period unjust and unreasonable.

v. The current three-year forward period undermines the accuracy of other BRA planning parameters, including the assumed resource mix in each Locational Deliverability Area used to calculate CETO/CETL values, leading to unjust and unreasonable results.

The planning parameters used in a given BRA play a critical role in the auction's outcome. For example, RPM utilizes an administratively set demand curve—the Variable Resource Requirement Curve ("VRR Curve")—which represents the prices that consumers should be willing to pay for varying quantities of capacity. In developing the demand curve for a given BRA, PJM forecasts the expected peak load for a particular Delivery Year and then sets a target level of capacity needed to reliably serve the load—also known as the Reliability Requirement—given the expected resource portfolio. The auction's supply curve is based on Sell Offers for capacity that Capacity Market Sellers submit at a specific price and, together, the offers comprise the auction's supply curve. RPM is a *locational* market, meaning there are defined areas within the PJM Region that have limits on the amount of capacity they can import. Those areas are LDAs, which recognize and quantify the locational value of capacity

[103] *Id.*, at ¶¶ 46, 49-50.

within the PJM Region. As relevant here, the modeled LDAs are determined by comparing the import limit of an LDA (CETL) with the amount of capacity that needs to be imported into a LDA to meet the reliability criterion (CETO). Sell Offers are located in specific LDAs based on where those resources are located.

The accuracy of the planning parameters used in a given auction are only as good as the data upon which they are based. As Dr. Nicholson explains, the three-year forward period *undermines* the accuracy of certain planning parameters, including CETO and CETL, because these values depend on assumptions about the resource mix and transmission topology that will actually exist in each LDA during the Delivery Year.[104] As with the ELCC and load forecast inputs discussed above, these assumptions are far less reliable when projected three and a half years in advance than when set closer to the Delivery Year. These inaccuracies and uncertainties introduced into the CETO and CETL parameters can, in turn, lead to capacity prices that do not reflect market fundamentals in the Delivery Year by misrepresenting the transmission system's ability to transfer capacity.[105] This can lead to unjust and unreasonable outcomes. Indeed, the idea that inaccurate planning parameters can warp the outcome of a given BRA and disassociate it from basic market fundamentals is unfortunately not an academic one. In December 2022, PJM discovered that certain Planned Generation Capacity Resources and planned Intermittent Resources in the DPL South LDA did not offer into the 2024/2025 Delivery Year BRA, notwithstanding the fact that such resources were included by PJM years earlier in the modeling assumptions (CETO) that formed the DPL South LDA Reliability Requirement. The absence of these resources from the 2024/2025 BRA resulted in

[104] *Id.*, at ¶ 52.

[105] *Id.*

an *overstated* LDA Reliability Requirement, and led to a dramatically higher clearing price that was wholly unrepresentative of the actual capacity needs of the LDA.[106] As the Independent Market Monitor ("IMM") described it, the clearing prices for DPL South "do not reflect the actual market supply and demand fundamentals, overstate the local reliability requirement, serve no useful purpose, and are therefore unjust and unreasonable."[107]

Accordingly, the three-year forward period of RPM is unjust and unreasonable, because it undermines the accuracy of important BRA planning parameters, including the assumed resource mix in each LDA used to calculate CETO/CETL values, leading to market outcomes divorced from underlying supply and demand conditions.

B. The Commission Should Adopt a Prompt Auction Schedule as the Just and Reasonable Replacement Rate.

In the event that the Commission finds the three-year forward period of RPM to be unjust, unreasonable, unduly discriminatory or preferential under FPA section 206, Exelon proposes the Commission direct PJM to adopt as a replacement rate a "prompt" BRA schedule, to run two months before a given Delivery Year, starting with the 2030/2031 Delivery Year BRA, currently scheduled for May 2027, and beyond. The Commission need not treat this proposal as novel or untested. To the contrary, the Commission has *already found*, on at least three occasions—for *all* of the other centralized capacity market structures in its jurisdiction—that a prompt capacity auction schedule is just and reasonable. Most recently, on March 30, 2026, the Commission accepted ISO-NE's proposal, filed jointly with the New England Power Participants Committee, to replace its three-year forward capacity market with a prompt

[106] *See generally* Docket No. ER23-729-000.

[107] *PJM Interconnection, L.L.C.*, Comments of the Independent Market Monitor of PJM, Docket No. ER23-729-000 (Jan. 20, 2023).

capacity market in which an Annual Capacity Auction is held approximately one month before the relevant Capacity Commitment Period, effective March 31, 2026.[108] In accepting ISO-NE's proposal, the Commission expressly relied on its prior orders finding that MISO's prompt capacity auction schedule, under which MISO holds its auction two months before the delivery year, is just and reasonable.[109] The Commission has likewise accepted prompt auctions relying on near-term procurement in NYISO.[110] For the reasons discussed below, moving to a prompt schedule in PJM will provide the same substantial benefits, and particularly so in the dynamic and uncertain environment currently facing the PJM Region.

i. A prompt auction will significantly improve the accuracy of key BRA auction parameters, resulting in capacity prices that better reflect actual supply and demand fundamentals and system conditions in the Delivery Year.

A prompt auction schedule will significantly enhance the accuracy of key BRA auction parameters, thereby resulting in capacity prices that better reflect actual market fundamentals and system conditions in the Delivery Year. As Dr. Nicholson explains, a shorter forward period would reduce forecast uncertainty across each of the BRA's key inputs. Specifically, it would allow PJM to forecast peak demand closer to the Delivery Year, reducing the risk of over-forecasting load and procuring more capacity than is actually needed, while also allowing PJM to base ELCC accreditation values on a resource mix and system conditions that are far more likely to reflect what will actually exist during the Delivery Year rather than a three-and-

[108] *See* ISO-NE Order, at P 1.

[109] *Id.,* at P 32 (MISO Order, at PP 70-74 (finding that MISO's prompt capacity auction market design may be beneficial because "[load-serving entities] can accurately forecast their loads by taking into consideration changes such as those resulting from shifting economic conditions and MISO can accurately account for transmission constraints, forced outage rates, and expected performance of Load Modifying Resources"); MISO Rehearing Order, at PP 125-26).

[110] *See N.Y. Indep. Sys. Operator, Inc.*, 179 FERC ¶ 61,102, at PP 2-3 (2022).

a-half-year-old projection.[111] It would also improve the accuracy of CETO/CETL values and the resulting Local Deliverability Area Reliability Requirements, which likewise depend on assumptions about the future resource mix and transmission topology.[112]

The net effect of this enhanced accuracy in BRA auction parameters is self-evident—capacity prices that better reflect actual market fundamentals and system conditions. The Commission has previously found this policy outcome to be just and reasonable. Specifically, in accepting ISO-NE's prompt auction schedule, the Commission found that the shorter forward period would "reduce demand uncertainty because the Installed Capacity Requirement will be calculated using data that is closer in time to the Capacity Commitment Period" and would "result in more accurate Qualified Capacity values for resource accreditation."[113] Similarly, in the Commission's order accepting MISO's prompt auction schedule as just and reasonable, the Commission found that "MISO's prompt Auction design allows load forecasting to occur within the year leading up to the Planning Year."[114] The Commission acknowledged the inherent benefits of this change, finding that "LSEs can accurately forecast their loads by taking into consideration changes such as those resulting from shifting economic conditions and MISO can accurately account for transmission constraints, forced outage rates, and expected performance of Load Modifying Resources."[115]

[111] Nicholson Affidavit, at ¶¶ 54-55.

[112] *Id.*, at ¶ 56.

[113] ISO-NE Order, at P 32 (citing to ISO-NE Transmittal, at 23-30).

[114] MISO Order, at PP 70-74 (finding that MISO's prompt capacity auction market design may be beneficial because "[load-serving entities] can accurately forecast their loads by taking into consideration changes such as those resulting from shifting economic conditions and MISO can accurately account for transmission constraints, forced outage rates, and expected performance of Load Modifying Resources"); MISO Rehearing Order, at PP 125-26.

[115] MISO Order, at PP 70-74.

The same legal and policy rationale the Commission used in the ISO-NE Order and the MISO Order apply with equal if not greater force here. The closer in time that PJM establishes its Installed Reserve Margin, ELCC accreditation values, CETO/CETL, and other key BRA auction parameters to the actual Delivery Year, the more those parameters will reflect the resource mix, load conditions, and system topology that actually exist, rather than a years-old projection of what they might be. These rationales are only strengthened by the rapidly changing conditions currently facing the PJM Region; that is, the demands of large loads and associated forecasting challenges, as well as the evolving resource mix and a shifting policy environment.

ii. A prompt auction will significantly enhance the quality of information and the accuracy of the price signal used in generator Deactivation decisions.

By definition, a prompt auction schedule narrows the window across which resource owners must attempt to forecast future operational, environmental, regulatory, and market conditions when deciding whether and how to bid into a BRA and commit their Capacity Resources for a Delivery Year. As explained by Dr. Nicholson, this in turn enhances the quality and accuracy of the price signal that RPM sends to those resource owners in two distinct ways.[116]

First, it increases the economic efficiency of resource exit from the market. This enhanced efficiency in market exit will become increasingly important in the PJM Region in the coming years, as a substantial volume of existing capacity in the PJM Region is expected to reach the end of its useful life and retire.[117] Some aging capacity has been kept operational

[116] *See* Nicholson Affidavit, at ¶ 57.

[117] *Id.*; *See also* PJM White Paper, at 16.

in response to high prices. Additional capacity has been kept operational by out-of-market mechanisms, such as RMR arrangements and FPA section 202c orders from the Department of Energy, but these interventions are, by definition, temporary and not designed as primary tools to achieve long-term resource adequacy. Furthermore, as generating assets continue to age, keeping them operational will become prohibitively expensive, their operations will become even more challenging, and the resulting policy goal should be to *manage* their exit, not keep them online indefinitely. To this point, the Commission has previously found proposals that increase the efficiency of economic market entry and exit to be just and reasonable.[118]

Second, a prompt auction allows resource owners that choose to remain in the market to "de-risk" their capacity supply offers by removing the need to price in the multi-year "operational and policy-uncertainty" premium described above in Section IV.A.iii.[119] This should apply downward pressure to capacity prices.

In short, the shift to a prompt structure will significantly enhance the quality of information and the accuracy of the investment signal used in resource owner market exit and Deactivation decisions. Specifically, a prompt structure will allow commitment decisions to be based on more current information, which will allow resource owners to better assess a Capacity Resource's remaining economic life, operating condition, needed capital

[118] *See e.g. Midcontinent Independent System Operator, Inc.,* 187 FERC ¶ 61,102, at P 80 (2024) (finding MISO's RBDC proposal to adopt a sloped demand curve in the Auction to be just in reasonable in part because it will result in capacity price signals that will "provide better incentives for efficient resource entry and exit," among other reasons), *modified on denial of reh'g* by *Midcontinent Independent System Operator, Inc.,* 189 FERC P 61159 (2024); *ISO New England, Inc.*, 173 FERC ¶ 61,161, at PP 48–50 (2020) (agreeing on rehearing that a capacity market design "appropriately allows the [Forward Capacity Market] to provide the proper price signal to trigger entry and exit of capacity supply resources," and finding that the Commission had properly "considered ... whether the [Forward Capacity Market] provides the proper price signals to trigger appropriate entry and exit of capacity resources").

[119] Nicholson Affidavit, at ¶ 57.

improvements, and market risks (*e.g.*, Capacity Performance risk), producing in aggregate outcomes that better reflect the actual state of the PJM fleet as it ages, and capacity prices that more accurately reflect the avoidable going forward costs of resources.

iii. A prompt auction schedule will significantly enhance the quality of data used in PJM's ELCC capacity accreditation, thereby better aligning both price and payments with resource contributions to resource adequacy.

Another important benefit to a prompt auction schedule is the enhanced quality of the data inputs used in PJM's ELCC capacity accreditation process. PJM's capacity accreditation methodology has grown substantially more complex and data-intensive since the Commission first approved the current multi-year forward period in 2006. As noted above, in 2021 the Commission approved PJM's transition from its longstanding eFORd methodology to an ELCC approach. In 2024 the Commission accepted PJM's proposal to make further enhancements by transitioning to a "marginal" ELCC framework and extending ELCC accreditation to all Generation Capacity Resources. In doing so, the Commission acknowledged a key underlying concern with ELCC in relation to the RPM's three-year forward period—namely that "PJM's RPM aims to ensure resource adequacy for a future delivery year, and as such, there will inevitably be differences between the resource mix forecasted at the time of the auction and the actual, cleared resource mix."[120] Nonetheless, the Commission found that PJM had demonstrated that any differences between the forecasted and cleared resource mix are unlikely to introduce significant capacity accreditation errors.[121] Specifically, the Commission found that, based on PJM's sensitivity analysis at the time, the forecast error was likely to be a "negligible amount" (an estimated 115 MW out of a 170,000

[120] *PJM Interconnection, L.L.C.*, 186 FERC ¶ 61,080, at P 75 (2024).

[121] *Id.*, at P 76.

MW system).[122] As discussed above in Section IV.A.iv, data over the last two years has disproven this assumption.[123]

Adopting a prompt auction will significantly improve the quality of data used in PJM's ELCC modeling, thereby better addressing the Commission's original concern in 2024 regarding the "differences between the resource mix forecasted at the time of the auction and the actual, cleared resource mix."[124] As Dr. Nicholson explains, because a prompt auction would base ELCC accreditation on a resource mix and system conditions far closer to the actual Delivery Year, this will lead to superior economic outcomes by reducing both over- and under-accreditation of resources and the resulting mispricing of capacity.[125] Indeed, the Commission has already found that a prompt auction schedule produces more accurate capacity accreditation values, including in the ISO-NE Order where the Commission found as just and reasonable a prompt auction schedule that would "result in more accurate Qualified Capacity values for resource accreditation."[126]

Finally, a prompt auction schedule will allow Capacity Resources that have previously received a capacity commitment to have their accreditation values recalculated annually, using more up-to-date data. This provides several benefits, including ensuring that a resource's accredited capacity value reflects the resource mix and system conditions that actually prevail closer to the Delivery Year, rather than a three-and-a-half-year-old projection, giving resource

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[122] *Id*.

[123] *See* Nicholson Affidavit, at ¶¶ 44-50.

[124] *See PJM Interconnection, L.L.C.*, 186 FERC ¶ 61,080 (2024) (approving PJM's transition to a marginal ELCC framework and acknowledging that the resource mix forecasted at the time of the auction will inevitably differ from the actual, cleared resource mix).

[125] Nicholson Affidavit, at ¶ 58.

[126] ISO-NE Order, at P 32.

owners better information with which to construct their capacity supply offers and plan maintenance and retirement decisions, and reducing the risk that a resource is over- or under-credited relative to its true reliability contribution.

iv. A prompt auction will significantly reduce the risks to new resources seeking to enter the market by creating more certainty regarding their expected availability for the Delivery Year.

A prompt auction will significantly reduce the risks, for customers and suppliers, associated with the timing of new resources entering the market, as resources will have more certainty about their expected availability for each Delivery Year, and particularly their first Delivery Year in service. This will directly address the problem that the Commission has previously described as "phantom entry," where resources that receive a capacity commitment years in advance are not actually operational in time for the delivery period.[127] As the Filing Parties explained in the ISO-NE proceeding, this phantom entry problem can raise capacity prices when the risk of non-commercial operation is priced into capacity offers.[128]

As explained by Dr. Nicholson, to the extent that it exists in PJM, a prompt auction would directly address the problem of "phantom entry" by allowing only those resources that have actually achieved, or are on the imminent path to achieving, commercial operation to participate, rather than requiring new entrants to make a binding capacity commitment years before they can demonstrate they will actually be available.[129] This will provide both PJM and Market Participants with far greater certainty regarding actual resource availability for the applicable Delivery Year.

[127] *See* ISO-NE Order, at PP 13, 32.

[128] *Id.,* at P 13.

[129] Nicholson Affidavit, at ¶ 59.

V. REFUND EFFECTIVE DATE

As discussed above, Exelon respectfully requests that the Commission establish a refund effective date of January 1, 2027, and permit Fast Track processing under Rule 206(h) to facilitate a Commission order by no later than January 31, 2027—currently the last day before the posting of the planning parameters for the 2030/31 Delivery Year BRA.

VI. RULE 206 REQUIREMENTS

To the extent not already provided above, Exelon provides the following additional information required by Rule 206 of the Commission's Rules of Practice and Procedure.[130] Exelon respectfully requests waiver of any part of the Commission's regulations necessary to process this filing.

A. Good faith estimate of financial impact or harm (Rule 206(b)(4))

The complaint sets forth in detail above the financial impact and harm to PJM Market Participants caused by the three-year forward period of RPM.

B. Practical, operational, or nonfinancial impacts (Rule 206(b)(5))

The practical, operational, and nonfinancial impacts of the RPM's three-year forward period are described at length in the sections above.

C. Whether the matters are pending in any other FERC proceeding or other forum (Rule 206(b)(6))

The issue of whether the three-year forward period of RPM has become unjust and unreasonable under FPA section 206, as presented in this complaint, is not to Exelon's knowledge pending in any other existing Commission proceeding or forum in which Exelon is a party.

[130] 18 C.F.R. § 385.206.

D. Specific relief or remedy requested (Rule 206(b)(7))

The complaint sets forth in detail the specific relief requested.

E. Documents supporting the complaint (Rule 206(b)(8))

This filing consists of the following:

- This Transmittal Letter;
- Affidavit of Dr. Emma Nicholson, included as Attachment A;
- Affidavit of Deborah M. Sears, included as Attachment B; and
- A Form of Notice, included as Attachment C.

F. Use of alternative dispute resolution (Rule 206(b)(9))

Exelon has not used the Enforcement Hotline, Dispute Resolution Service, tariff-based dispute resolution mechanisms, or other informal dispute resolution procedures, because the complaint argues that the three-year forward period of RPM is no longer just and reasonable, and is therefore unlawful under FPA section 206. Only the Commission has the legal authority to provide the statutory remedy that the complaint requests. For this reason, Exelon does not believe that alternative dispute resolution ("ADR") under the Commission's supervision could successfully resolve the complaint, nor could any specific ADR procedures. Exelon has not agreed to any process for resolving the complaint outside of the instant proceeding.

G. Notice (Rule 206(b)(10))

Exelon has appended a form of notice of this filing for publication in the *Federal Register*, in accordance with the specifications in section 385.203(d) of the Commission's rules.

H. Request for Fast Track Processing (Rule 206(b)(11))

As described above, Exelon respectfully requests that the Commission permit Fast Track processing under Rule 206(h) to facilitate a Commission order by no later than January

31, 2027—currently the last day before the posting of the planning parameters for the 2030/31 Delivery Year BRA.

VII. SERVICE AND NOTICE

In accordance with Rule 206(c), Exelon has served a copy of this complaint upon PJM, as Respondent, simultaneously with the filing of the complaint.

VIII. CONCLUSION

Wherefore, for the foregoing reasons, Exelon respectfully requests that the Commission: (i) find under FPA section 206 that the current three-year forward period of PJM's RPM is no longer just and reasonable; (ii) adopt as a replacement rate a "prompt" auction schedule, to run two months before a given Delivery Year, starting with the 2030/2031 Delivery Year and continuing beyond; (iii) establish a refund effective date of January 1, 2027; and (iv) permit Fast Track processing under Rule 206(h) to facilitate a Commission order by no later than January 31, 2027—currently the last day before the posting of the planning parameters for the 2030/31 Delivery Year BRA.

Respectfully submitted,

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Counsel for Exelon Corporation

Dated: November 3, 2026

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, L.L.C., 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):

Jessica M. Lynch
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Dated: November 3, 2026

/s/ Stuart B. Robbins
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Counsel for Exelon Corporation

Attachment A
Affidavit of Dr. Emma Nicholson

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Exelon Corporation,	)	
	)	
Complainant	)	
	)	
v.	)	**Docket No. EL27-___-000**
	)	
PJM Interconnection, L.L.C.,	)	
	)	
Respondent	)	
	)	

AFFIDAVIT OF DR. EMMA NICHOLSON
ON BEHALF OF EXELON CORPORATION

1. My name is Dr. Emma Nicholson, Ph.D., and my business address is 1201 F St, NW, Washington, DC 20004. I am a Principal in the Energy Practice of Charles River Associates ("CRA"). In this affidavit, I provide evidence and analysis in support of Exelon Corporation's ("Exelon") complaint in this proceeding.

I. QUALIFICATIONS

2. I joined CRA in July 2025 and have been continuously employed ever since. At CRA, I support electric utilities, data center developers, and state commissions in matters related to wholesale electricity markets, with a focus on PJM Interconnection, L.L.C. ("PJM"). I have also supported grid operators with wholesale electricity market design issues and other matters related to transmission planning.

3. Prior to this position, I served as Senior Economic Advisor to the Office of Energy Policy and Innovation at the Federal Energy Regulatory Commission ("FERC" or "Commission"), where I worked with staff to advise the Commission on wholesale electricity and ancillary services market design, capacity market design, Capacity Resource accreditation, and other matters. At the Commission, I also served as an Economist and in other roles. I also have prior consulting experience in the energy practices of economic consulting firms.

4. I hold a BA in economics and government and politics from the University of Maryland at College Park, and an MA and Ph.D in economics from Georgetown University. My CV is attached as Exhibit EN-4.

II. TESTIMONY

5. My testimony is divided into four parts, Parts A, B, C, and D. In Part A, I provide a general assessment of the current state of the PJM capacity market, the Reliability Pricing Model ("RPM").[1] In Part B, I provide evidentiary support and analysis for each of the five arguments identified in the complaint as to why the current three-year forward period of RPM is no longer just and reasonable. In Part C, I provide evidentiary support and analysis for each of the four arguments identified in the complaint as to why a "prompt" auction schedule is just and reasonable. Finally, in Part D, I provide analysis on general market design considerations regarding the implementation of a prompt capacity auction in PJM.

A. General Assessment of the Current State of RPM.

6. PJM's capacity construct is experiencing profound challenges. The last two primary capacity auctions, or Base Residual Auctions ("BRAs"), cleared considerably short of the Reliability Requirement. PJM is now undertaking efforts to address the problem in the short term through the Reliability Backstop Procurement ("RBP") proposal, which the Commission has accepted and suspended for further briefing. In this Part A, I summarize current conditions in PJM's capacity market.

7. BRA prices have increased significantly in recent years, as shown in Figure 1 below. The "Rest of RTO" PJM capacity price, a benchmark capacity price that most PJM zones pay, increased significantly starting with the 2025/26 BRA.[2] This price increase ultimately resulted in complaints and PJM proposing a price collar that the Commission accepted to be in place for the 2026/27 through 2029/30 BRAs. Since the collar was imposed, all successive BRAs have cleared at the price cap. For example, the most recent BRA was the 2028/29 BRA, held in July 2026, and it cleared at the price cap of $325.00/MW-day.[3] The 2028/29 BRA did not procure enough capacity to meet the region's Reliability Requirement, clearing 6,831 MW of unforced capacity ("MW UCAP") short of the Reliability Requirement. This was the second BRA that failed to procure the Reliability Requirement, with the 2027/28 BRA also having cleared 6,517 MW UCAP short of the Reliability Requirement.[4] Absent the price collar, the 2027/28 BRA would have cleared at $529.80/MW-day in all zones. In the 2028/29 BRA, the Rest of RTO price would have been $554.72/MW-day, the Dominion zone would have cleared

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[1] Terms not otherwise defined herein shall have the same meaning as in the PJM Open Access Transmission Tariff ("Tariff"), the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("Operating Agreement"), and the Reliability Assurance Agreement Among Load Serving Entities in the PJM Region ("RAA"). The Tariff, Operating Agreement, and RAA are currently located under PJM's "Intra-PJM Tariffs" eTariff Title, available here: https://etariff.ferc.gov/TariffBrowser.aspx?tid=1731.

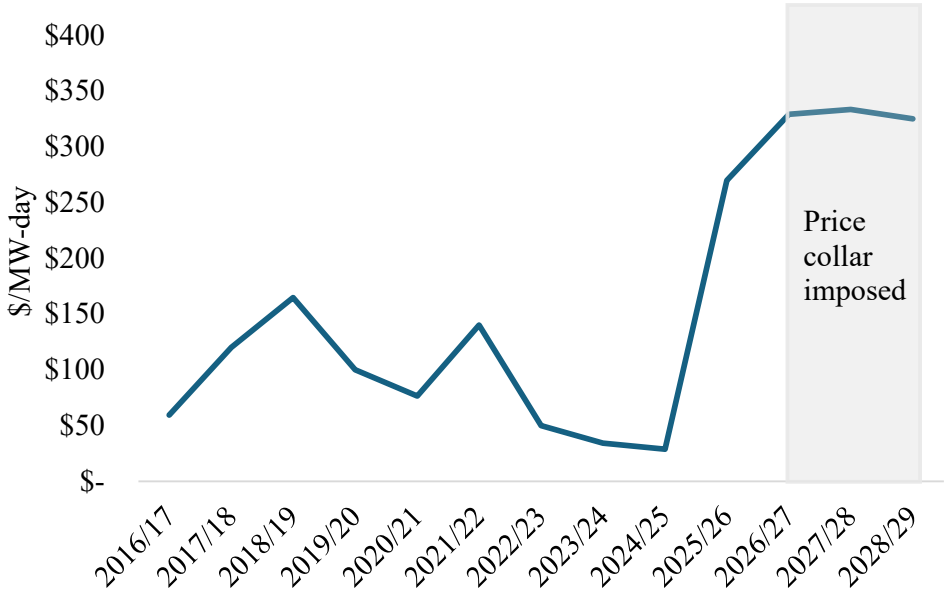
[2] The capacity price for the BGE Zone increased a year earlier, as the BG&E zone cleared at $466.35/MW-day and the Dominion zone cleared at $444.26/MW-day in the 2024/25 BRA. *See* PJM, 2026/2027 Base Residual Auction Report, *Table 1 (*July 22, 2025), https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2026-2027/2026-2027-bra-report.pdf.

[3] PJM, 2028/2029 Base Residual Auction Report, at 3 (July 14, 2026), https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2028-2029/2028-2029-bra-results-report.pdf.

[4] PJM, 2027/28 Base Residual Auction Report, at 3 (Dec. 17, 2025), https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2027-2028/2027-2028-bra-report.pdf.

at $542.83/MW-day, and the ComEd zone would have cleared at $776.69/MW-day without the price collar.

Figure 1
Historical PJM Rest of RTO prices



8. The significant capacity price increases in recent years were primarily driven by large load growth, which has outpaced the ability of new Capacity Resources to be developed and enter the PJM market. However, several factors have contributed to current capacity market conditions in PJM. PJM prepared an excellent diagnosis of the challenges currently facing PJM's capacity market and its design in a May 2026 White Paper, which I have reproduced below as it is the most concise and accurate diagnosis I am aware of.

> *PJM is facing a period of structural scarcity, a fundamental mismatch between how fast demand is growing and how fast new supply can follow.*
>
> *The region simultaneously faces hyperscale data centers adding load at an unprecedented pace, accelerated policy- and economically-driven retirements of generation, and new power plants that now take roughly twice as long to build and cost twice as much as they did a decade ago.*
>
> *New large loads are connecting faster than the fleet can expand to serve them, drawing on a shared reliability reserve that existing customers have paid to maintain, before contributing commensurate supply themselves.*
>
> *High capacity prices are the market's rational response to these conditions, but those prices translate directly into customer bills for a significant portion of load, particularly in restructured states, due to a*

lack of long-term supply contracts and hedging to buffer against the rapid rise in the wholesale spot price.

These pressures create a credibility trap: scarcity prices trigger affordability concerns and political pressure to intervene; investors see that pressure, discount the future revenue signal and hold back investment, so the shortage persists.[5]

9. Looking forward, the 2029/30 BRA, scheduled for December 2026, will have a price cap of $337.83/UCAP MW-day, established by the price collar.[6] PJM indicated in the RBP proposal that the 2029/30 BRA is likely to clear at the price cap.[7] I agree with this assessment. Based on the current tariff, the price collar will not be in effect in the 2030/31 BRA scheduled for May 2027.

10. In January 2026, the Commission approved a new formula to establish the maximum price for the Variable Resource Requirement ("VRR"), the demand curve in PJM's capacity market.[8] Applying this formula to the 2029/30 BRA parameters, which include gross Cost of New Entry ("CONE") and net energy and ancillary service revenue offset ("EAS Offset") figures for the gas combustion turbine reference unit in 2029/30, I estimate the price cap in the 2030/31 BRA will be approximately $595/UCAP MW-day for the Rest of RTO, and vary across regions. I estimate that the ComEd zone will have the highest price cap in the 2030/31 BRA, at approximately $892/UCAP MW-day, because the gas combustion turbine reference unit has a shorter economic life due to Illinois environmental legislation.[9] I highlight the ComEd zone because it is likely to clear at a higher price than other zones. As noted above, PJM calculated that the 2028/29 BRA clearing price would have been $776.69/UCAP MW-day in the ComEd zone and the Rest of RTO price would have been $554.72/UCAP MW-day. Additionally, the import limit into the ComEd zone continues to decline and will be lower in the 2029/30 BRA than it was in the 2028/29 BRA.[10] This means that without a price collar, the ComEd zone is

[5] PJM, *Powering Reliability Through Market Design,* at 16 (May 6, 2026) (hereafter, the "PJM White Paper"), https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2026/20260506-powering-reliability-through-market-design.pdf.

[6] PJM, 2029/2030 RPM Base Residual Auction Planning Period Parameters (Sept. 3, 2026), https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2029-2030/2029-2030-planning-period-parameters-for-base-residual-auction-report.pdf.

[7] PJM RBP Transmittal, Docket No. ER26-3380-000, at 124 ("Even with the intervention of the RBP, the 2029/2030 Delivery Year BRA may clear short, as new capacity that qualifies for procurement in the RBP are required to provide evidence of feasibility of commercial operation by no later than June 1, 2032").

[8] *See PJM Interconnection, L.L.C.*, 194 FERC ¶ 61,049 (2026). The capacity price cap (Point 1 of the VRR curve) that will be used in the 2030/31 BRA will be equal to the greater of 1.15 times Gross CONE minus 0.75 times the EAS Offset, and 0.20 times Gross CONE, where CONE is the Cost of New Entry for a new gas combustion turbine facility.

[9] *PJM Interconnection, L.L.C.*, 194 FERC ¶ 61,049, at P 13.

[10] PJM, 2029/2030 RPM Base Residual Auction Planning Period Parameters, at 4 (Sept. 3, 2026) ("The COMED LDA CETL had the largest overall percentage decrease, at 68%, compared to 2028/2029.").

likely to "price separate" in the 2030/31 BRA and have a higher clearing price than other PJM zones.[11]

B. Evidence and Analysis Supporting the Conclusion that the Current Three-Year Forward Period of RPM is No Longer Just and Reasonable.

11. Circumstances have changed significantly since 2006, when the Commission found the BRA's current three-year forward period to be just and reasonable. As explained further below, these changes have accumulated over the last twenty years and include increased load growth uncertainty, longer generator development timelines, and changes in RPM market rules. As such, the balancing and expectations the Commission relied upon when it found the BRA's three-year forward period to be just and reasonable no longer hold.

12. As I explain below, holding the BRA three years before the delivery period unnecessarily exposes PJM Market Participants to increased risks and uncertainties on both the demand side and the supply side. These risks result solely from a market design choice and could be avoided, or at the very least significantly reduced, with a shorter forward period. Holding the BRA three years prior to the Delivery Year (38 months to be exact) requires estimating BRA parameters *over* three years in advance, results in less accurate load forecasts and capacity resource accreditation, and impacts other key auction parameters, further divorcing the auction parameters and resulting clearing prices from supply and demand fundamentals and system conditions.

i. The risk balancing analysis the Commission relied on in 2006 to accept the load forecast inaccuracies inherent in RPM's multi-year forward period has fundamentally collapsed in 2026.

13. The Commission initially accepted a four-year forward period for the BRA in 2006, which was later reduced to three years via settlement. When the Commission accepted the four-year forward period, it reasoned that, on balance, the risk of inaccurate load forecasts was acceptable because the multi-year forward period would permit new resources to be constructed, thereby helping to meet PJM's resource adequacy needs.[12] The evidence I reviewed demonstrates that both of the factors the Commission weighed in 2006 have changed; the risk of inaccurate load forecasts has increased dramatically in recent years, and entry timelines for new natural gas

[11] PJM, 2029/2030 RPM Base Residual Auction Planning Period Parameters, (last accessed on October 12, 2026). I base my estimate on the 2029/30 BRA planning parameters; ComEd's Gross CONE is $969.59/UCAP MW-day and its EAS Offset is $297.16/MW-day UCAP. Applying the current maximum capacity price formula (i.e., the greater of 1.15 times Gross CONE minus 0.75 times the EAS Offset and 0.20 times Gross CONE) yields $892.16/UCAP MW-day.

[12] *PJM Interconnection, L.L.C.*, 115 FERC ¶ 61,079, at P 71 (2006) ("We agree, in part, with Morgan Stanley that RPM may cause customers to bear risks such as the risk that a four-year forward estimate of needed capacity may turn out to be inaccurate. However, we think that the risk is reasonable when it is compared to the risks of the current construct, namely that sufficient capacity resources may not be constructed to ensure the preservation of reliability"). *See also id.*, at P 15 ("PJM explains that RPM is intended to provide incentives for needed generation capacity in the near future").

resources now far exceed three years. I address both of these factors in subparts (a) and (b) below.

a. Load forecast uncertainty

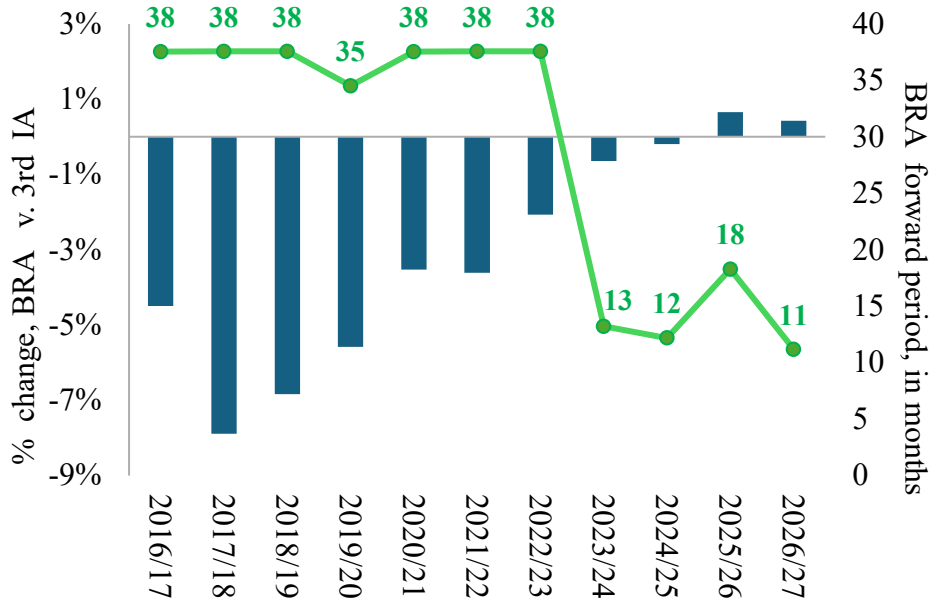
14. The level of uncertainty in PJM's near-term load forecast has increased dramatically since 2006, when the Commission initially accepted the BRA's three-year forward period. The data I present below demonstrate that current load growth projections, principally from large loads such as data centers, are likely to overstate the peak load forecast PJM uses to determine the Reliability Requirement, and thus the amount of capacity PJM procures in the BRA. Procuring too much capacity in the BRA unnecessarily increases costs for PJM Market Participants, because if a portion of the large loads included in the BRA load forecast does not materialize, capacity cost increases will be borne by all remaining customers. This outcome would be inefficient because the region would purchase more capacity than is necessary to achieve resource adequacy targets, and likely at higher prices than the fundamentals would support. The risks of over-forecasting data center loads are particularly acute today, as data center projects are encountering increasing delays driven by additional state requirements for data center development, siting and permitting challenges, greater local community opposition, and supply chain constraints.[13] Importantly, uncertainty associated with data center load growth is not unique to PJM; grid operators across the U.S. face similar challenges in forecasting large load growth stemming from similarly high degrees of uncertainty nationwide.

15. Figure 2 below shows the historical change in the peak load forecast between the BRA, which has historically been held 38 months before the start of the Delivery Year, and the third Incremental Auction ("IA"), which is typically held approximately three months before the Delivery Year (shown by blue bars).[14] The green line in Figure 2 shows the number of months that each BRA since the 2016/17 BRA was held before the applicable Delivery Year. As the BRA forward period declined from approximately three years (38 months) to closer to one year (owing to various regulatory delays), starting with the 2022/23 BRA, the difference between the BRA and final IA load forecasts fell significantly. The changes in load forecast show a key downside of the three-year forward period—forecast error. Forecast accuracy generally improves when the forecast horizon shortens, because shorter-term forecasts are based on more up-to-date information.

[13] *See e.g.*, Brian Martucci, *The Data Center Boom Continues Apace, but Projects Face Mounting Obstacles*, UtilityDive (Sept. 29, 2026), https://www.utilitydive.com/news/the-data-center-boom-continues-apace-but-projects-face-mounting-obstacles/830496/. *See also*, Jennifer Hiller, *'Phantom' Data Centers Are Demanding More From the Power Grid Than They Need*, The Wall Street Journal, (Oct. 13, 2026) https://www.wsj.com/business/energy-oil/phantom-data-centers-are-demanding-more-from-the-power-grid-than-they-need-77e322bb.

[14] The 1st, 2nd, and 3rd IAs are typically held twenty, ten, and three months, respectively, before the start of the Delivery Year.

Figure 2
BRA Forward Period (Green, Right Axis) and Load Forecast Change Between BRA and Third IA (Blue, Left Axis)



16. The historical load forecast changes between the BRA and the 3rd IA do not reflect a shortcoming of PJM or its prior load forecasting methods. No amount of modeling can eliminate the uncertainty inherent in forecasting peak loads in a 12-month Delivery Year over three years in advance, even without large load growth uncertainty. Rather, the increase in BRA load forecast precision shown in Figure 2 reflects the shorter forecast horizon; the 2023/24 through 2026/27 BRAs had a shorter forward period and smaller adjustments between the BRA and the IA, which suggests that the load forecasts used for the 2023/24 through 2026/27 BRAs were more accurate than prior BRAs with a three-year forward period.

17. The same dynamic of imprecise load forecasts that improve over time has occurred in ISO New England ("ISO-NE"). Like PJM, ISO-NE once held its primary capacity auction—the Forward Capacity Auction or "FCA" —three years before the delivery year, and, also like PJM, held three Annual Reconfiguration Auctions ("ARAs") between the FCA and the start of each delivery year. In 2026, the Commission accepted ISO-NE's proposal to change the FCA to a prompt capacity auction.[15] In a memorandum recommending a prompt seasonal capacity market, ISO-NE's Internal Market Monitor ("IMM") presented information, shown in Table 1 below, demonstrating that ISO-NE's load forecast precision increases with each ARA because each successive ARA has a shorter forecast horizon.[16]

[15] *ISO New England Inc.*, 194 FERC ¶ 61,249 (2026). Prior to proposing a prompt capacity auction, ISO-NE sought the Commission's approval to delay the FCA on two occasions, which the Commission granted.

[16] Memorandum from David Naughton, Executive Director, Internal Market Monitor to NEPOOL Markets Committee, IMM Thoughts on a Prompt and Seasonal Capacity Market, at 3 (Jan. 31, 2024), https://www.iso-ne.com/static-

Table 1
ISO-NE Forward Capacity Auction Load Forecast Error

Forward Capacity Auction	FCA NICR (MW)	ARA 1 change from FCA		ARA 2 change from FCA		ARA 3 change from FCA	
		MW	Percent	MW	Percent	MW	Percent
2018/19	34,189	(306)	−1%	(768)	−2%	(942)	−3%
2019/20	34,151	(396)	−1%	(744)	−2%	(761)	−2%
2020/21	34,075	(415)	−1%	(555)	−2%	(1,870)	−5%
2021/22	33,725	(175)	−1%	(1,495)	−4%	(800)	−2%
2022/23	33,750	(1,285)	−4%	(985)	−3%	(2,160)	−6%
2023/24	32,490	490	2%	(1,010)	−3%	(800)	−2%

18. The ISO-NE IMM explained that the differences between the FCA and the 3rd ARA "reveal the challenges of forecasting system conditions impacting [Net Installed Capacity Requirement] (peak loads, supply mix) years in advance of the Capacity Commitment Period."[17] The ISO-NE IMM further explained that the FCA—comparable to PJM's BRA—had a higher capacity requirement than the 3rd ARA—comparable to PJM's 3rd IA—in 17 of the prior 18 FCAs. The trend of over-forecasting in the primary three-year forward auction and successively reducing the load forecast in subsequent incremental capacity procurements, which have shorter forecast horizons, also occurred in PJM (*see* Figure 2). The ISO-NE IMM observed that, "[a]ll else equal, the over-forecasted [Net Installed Capacity Requirement] in the primary auctions results in higher clearing prices and consumer costs."[18] This evidence from PJM and ISO-NE suggests that, even *without* the current data center load growth uncertainty, a shorter BRA forward period will likely result in more accurate load forecasts, lower BRA capacity procurements, and thus lower capacity costs. However, as noted above, the Commission in 2006 recognized that a four-year forward period for RPM would increase the likelihood of load forecast errors, but reasoned that, on balance, the benefits of new entry outweighed the risks of inaccurate load forecasts.[19]

19. As discussed below, the magnitudes of likely load forecast errors in PJM are much higher today than they were in 2006 when the Commission approved the BRA's three-year forward period due to the uncertainty inherent with expected large load growth and the size of individual large loads. A key indicator of changes in the uncertainty involved in PJM load forecasts is the size (in MW) of the Load Adjustments PJM makes to its load forecast model, which is based on an econometric model that considers historical demand, weather, and other demographic, policy, and macroeconomic variables ("PJM Model"). Adjustments to the PJM Model are necessary because econometric models can only capture historically observed trends and relationships with the historical independent variables included in the model. Econometric models cannot account for entirely new factors and relationships that could impact future load growth, such as new retail rooftop solar programs or data center load growth at rates above

assets/documents/100009/a02b_mc_2024_03_12_13_imm_perspective_alternative_fcm_commitment_horizons.pdf.

[17] *Id.*

[18] *Id.,* at Figure 1.

[19] *See supra* note 12.

historical trends. To account for this, Transmission Owners submit Load Adjustment requests to PJM, but PJM does not necessarily include these adjustment requests in its final forecast. Instead, PJM considers whether and how to include the requests on a case-by-case basis.[20]

20. The Load Adjustments included in the PJM load forecast have grown significantly in the past several years. Table 2 below summarizes the Load Adjustments included in the forecasts as a proportion of the PJM RTO's Summer Peak load forecast in the last ten PJM load forecast reports. The columns of Table 2 represent PJM's prior load forecasts, with the column heading reflecting the year the forecast was issued.[21] The first row of Table 2 shows the impact of the Load Adjustment in the first year of the forecast, or "Y_0" (Y_0 is also the publication year of the forecast). The additional rows in Table 2 reflect forecast years beyond the first year (e.g., Y_0 +1 represents the second year in the forecast). The rows of Table 2 show the ratio of the Load Adjustment to the Summer Peak load forecast, thereby creating a quantitative measure of the impact the Load Adjustment had on the projected Summer Peak forecasts. The Y_0 Summer Peak forecast is a key input to the BRA Reliability Requirement.

Table 2
Load Adjustments as a Percent of the Summer Peak Load Forecasts, 2017 - 2026[22]

Historical PJM Load Forecasts by Year Forecast was Published

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Y_0	0.6%	0.8%	1.1%	0.0%	-0.2%	0.6%	1.9%	1.8%	2.3%	4.1%
Y_0 +1	0.7%	1.0%	1.3%	0.1%	-0.1%	1.1%	2.2%	3.0%	5.3%	6.7%
Y_0 +2	0.8%	1.2%	1.5%	0.3%	-0.1%	1.6%	2.4%	4.8%	8.3%	9.8%
Y_0 +3	1.0%	1.4%	1.6%	0.4%	0.0%	2.0%	2.5%	6.3%	11.4%	13.0%
Y_0 +4	1.2%	1.6%	1.8%	0.5%	0.1%	2.6%	2.6%	7.8%	14.4%	18.4%
Y_0 +5	1.4%	1.7%	1.9%	0.4%	0.0%	2.7%	2.7%	8.9%	17.8%	21.7%

21. What was once a modest adjustment, representing at most 2% of the peak load projections in the 2017 through 2021 forecasts, has grown significantly, reflecting a structural change in the uncertainty that underlies PJM's load forecast.[23] The recent increases in Load Adjustments included in PJM's forecast are driven primarily by expected data centers.[24] The size of Load Adjustments in the later-year forecasts (i.e., Y_0+3, Y_0+4, and Y_0+5) in the three most recent

[20] PJM, Manual 19: Load Forecasting and Analysis, Rev. 39, at 14 (effective June 30, 2026), https://www.pjm.com/-/media/DotCom/documents/manuals/m19.pdf.

[21] PJM load forecast reports are published in January of each year.

[22] Source: PJM Load Forecasts, 2017 through 2026, Load Adjustment (Table B-9) as a percent of the Summer peak forecast (Table B-1). Notes: Load Adjustments are not necessarily included in full in the load forecast. Y_0 is the first year of the forecast. For example, in the 2017 PJM load forecast, Y_0 is 2017, Y_0+1 is 2018, and so on. See Exhibit 1 for details. Heat map coloring added for convenience.

[23] *See e.g.,* Monitoring Analytics, Analysis of the 2025/2026 RPM Base Residual Auction, Part G, at 3 (June 3, 2025), https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_G_20250603_Revised.pdf.

[24] *See e.g.*, PJM, 2025 PJM Load Forecast Report, at 5-6 (Jan. 24, 2025), https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2025-load-report.pdf.

PJM load forecasts is particularly striking. For example, in PJM's 2026 forecast, the Load Adjustment constitutes 18.4% of the Summer Peak forecast in 2030 (Y_0+4).

22. Another significant change in PJM's load forecasts from prior years is the sharp increase in projected year-over-year load growth. This increase is also driven by expected data center load growth. Table 3 below shows PJM's last ten load forecasts and the projected year-over-year load growth in the Summer Peak for the first five years of the forecast. As recently as 2022, PJM was projecting year-over-year Summer Peak load growth of less than 1% per year. Year-over-year load growth has increased to between 3.1 and 4.4% in PJM's 2025 load forecast and to between 2.6 and 6.7% in the 2026 load forecast.

Table 3
Year-Over-Year Growth in Summer Peak Load Forecasts, 2017 - 2026[25]

	Historical PJM Load Forecasts by Year Forecast was Published									
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Y_0+1	0.6%	0.2%	-0.3%	1.0%	0.5%	0.3%	0.5%	1.5%	3.1%	2.6%
Y_0+2	0.2%	-0.3%	0.4%	1.0%	0.6%	0.6%	0.8%	2.2%	3.3%	3.2%
Y_0+3	-0.4%	0.3%	0.5%	0.6%	0.4%	0.6%	1.2%	1.9%	3.5%	3.6%
Y_0+4	-0.2%	0.3%	0.4%	0.4%	0.3%	0.7%	1.0%	1.9%	3.6%	6.7%
Y_0+5	0.0%	0.5%	0.4%	0.6%	0.2%	0.0%	0.9%	1.7%	4.4%	4.4%

23. The increased size of Load Adjustments accepted by PJM (Table 2) and increases in the projected year-over-year Summer Peak load growth (Table 3) both indicate a structural shift in the nature of the uncertainty that underlies PJM's current load forecast. This uncertainty is driven almost entirely by expected data center load growth. The Commission's orders approving the current three-year forward period in the 2006 proceeding do not suggest that the Commission envisioned this type of load forecast uncertainty when it approved this element of PJM's RPM design. PJM has taken measures to improve the accuracy of Load Adjustments with a vetting process of large load additions and has engaged CRA to prepare an independent third-party data center forecast.[26] Notably, Transmission Owners have also taken steps to improve load forecast accuracy. For example, Exelon explained in its September 2026 Large Load Adjustment request that it only included large loads that had either a signed Transmission Security Agreement (or a comparable binding agreement and letter of credit), or projects that were in Phase 1 engineering that had submitted a financial deposit.[27] These measures are likely to improve the accuracy of PJM's load forecast, but data center load forecasts will remain inherently uncertain. This uncertainty flows from both the dynamic commercial nature of these projects, as well as data center delays due to growing levels of opposition to data centers,

[25] Source: PJM Load Forecasts, 2017 through 2026, Summer peak forecast (Table B-1). Heat map coloring added for convenience.

[26] *See e.g.*, PJM Inside Lines, PJM Kicks Off Annual Process of Vetting Large Load Requests, September 29, 2026, https://insidelines.pjm.com/pjm-kicks-off-annual-process-of-vetting-large-load-requests/.

[27] Exelon 2027 PJM Large Load Submission, September 29, 2026, at 2, https://www.pjm.com/-/media/DotCom/committees-groups/subcommittees/las/2026/20260929/20260929-item-5i---exelon.pdf.

resulting in everything from local siting challenges to state pauses or moratoria, discussed further below.

24. PJM will issue a new load forecast in January 2027 and is in the process of collecting Load Adjustment requests, and data center load projections continue to be significant. For example, stakeholders discussed Load Adjustment requests at the September 29, 2026, Load Analysis Subcommittee meeting.[28] Table 4 shows these Load Adjustment requests and the Load Adjustments included in the 2025 and 2026 PJM Summer Peak load forecasts.

Table 4
Load Adjustments and requests to Summer Peak forecasts, MW[29]

	2027	2028	2029	2030	2031
Load Adjustment included in 2025 Forecast	13,668	19,320	25,334	32,795	41,101
Load Adjustment Included in 2026 Forecast	10,785	16,242	22,290	33,707	41,477
Sept. 2026 Load Adjustment Request	18,653	27,982	40,738	61,322	75,507

25. The September 2026 Load Adjustment requests in Table 4 have not yet been vetted by PJM, and PJM will consider them when preparing the next load forecast, due to be released in January 2027. PJM will review them, and some of the requests will impact PJM's 2027 load forecast and the load forecast PJM will use for the 2030/31 BRA. The Load Adjustment requests for the 2027 PJM load forecast are overwhelmingly driven by increased demand from data center customers.[30] As such, expected data center load growth, and the inherent uncertainty involved, will impact the 2030/31 BRA forecast.

26. One might presume that data center load growth within the next five years is more certain than in later years in the forecast. This is certainly true, but near-term data center load projections, especially those that impact BRA load forecasts, are the most consequential for Market Participants. For example, CRA prepared a range of data center forecasts for PJM based on the outcomes of several key unknowns, including the impact of data center moratoria, the demand for compute, and new generation in PJM. CRA's "Hard Supply Constraint" scenario assumes that power, supply chain, and siting constraints will slow near-term data center deployment in PJM. Under this scenario, data center demand in 2030 is approximately 20 GW below the level included in PJM's January 2026 load forecast for the same year.[31] PJM's next load forecast expected in January 2027 is subject to a significant degree of near-term

[28] PJM, Load Analysis Subcommittee Meeting Materials (Sept. 29, 2026), https://www.pjm.com/forms/registration/Meeting%20Registration.aspx?ID=%7ba99eab91-15f3-4427-a3fe-de2636a19ac8%7d.

[29] Sources: PJM 2025 and 2026 Load Forecast Reports, Table B-9. The September 2026 Load Adjustment requests were presented at the September 29, 2026 Load Analysis Subcommittee meeting.

[30] *See e.g.*, AEP, 2026 Load Forecast Adjustments, PJM Load Analysis Subcommittee, at 2 (Sept. 29, 2026), https://www.pjm.com/-/media/DotCom/committees-groups/subcommittees/las/2026/20260929/20260929-item-5f---aep.pdf.

[31] CRA, LAS Meeting, at 13, 17 (November 2, 2026), https://www.pjm.com/-/media/DotCom/committees-groups/subcommittees/las/2026/20261102/20261102-item-03---charles-river-associates-review-of-data-center-forecast.pdf. Note: I played no role in developing these forecasts.

uncertainty, and this forecast will directly impact the quantity of capacity procured in the 2030/31 BRA, the resulting capacity prices, and capacity costs in PJM.

27. While the near-term forecasts tend to have less uncertainty than longer-term forecasts, even near-term data center load growth is highly uncertain at this time. The uncertainty surrounding data center development in the next one to three years is particularly acute because the data center projects currently under development are encountering increasing delays driven by greater local opposition that can also delay siting and permitting, supply chain constraints, and additional state requirements. For example, the Governors of Virginia and Pennsylvania have signed executive orders calling for more scrutiny of new data centers and imposed additional requirements that could delay data center development.[32] Additionally, Goldman Sachs reported that although data center load growth is expected to be robust, only 50 to 60% of planned data centers will come online in 2026 and 2027 due to project delays and cancellations.[33]

28. As explained above, load forecast accuracy improves with a shorter forward period. In recent years, this has meant significant downward adjustments. As the Commission noted in its September 29, 2026, RBP order, PJM's 2026 forecast reduced its near-term demand forecasts for summer 2027 and summer 2028 by 4,000 MW and 4,400 MW, respectively, citing economics, tighter vetting of Load Adjustment requests, and updates to its electric vehicle forecast.[34] I expect this dynamic to continue given the heightened uncertainty and delays in data center development timelines.

29. It is worth emphasizing the importance of accuracy in the load forecast, as forecast errors can have a significant impact on the BRA clearing price. The illustrative example in Figure 3 is

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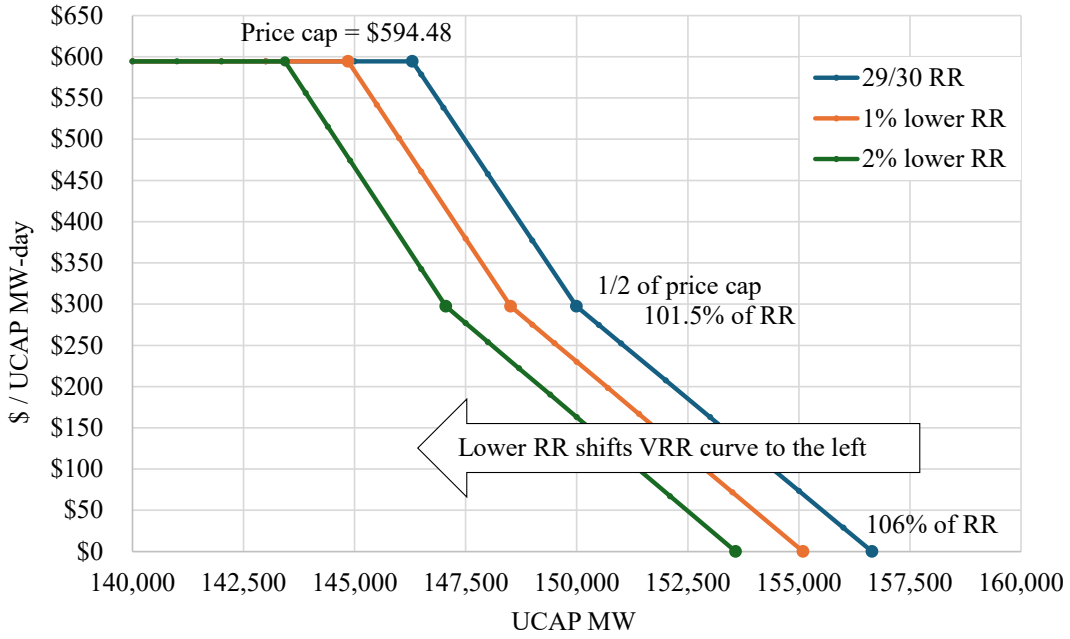
[32] Governor Abigail D. Spanberger of Virginia signed Executive Order No. 22 on September 18, 2026, establishing the Virginia Data Center Accountability Framework and directing that the Virginia Economic Development Partnership may no longer assist data center projects with anticipated peak electrical demand of 25 MW or greater through the Virginia Business Ready Sites Program or any expedited permitting program. *See* Exec. Order No. 22, *Establishing New Nation-Leading Standards and Initiatives to Implement the Virginia Data Center Accountability Framework and Responding to Unprecedented Risk from Artificial Intelligence* (Va. Sept. 18, 2026), https://www.governor.virginia.gov/media/governorvirginiagov/governor-of-virginia/pdf/eo/eo-22-establishing-va-data-center-accountability-and-ai-initiatives.pdf. Governor Josh Shapiro of Pennsylvania signed Executive Order 2026-05 on August 18, 2026, directing the Department of Environmental Protection to review permit applications only if developers have made a legally binding commitment to meet the Governor's Responsible Infrastructure Development Requirements and have received local approval, and removing all AI data center proposals from Pennsylvania's Fast Track permitting process. *See* Exec. Order 2026-05, *Demanding Data Center Developers Comply with Strict Requirements and Blocking Speculative, Irresponsible Data Center Projects* (Pa. Aug. 18, 2026), https://www.pa.gov/content/dam/copapwp-pagov/en/governor/documents/eo2026_05_protecting%20pennsylvania%20consumers%20from%20data%20center%20impacts_final_executed.pdf.

[33] Goldman Sachs, Artificial Intelligence, US Data Center Power Demand Projected to Double by 2027 (May 20, 2026), https://www.goldmansachs.com/insights/articles/us-data-center-power-demand-projected-to-double-by-2027?_sp=cc585d29-9eeb-4707-8fe4-30ef86573332.1791056406860.

[34] *PJM Interconnection, L.L.C.*, 196 FERC ¶ 61,245, at n. 8 (2026) ("In PJM's 2026 load forecast released in January, PJM cut its peak demand forecasts for summer 2027 and summer 2028 by 4,000 MW and 4,400 MW, respectively, citing tighter vetting of Load Adjustment requests and revised electric vehicle and economic assumptions.").

based on a VRR Curve constructed using PJM's 2029/30 BRA parameters, the VRR Curve formulation the Commission accepted in Docket No. ER26-455, and no price collar.[35] The blue plot shows an estimate of what the VRR Curve would be with the 2029/30 BRA Reliability Requirement, the orange plot shows what the VRR Curve would have been if the Reliability Requirement were 1% lower, and the green plot shows the VRR Curve with a Reliability Requirement that is 2% lower. Both 1% and 2% are reasonable load forecast sensitivities to explore because they are consistent with historically observed forecast errors with a three-year forward BRA. For example, the 2016/17 through 2022/23 BRAs in Figure 2, which were held before uncertainty about large load growth was an issue in PJM forecasts, had similar downward load forecast adjustments. Additionally, when comparing the January 2025 and January 2026 PJM load forecasts, the Summer Peak forecasts for 2027 through 2029 fell by between 2.3% and 2.6%.[36]

Figure 3
Illustrative Example of the Cost Implications of the Reliability Requirement on the BRA Clearing Price



30. Figure 3 shows that the Reliability Requirement, which is based on the load forecast, can have a significant impact on capacity prices because a lower Reliability Requirement shifts the VRR Curve to the left. For example, assuming 147,500 UCAP MW of capacity clears against the VRR Curves, the price would be $498.06/UCAP MW-day with the 2029/30 BRA Reliability Requirement, $379.39/UCAP-MW-day, or $118.67/UCAP MW-day lower, if the Reliability

[35] The price collar is set to expire after the 2029/30 BRA.

[36] PJM, 2026 Load Forecast Report Tables, Table B-1, https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/2026-load-report-tables.xlsx, and PJM, 2025 Load Forecast Report Tables, Table B-1, https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/2025-load-report-tables.xlsx.

Requirement were just 1% lower, and $276.95/UCAP MW-day, or $221.11/UCAP MW-day lower, if the Reliability Requirement were 2% lower.

Table 5
Illustrative capacity price impact of 1% and 2% lower reliability requirements

	(a)	(b)	(c)	(d)	(e)
UCAP MW	**2029/30 BRA RR**	**Sensitivity 1 1% lower RR**	**Sensitivity 1 Price impact (b) – (a)**	**Sensitivity 2 2% lower RR**	**Sensitivity 2 Price impact (d) – (a)**
147,500	$498.06	$379.39	($118.67)	$276.95	($221.11)
150,000	$297.06	$176.24	($120.82)	$162.97	($134.09)

31. The illustrative price impacts in Table 5 demonstrate that relatively small load forecast errors can have material impacts on capacity prices, resulting in loads paying billions of dollars more for capacity that is not ultimately needed. Price impacts in the approximately $120-220/UCAP MW-day range can translate to a $6 to $12 billion change in total capacity costs to customers resulting from a historically "normal" 1-2% level of load forecast adjustment. Furthermore, in today's high magnitude of load forecast uncertainty, it is conceivable that forecast errors could be even greater than the downward sloping portion of the VRR Curve. For example, the sloped portions of the three illustrative VRR Curves in Figure 3 cover approximately 10 GW, which is just below one-third of the 33.7 GW Load Adjustment included in the January 2026 load forecast for the 2030 Summer Peak (*see* Table 4).

b. Resource entry timelines have changed

32. Another important condition has changed since 2006 when the Commission initially approved the three-year forward period. Specifically, new resource entry within the BRA's three-year forward period is no longer possible, which removes the major benefit the Commission weighed against that load forecast risk. In 2006, when approving a four-year forward period for the BRA, the Commission found, on balance, that the forward period was just and reasonable despite the associated load forecast uncertainty because the forward period would provide enough time for new capacity to be constructed between the BRA and the start of the Delivery Year.[37] The BRA's forward period was reduced to three years in the RPM Settlement Agreement, which the Commission approved. The RPM Settlement Agreement explained that the BRA's three-year forward period was based on the premise that three years was enough time to permit "credible entry" by new natural gas resources.[38] The RPM Settlement Agreement referenced record evidence that the time between the signing of an Incremental Facilities Study Agreement for a new gas combustion turbine unit and the unit's commercial operation date in PJM was typically 33 months.[39] Although this was the case in 2006 when

[37] *See supra* note 12.

[38] RPM Settlement, Explanatory Statement, Docket Nos. ER05-1410-000 and -001 and EL05-148-000, and 001, at 11-12 (Sept. 29, 2006) ("As explained by Mr. Ott in his accompanying affidavit, three years remains sufficient to meet the essential purpose of forward commitment, i.e., to provide a credible prospect of new entry.).

[39] RPM Settlement, Explanatory Statement, Docket Nos. ER05-1410-000 and -001 and EL05-148-000, and 001, at 12 (Sept. 29, 2006).

the Commission approved the BRA's three-year forward period,[40] a 33-month timeline is simply not possible today for several reasons. The timelines for new natural gas resource entry in PJM remain important because the current reference resource for the VRR Curve in RPM is a gas-fired combustion turbine.[41]

33. PJM explained in its May 2026 White Paper that current construction timelines for new gas-fired generators have doubled or tripled since the three-year forward period was accepted. As a result, PJM concluded that a "foundational assumption of the RPM design" is now "physically broken."[42] Extended generator development timelines are not unique to PJM. For example, ISO-NE's Director of Economic Analysis Dr. Christopher Geissler noted similar resource development delays in an affidavit accompanying ISO-NE's proposal to change its capacity market from a three-year forward period to a prompt capacity auction.[43]

34. PJM has implemented reforms to streamline its generator interconnection queue and clear prior backlogs. For example, under PJM's reformed interconnection process, the standard Cycle study is designed to take one to two years.[44] Unfortunately, shortening generator interconnection timelines is not enough to make three-year entry possible. Despite PJM's progress in reforming the generator interconnection queue, since 2020 approximately 24 GW of planned generation with fully executed interconnection agreements have terminated their agreements before reaching commercial operation, including 13.5 GW of natural gas capacity.[45] As PJM noted, these terminations suggest that project economics, permitting delays, and supply chain issues, and not simply generator interconnection timelines, are impacting generator development. These factors are beyond PJM's control and cannot be addressed through changes to PJM's capacity market design or generator interconnection processes alone. For example, a Johns Hopkins University study of PJM's generator interconnection queue between 2015 and 2026 estimates that new large natural gas generation

[40] *PJM Interconnection, L.L.C.*, 115 FERC ¶ 61,079, at P 15 (2006) ("PJM explains that RPM is intended to provide incentives for needed generation capacity in the near future"). *See also* RPM Settlement, Explanatory Statement, Docket Nos. ER05-1410-000 and -001 and EL05-148-000, and 001, at 11-12 ("As explained by Mr. Ott in his accompanying affidavit, three years remains sufficient to meet the essential purpose of forward commitment, i.e., to provide a credible prospect of new entry.").

[41] The development delays discussed below apply equally to the entry of a combined-cycle natural gas unit.

[42] PJM White Paper, at 18 ("Crucially, a foundational assumption of the RPM design has been physically broken. The three-year forward timeline was originally established because it aligned with the construction schedule of many of the resources that could be built to meet the system's resource adequacy needs, including both combustion turbine and combined cycle gas resources… Today, due to compounding frictions in siting, permitting, supply chains and interconnection, it can take two or three times as long to build a gas resource as it does to build a hyperscale data center.").

[43] Attachment A, Testimony of Dr. Christopher Geissler, Director of Economic Analysis, ISO-NE, Docket No. ER26-925-000, at 15 ("On the entry side, development timelines in New England generally have not aligned with the three-year-forward auction timeline, with many resources needing additional time for construction, and many others needing (sometimes significantly) less time for construction. This means that the theoretical benefit of having new resources compete with each other to sell capacity has not always been realized, as the actual timelines between competing resources may be quite different in practice.").

[44] PJM White Paper, at 18.

[45] *Id*.

projects that complete the interconnection process will have an average of 10.8 years spent between initial submission into the queue and commercial operation.[46] This study also found that, out of a total of 102 gas-fired generators over 100 MW submitted into the interconnection queue since 2015, only 13 were online by early 2026.[47] This finding is consistent with PJM's finding that in May 2026, "~53 GW of interconnection projects – enough to power 40 million homes at full output – currently have signed agreements to connect to the grid, but many are being stymied by issues beyond PJM's control, like federal, state and local permitting, siting, and supply chain challenges."[48]

35. Another major factor delaying the development of new gas resources in PJM and across the U.S. is a shortage of gas turbines. In an August 2026 earnings call, Siemens Energy reported not only a 69 GW backlog in gas turbines, but also that it received 15 GW of new orders in the second quarter of 2026 alone. Siemens Energy explained that lead times were running three years or more for new turbines.[49] Similarly, GE Vernova reported a 116 GW backlog in gas generation equipment and slot reservations and that it expects this backlog to reach at least 125 GW by the end of 2026.[50] Finally, lead times for new Mitsubishi gas turbines have increased from roughly two years just after the COVID-19 pandemic to five or more years today, and the company is now signing contracts for deliveries between 2031 and 2034.[51] These gas turbine backlogs effectively make three-year entry by PJM's current reference resource impossible. Other factors impact generator development timelines as well, such as siting and permitting processes and non-turbine supply chain delays. For example, PJM tracked milestone changes for projects in active development in the generator interconnection queue between January 2023 and January 2026. Of these projects, 29% of all milestone changes were due to permitting delays, and 23% were due to supply chain delays.[52]

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[46] Gianna Murphy and Abraham Silverman, Ralph O'Connor Sustainable Energy Inst., Johns Hopkins Univ., *Natural Gas Generator and Energy Storage Timelines in PJM*, at 2-3 (May 18, 2026), https://energyinstitute.jhu.edu/natural-gas-generator-and-energy-storage-timelines-in-pjm/.

[47] *Id.,* at 2.

[48] *See* PJM, *New, Faster Generation Interconnection Process Fact Sheet* (Updated May 21, 2026), https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/interconnection-reform-progress-fact-sheet.pdf.

[49] Emma Penrod, *Siemens Energy's Gas Turbine Backlog Nears 70 GW as Company Expands Manufacturing*, UtilityDive (Aug. 10, 2026), https://www.utilitydive.com/news/siemens-gas-turbine-backlog-nears-70-gw-as-company-expands-manufacturing/827390/.

[50] *GE Vernova Releases Second Quarter 2026 Financial Results*, GE Vernova (July 22, 2026), https://www.gevernova.com/news/articles/ge-vernova-releases-second-quarter-2026-financial-results.

[51] James, Burgess, *Interview: Mitsubishi Power Gas Turbine Orders Stretch to 2030 Amid AI, Security Demand, S&P Global Commodity Insights*, S&P Global (July 3, 2026), https://www.spglobal.com/energy/en/news-research/latest-news/energy-transition/070326-interview-mitsubishi-power-gas-turbine-orders-stretch-to-2030-amid-ai-security-demand.

[52] PJM White Paper, at 23.

ii. The prospective assumptions in 2006 regarding the ability of RPM's multi-year forward period to incentivize LSE bilateral contracting and risk hedging have been disproven over the course of 20 years.

36. When accepting the four-year forward period in 2006, the Commission found it unlikely that RPM as a whole would *reduce* forward-capacity contracting in PJM.[53] The Commission also found that a multi-year BRA forward period and RPM more generally could encourage market participants "to manage their risk more effectively, whether through bilateral contracting or otherwise."[54] At the time, PJM explained that there was only a small amount of forward contracting for capacity taking place in PJM.[55]

37. However, evidence from PJM, Exelon's Affiant Deborah Sears, and others suggests that many LSEs are *not* engaging in forward contracting for capacity. For example, Stu Bresler, PJM's Chief Operating Officer, explained that although the RPM was initially expected to be a residual market, with the majority of capacity contracted bilaterally, that contracting has not occurred. Instead, Mr. Bresler explained that "[r]ather, it appears that substantial load in the states that have expressed concern are *directly exposed* to Base Residual Auction prices for the *entirety* of their capacity obligations."[56]

38. Further, a New Jersey Board of Public Utilities ("NJBPU") assessment of the PJM capacity market explained that legal restrictions limit the types of bilateral contracting the state of New Jersey can engage in to procure capacity bilaterally on a long-term basis outside of the RPM. The NJBPU assessment found that "[t]he only way an LSE can use capacity procured wholly outside the RPM to meet its capacity needs is by electing to use the Fixed Resource Requirement ("FRR") Alternative under which it must meet all of its capacity needs outside of the RPM for the relevant service area. However, the Reliability Assurance Agreement effectively bars LSEs in states like New Jersey that allow full retail choice from electing the FRR Alternative."[57] The assessment went on to explain that the state of New Jersey attempted

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[53] *PJM Interconnection, L.L.C.*, 115 FERC ¶ 61,079, at P 70 (2006).

[54] *Id.* emphasis added ("Second, as PJM has alleged, parties are not engaging in significant amounts of forward contracting now: RPM will provide more information to all market participants, and all parties will be able to use this information to manage their risk more effectively, whether through bilateral contracting or otherwise.").

[55] *Id.* ("[A]s PJM has alleged, parties are not engaging in significant amounts of forward contracting now.").

[56] Affidavit of Mr. Frederick S. Bresler III on Behalf of PJM Interconnection, L.L.C. Docket No. ER25-1357-000, at 6, emphasis added ("The original vision of the RPM was for it to function primarily as a residual market, with the majority of capacity procured through bilateral contracts and only a small portion needed to cover remaining needs from the market. Participation in this way as originally intended would serve to substantially hedge market participants on both the supply and demand sides from uncertain and potentially volatile Base Residual Auction clearing prices. The historic and existing capacity market design and results do not appear to have sufficiently stimulated this type of activity. Rather, it appears that substantial load in the states that have expressed concern are directly exposed to Base Residual Auction prices for the entirety of their capacity obligations.").

[57] N.J. Bd. of Pub. Utils., *An Investigation of PJM's Capacity Market*, at 6 (Aug. 2026), https://nj.gov/bpu/pdf/reports/AN_INVESTIGATION_OF_PJMs_CAPACITY_MARKET_FINAL_8.12.26.pdf . The New Jersey legislature passed an act establishing the Long-Term Capacity Pilot Program in 2011 which required the NJPBU to issue an order directing New Jersey Electric Distribution Companies to bilaterally procure

to make long-term bilateral capacity procurements through the Long-Term Capacity Pilot Program, but courts found the program was preempted by the Federal Power Act in *PPL v. Hannah* and *PPL v. Solomon*.[58] The NJBPU further explained that *Hughes v. Talen* put further limits on the types of long-term bilateral capacity contracting PJM states can engage in.[59] As a result of these legal constraints, NJBPU concluded that "to date New Jersey LSEs have opted to procure the capacity they needed exclusively or nearly exclusively through RPM auctions."[60]

39. Given these conditions, a significant portion of retail customers in PJM, particularly those in restructured states, are directly exposed to RPM prices, principally those resulting from BRAs which have the largest customer cost impact. The lack of forward capacity contracting in PJM magnifies the consequences of the BRA's three-year forward period, which as described above often results in load forecasts and other parameters that are divorced from supply and demand fundamentals. The 2030/31 BRA will be the first capacity auction in four BRAs that will be run without a price collar, exposing PJM Market Participants, including millions of retail customers, to an RPM auction schedule based on predicates that are no longer true, without a means to hedge against it.

iii. The current three-year forward period inhibits efficient resource exit and Deactivation, as it requires generator owners to invest in the absence of reasonable predictability in future operational capability and environmental policy.

40. A three-year forward period needlessly adds risks for Capacity Resources, particularly resources at or near Deactivation, with no counterbalancing benefits. Generally, selecting a forward period for a capacity auction involves balancing two key goals of the capacity market—that is, sending price signals that manage orderly and economic entry *and* exit. As noted above, the primary benefit of the BRA's three-year forward period is to permit credible entry, but entry for physical generation resources within three years is no longer feasible in PJM. As such, the three-year forward period adds risks without any commensurate benefits.

41. For example, when the BRA is held three-years forward (38 months before the start of the Delivery Year) Capacity Resources must make estimates about their operational capabilities more than four years into the future (*i.e.*, through the forward period *and* to the end of the 12-month Delivery Year). These risks are particularly high for older resources at or near

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2,000 MW of new capacity through "Standard Offer Capacity Agreements," which were 15-year fixed price capacity contracts. Compensation would have occurred through a contract for differences structure, with the capacity supplier paying the price difference to the Electric Distribution Company in Delivery Years when the BRA price exceeded the fixed price, and the Electric Distribution Company paying the supplier the price difference in Delivery Years when the BRA price was below the fixed price.

[58] *Id.,* at 6-10.

[59] *Id.,* at 9-10.

[60] *Id.,* at 10.

Deactivation.[61] According to PJM's Market Monitor, 37.3% (75.5 GW) of installed generation capacity in PJM is over 40 years old, 30.8 GW of which are coal-fired steam units.[62] Under PJM's Capacity Performance construct, resources that take on capacity commitments face non-performance penalties if they are not available during a Performance Assessment Interval ("PAI"). In PJM, these risks are explicitly recognized and can be included in the Capacity Performance Quantitative Risk ("CPQR") component of a resource's capacity supply offer. In its prompt capacity auction proposal, ISO-NE explained this dynamic (which also applies through ISO-NE's Pay for Performance rules) stating, "the uncertainty about whether a new or existing resource will be available to perform three years into the future can be reflected in suppliers' capacity offers or bids through higher risk premiums."[63] ISO-NE went on to explain that the increased risk premiums—driven solely by the three-year forward period—raise capacity offers and capacity prices over what they otherwise would have been in a prompt auction held closer to the delivery period.[64] These dynamics are not unique to ISO-NE. Given the load forecast uncertainty described above, CPQR risk is even more difficult to estimate today given increasing extreme weather, new load characteristics, and the evolving resource fleet, which affect the number of PAIs the PJM system will have. Furthermore, the PJM system is currently in a state of capacity shortage, which all else equal, makes PAIs more likely.

42. When submitting capacity supply offers, resources must also predict what environmental regulations will be in effect during the future Delivery Period, which is particularly challenging for coal, oil, and natural gas resources given relatively frequent changes in environmental regulations. Adding this uncertainty can undermine the BRA's ability to send accurate signals about supply and demand fundamentals and facilitate efficient entry and exit.[65] Federal environmental regulations can change within a three-year period in ways that can impact resource Deactivation decisions. For example, in May 2024, the Environmental Protection Agency (EPA) passed effluent limitations guidelines (ELG) that apply to coal plants. The EPA

[61] *See e.g.*, Todd Schatzki, Joseph Cavicchi, and Phillip H. Ross, Analysis Group, *Capacity Market Alternatives for a Decarbonized Grid: Prompt and Seasonal Markets*, at 31-32 (Jan. 2024), https://www.iso-ne.com/static-assets/documents/100007/a08b_mc_2024_01_09_11_agi_updated_report.pdf.

[62] Monitoring Analytics, 2025 Annual State of the Market Report, March 12, 2026, at 711, https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2025/2025-som-pjm-sec12.pdf.

[63] ISO-NE Transmittal, Docket No. ER26-925-000, at 24 (Dec. 30, 2025) ("Moreover, the uncertainty about whether a new or existing resource will be available to perform three years into the future can be reflected in suppliers' capacity offers or bids through higher risk premiums, increasing Capacity Clearing Prices over what those prices would have been had the auction been held closer in time to the Capacity Commitment Period, where sellers would have more certainty about their performance and the costs associated with holding an obligation.")

[64] *Id*.

[65] *ISO New Eng., Inc.*, 162 FERC ¶ 61,205, at P 21 (2018) ("A capacity market should facilitate robust competition for capacity supply obligations, provide price signals that guide the orderly entry and exit of capacity resources, result in the selection of the least-cost set of resources that possess the attributes sought by the markets, provide price transparency, shift risk as appropriate from customers to private capital, and mitigate market power."). *See also* New York Independent System Operator, Inc., 179 FERC ¶ 61,102, at P 41 (2022).

then issued a final rule in December 2025 that extended the ELG compliance deadlines by five years, giving coal units the opportunity to delay Deactivation decisions.[66]

43. In summary, for the owners of older Capacity Resources that may be trying to ascertain whether it is economic to remain in the market or exit through Deactivation, the three-year forward period of RPM clouds the requisite balancing analysis, because these resource owners cannot see three years (and in practice, four years) into the future. As a result, they are unable to make two important determinations (among others): (i) whether they will be able to physically operate their resource during the future Delivery Year; and (ii) whether applicable environmental policy will legally allow them to operate their resource during the future Delivery Year. Accordingly, even if it *would be* efficient for the market, economic for the resource owner, and beneficial to reliability as a whole for the Capacity Resource to remain in the market, it is much more challenging for these resource owners to conduct an accurate risk assessment and thus they may choose to prematurely Deactivate.

iv. PJM's current capacity accreditation methodology (ELCC) bears no resemblance to the eFORd model considered by the Commission in 2006, and the three-year forward period forces PJM to integrate speculative assumptions into its ELCC modeling.

44. At the time of the Commission's 2006 approval of RPM's multi-year forward period, PJM used a capacity accreditation methodology known as Equivalent Forced Outage Rate - demand, or "eFORd." This methodology focused on historic, unit-specific metrics that measured the percentage of time that a specific unit was forced out of service or unable to run when called upon. Additionally, because eFORd relied on a resource's own historical performance rather than on system-wide, forward-looking modeling of the resource mix, it had a fairly high level of predictability, stability, and replicability for resource owners.

45. The Commission approved PJM's current capacity accreditation method, which accredits all resource types with the marginal Effective Load Carrying Capability ("ELCC") methodology, in January 2024.[67] Unlike eFORd, ELCC considers the simultaneous reliability contribution of all resources, and recognizes the complementary and antagonistic interactions among the resources expected to be able to provide capacity in a given Delivery Year. In general, a resource that supports resource adequacy during high-risk periods (*i.e.*, periods with a high probability of a capacity shortage) will have a higher capacity value under ELCC than a resource that delivers the same generating capability but only during low-risk hours. These risk hours may vary as the resource mix changes (*e.g.*, more wind and solar resources are installed) and hours of high demand evolve (*e.g.*, wide-scale electric car charging at night).

46. Although ELCC accreditation is an improvement over eFORd and similar methodologies that rely primarily on historical performance, it depends on a much larger set of assumptions. A downside of ELCC accreditation is that errors in those assumptions can lead to inaccurate

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[66] EPA, EPA Extends Wastewater Compliance Deadlines for Coal-fired Power Plants, https://www.epa.gov/system/files/documents/2025-12/deadline-extensions-final-rule_fact-sheet_12_23_2025.pdf.

[67] *PJM Interconnection, L.L.C.*, 186 FERC ¶ 61,080 (2024).

accreditation values that do not reflect actual system conditions; this downside is greater with a three-year forward BRA compared to an auction with a shorter forward period. ELCC accreditation for a given Delivery Year requires a host of assumptions including, but not limited to, hourly load forecasts under various scenarios and the resource mix during that Delivery Year. As discussed above, PJM's load forecast is currently subject to a high degree of uncertainty. The future resource mix is also highly uncertain. A BRA with a three-year forward period requires PJM to estimate the resource mix approximately three and a half years before the start of the Delivery Year, because capacity suppliers must know their accreditation values before the BRA.[68] This means PJM must accurately predict both entry and exit. First, PJM must predict which planned Capacity Resources will be online and clear the BRA more than three years before the start of the Delivery Year. As noted above, this is quite challenging because the entry of new resources—of all types—is uncertain given supply chain delays, siting and permitting timelines, and generator interconnection timelines (including completion times for Network Upgrades) for planned generation resources. Even if a planned resource submits a notice of intent to bid and clears the three-year forward BRA in a given Delivery Year, clearing alone does not guarantee the planned resource's availability during the Delivery Year.[69] Uncertainty about the in-service date of planned resources, which ISO-NE, referred to as "phantom entry", was one of the rationales ISO-NE provided to the Commission when requesting its move from a three-year forward to a prompt capacity auction.[70] PJM must also predict resource exits, which is also challenging given uncertainties about the economics and physical condition of older resources near Deactivation. PJM's generator deactivation rules only require 12 months of advance notice,[71] which is late to inform PJM's ELCC accreditation model in the context of a three-year forward BRA.

47. ELCC class accreditations also change over time with the resource mix and load profiles (including extreme weather risks). This is by design; ELCC accreditation values reflect the estimated reliability contribution of each resource class and account for correlated availability and outage patterns among resources of the same class and across classes. ELCC accreditation methodologies use sophisticated probabilistic modeling to estimate resource performance across a range of system conditions, with the greatest weight placed on periods with the greatest reliability risk.

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[68] PJM Manual 20A: Resource Adequacy Analysis, Sections 2.1 and 2.2, Rev. 3 (eff. June 24, 2026), https://www.pjm.com/-/media/DotCom/documents/manuals/m20a.pdf. According to the 2030/31 BRA schedule, PJM will post the Preliminary ELCC Class Rating and Accredited UCAP Factors on January 11, 2027, four months before the 2030/31 BRA window opens and approximately three and a half years before the start of the 2030/31 Delivery Year. *See also PJM*, RPM Auction Schedule, available here.

[69] For example, the planned resource can buy out its capacity supply obligation in subsequent IA.

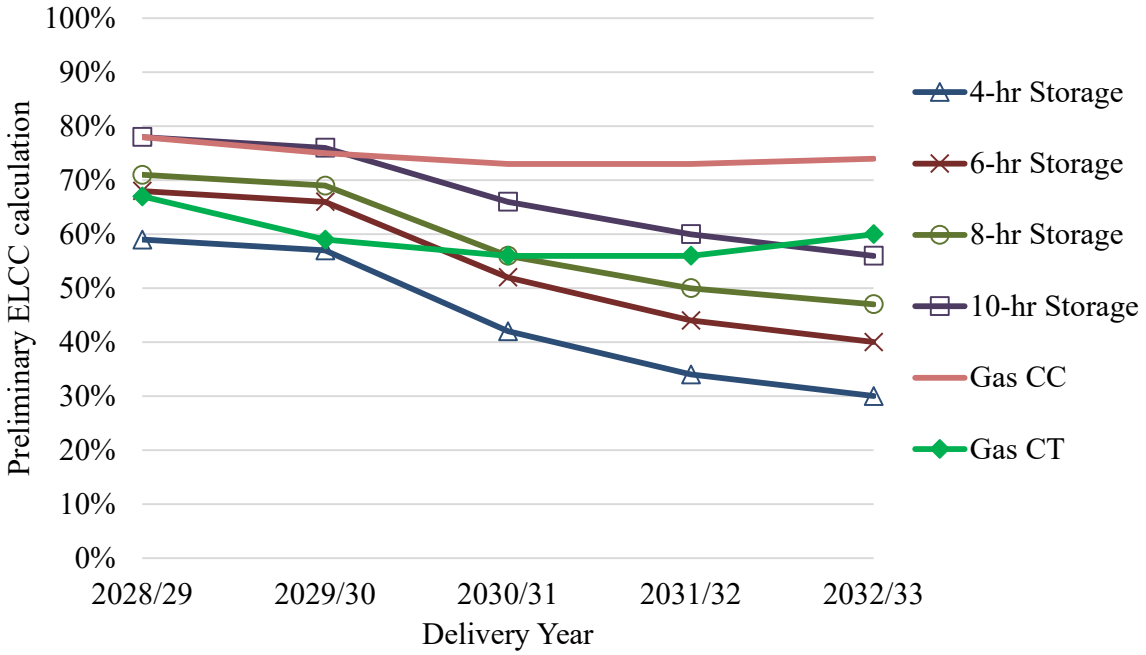
[70] ISO-NE, Transmittal Letter, Docket No. ER26-925-000 at 5, ("Today's filing contains the first such reform, the proposed prompt capacity market that will allow the capacity auction to utilize more up-to-date, and thus more accurate information regarding available supply and demand for the delivery period, and address the scenario wherein the Forward Capacity Market clears new capacity that does not materialize even two years after the start of the delivery period (referred to as "phantom entry"). Although it does not appear that phantom entry is an issue in PJM, PJM faces similar uncertainties about the actual on-line date of planned resources as ISO-NE. See *supra* note 43.

[71] PJM Tariff, Part V, §113.1 (Generation Owner Notice).

48. PJM indicated it will estimate ELCCs for the 2030/31 BRA in January or February 2027 based on a projected resource portfolio using information from notices of intent from planned resources and potential new deactivations that may be announced closer to December 2026/January 2027.[72]

49. PJM routinely prepares estimates of how ELCC values will change over the next 10 years as the resource mix and system loads evolve. Figure 4 below shows the final ELCC values for Delivery Years 2028/29 and 2029/30 along with PJM's preliminary estimates through Delivery Year 2032/33. The ELCC values for storage resources are expected to experience the biggest changes over the time period. PJM explained that the ELCC estimates for storage resources decreased due to assumptions about extended cold weather periods when the ability to charge from other resources is limited.[73] The gas combustion turbine class, the current reference resource, also experienced changes. Exhibit EN-2 contains a table of the ELCC values shown in Figure 4 as well as accreditation values for other ELCC classes. Figure 4 illustrates how much projected and actual ELCC values can change over the three-year forward period of RPM depending on the assumptions used, such as the assumed resource mix and system loads.

Figure 4
Actual and Preliminary ELCC Values, Delivery Years 2028/29 Through 2032/33



50. Importantly, my comments about PJM's ELCC accreditation methods are not critiques of PJM's ELCC accreditation method, which the Commission has found to be just and reasonable, or ELCC accreditation methodologies more generally. ELCC accreditation methods are a

[72] PJM, Preliminary ELCC Class Ratings for Period 2028/29 through 2042/43 (Discussion), at 1 (Sept. 2026), https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/discussion-of-preliminary-elcc-class-ratings-for-period-dy28-dy42-elcc.pdf. For example, the resource mix PJM assumed to calculate the preliminary ELCC values for the 2029/30 are available here.

[73] *Id.*, at 7-8.

refinement to traditional capacity accreditation methods and result in a more accurate estimate of a resource's expected ability to meet a power system's resource adequacy needs. Indeed, in December 2025, an independent consultant determined that PJM's ELCC approach is methodologically sound and consistent with industry best practices.[74] However, in the context of the three-year BRA forward period, ELCC values are more susceptible to forecast errors and subsequent inaccuracies than the traditional accreditation methods that were used in 2006 when the BRA's three-year forward period was first accepted. Importantly, BRAs have been running on a compressed schedule since PJM's current ELCC method has been implemented, so the 2030/31 BRA will be the first time PJM uses ELCC accreditation values based on an assumed resource mix three-and-a-half years in the future. Because PJM has not been required to prepare ELCC values over three years in advance yet, there is no information about the impacts that estimating ELCC accreditation values so far ahead of the Delivery Year will have on ELCC resource accreditation.

v. The current three-year forward period undermines the accuracy of other BRA planning parameters, including the assumed resource mix in each Locational Deliverability Area used to calculate CETO/CETL values, leading to unjust and unreasonable results.

51. Beyond the load forecast and ELCC accreditation discussed above, other BRA planning parameters play a critical role in the market outcomes. For example, the BRA is a locational market and reflects the fact that the transfer of capacity between zones in a given BRA is limited by the amount of transfer capability between zones. PJM defines Locational Deliverability Areas ("LDAs") where those transfer limits might bind, and constrain imports into that LDA, possibly causing the LDA to clear at a higher price than other PJM regions (*i.e.*, price separation). Prior to each BRA, PJM performs studies to determine each LDA's Reliability Requirement by adding Capacity Emergency Transfer Objective ("CETO") to the capacity within the LDA. PJM also calculates each LDA's Capacity Emergency Transfer Limit ("CETL"), which is the amount of capacity the LDA can import from other regions during peak conditions. The CETO and CETL are important BRA parameters because if an LDA's CETL is below its CETO, the LDA must meet a portion of its Reliability Requirement with resources within the LDA. Generally speaking, a lower CETL means that the LDA must meet a higher portion of its Reliability Requirement with internal resources, which can result in higher capacity prices than other PJM regions if the LDA must purchase capacity from internal resources that are more expensive than the capacity available in neighboring regions.

52. The three-year forward period of RPM can significantly impact the accuracy of CETO/CETL, which are based on several factors, including expected demand, the assumed resource mix in each LDA and region, and the transfer capability between zones. The accuracy of the planning parameters used in each BRA depends on the underlying data and assumptions they are based on. The BRA's three-year forward period *undermines* PJM's ability to accurately estimate BRA parameters, such as CETO and CETL, because in addition to the load forecast, these

[74] Energy+Environmental Economics, PJM ELCC / RRS Model Evaluation, at 3 (Dec. 2025), https://www.pjm.com/-/media/DotCom/committees-groups/task-forces/elccstf/2025/20251209/20251209-item-02---pjm-elcc-rrs-model-evaluation---e3-report.pdf. E3 also identified "a few areas" where the model could be improved. *Id*.

values depend on assumptions about the future resource mix and transmission topology that will actually exist in each LDA during the Delivery Year. As with the ELCC and load forecast inputs discussed above, these assumptions are far less reliable when projected three-and-a-half years in advance than when estimated closer to the Delivery Year. The inaccuracies and uncertainties introduced by projecting BRA parameters over three years in advance can lead to capacity prices that do not reflect market fundamentals in the Delivery Year. This enhanced accuracy is particularly important when considering the issues PJM experienced in DPL-South in the 2024/25 BRA, when an inaccurate assumption about the availability of planned resources in the DPL-South zone resulted in a significant price increase in that zone and subsequent litigation.[75] Although PJM has proposed and implemented tariff revisions to address the particular issues raised in DPL-South, a shorter BRA forward period will have a shorter forecast horizon, more accurate forecasts of BRA parameters based on more up-to-date information, and clearing prices that better reflect actual system conditions.

C. Evidence and Analysis Supporting the Conclusion that a Prompt Auction is Just and Reasonable.

53. As discussed above in Part B, the BRA's current three-year forward period needlessly introduces risks into the BRA in a manner that likely raises costs to customers and frustrates the BRA's ability to inform orderly resource exit. A shorter forward period via a prompt BRA would reduce these risks. The remainder of this section explains the benefits of a prompt BRA.

i. A prompt auction will significantly improve the accuracy of key BRA auction parameters, resulting in capacity prices that better reflect actual supply and demand fundamentals and system conditions in the Delivery Year.

54. A prompt BRA schedule is likely to significantly enhance the accuracy of key BRA auction parameters and result in capacity prices that better reflect actual market fundamentals. For example, one of the most important BRA parameters is the load forecast, as discussed above. A prompt auction would reduce forecast uncertainty and allow PJM to use a peak demand forecast months before the start of the Delivery Year, as opposed to over three years before the start of the Delivery Year. As explained above, a three-year forward period tends to result in the ISO/RTO over-forecasting load, which raises costs to loads by requiring the purchase of unnecessary capacity. The price and cost impact of this dynamic should be expected to be considerably larger in magnitude at this time given the significant added uncertainty surrounding data center loads.

55. A prompt BRA would also result in more accurate ELCC capacity accreditation values than a three-year forward BRA because PJM will have access to more accurate information when it determines ELCC accreditation, as discussed above. For example, estimates about the Capacity Resources that will be available during the upcoming Delivery Year will be based on up-to-date information. From this will flow prices that better reflect supply and demand fundamentals. The ISO-NE IMM recognized the benefits of a prompt auction for improving

[75] *See generally PJM Interconnection, L.L.C.,* Docket No. ER23-729-000.

the accuracy of ELCC accreditation.[76] The accurate load forecasts noted above will also improve the accuracy of the assumptions used to estimate ELCC values.

56. Additionally, having more certainty about the resource mix and other system information such as transmission topology will also increase the accuracy of other BRA parameters, such as the CETO and CETL, which will ultimately result in Locational Deliverability Area Reliability Requirements that better reflect actual system conditions.

ii. A prompt auction will significantly enhance the quality of information and the accuracy of the price signal used in generator Deactivation decisions.

57. Under a prompt BRA schedule, resources offering into a prompt BRA would have much better information about the operational capabilities of their resources and the applicable environmental regulations in the upcoming Delivery Year. In this way, a prompt BRA would facilitate more informed—and thus more efficient—resource entry and exit decisions. This will be particularly important in the coming years, as a substantial volume of existing capacity in the PJM Region is expected to reach the end of its useful life and retire. A prompt BRA is also likely to reduce the risk premiums associated with the BRA's three-year forward period, especially from resources near Deactivation. As noted above, ISO-NE explained in the context of the ISO-NE capacity market that a prompt capacity auction will reduce the risk premiums Capacity Resources include in their supply offers relative to a three-year forward auction.[77]

iii. A prompt auction will significantly enhance the quality of data used in PJM's ELCC capacity accreditation, thereby better aligning both price and payments with resource contributions to resource adequacy.

58. A prompt BRA would result in more accurate ELCC capacity accreditation values than a three-year forward BRA because PJM will have more information about the resource mix that will actually be available during the next Delivery Year. More accurate load forecasts will also improve the accuracy of the assumptions used to estimate ELCC values. More accurate capacity resource accreditation will result in capacity prices that better reflect supply and demand fundamentals. The ISO-NE IMM explained that a prompt capacity auction could improve the accuracy of capacity accreditation.[78]

[76] ISO-NE IMM Comments, Docket No. ER26-925-000, at 2 (Jan. 20, 2026) ("A prompt market should address the impacts of observed issues with the forward market construct, in particular inaccuracies due to the uncertainty of auction inputs four-plus years ahead of the delivery time—on both the demand and supply side—such as peak load forecasting, supply side deliverability and capacity value accreditation."). Note that many of the ISO-NE IMM's comments about the benefits of a prompt market also mentioned the benefits of a seasonal market with marginal accreditation but this comment focused specifically on the forward period. The quote referenced was specific to prompt auctions.

[77] *See supra* note 63.

[78] *See supra* note 76.

iv. A prompt auction will significantly reduce the risks to new resources seeking to enter the market by creating more certainty regarding their expected availability for the Delivery Year.

59. A prompt auction will also significantly reduce the risks that new resources seeking to enter the market include in their capacity supply offers because such resources would have more certainty about their expected availability during the Delivery Year compared to a BRA with a three-year forward period. Requiring new entrants to make a financially binding capacity commitment three years before they expect to be online introduces risk for Planned Capacity Resources. To the extent it exists in PJM, a prompt auction would also address "phantom entry" by allowing only those resources that have actually achieved, or are on the imminent path to achieving, commercial operation prior to the start of the Delivery Year to bid into the BRA. Indeed, this is precisely the solution identified by the ISO-NE IMM for the issue of "phantom entry."[79] All else equal, reducing the risk premiums associated with the BRA's three-year forward period from the capacity supply offers of both existing and planned resources will place downward pressure on capacity supply offers and thus capacity prices.

D. Market design considerations regarding the implementation of a prompt capacity auction in PJM.

60. In this Part D, I provide general market design considerations regarding the implementation of a prompt capacity auction in PJM.

61. First, market power concerns in a prompt BRA can be addressed with market power mitigation, as occurs in NYISO and MISO, and will occur under the market power mitigation rules the Commission approved for ISO-NE. As the ISO-NE IMM observed, a prompt capacity auction could simplify market power mitigation because eliminating the multi-year forward period offers greater clarity on the difference between sunk costs and the incremental costs the supplier would undertake to accept a capacity supply obligation in the upcoming Delivery Year.[80] Although it would change deadlines for capacity resources to submit information to PJM and the IMM, switching to a prompt BRA would not require substantive changes to PJM's capacity market power mitigation. Indeed, capacity market power mitigation was successfully conducted in all BRAs since 2019, all of which were held with forward periods that were less than three years.

62. Second, a prompt BRA would impact state-led auctions for retail default service procurements. As an initial matter, default service procurements have proceeded with compressed BRA forward periods since 2019, demonstrating that a three-year forward period is not essential to conduct such procurements. For example, several states in PJM adjusted their default service procurements when Commission action led to compressed BRA forward periods starting in 2019. Specifically, Maryland, New Jersey, Ohio, and Pennsylvania added a Capacity Proxy Price ("CPP") mechanism that allowed suppliers bidding into default service procurements to

[79] *ISO New England Inc.*, 194 FERC ¶ 61,249, at P 13 (2026).

[80] ISO-NE Internal IMM Comments, Docket No. ER26-925-000, at 8-9.

pass capacity costs through to customers when the procurement was held before the BRA price for a given delivery year was known. Under the CPP, once the actual BRA price for a Delivery Year is known, the difference between the CPP and the actual BRA price is trued up.[81] In other words, since the BRA price is treated as a direct pass-through, shifting to a prompt auction would not add risk to supplier bids in default service procurements relative to the status quo.

63. Third, a prompt BRA does not present new price formation issues or fundamentally change the purpose of the BRA, which has already been running with a forward period of less than three years since 2019. The Commission has already accepted a prompt capacity auction as just and reasonable in ISO-NE, MISO, and NYISO, indicating that the prompt construct does not present price formation concerns. The current VRR Curve would still be appropriate in a prompt auction, just as the capacity market demand curves in ISO-NE, MISO, and NYISO are still appropriate. The prompt auction merely dispenses with the faulty assumption that entry is possible in three years, while also reducing the forecast error included in BRA parameters and the risk premiums included in capacity supply offers. The maximum capacity price in a prompt BRA—an administratively determined price indicating that capacity is short—would still be formulaically based in part on the Net CONE of the market's reference resource. The capacity price would serve the same function in a prompt BRA as it would in a three-year forward BRA—an indication of supply and demand fundamentals to guide orderly resource entry and exit.

64. Fourth, all else equal, moving from a three-year forward BRA to a prompt BRA would not increase year-to-year capacity price volatility. Dr. David Patton noted this in comments to the Commission in a proceeding about delaying ISO-NE's FCA to implement a prompt and seasonal auction. Dr. Patton explained that price volatility in the capacity market is driven by the slope of the demand curve and the amount of accredited capacity offered in a given year.[82] The same dynamics apply equally to PJM as they do to ISO-NE. PJM, like ISO-NE, uses an administratively-determined demand curve. All else equal (*e.g.,* assuming no changes to the VRR curve or capacity accreditation), the year-over-year price changes in a prompt BRA would be driven by changes in the accredited capacity that offers into the BRA each year. The evidence establishes that it is not possible for the reference resource—a gas CT—to bid into the three-year forward BRA and be constructed prior to the start of the Delivery Year. As such, there is no reason to expect that moving from a three-year forward to a prompt auction will materially affect year-on-year changes in the amount of capacity offered into the capacity market. Year-on-year price volatility could occur in the first year PJM transitions from a three-year forward to a prompt BRA because the prompt BRA parameters would likely be more reflective of system conditions than has been the case in prior years. However, PJM has not been running BRAs three years ahead of the Delivery Year for the last several BRAs, so I

[81] Margarita Patria and Alexander Vanderhoof, Charles River Associates, Default Service as a Risk Management Framework, section 3.2, (Aug. 31, 2026), https://www.pjm.com/-/media/DotCom/committees-groups/workshops/prtmdw/postings/2026/charles-river-associates-with-support-from-the-power-procurement-initiative-default-service-as-a-risk-management-framework.pdf.

[82] Motion to Intervene and Comments of the ISO New England's External Market Monitor, Docket No. ER24-1710-000, at 4-5 (Apr. 22, 2024).

expect the transition to prompt would be less impactful than would have been the case if PJM's recent BRAs had been running three years forward in recent years.

65. Fifth, notwithstanding the fact that the last two PJM BRAs have cleared short of the requirement, a prompt auction schedule will not make the BRA more prone to clearing short when compared to a three-year forward period. As Dr. Patton explained in an ISO-NE proceeding related to implementing a prompt capacity auction, capacity resources do not base their retirement decisions on capacity prices in a single year:

> *The existing generators with the highest going forward costs are typically ones contemplating capital expenditures that would be recouped over multiple years. Regardless of the auction timing, these decisions depend not only on the outcome of the upcoming auction, but typically also on their price outlook for the subsequent three to five years. The forward auction provides one year of capacity price certainty, but this has limited value when the decision to sell capacity involves a multi-year capital investment.*[83]

Furthermore, since the three-year forward period is not sufficient to permit entry by PJM's reference resource—or likely by any new physical generating resource—holding the BRA three years in advance of the Delivery Year is unlikely to increase the supply of new resources either. As PJM explained, multi-year offtake agreements are now generally required to finance new merchant capacity, meaning that new resource entry is not determined by the capacity price in a single year or the length of the forward period.[84] Instead, the timing of capacity resource entry depends on a variety of factors including expected net revenues over the generator's life, the costs to purchase and construct the generator, land, siting and permitting, and generator interconnection, the ability to obtain financing, and the project's timeline to achieve commercial operation. As such, entry or exit decisions do not generally hinge on the capacity price in a single year or the length of the forward period.

66. Sixth, a prompt BRA does not present issues regarding Reliability Must Run ("RMR") arrangements for several reasons. First, as discussed throughout, the primary benefit of a prompt capacity auction is that it will be based on up-to-date information, including information about any resources with RMR arrangements that will be online during the Delivery Year. The Commission recently accepted PJM's proposal to extend, through the 2030/31 BRA, tariff provisions that recognize the resource adequacy contributions of certain qualifying RMR resources in the BRA supply curve.[85] Compared to a three-year forward BRA, a prompt BRA increases the likelihood that such qualifying RMRs will be appropriately

[83] *Id.* at 5-6.

[84] *See e.g.*, PJM White Paper, at 5 ("…project finance lenders now require greater revenue certainty, typically in the form of long-term off-take agreements, to underwrite generation projects at manageable financing costs.")

[85] *PJM Interconnection, L.L.C.*, 196 FERC ¶ 61,098 (2026). PJM proposed tariff revisions to create a pro forma RMR agreement on October 15, 2026 in Docket No. ER27-167-000.

recognized in the BRA.[86] Second, the primary purpose of the capacity market is to send price signals that inform investment and guide orderly entry and exit; capacity market design should not be based on RMR arrangements, which are out-of-market constructs.[87] Third, one might argue that a three-year forward BRA could give Market Participants enough time to obviate the need for or shorten the timelines of RMR arrangements. However, RMR arrangements tend to require transmission upgrades which generally take longer than three years to develop.[88]

67. Finally, even assuming for the sake of argument that the BRA's three-year forward period permits credible entry by new Capacity Resources, this is less likely to be true for the 2030/31 BRA. A separate capacity procurement only open to new Capacity Resources—the Reliability Backstop Procurement or RBP—has the potential to be held and cleared in 2027, around the same timeframe as the 2030/31 BRA (scheduled for May 2027). The Commission accepted and suspended PJM's RBP proposal for further briefing, and PJM submitted a revised RBP proposal on October 29, 2026, in accordance with the Commission's prior order. The RBP will procure capacity with terms of up to 15 years on a pay-as-bid basis, with the MW-weighted average price of procurement each Delivery Year capped at $555/MW-day.[89] Among other eligibility requirements, RBP resources must be new and have an expected in-service date on or before June 1, 2032.[90] PJM has also engaged CRA to facilitate voluntary bilateral transactions between new large loads and new resources in parallel with the RBP to incent the development of new Capacity Resources.[91] Given that multi-year offtake agreements are now generally required to fund new merchant capacity,[92] the longer terms available in the RBP and the bilateral matchmaking process are likely to attract at least some, and likely most, new capacity suppliers in PJM away from offering into the 2030/31 BRA and towards the RBP or a facilitated bilateral transaction. Provided the RBP or bilateral prices are sufficient, new Capacity Resources will generally prefer a multi-year capacity contract with terms of up to 15 years to a guaranteed capacity payment for a single year, as available in a 2030/31 BRA. A strong indicator of capacity supplier preference for multi-year capacity arrangements is the

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[86] For example, if PJM identifies a resource that seeks to deactivate rather than offer into a three-year forward BRA and is subsequently retained in the three years between the BRA and the start of the Delivery Year, a prompt auction could include the RMR resource provided the agreement meets the applicable requirements. By contrast, in this example, the BRA with the three-year forward period would procure capacity that is not ultimately needed given the availability of the RMR resource that was negotiated after the BRA was held.

[87] PJM has very few resources RMR agreements compared to the total number of resources in PJM. *See e.g.,* Monitoring Analytics, RMR Memorandum to the Deactivation Enhancements Senior Task Force, December 1, 2023, https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_DESTF_RMR_Table_20231208.pdf.

[88] For example, the Brandon Shores and H.A. Wagner units initially had RMR agreements, starting on June 1, 2025, to allow time for transmission upgrades. However, due to delays in constructing those upgrades and PJM identifying new upgrades, PJM is extending the RMRs through May 31, 2031. *See H.A. Wagner LLC and Brandon Shores LLC* 196 FERC ¶ 61,140 (2026).

[89] *PJM Interconnection, L.L.C.*, 196 FERC ¶ 61,245 (2026).

[90] *Id*. at P 32 (2026).

[91] PJM RBP Transmittal, Docket No. ER26-3380-000, at 30-31.

[92] *See supra* note 84.

response to PJM's Request for Interest in the RBP. PJM reported that approximately 136 GW of potential new capacity from 397 potential projects and 87 entities expressed interest in the RBP or facilitated bilateral matching.[93] The dynamics of the RBP are also likely to impact the 2029/30 BRA and subsequent auctions until PJM and stakeholders determine and propose broader reforms to PJM's resource adequacy construct and the Commission accepts those reforms.

68. This concludes my affidavit.

[93] PJM RBP Transmittal, Docket No. ER26-3380-000, at 18.

Exhibit EN1: Historical PJM Load Forecasts, Summer Peak Forecasts and Load Adjustments

	Y_0	Y_0+1	Y_0+2	Y_0+3	Y_0+4	Y_0+5
2017 Forecast	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
PJM RTO Summer Peak, MW	152,999	153,951	154,278	153,684	153,384	153,425
Load Adjustments, MW	878	1,066	1,279	1,533	1,826	2,115
Load Adjustments, %	0.6%	0.7%	0.8%	1.0%	1.2%	1.4%
2018 Forecast	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
PJM RTO Summer Peak, MW	152,108	152,479	151,962	152,363	152,887	153,632
Load Adjustments, MW	1,218	1,491	1,825	2,181	2,450	2,667
Load Adjustments, %	0.8%	1.0%	1.2%	1.4%	1.6%	1.7%
2019 Forecast	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
PJM RTO Summer Peak, MW	151,358	150,870	151,547	152,253	152,854	153,435
Adjustments, MW	1,603	1,886	2,199	2,480	2,753	2,921
Adjustments, %	1.1%	1.3%	1.5%	1.6%	1.8%	1.9%
2020 Forecast	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
PJM RTO Summer Peak, MW	148,092	149,616	151,051	151,898	152,443	153,315
Adjustments, MW	(7)	209	424	628	713	663
Adjustments, %	0.0%	0.1%	0.3%	0.4%	0.5%	0.4%
2021 Forecast	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
PJM RTO Summer Peak, MW	149,224	149,966	150,855	151,503	151,928	152,290
Load Adjustments, MW	(268)	(184)	(82)	28	92	59
Load Adjustments, %	-0.2%	-0.1%	-0.1%	0.0%	0.1%	0.0%
2022 Forecast	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
PJM RTO Summer Peak, MW	148,938	149,351	150,309	151,165	152,259	152,322
Load Adjustments, MW	897	1,643	2,344	3,061	3,885	4,166
Load Adjustments, %	0.6%	1.1%	1.6%	2.0%	2.6%	2.7%
2023 Forecast	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
PJM RTO Summer Peak, MW	149,059	149,737	150,924	152,736	154,275	155,703
Load Adjustments, MW	2,888	3,269	3,566	3,841	4,035	4,185
Load Adjustments, %	1.9%	2.2%	2.4%	2.5%	2.6%	2.7%
2024 Forecast	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
PJM RTO Summer Peak, MW	151,247	153,493	156,803	159,859	162,972	165,681
Load Adjustments, MW	2,664	4,673	7,557	10,064	12,643	14,757
Load Adjustments, %	1.8%	3.0%	4.8%	6.3%	7.8%	8.9%
2025 Forecast	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
PJM RTO Summer Peak, MW	154,144	158,937	164,186	169,981	176,094	183,883
Load Adjustments, MW	3,591	8,453	13,668	19,320	25,334	32,795
Load Adjustments, %	2.3%	5.3%	8.3%	11.4%	14.4%	17.8%
2026 Forecast	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
PJM RTO Summer Peak, MW	156,373	160,451	165,567	171,530	183,008	191,017
Load Adjustments, MW	6,403	10,785	16,242	22,290	33,707	41,477
Load Adjustments, %	4.1%	6.7%	9.8%	13.0%	18.4%	21.7%

Source: PJM Load Forecasts, years 2017 through 2026, available here. PJM RTO Summer Peak figures are in Table B-1 and Load Adjustments are in Table B-9.

Exhibit EN2:
PJM Preliminary ELCC Class Estimate for RBP timeframe

	Delivery Year				
ELCC Class	**Actual 2028/29**	**Actual 2029/30**	**Prelim. 2030/31***	**Prelim. 2031/32**	**Prelim. 2032/33**
Onshore Wind	34%	37%	40%	41%	38%
Offshore Wind	60%	65%	67%	70%	63%
Fixed-Tilt Solar	7%	6%	7%	7%	7%
Tracking Solar	10%	7%	8%	8%	7%
Landfill Intermittent	50%	50%	49%	49%	49%
Hydro Intermittent	35%	34%	35%	36%	37%
4-hr Storage	59%	57%	42%	34%	30%
6-hr Storage	68%	66%	52%	44%	40%
8-hr Storage	71%	69%	56%	50%	47%
10-hr Storage	78%	76%	66%	60%	56%
Demand Response	91%	90%	84%	82%	82%
Nuclear	96%	96%	96%	95%	95%
Coal	85%	84%	84%	83%	83%
Gas Combined Cycle	78%	75%	73%	73%	74%
Gas Combustion Turbine	67%	59%	56%	56%	60%
Gas Combustion Turbine Dual	79%	76%	75%	75%	77%
Diesel Utility	93%	92%	92%	92%	92%
Steam	75%	75%	74%	74%	74%
Waste to Energy Steam	84%	83%	82%	82%	82%
Oil-Fired CT	83%	81%	79%	79%	79%

Sources: 2028/29 BRA ELCC class ratings: PJM, ELCC Class Ratings for the 2028/2029 Base Residual Auction, https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/28-29-bra-elcc-class-ratings.pdf; 2028/29 BRA ELCC class ratings: Preliminary ELCC ratings for Delivery Years 2030/31 through 2032/33: PJM, Preliminary ELCC Class Ratings For Period Delivery Year 2028/29 – Delivery Year 2042/43, September 2026, https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/preliminary-elcc-class-ratings-for-period-dy28-dy42-elcc.pdf. Notes: The ELCC values for 2028/29 and 2029/30 Delivery Years will be used in the 2028/29 and 2029/30 Delivery Years, respectively. Preliminary ELCC ratings for Delivery Year 2033/34 and later are excluded from this table.

Exhibit EN-3

To demonstrate the impact that modest changes in the reliability requirement (RR) can have on the BRA clearing price, I constructed a VRR curve based on the 2029/30 BRA parameters without the price collar, which is set to expire after the 2029/30 BRA. The first column of Table EN-3 below shows the points used to construct the 2029/30 VRR curve for the "Rest of RTO" based on the VRR curve the Commission approved in January 2026 in Docket No. ER26-455. To calculate the RR for the 2029/30 BRA, I subtracted the Fixed Resource Requirement (FRR) from the 2029/30 RTO RR, a figure based on PJM's January 2026 forecast. The Price Cap, or Point 1, is equal to the higher of 1.15 times the Gross Cost of New Entry ("CONE") minus 0.75 times the net Energy and Ancillary Services Offset, or 0.20 times Gross CONE, and the Point 1 quantity is based on 99% of the RR for the Delivery Year. The price cap without the collar ─ $594.48/UCAP MW-day ─ can be calculated from the Gross CONE and Net CONE figures PJM provides for the 2029/30 BRA planning parameters. Point 2 has a price equal to half of the Price Cap ($297.24/UCAP MW-day) and a quantity equal to 101.5% of the RR. Finally, Point 3 has a price of $0/MW-day and a quantity of 106% of the RR. The first column of Table EN-3.1 shows the three points of the VRR based on the 2029/30 BRA RR adjusted for the expected FRR Obligation. The second column of Table EN-3.1 shows the three points of a VRR curve with an RR that is 1% lower than the 2029/30 BRA ("Sensitivity 1"), and the third column shows a VRR with a RR that is 2% lower ("Sensitivity 2").

Table EN-3.1
Illustrative "Rest of RTO" VRR Curves

		2029/30 BRARR	**Sensitivity 1 1% lower RR**	**Sensitivity 2 2% lower RR**
	Reliability Requirement (RR) UCAP MW	147,779.4	146,316.2	144,881.8
Point 1	P_1: Price Cap, $/UCAP MW-day	$594.48	$594.48	$594.48
	Q_1: UCAP MW, 99% of RR	146,301.6	144,853.1	143,432.9
Point 2	P_2: Half of Price Cap, $/UCAP MW-day	$297.24	$297.24	$297.24
	Q_2: UCAP MW, 101.5% of RR	149,996.1	148,511.0	147,055.0
Point 3	P_3: UCAP Price, $/UCAP MW-day	$0.00	$0.00	$0.00
	Q_3: UCAP MW, 106% of RR	156,646.2	155,095.2	153,574.7

The VRR curves in Table EN-3 are plotted below. I calculated the capacity prices each VRR curve would produce for the different levels of cleared capacity (i.e., 147,500 UCAP MW and 150,000 UCAP MW) by finding the corresponding price in each VRR curve for that quantity of capacity.

Figure EN-3.1
Illustrative Example of the Cost Implications of the Reliability Requirement on the BRA Clearing Price



The price impacts of a lower RR at various assumed levels of cleared capacity (in UCAP MW) are shown in Table EN-3.2 below.

Table EN-3.2
Illustrative price impacts from lower reliability requirements, $/UCAP MW-day

	(a)	(b)	(c)	(d)	(e)
UCAP MW	2029/30 BRA RR	Sensitivity 1 1.0% lower RR	Price impact (b) – (a)	Sensitivity 2 2% lower RR	Price impact (d) – (a)
147,500	$498.06	$379.39	($118.67)	$276.95	($221.11)
150,000	$297.06	$176.24	($120.82)	$162.97	($134.09)

Exhibit EN4

Emma Nicholson, Ph.D.

Principal

Emma Nicholson is a Principal in the Energy practice. She is a Ph.D. economist with extensive regulatory and consulting experience. Her expertise lies in evaluating wholesale electricity market designs and estimating the impacts of existing and proposed market rules on market outcomes. She supports clients on matters related to RTO/ISO markets and market design, Federal Energy Regulatory Commission (FERC) policy and precedent, resource adequacy, capacity markets and accreditation, and transmission planning.

Education

Ph.D. Economics, Georgetown University, August 2008
M.A. Economics, Georgetown University, December 2004
B.A. Economics and Government and Politics, University of Maryland College Park, May 2001

Professional History

Charles River Associates
Principal, July 2025 - Present

- Lead an assessment of load resource and demand response (DR) opportunities to participate in ERCOT and the impact of retail DR programs and transmission cost allocation on ERCOT market outcomes. Examine ERCOT's proposed retail DR program and provide recommendations to better align ERCOT's existing programs with the system's acute and near-term operational needs. This report was presented to the ERCOT board in April 2026.
- Lead research and assist with the drafting of an expert report filed at FERC to rebut a complaint questioning MISO's benefit calculations for the Tranche 2.1 projects (Docket No. EL25-10). Critically analyze and rebut an expert report critiquing MISO's benefit calculation methodologies and craft arguments supported by evidence to demonstrate that MISO's Tranche 2.1 planning process and results were just and reasonable.
- Lead research and drafting of a report prepared for the Edison Electric Institute about retail electric rate trends in the US focusing on underlying cost drivers and the impacts of large loads.
- Advise a market participant developing a capacity market design proposal in an RTO/ISO stakeholder process. Identify economic and technical considerations, and relevant FERC precedent.
- Advise to neighboring RTOs on FERC Order No. 1920 interregional coordination compliance requirements, appropriate methods to estimate transmission benefits, and opportunities to enhance interregional transmission coordination.
- Provide strategic advice and technical expertise to a market participant to support their participation in an RTO stakeholder process to implement seasonal capacity market reforms.

Federal Energy Regulatory Commission, Office of Energy Policy and Innovation
Senior Economic Advisor, October 2021 – February 2025; Acting Deputy Director, February 2025-July 2025

- Lead discussions with FERC senior staff to analyze proposed RTO/ISO market rule changes and assess potential impacts on market efficiency, clearing prices, competition, operations, and electric reliability. Review and draft policy options memos and draft orders on such proposals.
- Critically review and analyze RTO/ISO market proposals to introduce new ancillary service products such as ISO-NE's Day-Ahead Ancillary Services Initiative, CAISO's Day-Ahead Energy Market Enhancements, and SPP's Uncertainty Product. Focus on operational and market impacts, how the new products would interact with existing ancillary service products, and market power and competition concerns.
- Review of proposals to establish new wholesale electricity markets, such as the CAISO's Extended Day-Ahead Market, SPP's Markets+, and the Southeast Energy Exchange Market. Analyze the likely operational and economic outcomes of the proposed markets given the market rules, transmission access and scheduling, and market optimization, and evaluate competitive concerns given market participants' incentives.
- Advise Chairman and Commissioners on options to enhance coordination between the gas and electric industries. Lead staff in developing and hosting two New England Winter Gas-Electric forums in August 2022 and September 2023. Conduct research and deliver briefings about fuel security and gas-electric coordination challenges in New England.
- Serve as an expert on RTO/ISO capacity accreditation reforms adopted across the U.S., such as the effective load carrying capability approach, performance-based methods, and other methods, and estimate their impact on capacity market outcomes and resource investment.

Federal Energy Regulatory Commission, Office of Energy Policy and Innovation
Economist, Advisor to the Director, November 2020 – October 2021

- Staff lead on the Commission's Modernizing Wholesale Electricity Markets proceeding (Docket No. AD21-10). Led a staff team to host two technical conferences in the Fall of 2021 that discussed the RTO/ISO market reforms necessary to address changing system needs brought on by the changing resource mix.
- Lead author of FERC staff whitepaper about RTO/ISO energy and ancillary service market reforms to address new operating needs, such as increased operational flexibility.
- Direct, review and finalize internal staff-led quantitative research about economic and technical issues related to RTO/ISO energy, ancillary services, and capacity markets, and natural gas markets.

Concentric Energy Advisors
Senior Project Manager, November 2018 – November 2020

- Conduct extensive empirical and regulatory research about FERC Order No. 1000 requirements, which govern regional transmission planning and interregional transmission coordination. This publicly available report examined competitive solicitations for new transmission projects developed in RTO/ISO regional transmission planning processes.
- Draft a report about regional and interregional transmission planning in SPP, PJM, and MISO to explain the obstacles and impediments to interconnecting increasing amounts of wind and solar generation in these markets. Engage with ISO New England (ISO-NE) staff and stakeholders to develop Cost of New Entry (CONE) and Offer Review Trigger Price (ORTP) parameters for the Forward Capacity Market. Estimate the capital, construction, financing, and interconnection costs of new resource types. Develop models to estimate the energy and ancillary services revenues for new natural gas, onshore wind, offshore wind, solar, battery storage, and hybrid (solar + storage) resources with a dispatch model that incorporated

production costs and projected market prices to estimate energy and ancillary services revenues in ISO-NE day-ahead and real-time markets. Draft an expert report supporting the parameters that ISO-NE filed with FERC in Docket No. ER21-1637.

- Prepare a report about the Public Utility Regulatory Policy Act (PURPA) for the Edison Electric Institute that compared annual levelized contract rates from a national sample of long-term utility PURPA contracts with wind and solar Qualifying Facilities to competitively procured wind and solar in the United States over the same time period. The report also estimated how Qualifying Facility wind and solar contract rates tracked with underlying cost trends in wind and solar facilities in the states the Qualifying Facilities were located. The report was filed in the Edison Electric Institute's comments on FERC's Notice of Proposed Rulemaking to revise PURPA (Docket No. RM19-15).
- Prepare a whitepaper for the PJM Power Providers Group about how increased renewable energy generation, distributed energy resources, and price-responsive demand in RTO/ISO markets create an emerging challenge that drives the need for increased operational flexibility in RTOs/ISOs and explained market-based mechanisms to incent and procure additional operational flexibility. The whitepaper included an analysis of flexible ramping products and revising the operating reserve demand curve to procure reserves beyond the minimum reserve requirement and was filed in FERC Docket No. ER19-1486.
- Submitted an expert affidavit on behalf of the American Wind Energy Association about PJM's proposed minimum duration requirement for electric storage resources in FERC Docket No. ER19-469 that critically analyzed the evidentiary support for PJM's proposed 10-hour minimum requirement for electric storage resources and concluded the evidence was insufficient.
- Led a team to support the Chief Executive Officer's expert witness testimony in support of a commercial restructuring of the largest oil pipeline system in North America, the Enbridge Mainline.

Federal Energy Regulatory Commission, Office of Energy Policy and Innovation, Division of Economic and Technical Analysis
Economist, April 2013-October 2018

- Core team member in the Commission's Price Formation effort (Docket No. AD14-14), which involved several tasks including analyzing RTO/ISO energy and ancillary services market rules and operational practices, writing policy options memos, conducting empirical analyses of RTO/ISO market data and drafting a publicly available staff report, and moderating technical conferences about energy offer caps, market power mitigation, and operator-initiated commitments in RTOs/ISOs.
- Serve as technical advisor to Chairman Norman Bay (November 2016 - January 2017) on FERC final and proposed rulemakings, oil and natural gas pipeline rates, natural gas pipeline certificate orders, and RTO/ISO energy, ancillary services, and capacity market design proposals by providing strategic and technical advice to the Chairman and helping him advance his goals and priorities.
- Staff lead on FERC final rule that capped energy offers into FERC-jurisdictional RTOs/ISOs (FERC Order No. 831 in Docket No. RM16-5).
- Conduct quantitative studies of RTO/ISO energy, ancillary service, and capacity market outcomes by making use of non-public transaction-level RTO/ISO data and present findings in memos to the Commission to inform decision making. Topics include market power and mitigation, offer price caps, resource self-scheduling practices, offer flexibility, virtual bidding,

fast-start pricing, uplift allocation, market model parameter values, and RTO/ISO operational practices.
- Lead author of publicly available staff paper on operator-initiated commitments in RTOs/ISOs which involved a detailed tariff review and original empirical research. Analyze quantitative information about out-of-market commitments by operators in RTOs/ISOs.
- Sole author of publicly available staff paper on market power mitigation in RTOs/ISOs that involved a detailed tariff review and original empirical research that evaluated markups and the efficacy of market power mitigation in ISO-NE and CAISO by exploring how resource markups changed with load levels, marginal cost, and proximity to the marginal offer.
- Serve as non-decisional FERC staff to act as a resource to PJM stakeholders regarding developing proposals to comply with FERC's June 2018 Order in Docket No. ER18-1314 regarding the Minimum Offer Price Rule.
- Detail with the Office of Administrative Litigation – served as staff's lead economic expert witness in a market-based rate application proceeding for an oil pipeline (Wood River). Review evidence in the record and apply FERC precedent regarding oil pipeline competition to determine whether the applicant met FERC's requirements to possess market-based rate authority.

Exeter Associates, Inc., Columbia, MD
Senior Economist, November 2009 - April 2013

- Testify as an expert witness on matters of retail electric cost allocation and rate design for Consumer Advocates and Staff in Indiana, Pennsylvania, and Rhode Island and use the company's cost-of-service model to propose alternative rate designs.
- Lead role in developing the Long-Term Electricity Report for the State of Maryland, specifically review, analyze, and summarize the results of production cost model runs, conduct research, and draft a report that projected energy prices, capacity prices, and emissions under various load, natural gas, and renewable capacity penetration scenarios.
- Conduct training sessions about cost allocation and rate design for the staff of the Indiana Office of Utility Consumer Counselor that included numerical examples from Indiana electric rate cases.
- Assist large Federal customers with wholesale electric power procurement, planning, and utility supply assessments (natural gas, electricity, and water).
- Use ARIMA time series models on real-time ERCOT data to estimate the impacts of wind generation on the price of balancing energy.

Bates White, Washington, DC
Senior Consultant, September 2008 - November 2009

- Perform econometric analyses of natural gas trading data in support of Bates White expert for testimony filed on behalf of the FERC's Office of Enforcement regarding alleged natural gas market manipulation.
- Forecast demand and generation capacity in New York state for the public convenience and necessity certificate hearing of a proposed transmission line in New York by making use of output from production cost models.
- Prepare damages model for commercial litigation by calculating but-for electricity prices.
- Assist Bates White expert witness with a depreciation study and research natural gas supply forecasts for testimony submitted in a natural gas pipeline rate manipulation case before FERC.

Publications

- “Assessment of load participation and demand response in ERCOT,” with Chris Russo and Nirmal Bhatt, April 2026.
- “An Empirical Analysis of Avoided Cost Rates for Solar and Wind QFs Under PURPA,” with Michael Kagan, prepared for the Edison Electric Institute, November 2019.
- “Building New Transmission: Experience to Date Does Not Support Expanding Solicitations,” with Meredith Stone and Danielle Powers, prepared for Ameren, Eversource Energy, ITC Holdings Corp., National Grid USA, and PSE&G, June 2019.
- “Future Challenges in Wholesale Electricity Market Design,” with Arnie Quinn, IEEE Power & Energy Magazine, January 2019.
- “Operator-Initiated Commitments in RTO and ISO Markets,” FERC Staff paper, December 2014, (lead author and technical contact)
- “Energy Offer Mitigation in RTO and ISO Markets,” FERC Staff paper, August 2014 (lead author, researcher, and technical contact)
- “Towards Equilibrium Offers in Unit Commitment Auctions with Nonconvex Costs,” with R. Sioshansi. Journal of Regulatory Economics, Vol. 40. No. 1, August 2011.
- “The Relationship between Wind Generation and Balancing Energy Market Prices in ERCOT: 2007-2009,” with J. Rogers and K. Porter. National Renewable Energy Laboratory, November 2010.
- “Abandon all Hope? FERC’s evolving standards for identifying comparable firms and estimating the rate of return” with J. Lesser. The Energy Law Journal. April 2009. Vol. 30:105.

Expert Witness Testimony

- Before the Public Utilities Commission of Rhode Island, Docket No. 4323, August 2012, on behalf of the Division of Public Utilities and Carriers on cost allocation and rate design issues.
- Before the Indiana Utility Regulatory Commission, Cause No. 44075, April 2012, on behalf of the Indiana Office of Utility Consumer Counselor on cost allocation and rate design issues.
- Before the Pennsylvania Public Utility Commission, Docket No. R-2010-2172665, September 2010, on behalf of the Pennsylvania Office of Consumer Advocate on cost allocation and rate design issues.
- Before the Indiana Utility Regulatory Commission, Cause No. 43839, June 2010, on behalf of the Indiana Office of Utility Consumer Counselor on proper cost allocation methods.
- Before the Alberta Utilities Commission, Proceeding 28829, with Seabron Adamson, February 2026, on behalf of BHE Canada on the Alberta Electricity System Operator’s import rules.
- Before the New York Public Service Commission, Case 26-W-0358, May 2026, on behalf of Liberty Utilities New York Water on water consumption forecasts.

Expert Affidavits

- Expert affidavit and whitepaper analyzing the operational drivers and market impacts of flexible ramping products and operating reserve demand curves, filed in FERC Docket No. ER19-1486 in May 2019 on behalf of PJM Power Providers Group

Expert affidavit analyzing PJM’s proposed minimum duration requirement for electric storage capacity resources, filed in FERC Docket No. ER19-469 in February 2019 on behalf of the American Wind Energy Association

UNITED STATES OF AMERICA

BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Exelon Corporation,	)	
	)	
Complainant	)	
	)	
v.	)	**Docket No. EL27-___-000**
	)	
PJM Interconnection, L.L.C.,	)	
	)	
Respondent	)	

VERIFICATION OF EMMA NICHOLSON

Emma Nicholson, being duly sworn, deposes and states on this date of November 2, 2026, that she is the Emma Nicholson referred to in the foregoing document entitled "Affidavit of Emma Nicholson on Behalf of Exelon Corporation," that she has read the same and is familiar with the contents thereof, and that the testimony set forth therein is true and correct to the best of her knowledge, information, and belief.

Emma Nicholson
Principal
Charles River Associates

SUZANNE M. WALSH
Notary Public
Massachusetts
My Commission Expires
Dec 11, 2031

Attachment B
Affidavit of Deborah M. Sears

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Exelon Corporation,	)	
	)	
Complainant	)	
	)	
v.	)	**Docket No. EL27-___-000**
	)	
PJM Interconnection, L.L.C.,	)	
	)	
Respondent	)	
	)	

AFFIDAVIT OF DEBORAH M SEARS
ON BEHALF OF EXELON CORPORATION

My name is Deborah Sears, and my business address is 500 N Wakefield Drive, Newark, DE 19702. I currently serve as the Senior Manager, Energy Acquisition, in the Governmental, Regulatory and External Affairs group of Pepco Holdings, LLC, which is an indirect wholly-owned subsidiary of Exelon Corporation ("Exelon") and which itself owns Atlantic City Electric Company ("ACE"), Delmarva Power & Light Company ("DPL"), and Potomac Electric Power Company ("Pepco" and collectively with ACE and DPL, the "Exelon PHI Companies"). I am submitting this affidavit in support of Exelon's complaint in this proceeding.

1. Specifically, in this affidavit, I:

    a. Provide a general overview of the Exelon PHI Companies' procurement responsibilities as Load Serving Entities ("LSEs"), focusing on several of Exelon's operating jurisdictions where I have experience; and

    b. Describe the constraints and limitations imposed by state law and regulation on the ability of Exelon LSEs to engage in long-term bilateral contracting and risk hedging to mitigate the risk of high clearing prices in PJM Interconnection, L.L.C.'s ("PJM") Reliability Pricing Model ("RPM").

I. QUALIFICATIONS

2. I joined Exelon in 2023 and have been continuously employed ever since. As Senior Manager, Energy Acquisition, I am responsible for overseeing the procurement and settlement of supply for the Exelon PHI Companies, which include ACE, DPL, and Pepco.

3. Prior to joining Exelon, my experience includes 13 years of wholesale energy experience, working at Exelon PowerTeam, later as Constellation, in various roles, including accounting, power scheduling, generation dispatch, energy trading, and commercial transactions where I participated in long-term contract negotiation and administration, load auctions, and other projects. During my time in these roles, I also held certifications as a PJM Generation Operator and NERC Reliability Coordinator.

4. I hold a Bachelor of Science in Accounting from The Pennsylvania State University.

II. TESTIMONY OF DEBORAH M SEARS

A. Exelon LSEs' Procurement Responsibilities

5. The Exelon PHI Companies are responsible for providing Standard Offer Service ("SOS") (Basic Generation Service ("BGS") in New Jersey) within the ACE, DPL, and Pepco service territories within Maryland, Delaware, New Jersey, and the District of Columbia ("DC") for customers who do not select a competitive supplier. In order to provide these services, the Exelon PHI Companies must procure wholesale energy, capacity, ancillary services, and sufficient Renewable Energy Credits ("RECs") required to meet Renewable Portfolio Standards ("RPS") within each jurisdiction.

6. Supply is procured through auction processes. The procedure to procure supply differs for each of these jurisdictions but all such processes are regulated by the applicable state utility regulatory commissions.

7. Maryland and Delaware each require procurement of supply for residential and small commercial customer classes for a two-year period, while the District of Columbia and New Jersey procure for a three-year period. Large commercial contracts have a tenor of one year in all jurisdictions except for Maryland, where they procure 3-month contracts. Within these auctions, suppliers are bidding on a slice of load basis, and "slices" are separated into tranches representing approximately 50 MW of capacity. The results of the winning bids are then averaged to determine the SOS/BGS price for the upcoming energy year. Maryland, the District of Columbia, and New Jersey all have a full requirements product, while Delaware is energy, ancillary services, and capacity only. The auctions themselves also differ in methodology, but all are structured to procure the lowest cost supply for customers.

8. The auctions are all monitored by a market monitoring unit and results are approved by the applicable state utility regulatory commission.

B. Constraints and Limitations Imposed by State Law and Regulation on the Ability of Exelon's LSEs to Engage in Long-Term Bilateral Contracting and Risk Hedging.

9. The SOS/BGS auction structures are highly prescriptive and any changes to the annual auction process are reviewed through a stakeholder meeting called the Procurement

Improvement Process, and the final changes to the Request for Proposal and Full Requirements Service Agreement require approval by the applicable state utility regulatory commission. Pepco, DPL, and ACE are not permitted to enter into any bilateral transactions, including hedging agreements, without approval from the applicable state utility regulatory commission. Below, for each state, I describe the general contracting constraints and, as appropriate, offer recent examples where the regulator has directed specific contracting activities

10. In Maryland, utilities are not permitted to bilaterally contract unless first directed to do so by statute or through a Maryland Public Service Commission ("Maryland PSC") approved procurement program, like the current SOS program. In April 2026, the Maryland PSC began conducting a study through the Renewable Energy Certainty Act ("RECA")[1] to evaluate the advantages and disadvantages of different generation procurement models, which include long-term contracting structures. It is unclear at this stage which, if any, of these programs will ultimately be advanced by the Maryland PSC.

11. In Delaware, the SOS requirements are described in Order 6746.[2] As in the case of Maryland, DPL does not have the ability to bilaterally contract within Delaware unless it is first approved by the Delaware Public Service Commission. However, without legislative changes, any DPL expense related to a long-term contract would only be allocated to SOS customers, making long-term contracting cost prohibitive because any associated costs could only be recovered from SOS customers, not from those receiving service from a third-party supplier or a cooperative.

12. New Jersey provides the guidelines for BGS within the Electric Discount and Energy Competition Act, section 48:3-57, which also restricts bilateral contracting. As part of the Clean Energy Act of 2018, New Jersey launched the Garden State Energy Storage Program ("GSESP"), which is a multi-phase program designed to deploy 2,000 MW of energy storage by 2030, but this is a specific, statutorily directed procurement.

13. Finally, the District of Columbia also restricts bilateral contracting outside of SOS, as described in the Code of the District of Columbia Section 34-1509, Standard Offer Service.[3] In 2019, Order 19897 under FC1017[4] required Pepco to issue an RFP for "a long-term renewable energy purchase power agreement for energy generated by solar or wind power facilities located within the PJM Region to provide a target quantity of five percent of the SOS load." The RFP was issued four times before an agreement was executed and

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[1] Power Advisory LLC, *RECA Generation Procurement Model Study: Discussion Paper* (Md. Pub. Serv. Comm'n Apr. 2026), https://psc.maryland.gov/wp-content/uploads/2026/04/Power-Advisory_Procurement-Model-Study-White-Paper-April-2026.pdf.

[2] *In re Delmarva Power & Light Co.,* PSC Docket 04-391, Findings, Opinion & Order No. 6746 (Del. Pub. Serv. Comm'n Sept. 1, 2005), https://depsc.delaware.gov/wp-content/uploads/sites/54/2017/03/6746.pdf.

[3] D.C. Code § 34-1509 (2001 & Supp. 2026).

[4] *In re Development & Designation of Standard Offer Service in the District of Columbia*, Formal Case No. 1017, Public Notice (D.C. Pub. Serv. Comm'n Apr. 12, 2019), https://dcpsc.org/PSCDC/media/PDFFiles/Electric/FC1017_SOSWorkingGroupNotice.pdf.

approved by the Public Service Commission of the District of Columbia in September of 2025.

14. This concludes my affidavit.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Exelon Corporation,	)	
	)	
Complainant	)	
	)	
v.	)	**Docket No. EL27-___-000**
	)	
PJM Interconnection, L.L.C.,	)	
	)	
Respondent	)	
	)	

VERIFICATION OF DEBORAH M SEARS

Deborah Sears, being duly sworn, deposes and states on this date of November 2, 2026, that she is the Deborah Sears referred to in the foregoing document entitled "Affidavit of Deborah M Sears on Behalf of Exelon Corporation," that she has read the same and is familiar with the contents thereof, and that the testimony set forth therein is true and correct to the best of her knowledge, information, and belief.

Deborah Sears

DIGITALLY SIGNED

Deborah Sears
Senior Manager, Energy Acquisition,
Governmental, Regulatory and External Affairs,
Pepco Holdings, LLC

State of New York
County of Monroe

Sworn to and subscribed before me on this 2nd day of November 2026 by Deborah Sears

DIGITALLY SIGNED

Marcelle N Tiberio



Online Notary Public. This notarial act involved the use of online audio/video communication technology. Notarization facilitated by SIGNiX®

Attachment C
Form of Notice

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Exelon Corporation,	)	
	)	
Complainant	)	
	)	
v.	)	**Docket No. EL27-___-000**
	)	
PJM Interconnection, L.L.C.,	)	
	)	
Respondent	)	
	)	

NOTICE OF COMPLAINT

(November 3, 2026)

Take notice that on November 3, 2026 pursuant to sections 206, 306, and 309 of the Federal Power Act ("FPA"), 16 U.S.C. § 824e, 825e, and 825h, and Rule 206 of the Federal Energy Regulatory Commission's ("Commission") Rules of Practice and Procedure, 18 CFR 385.206, Exelon Corporation ("Exelon" or "Complainant") filed a formal complaint against PJM Interconnection, L.L.C. ("PJM" or "Respondent") requesting that the Commission: (i) find under FPA section 206 that the current three-year forward period of PJM's Reliability Pricing Model ("RPM") is no longer just and reasonable; (ii) adopt as a replacement rate a "prompt" auction schedule, to run two months before a given Delivery Year, starting with the 2030/2031 Delivery Year and continuing beyond; (iii) establish a refund effective date of January 1, 2027; and (iv) permit Fast Track processing under Rule 206(h) to facilitate a Commission order by no later than January 31, 2027—currently the last day before the posting of the planning parameters for the 2030/31 Delivery Year Base Residual Auction.

Exelon certifies that copies of the complaint were served on the contacts for PJM as listed on the Commission's list of Corporate Officials.

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211, 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. The Respondent's answer and all interventions or protests must be filed on or before the comment date. The Respondent's answer, motions to intervene, and protests must be served on the Complainant.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the "eFiling" link at *http://www.ferc.gov*. Persons unable to file electronically should

submit an original and 5 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426.

This filing is accessible on-line at *http://www.ferc.gov,* using the "eLibrary" link and is available for electronic review in the Commission's Public Reference Room in Washington, DC. There is an "eSubscription" link on the Web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email *FERCOnlineSupport@ferc.gov,* or call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Comment Date: 5:00 p.m. Eastern Time on November 23, 2026.

Dated: November 3, 2026.