Drivers of PJM's Capacity Market Price Surge and its Impacts on Electricity Consumers in the District of Columbia

Bill and Rate Impacts Associated with Recent and Upcoming Changes to PJM's Capacity Market

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AUTHORS

Sarah Shenstone-Harris
Chelsea Mattioda
Ariella Fuzaylov
Wooddynne Dejeanlouis
Bob Fagan

Synapse Energy Economics, Inc.

485 Massachusetts Avenue, Suite 3
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

CONTENTS

EXECUTIVE SUMMARY

PJM Interconnection (PJM) is the regional transmission organization (RTO) that coordinates the movement of wholesale electricity across the District of Columbia (DC) and 13 states. Its capacity market auction procures power to ensure that electricity demand can be met on the hottest and coldest days of the year when demand is highest. PJM's most recent capacity market auction, its Base Residual Auction (BRA) that secured capacity for the 2025/2026 delivery year, resulted in the highest capacity prices ever seen in the region. System-wide prices rose from the 2024/2025 delivery year by a factor of nine, increasing from $28.92/MW-day to $269.92/MW-day. PJM-wide total capacity costs increased from $2.2 billion to $14.7 billion.[1] These auction results prompted PJM and stakeholders to reexamine the market dynamics that led to such high prices and explore various market reforms. The Office of People's Counsel (OPC) for DC commissioned Synapse Energy Economics (Synapse) to evaluate these market dynamics, assess market reforms, and quantify both recent and anticipated bill impacts for electricity customers in Washington, DC.

PJM's Pepco zone, where Washington, DC is located, saw a five-fold increase in capacity prices. Capacity clearing prices jumped for the sub-region from $49.49/MW-day in 2024/2025 to $269.92/MW-day for 2025/2026.[2] We estimate that starting in June 2025, the start of the 2025/2026 delivery year, the average residential electric customer will see a $10 increase in their monthly bill as a result of this latest capacity auction (holding all other bill changes constant), or a 9 percent increase (Table 1).

Table 1. DC bill and rate impacts of the 2025/2026 capacity auction results relative to the 2024/2025 delivery year

Rate Class	Monthly Bill Change (%)	Additional $/kWh Rate	Additional Cost on Month Bills ($)
Residential	9%	$0.017	$10
Commercial	9%	$0.016	$345

These unprecedented prices are primarily due to a few key factors—in a real sense, these factors represent a perfect storm of fundamental economic drivers causing prices to rise.

1) **Existing Supply Decreases**. PJM recently updated its resource accreditation methodology (which determines the capacity value of a resource, existing or new). It also entered into two new Reliability-Must-Run (RMR) arrangements and removed those units from the capacity market.

[1] 2025/2026 Base Residual Auction Report. July 30, 2024. PJM Interconnection, LLC. https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-report.pdf.

[2] 2025/2026 Base Residual Auction Report. July 30, 2024. PJM Interconnection, LLC. https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-report.pdf.

Added to this, older, uneconomic polluting fossil resources at the end of their life are also retiring. These three factors reduced total supply in the market, thereby increasing prices.

2) **New Supply Entry Barriers**. Meanwhile, the clogged PJM interconnection queue has prevented new, mostly cleaner resources from being able to enter the market in recent years. This is despite increasing prices and a clear market signal that more supply is needed.

3) **Dramatically Increasing Demand Projection**. Lastly, demand projections are also increasing across the PJM footprint, further exacerbating these issues and putting upward pressure on capacity prices.

PJM has already put several reforms in motion to change some of these market dynamics before its next auction (scheduled for July 2025). The Federal Energy Regulatory Commission (FERC) approved these reforms in February 2025. On the supply side, these reforms include removing exemptions where certain resources were not required to offer into the capacity market and changes that require RMR units to offer into the capacity market if they are providing capacity to the system. On the demand side, PJM will change certain parameters of its demand curve. More recently, PJM proposed a capacity price maximum and minimum, which was approved on April 21, 2025. These approved changes will apply to the 2026/2027 and 2027/2028 delivery years; PJM considers these changes to be stop-gap measures and will consider longer-term reforms for the 2028/2029 delivery year and beyond. Interconnection queue reform is also underway.

These reforms, along with planned retirements and updates to PJM's resource accreditation methodology (new ratings for effective load carrying capacity, or ELCC), could increase average monthly electric bills in DC by $1 for the 2026/2027 delivery year, incremental to the bill impact from the 2025/2026 auction results (Table 2). Synapse estimated the potential bill impacts of these reforms across four scenarios: (1) no new additional supply enters the market, (2) 2,000 MW of reliable (i.e., unforced) capacity enters the market, (3) 15,000 MW come online to enable the capacity price to fall to the proposed floor of $175/MW-day, and (4) 2,000 MW of capacity enters but there is no $325/MW-day price cap. Actual impacts will depend on a range of factors that remain in flux; these results demonstrate a potential range of impacts.

Table 2. DC bill impacts estimated for the 2026/2027 capacity auction relative to the 2025/2026 delivery year

	No Additional New Builds	Some New Entry	Price Floor	Some New Entry with No Price Cap
Residential Average Monthly Bill Change (relative to previous year)	+ $1	+ $1	- $5	+ $9
Commercial Average Monthly Bill Increase (relative to previous year)	+ $26	+ $26	- $172	+ $321

Source: Synapse analysis, see Section 4.

PJM must be able to bring new resources online to be able to (a) respond to high prices and market signals, (b) continue to meet growing levels of demand, and (c) enable states in PJM to meet their renewable energy and emissions targets. Although PJM began implementing interconnection reforms in 2024, many stakeholders have expressed concern that these reforms are insufficient. PJM has responded to these concerns with its Resource Reliability Initiative (RRI), another stop-gap measure, aimed at accelerating the interconnection of qualifying resources to bring more generation online before the 2029/2030 delivery year. Consumer advocates in the region called for reforms to prioritize ready-to-study projects sited in areas that are more likely to be constrained. However, RRI will prioritize larger capacity projects that can provide firm capacity and have high reliability ratings. Environmental groups are worried that RRI is unduly discriminatory against non-dispatchable resources in favor of gas, which has a high reliability rating, and there is additional concern that it may create challenges for PJM states and the District as they strive to meet renewable energy targets. Furthermore, the initiative does not guarantee that new resources will be online by the 2029/2030 delivery year.

Stakeholders will continue to have the opportunity to weigh in on these items and other market dynamics impacting future auctions, especially as many of these measures are intended to be temporary. This report assesses these market changes and their impacts on DC electricity customers to support DC OPC's navigation of these topics that are essential to managing the impact for DC residents and electricity consumers.

Joint Consumer Advocates' Response to PJM's Recent Base Residual Auction

In response to the BRA results for the 2025/2026 delivery year, the DC OPC along with state advocate offices from Maryland, New Jersey, Illinois, and Ohio (the "Joint Consumer Advocates" or "JCA") filed a complaint before FERC on November 18, 2024, requesting (1) a Rule 206 refund effective date be established; (2) a finding that PJM's existing capacity market rules are unjust and unreasonable, due to the failure to mitigate market power and excessive capacity charges; and (3) establishment of reasonable replacement rates based on recommended changes to the auction. These changes included:

1. Removing exemptions for resources to participate in the capacity auction, thus requiring the participation of intermittent resources, battery storage, demand response, and generation resources operating under RMR arrangements;
2. Reforming RMR resource treatment, including longer notice periods for generator deactivation and creating standardized provisions for RMR including a *pro forma* agreement delaying retirements as long as the resource is needed for reliability. Where continued service is required, compensation should be at the full cost of service and include a return on investment;
3. Using the winter ELCC ratings for gas-fired generators that seasonally match the winter risks for such resources when calculating their capacity values—thus allowing for more supply to be reflected in the auction;
4. Addressing the interconnection queues by prioritizing "ready-to-study" projects sited at Locational Deliverability Areas that are more likely to be constrained;
5. Requiring demand response resources to submit offers based on the maximum dispatchable demand reduction that the resource is making available to PJM and measure the actual reduction delivered (metered consumption before instruction less metered consumption after instruction) in response to a dispatch instruction during a system stress event; and
6. Imposing an offer cap on demand response resources when the structural market power tests fail.

The JCA also filed comments in support of Pennsylvania's challenge to PJM's use of Net CONE and later in opposition to the price cap and price floor proposed in the joint settlement filed by Pennsylvania and PJM of Pennsylvania's Complaint. With respect to Net CONE, in addition to supporting a multiplier of 1.5 times Net CONE as opposed to 1.75, the JCA advocated abandoning the use of the Reference Resource's Gross CONE to set the price cap. The JCA also recommended that PJM calculate Net CONE empirically, using an average of past auction clearing prices that have supported new entry. The JCA have argued that both the price floor and price cap are too high, though they acknowledge that the price floor could be reasonably accepted if proposed on its own. Since the cap and floor are not severable, both must be rejected. PJM's subsequent filings have adopted some of the recommendations initially proposed by the JCA.

1. BACKGROUND AND OVERVIEW

PJM Interconnection (PJM) is the regional transmission organization (RTO) that coordinates the movement of wholesale electricity across the District of Columbia (DC) and 13 states.[3] It manages competitive electricity markets, oversees long-term planning, and balances supply and demand to maintain a stable and reliable power system.

1.1. Capacity Market Basics

PJM's wholesale electricity marketplace consists of three important and distinct markets:

1. The **energy market** includes day-ahead and real-time auctions, responding to near-instantaneous fluctuations in supply and demand. It is designed to provide the lowest-cost electricity to consumers.
2. The **capacity market** ensures there is enough electricity supply to meet future demand by paying power plants and other resources to be available when needed in the future. The market selects the most cost-effective mix of resources, including thermal power plants, renewables and intermittent resources, grid-connected battery storage, and demand response programs.
3. The **ancillary services markets** help maintain grid reliability by providing essential services such as frequency regulation, operating reserves, and voltage control.

In the electricity market, **capacity** refers to the commitment of power resources—such as power plants, energy storage, and demand response programs—to be available when needed, particularly during peak demand periods and grid emergencies. Capacity represents the ability to supply electricity rather than the actual energy produced, to ensure grid reliability.

In PJM, the capacity market is called the Reliability Pricing Model (RPM), which is meant to cost-effectively procure enough power supply and demand response resources to meet future electricity demand, on the hottest and coldest days of the year. This procurement occurs through annual capacity auctions (the Base Residual Auction, or BRA, and subsequent incremental auctions),[4] which secure commitments from power generators and demand response resources to be available for one 12-month period. This 12-month period is referred to as the delivery year, from June through May. This auction

[3] In addition to the District of Columbia, PJM operates in Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia.

[4] PJM holds incremental auctions between BRAs. These supplemental auctions provide flexibility to account for changes in demand or supply conditions that may occur after the initial BRA.

traditionally occurs three years ahead of the delivery year, but PJM is currently off schedule and is conducting BRAs six to 12 months in advance of the start of the delivery year.

PJM's capacity market serves two primary purposes. First, it aims to send clear price signals to generator owners/developers and demand response program administrators. When the market is oversupplied, low-capacity prices can encourage costly and uneconomic resources to retire. Conversely, when there is a shortage in capacity, high-capacity prices incentivize the implementation of new generation. Second, it solves the "missing money" problem, whereby some resources may not make enough revenue in the energy market alone to remain online and provide a 12-month capacity commitment. The capacity market provides generators with an additional revenue stream (typically more stable than the price-volatile energy markets) to recover their capital investments and fixed costs.

1.2. Supply and Demand Curves

PJM's capacity market balances supply and demand to set a cost-effective market clearing price in each of numerous Locational Deliverability Areas (LDA), with clearing prices remaining the same across LDAs if transmission constraints between regions are not binding. When such constraints bind, a 'congested' region will have a higher clearing price than its uncongested neighboring region.

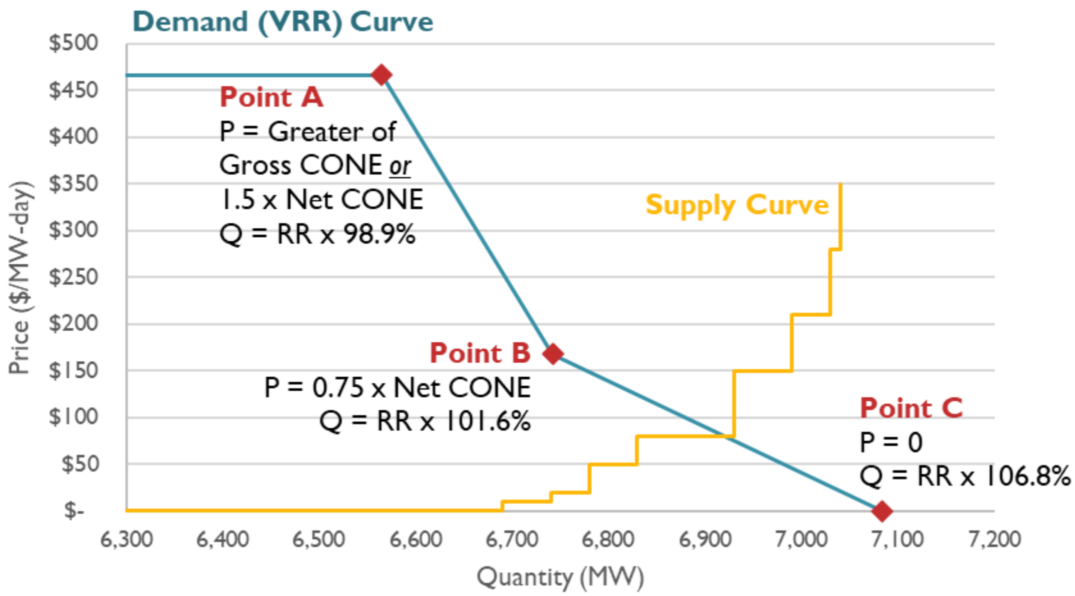
1. **Supply Curve (Seller Bids)** – Capacity suppliers (power plants, demand response resources, etc.) submit bids with the quantity and price at which they are willing to provide capacity. The seller bids are stacked from lowest to highest price, to create an upward sloping curve.

2. **Demand Curve (Variable Resource Requirement Curve)** – PJM sets a demand curve which reflects how much capacity is needed to ensure grid reliability. The demand curve is a downward sloping 3-point "curve" called the variable resource requirement (VRR) curve and reflects aggregate consumers' willingness to buy slightly more reliability if supply costs are low enough.

3. **Market Clearing Price** – The auction clears where the supply curve intersects the demand curve. This means PJM selects the lowest-cost resources first, moving up the supply curve, until the capacity requirement is met. The highest-priced accepted bid sets the uniform **clearing price**, which is paid to all cleared capacity resources.

Resources with a capacity commitment have "cleared" in the capacity auction in a respective LDA and are subsequently paid the market clearing price ($/MW-day) for that delivery year for the LDA. Figure 1 shows the VRR curve, supply curve, and clearing price dynamics (the supply curve is illustrative, and the clearing price is thus an example). We discuss each of these three components in more detail below.

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



Source: VRR curve for Pepco LDA, 2025/2026 Planning Period Parameters for Base Residual Auction, April 12, 2024. Figure originally developed by Synapse for the Bill and Rate Impacts of PJM's 2025/2026 Capacity Market Results & Reliability Must-Run Units in Maryland, August 2024, Maryland Office of People's Counsel, Available at: https://opc.maryland.gov/Portals/0/Files/Publications/RMR%20Bill%20and%20Rates%20Impact%20Report_2024-08-14%20Final.pdf?ver=V9hZfyTmjLeNVt2Dg3cTgw%3D%3D.

Supply Curve: Offer Prices and UCAP Quantity

Generators and demand response resources submit offers that reflect their megawatt (MW) value and price. The MW quantity in a resource's offer is defined by how much capacity it can provide at peak periods and grid emergencies, to contribute to the system's reliability (referred to as its unforced capacity (UCAP)). A resource's UCAP is less than its nameplate or "installed" capacity (ICAP).

An existing resource offers its UCAP value at a price equal or less than the costs it would avoid by not operating for the delivery year, as defined by the Market Seller Offer Cap (MSOC) rules. New market participants can enter at a price of zero (price takers) or at prices that reflect their net costs of entering.

VRR Curve: Reliability Requirements and Net CONE

PJM has an RTO-wide VRR curve, while LDAs that are transmission or capacity constrained have LDA-specific VRR curves. Each point on the VRR curve is defined by the reliability requirement (based on peak load) and Net Cost of New Entry (CONE). For instance, in the 2025/2026 BRA, Point A on the VRR Curve was 98.8 percent times the reliability requirements (quantity (MW), on the x axis) and either the greater of 1.5 x Net CONE or Gross CONE (price, on the y axis) (as shown in Figure 1). These three points, defined by the reliability requirement and Net CONE, create a three-point downward-sloping curve.

The reliability requirement is the target level of capacity required to meet PJM's reliability standards. This is expressed as forecasted peak load plus a reserve margin and is meant to reflect the amount of capacity necessary to meet the reliability criteria of a loss of load expectation (LOLE) of one day in 10 years for the RTO as a whole (or one day in 25 years for individual LDAs). PJM determines this reliability requirement through probabilistic risk modeling, which incorporates load forecasts, outage rates, and the availability of different resource types.

CONE is the average revenue that a newly built resource—specifically a reference resource selected by PJM—would need to earn in the capacity market within its first year of operation.[5] PJM currently uses a simple-cycle combustion turbine (CT) as the reference resource to calculate CONE.[6] Net CONE is calculated by subtracting the reference resource's expected revenues in the energy and ancillary services (E&AS) markets from the total gross CONE value. Net CONE changes from year to year, based on estimates of capital costs, ongoing operating and maintenance expenses, and expected E&AS offsets for the reference technology. PJM publishes the reliability requirement, Net CONE, and VRR curve for the RTO and each constrained LDA in its Planning Period Parameters no more than 100 days before the auction.

LDAs and Price Separation

In PJM's capacity market, LDAs are geographic subregions used to model transmission constraints and reliability needs. These LDAs can be nested within larger LDAs, creating a hierarchy (e.g., Baltimore Gas and Electric, or BGE, and Pepco are both nested within SWMAAC, which is nested within MAAC, which is in turn is nested within the RTO). This nesting hierarchy is referred to as child and parent (e.g., SWMAAC is the child of MAAC). During the capacity auction, each LDA clears sequentially, starting with the smallest/narrowest areas. If a specific LDA has limited import capability, it may need more local (and higher priced) capacity, leading to a higher clearing price compared to its parent LDA, referred to as price separation. The nesting allows PJM to reflect transmission limitations and localized scarcity more accurately. A constrained nested LDA (such as BGE within SWMAAC) may clear at a significantly higher price than the broader area if local capacity is scarce, signaling the need for more local investment or upgrades to transmission infrastructure.

DC is located within the Pepco LDA, which is nested within SWMAAC LDA (along with BGE LDA). Pepco has not experienced price separation in recent years.

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[5] Newell, S., Hagerty, J.M., Pfeifenberger, J., Zhou, B., Carless, T., Janakiraman, R., Gang, S., Daou, P., Junge, J. April 21, 2022. PJM CONE 2026/2027 Report. Prepared for PJM Interconnection. Available at: https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2022/20220422-brattle-final-cone-report.ashx.

[6] Ibid.

2. The 2025/2026 BRA Results and Its Impact on DC Electricity Customers

2.1. Auction Results

In the latest BRA, which occurred in July 2024 for the delivery year 2025/2026, capacity auction clearing prices reached unprecedented levels. System-wide prices increased by a factor of nine, increasing from $28.92/MW-day to $269.92/MW-day.[7] This resulted in total PJM-wide capacity costs of $14.7 billion for 2025/2026, over $12 billion more than the previous year.[8] Prices in the BGE and Dominion (DOM) LDAs were even higher, clearing at the maximum allowable price. The Pepco LDA, where DC is located, saw a five-fold increase in capacity prices. It cleared with its parent LDAs SWMAAC and MAAC at $49.49/MW-day in 2024/2025 and cleared with the RTO as a whole in 2025/2026 at $269.92/MW-day.[9] Table 3 outlines the capacity clearing prices for the 2025/2026 and 2024/2025 delivery years for a subset of LDAs, including the Pepco LDA.

Table 3. BRA clearing pricing for 2024/2025 and 2025/2026 delivery years, for a selection of LDAs

LDA	2024/2025 Clearing Price ($/MW-day)	2025/2026 Clearing Price ($/MW-day)
RTO	$28.92	$269.92
MAAC	$49.49	$269.92
EMAAC	$54.95	$269.92
SWMAAC	$49.49	$269.92
PEPCO	**$49.49**	**$269.92**
BGE	$73.00	$466.35
DOM	$28.92	$444.26

Source: PJM's RPM Base Residual Auction Results for 2024/2025 and 2025/2026, available at: https://www.pjm.com/markets-and-operations/rpm.

2.2. Bill and Rate Impact for DC Electricity Customers

We calculate that the 2025/2026 capacity auction market results will increase the average residential customer's energy bill in DC by approximately $10/month relative to the 2024/2025 delivery year,

[7] 2025/2026 Base Residual Auction Report. July 30, 2024. PJM Interconnection, LLC. https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-report.pdf.

[8] 2025/2026 Base Residual Auction Report. July 30, 2024. PJM Interconnection, LLC. https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-report.pdf.

[9] 2025/2026 Base Residual Auction Report. July 30, 2024. PJM Interconnection, LLC. https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-report.pdf.

holding all other bill changes constant (Table 4). The additional $10 per month will likely be felt by residential customers starting in June 2025 through May 2026, the length of the delivery year.

Table 4. DC bill and rate impacts of the 2025/2026 capacity auction results relative to the 2024/2025 delivery year

Rate Class	Monthly Bill Change (%)	Additional $/kWh Rate	Additional Cost on Month Bills ($)
Residential	9%	$0.017	$10
Commercial	9%	$0.016	$345

Source: see description in text.

Synapse calculated the average bill increase by first determining the incremental cost to electricity customers in the Pepco LDA between the 2024/2025 and 2025/2026 delivery years, using auction result data from PJM.[10] The Pepco LDA covers DC and portions of Maryland. Using data from the U.S. Energy Information Administration's (EIA) Form EIA-861,[11] we first allocated the incremental cost to electricity customers to the DC portion of the Pepco LDA. Based on EIA data, the DC portion of the Pepco LDA is responsible for 38 percent of total electricity consumption in the LDA. We therefore assume that the DC portion of the Pepco LDA is also responsible for 38 percent of the LDA's capacity market costs. We then allocated the DC portion of the Pepco LDA capacity costs to either residential or commercial customers, using Pepco[12] and EIA data on electricity consumption.[13] We exclude any other bill changes for electricity customers that may be in effect during this period, such as distribution and delivery costs, transmission costs, energy costs, or others.

Capacity procurement schedules (both for Pepco's standard offer service and for third-party suppliers) may occur on slightly different schedules than PJM's auction timing. Capacity procurement schedules may affect the estimated timing of the expected bill impacts; our estimated $10/month increase for residential customers is the annual expected average over 12 months.

2.3. Driving Factors Behind the Capacity Market Price Increase

There are four key factors that help explain the soaring prices, which have led to concerns about the region's ability to effectively and affordably meet demand:

1. Changes to capacity market rules, in particular how capacity is valued in the market

[10] PJM, Base Residual Auction Results and Third Incremental Auction Results for Delivery Years 2024/2025 and 2025/2026, available at: https://www.pjm.com/markets-and-operations/rpm

[11] United States Energy Information Administration, Annual Electric Power Industry Report Form EIA-861, https://www.eia.gov/electricity/data/eia861/

[12] Assuming residential customers use on average 614 kWh/month.

[13] United States Energy Information Administration, Annual Electric Power Industry Report Form EIA-861, https://www.eia.gov/electricity/data/eia861/.

2. Generator retirements and the impact of how PJM treats reliability-must-run (RMR) units in the capacity market

3. Interconnection queue backlogs

4. Increases in demand as a result of electrification and data center growth

The first two drivers, recent market reforms and PJM's treatment of RMR units in the capacity market, reduced supply in the market. As with any market, all else equal, a reduction in supply typically increases prices. The reduction in supply was further compounded by the third driver, the clogged PJM interconnection queue. This has meant that few new resources have been able to enter the market in recent years, despite the increasing prices that sent a clear market signal that more supply is needed. Lastly, demand is also increasing across the PJM footprint, further exacerbating these issues and putting upward pressure on capacity prices. Concerningly, PJM expects these dynamics to continue for the foreseeable future, which could lead to increasingly unaffordable electricity prices across the region.[14] We discuss each of these factors in greater detail below.

Changes to PJM's Capacity Accreditation

Capacity markets are designed to ensure that the electrical grid has sufficient generating resources to meet current and future electricity demand. Generators and demand response resources with a capacity commitment are paid the market clearing price times the amount of capacity value they are providing to the market. The process of measuring and valuing a resource's capacity value is called capacity accreditation (i.e., determination of its unforced capacity (UCAP)).

Following winter storm Elliot in 2022, the region saw major outages and reliability shortfalls. In response, PJM implemented various capacity market reforms for the 2025/2026 delivery year, most notably its capacity accreditation methodology. Previously, PJM used various methods to determine a generator's accredited value (or UCAP). However, starting with the 2025/2026 delivery year, PJM adopted a Marginal Effective Load Carrying Capability (ELCC) approach.[15] This approach accredits resources based on their marginal contribution to the system's reliability needs, modeling all 8,760 hours in a year across multiple scenarios.[16]

This new ELCC approach has resulted in a reduced UCAP value for most resource types, reducing the total firm supply of capacity participating in the market. As seen in Table 5, solar and natural gas resources experienced the most significant change in their ELCC values, decreasing by an average of 29 and 22 percent, respectively, between the 2024/2025 and 2025/2026 delivery years.

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[14] PJM Interconnection. December 9, 2024. Revisions to Reliability Pricing Model, Docket No. ER25-682, at page 5.

[15] PJM previously used a few capacity accreditation methods for different resource types (e.g., thermal versus intermittent resources). Federal Energy Regulatory Commission, January 30, 2024. Order Accepting Tariff Revisions Subject to Condition. Docket ER24-98, at 3-5.

[16] PJM's ELCC approach explicitly models how generator forced outages and other de-rates vary with temperature.

Table 5. PJM's average capacity class ratings for the 2024/2025, 2025/2026, and 2026/2027 delivery years

Resource Type	2024/2025	2025/2026	2026/2027
	Historical Method	Marginal ELCC Method	
Fixed-Tilt Solar	30%	9%	8%
Tracking solar	50%	14%	11%
Coal	87%	85%	83%
Gas Combined Cycle	96%	80%	74%
Gas Combustion Turbine	90%	62%	60%
Diesel (Oil)	91%	90%	91%

Source: Class ratings for 2025/2026 using historical capacity accreditation method from: PJM Interconnection, December 1, 2023. Docket ER24-99-001. Responses to Deficiency Letter – Capacity Market Reforms to Accommodate the Energy Transition, at 27. Updated 2025/2026 Class Ratings from: PJM Interconnection, ELCC Class Ratings for the 2025/2026 Base Residual Auction, March 13, 2024, available at: https://www2.pjm.com/-/media/planning/res-adeq/elcc/2025-26-bra-elcc-class-ratings.ashx. ELCC Class Ratings for the upcoming 2026/2027 delivery year from: PJM Interconnection, ELCC Class Ratings for the 2026/2027 Base Residual Auction, February 28, 2025, available at: https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2026-27-bra-elcc-class-ratings.pdf.

The derating of gas and renewable resources between delivery years 2025/2025 and 2025/2026 resulted in a substantial decrease in the UCAP offered into the market. It also meant that affected resources had to increase their offer prices. As a resource's effective capacity (UCAP) is reduced—meaning it can sell fewer megawatts—it must raise its prices to ensure it can still cover its annual costs and remain financially viable. For instance, consider an 8 MW UCAP resource that previously bid in at $50/MW-day, reflecting costs of $400/day; if now accredited at 5 MW UCAP, the offer would be adjusted to $80/MW-day resulting in the same total $400/day amount.[17] This dynamic creates a scenario in which consumers have to pay more for less capacity. PJM's adoption of the new ELCC approach caused auction revenues to increase by an estimated 49.1 percent, or $4.4 billion, between the 2024/2025 and 2025/2026 delivery years.[18]

Retirements and Reliability-Must-Run Units

In recent years, many aging coal power plants and other fossil fuel generators have economically retired across the PJM region, reducing the amount of conventional, higher-emission supply available to the capacity market. Between the 2024/2025 and 2025/2026 BRAs, 3,640 MW of nameplate capacity retired

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

[18] Compared to what RPM revenues would have been had PJM cleared the auction without locational constraints and using the prior, EFORd approach. Monitoring Analytics, Analysis of the 2025/2026 RPM Base Residual Auction Part A. Available at: https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_A_20240920.pdf.

across the PJM footprint.[19] We estimate this to be roughly 3,300 MW of accredited capacity (UCAP),[20] or approximately 2 percent of the capacity that cleared in the 2024/2025 auction.

The reduction in supply has been further compounded by two recent RMR agreements. In 2023, Talen Energy announced its intent to retire Brandon Shores and Herbert A. Wagner (Wagner) generators. The units are located in the BGE LDA, which is highly transmission constrained. PJM determined that if Brandon Shores units 1 and 2, and Wagner units 3 and 4 were to retire, there could be major grid reliability issues. PJM asked Talen to continue operating these four units beyond their proposed retirement date of June 2025, through RMR arrangements, until the associated reliability issues can be addressed with upgrades to the transmission system. These upgrades would alleviate the reliability concerns by enabling electricity to be imported from neighboring areas. The RMR service[21] is a specific designation applied to generating units that agree to remain operational beyond their planned retirement dates, until transmission solutions are put in place that address the reliability issue. PJM entered into two RMR arrangements with Talen Energy for its Brandon Shores and Wagner generators starting in June 2025, [22] which are expected to extend to May 31, 2029.[23]

Importantly, although PJM needs RMR units to continue operating to avoid reliability issues (e.g., to generate energy during critical periods), these units have not participated as supply-side resources in any previous PJM capacity auction.[24] This means that when a unit enters into an RMR arrangement with PJM, the LDA where it is located will see a sudden drop in capacity market supply (despite having the same amount of grid-connected resources in that LDA). For instance, in the latest BRA, the removal of Brandon Shores and Wagner dramatically reduced supply for the BGE LDA. That meant that only 10 percent of the LDA's capacity was located within the LDA, while the remaining amount was imported from neighboring regions. However, since the LDA was so transmission-constrained, it could not import enough capacity to meet its reliability requirements (the target amount of capacity required to meet PJM's reliability standard). As a result of the sudden drop in supply, the transmission-constrained zone cleared at the maximum allowable capacity price in the 2025/2026 BRA. This capacity shortfall in the BGE LDA, as a result of the RMRs not participating in the capacity auction, had a spillover effect into the

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

[20] Using average class ratings for the 2024/2025 delivery year.

[21] RMRs are referred to as "Part V Reliability Service" in the PJM tariff.

[22] In 2024, PJM arranged to retain one resource under RMR contracts: the Indian River plant ("IR4"), a 410 MW coal facility owned by NRG Power Marketing, located in Delaware in the DPL South LDA. The Indian River RMR arrangement terminated in February 2025, approximately 22 months ahead of schedule. PJM Inside Lines. December 23, 2024. "Delaware Generator To Retire Ahead of Schedule." Available at: https://insidelines.pjm.com/delaware-generator-to-retire-ahead-of-schedule/.

[23] Talen Energy, January 27, 2025. "Talen Energy, Other Parties Reach Reliability Must Run Settlement Agreement for Brandon Shores and H.A. Wagner Power Plants." Available at: https://ir.talenenergy.com/news-releases/news-release-details/talen-energy-other-parties-reach-reliability-must-run-settlement.

[24] PJM Interconnection, LLC. 2024. "PJM Response to Independent Market Monitor Report on 2025/2026 Base Residual Auction." Available at: https://www.pjm.com/-/media/DotCom/library/reports-notices/reliability-pricing-model/20241011-response-to-imm-25-26-bra-report.ashx.

RTO as a whole. It increased the RTO-wide clearing prices and pushed up consumer prices in the Pepco zone and beyond, resulting in a 41.2 percent increase in overall auction revenues, or an increase of $4.3 billion.[25]

Electricity customers compensate units retained through RMR arrangements for their continued operation through out-of-market payments administered by PJM. These payments are in addition to the capacity price spike associated with their removal from the capacity auction, as described above. RMR costs are allocated to LDAs proportionally to the cost allocation of the transmission upgrades that will address the reliability issues that necessitated the RMRs to begin with. Table 6 shows the total out-of-market costs of Brandon Shores and Wagner RMRs, and the bill impact of these procurements on DC Pepco customers. The Pepco LDA is responsible for 11 percent of total RMR costs, the second largest share after the BGE LDA. The DC portion of Pepco is responsible for roughly 4 percent of total annual RMR costs, with the Maryland portion paying for the remaining 7 percent.

Table 6. Initial RMR costs for Brandon Shores and Wagner RMR arrangements, and the costs allocated to DC Pepco electricity customers

Generator	Nameplate MW	Annual RMR Costs	Percent of Costs Allocated to DC Pepco Customers	Annual RMR Costs Allocated to DC Pepco Customers	Additional cost on the average residential monthly electric bill
Brandon Shores (units 1&2)	1,282	$145.9 million		$5.9 million	-
Wagner (units 3&4)	703	$35.2 million	4 percent	$1.4 million	-
Combined Total	**1,985**	**$181.1 million**		**$7.3 million**	**$0.50 per month**

Notes: Brandon Shores and Wagner RMR cost recovery is subject to litigation by intervening stakeholders in a proceeding before FERC. As a result, the final cost recovery amount approved by FERC may be lower than the initial proposal. Cost data Talen Energy, January 27, 2025. "Talen Energy, Other Parties Reach Reliability Must Run Settlement Agreement for Brandon Shores and H.A. Wagner Power Plants", Available at: https://ir.talenenergy.com/news-releases/news-release-details/talen-energy-other-parties-reach-reliability-must-run-settlement

Brandon Shores and Wagner units are scheduled for use as RMR units through May 2029,[26] when the transmission enhancements are complete that will address the reliability issues associated with these

[25] Holding everything else constant, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day resulted in a 41.2 percent increase in RPM revenues, $4,287,256,309, for the 2025/2026 RPM Base Residual Auction compared to what RPM revenues would have been had the capacity of those RMR resources been included in the supply curve at $0 per MW-day. Monitoring Analytics, Analysis of the 2025/2026 RPM Base Residual Auction Part A. Available at: https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_A_20240920.pdf.

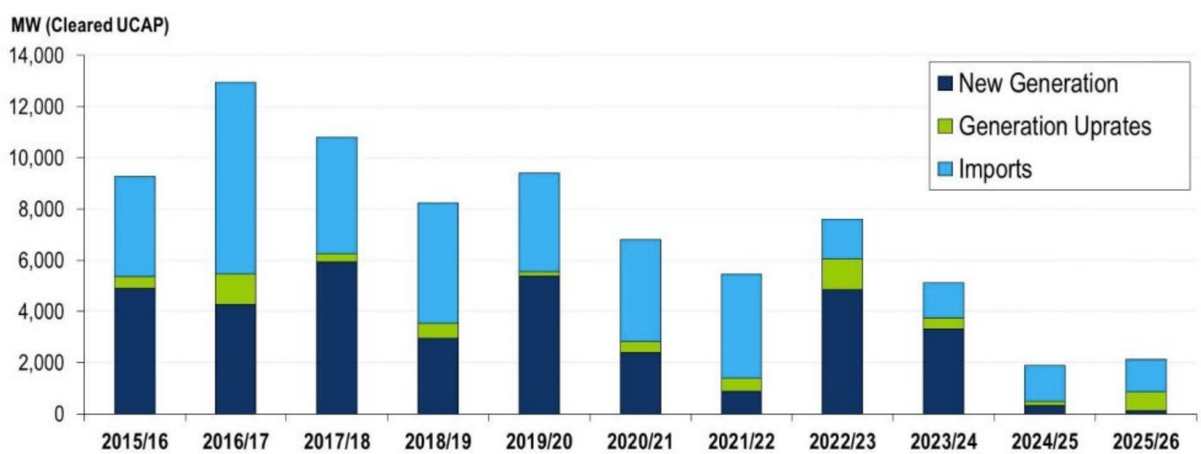
[26] According to the latest settlement agreement, Talen Energy, January 27, 2025. "Talen Energy, Other Parties Reach Reliability Must Run Settlement Agreement for Brandon Shores and H.A. Wagner Power Plants." Available at:

unit retirements. However, there are multiple factors that could delay the construction and completion of the required transmission projects, making this timeline uncertain.

PJM Interconnection Queue Constraints

Capacity supply across the region has decreased in recent years, as result of PJM's new capacity accreditation methodology and PJM's historical treatment of RMRs in the auction. This led to historically high capacity market prices in the last BRA. High market prices should incentivize new market entry to ultimately bring prices down. However, the PJM interconnection queue is currently experiencing major delays and constraints, meaning that it has been increasingly difficult for new generation to enter PJM's capacity markets in recent years. This is evident in Figure 2, which shows that the volume of new supply resources clearing in the capacity market has been substantially lower in the last two auctions (2024/2025 and 2025/2026) relative to previous delivery years. New supply is not able to replace the retiring resources and the reductions in supply associated with the new capacity accreditation methodology. The impact of delayed new resource entry has been compounded by the truncated periods between the most recent auctions and the start of delivery years, which further reduces the ability of capacity prices to incentivize new entry.[27] Ultimately, because of the clogged queue and shortened auction schedule, generator owners and developers are not able to respond to the capacity market's price signal with new entry as quickly as needed, thus reducing the market's efficiency and effectiveness.

Figure 2. Cleared MWs (UCAP) of new generation, upgrades, imports by delivery year (excludes existing generation)



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

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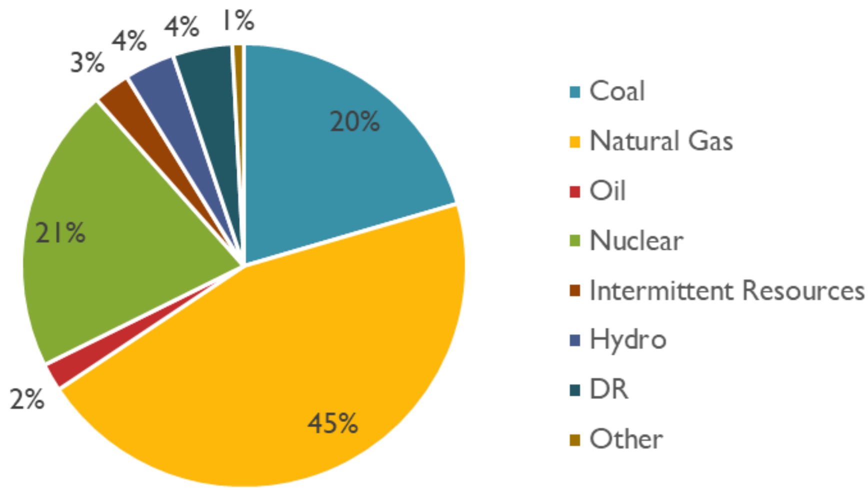
https://ir.talenenergy.com/news-releases/news-release-details/talen-energy-other-parties-reach-reliability-must-run-settlement.

[27] Complaint of Joint Consumer Advocates. FERC EL25-18, page 3.

In the latest auction, natural gas represented the largest share of cleared resources (UCAP), representing 45 percent, followed by nuclear and coal (21 percent each) (Figure 3). Conversely, the interconnection queue is made up of 94 percent renewables and storage, and only 6 percent gas-fired resources, on a MW basis.[28]

Figure 3. Cleared resources by type, in UCAP MW, in the latest 2025-2026 BRA



Notes: Other includes "Aggregate Resources" and "Other" (as defined by PJM), Oil includes "Oil" and "Distillate Oil (No.2)", and Intermittent Resources include Solar, Wind, and Battery/Hybrid. 2025/2026 Base Residual Auction Report. July 30, 2024. PJM. Available at: https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-report.pdf.

Increasing Load and Demand

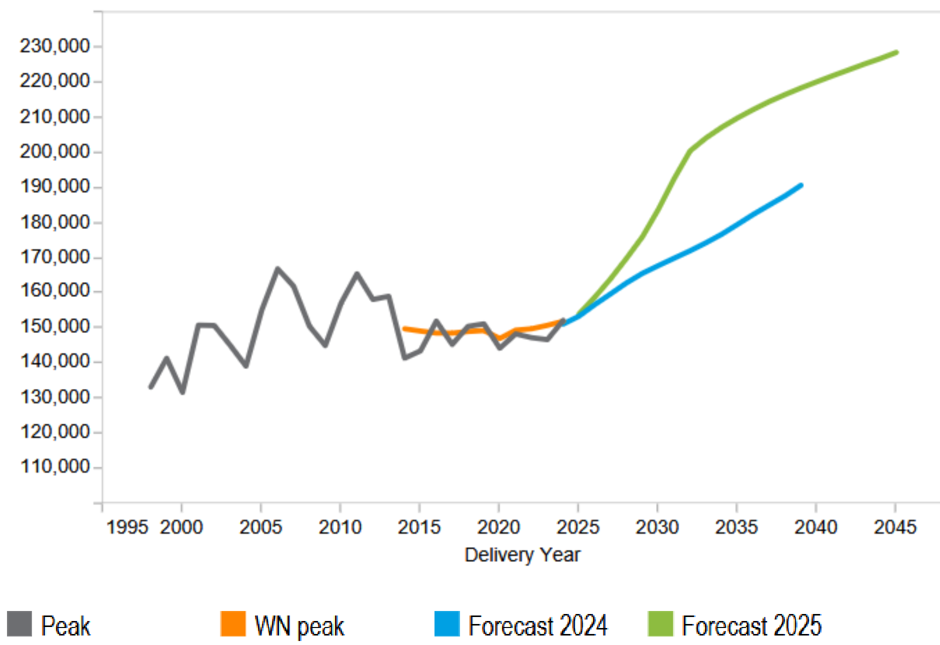
Alongside PJM's new capacity accreditation, recent retirements, new RMR agreements, and clogged queue, increasing demand is also contributing to rising capacity costs. Total load across the PJM footprint increased by 3,243 MW (or 2 percent) between the 2024/2025 and 2025/2026 delivery years, representing a substantial increase relative to historical changes to demand. A similar increase is expected for the next delivery year, followed by rapid escalation beyond 2026 (Figure 4).[29] Much of this is due to projected demand from new data centers, as well as growing electrification of buildings and

[28] Energy Transition in PJM: Resource Retirements, Replacements & Risks, PJM Interconnection, L.L.C., 2 (Feb. https://www.pjm.com/-/media/library/reports-notices/special-reports/2023/energytransition-in-pjm-resource-retirements-replacements-and-risks.ashx ("Four Rs Report").

[29] 2025 Preliminary PJM Load Forecast, Load Analysis Subcommittee. December 9, 2024. Available at: https://www.pjm.com/-/media/DotCom/committees-groups/subcommittees/las/2024/20241209/20241209-item-03---2025-preliminary-pjm-load-forecast.ashx

transportation (e.g., heat pumps and EVs). The increasing load forecasts further exacerbate these market dynamics and the tightening balance of supply and demand in PJM, and thus drives up prices.

Figure 4. PJM's summer peak forecast (MW) for the RTO



Source: 2025 PJM Long-Term Load Forecast Report. January 24, 2025. PJM. Available at: https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2025-load-report.pdf.

3. Upcoming Changes to the 2026/2027 and 2027/2028 Capacity Markets

Given the very high clearing prices in the 2025/2026 delivery year, and the strong likelihood that these recent market dynamics will continue for the foreseeable future, there have been widespread calls for capacity market reform in PJM.[30] As a result, PJM recently reexamined several of its capacity market rules and proposed "stop gap" measures for the 2026/2027 and 2027/2028 delivery years. In February 2025, FERC approved these reforms, which will affect how PJM treats RMRs in the capacity market, what resources must offer into the capacity market, and the selection of the reference resource used for Net CONE calculations and the VRR Curve. On April 21, 2025, FERC also approved PJM and Pennsylvania's proposal to set a new price maximum and minimum. These approved reforms will affect how much

[30] Several entities filed a complaint in Docket No. El24-148.

supply will participate in the auction, as well as how the VRR demand curve is defined. This section discusses these reforms.

Separately, PJM plans to continue to evaluate and develop its rules around RMR treatment before the 2028/2029 BRA; and later in 2026, PJM will review the reference technology and other parameters that influence the VRR curve. Section 6 (Ongoing Reform Discussions) summarizes these longer-term reforms.

3.1. Upcoming Changes to Supply

Ending the Must-Offer Exemption for Intermittent, Storage, and Hybrid Resources

Since 2015, all existing generation capacity resources with capacity interconnection rights (CIR) have been required to submit a supply offer into the BRA, except for intermittent resources, storage, hybrid, and demand response resources. However, FERC recently ended the must-offer exemption for intermittent, storage, and hybrid resources, effective for the upcoming 2026/2027 delivery year. This change will increase the total amount of available supply. Only demand response resources will remain categorically exempt.

This change was proposed by PJM and supported by various stakeholders. As PJM explains, the resource mix in PJM has changed substantially over the last decade. The amount of UCAP supplied by intermittent, storage, and hybrid resources has tripled since 2018/2019 alone, and these resource types now make up 97 percent of the planned MW in the PJM interconnection queue (substantially more than in 2015).[31] PJM and the market monitor also argue that the must-offer exemption could lead to market power issues, especially as the share of solar, wind, and storage resources continues to grow in the future.[32] The Joint Consumer Advocates in PJM (the District of Columbia, Maryland, Ohio, New Jersey, and Illinois) also supported lifting the must-offer exemption for demand response resources, citing market power issues.[33] Lastly, the market monitor argued that the exemption for resources with CIRs tie up CIRs that could be allocated to other resources.[34]

However, some intervenors opposed the change. For instance, certain parties argued that if intermittent resources are forced to participate in the capacity market, they could face an elevated risk of high non-performance charges as they may not always be able perform reliably in emergency conditions (e.g., solar cannot perform at night). They argued that this could discourage investment in future intermittent resources across PJM.[35] However, FERC dismisses this concern with the explanation that the ELCC

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[31] Order Accepting Tariff Revisions. FERC ER25-785-000. February 20, 2025, page 5.

[32] Order Accepting Tariff Revisions. FERC ER25-785-000. February 20, 2025, page 23.

[33] Complaint of Joint Consumer Advocates. FERC EL25-18, page 5.

[34] Order Accepting Tariff Revisions. FERC ER25-785-000. February 20, 2025, page 22.

[35] Order Accepting Tariff Revisions. FERC ER25-785-000. February 20, 2025, page 26.

accreditation methodology objectively accounts for each capacity resource's expected availability during grid emergencies (e.g., solar has lower ELCC ratings to account for its inability to perform at night).[36]

We estimate that lifting the exemption for intermittent and storage resources will increase supply in the upcoming BRA by an estimated 2,000 (UCAP).[37] This is in addition to the 3,969 MW UCAP of solar, wind, and battery resources offered into the market in the 2025/2026 BRA (3,027 MW of which cleared).

RMR Participation in the Capacity Market

The capacity market clearing price should reflect the actual level of supply in the market. However, as discussed above, RMRs have been removed from the capacity supply curve and do not participate in the auction. This reduces apparent supply, often resulting in artificially high clearing prices. This occurred in the BGE LDA, where capacity prices cleared at the maximum. Astoundingly, Brandon Shores and Wagner's removal from capacity market participation had a spillover effect into the rest of the RTO, costing PJM customers as a whole an additional $4.3 billion in the 2025/2026 delivery year,[38] in addition to the annual $181 million that the local LDA customers are paying for the out-of-market RMR arrangement.

PJM's historical treatment of RMRs in the market leads to customers paying twice for the same capacity: (1) for the out-of-market RMR arrangement costs and (2) in the capacity market to procure the capacity that is already provided by the RMR resource.[39] In their November 2025 filing arguing that PJM's current BRA construct is unjust and unreasonable, a group of consumer advocates within the PJM region (including the DC OPC) requested that FERC require PJM to compensate RMR resources at a full cost-of-service rate in exchange for their full participation in PJM's capacity, energy, and ancillary service markets where they are eligible.[40] This would include requiring them to function as price takers in BRAs, which would increase the capacity market supply and prevent double-payment by consumers. PJM's accepted reforms partly accomplish this.

PJM now agrees that RMRs should participate in the PJM auction to reflect more accurate price signals and prevent electricity customers from paying twice for capacity. FERC approved PJM's proposal to

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[36] Order Accepting Tariff Revisions. FERC ER25-785-000. February 20, 2025, page 26.

[37] We estimate that there is an additional 2,000 MW (UCAP) of solar, wind, and battery/hybrid resources that are not participating in the market. We estimate this by reviewing the capacity (nameplate MW) of all existing resources in PJM (from U.S. EIA form 923 and 860), applying ELCC ratings to estimate the total UCAP by resource type, and comparing that value against the offered and cleared amount of capacity in the 2025/2026 BRA.

[38] Monitoring Analytics, *IMM Analysis of the 2025/2026 RPM Base Residual Auction – Part A*, September 20, 2024, https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_A_20240920.pdf.

[39] PJM Interconnection. December 9, 2024. Revisions to Reliability Pricing Model, Docket No. ER25-682, page 30.

[40] Complaint of Joint Consumer Advocates. FERC EL25-18, page 5.

allow Brandon Shores and Wagner to provide capacity, as long as they meet the four criteria developed by PJM.

Four Criteria for RMR Participation in the Capacity Market

Starting in the upcoming 2026/2027 auction (currently scheduled for July 2025), RMR units will participate in the capacity market as supply-side resources if they meet four criteria:

1. The RMR resource must have sufficient CIRs. In other words, the transmission system must be able to accommodate the injection of the resource's energy.
2. The RMR resource must have an RMR agreement that has been accepted by FERC at least three months before the planning parameters are published, ensuring that PJM can properly incorporate the resource into its planning.[41,42]
3. The RMR resource must be reasonably expected to be able to operate for the entire delivery year. It must have all the necessary permits to operate, and no conditions or contractual commitments that would unduly prevent it from operating.
4. The RMR arrangement terms must not preclude PJM dispatching the RMR unit for such emergencies (each RMR agreement is negotiated between PJM and the resource owner, and the terms can vary).[43]

The four criteria are designed to provide assurance that the resource is physically and contractually capable of performing during grid emergencies and therefore can and should be considered a capacity resource. As PJM argues, if an RMR resource is not able to meet all four criteria, then the unit cannot reasonably provide capacity to the system, and consumers would therefore not be double-paying for capacity.[44] If a resource does meet all four criteria, then PJM can rely on the resource to contribute to the region's resource adequacy.

Brandon Shores and Wagner Expected Future Participation in the Capacity Market

Brandon Shores units 1 and 2, and Wagner units 3 and 4 are expected to meet all four criteria above and provide supply in the 2026/2027 and 2027/2028 delivery years (until transmission solutions are put in place to address the related reliability issues). No other units are expected to be needed for RMR service for the next two delivery years. If Brandon Shores and Wagner are needed for RMR service beyond that

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[41] PJM's planning parameters are released no later than 100 days ahead of the auction.

[42] The RMR resource also cannot have cleared in an RPM auction for the relevant delivery year. If it is already counted as capacity, PJM need not separately deem that resource as capacity supply.

[43] There have been some cases where the RMR agreement have been limited to addressing transmission needs, and specifically not capacity emergencies. PJM Interconnection. December 9, 2024. Revisions to Reliability Pricing Model, Docket No. ER25-682, page 21.

[44] PJM Interconnection. December 9, 2024. Revisions to Reliability Pricing Model, Docket No. ER25-682, page 23.

period, PJM has stated that it could submit a future filing to extend these provisions and rules.[45] This extension may be necessary, as Talen and PJM recently announced that these RMR units would be in use until May 31, 2029.

Brandon Shores and Wagner have an estimated UCAP of 1,569 MW, based on ELCC ratings for 2026/2027.[46] The inclusion of Brandon Shores and Wagner will provide a much-needed injection of supply into the BGE LDA, as well as into the SWMAAC LDA, the parent LDA of BGE and Pepco LDAs (where DC is located).

Rights and Obligations for RMR Resources Participating in the Capacity Market

FERC has approved PJM's proposal that RMRs that participate in the capacity auction will not be subject to the same rights and obligations of other generators, such as operational testing or Non-Performance Charges for underperformance during grid emergencies. PJM argues that the four criteria which determine RMR participation "provide sufficient structural assurances that these resources will perform during capacity emergencies."[47] However, this argument is far from certain; PJM's criteria focus on whether the RMR is *able* to perform during grid emergencies, not whether it *will* indeed perform. As the current RMR rules stand, there may not be a strong incentive for the RMRs to perform for all grid emergencies, and the lack of incentive could erode their capacity contributions.

In contrast, the Consumer Advocates' request was for complete capacity market participation by RMR resources, which would require full performance when these resources are needed.[48] This approach by PJM also differs from other RTOs. In ISO New England, RMRs have capacity supply obligations,[49] suggesting that they are subject to performance penalties. Similarly, it appears that in NYISO and MISO, RMRs are also subject to performance penalties.[50]

RMR Capacity Market Revenue Crediting Mechanism

Now that RMRs will be participating as supply in the upcoming auctions, FERC has also approved a crediting mechanism for any revenues the RMR resource will make in the capacity market. Capacity market revenues will be credited back to the LDAs that are paying for the out-of-market RMR

[45] PJM Interconnection. December 9, 2024. Revisions to Reliability Pricing Model, Docket No. ER25-682, page 16.

[46] ELCC Class Ratings for the 2026/2027 Base Residual Auction. PJM. Available at: https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2026-27-bra-elcc-class-ratings.pdf.

[47] PJM Interconnection. December 9, 2024. Revisions to Reliability Pricing Model, Docket No. ER25-682, page 15.

[48] Complaint of Joint Consumer Advocates. FERC EL25-18, page 5.

[49] ISO New England. October 9, 2024. ISO's Thinking on Representing Retained Resources in the Capacity Market. NEPOOL Markets Committee (MC). Available at: https://www.iso-ne.com/static-assets/documents/100016/a05_mc_2024_10-16_representing_retained_resources_iso_memo.pdf.

[50] Staevska, A., Foley, P. January 18, 2023. RTO/ISO Deactivation Processes. Deactivation Enhancements Senior Task Force. PJM.

arrangement. As discussed above, an RMR resource is already being compensated for its operation and maintenance through the RMR arrangement. These costs are allocated to LDAs and their electricity customers following the cost allocation of the transmission investments that will eventually eliminate the RMR need. As part of the RMR and auction reforms, the LDAs that are paying for the cost of the RMR arrangement will now be the ones who receive the resource's capacity market revenues. This approach will prevent electricity customers from paying twice for the RMR. On the other hand, it will have no impact on the owner of the RMR resource, who will continue to receive the full approved RMR cost recovery amount. As PJM stated, "The RMR resource owner is already being fully compensated for its operation through the RMR agreement, and the RMR resource owner faces no performance risk as the resource is not eligible for Non-Performance Charges. Thus, there is no reason to compensate the RMR resource owner" with any capacity market revenues.[51]

RMR Participation as a Price Taker

Going forward, the RMR resource will participate in the capacity auction as a "price taker," meaning it will have an offer price of $0/MW-day and is therefore guaranteed to clear in the market. The resource thus cannot be the marginal resource and set the clearing price. This approach is consistent with ISO New England's treatment of RMRs in its capacity markets. PJM's Internal Markets Monitor also recommended that PJM include RMRs as price takers in its future BRAs.[52]

Some argue that RMRs participating as a price-taker could result in artificial price suppression, as the offer price does not reflect its true forward-going avoidable costs. For this reason, the New York ISO (NYISO) requires RMRs to offer in at levels no lower than their going-forward costs, which when considering revenues received through the out-of-market RMR agreement, should be relatively low.[53]

3.2. Upcoming Changes to the Demand Curve

Recent History of PJM's Demand Curve Parameters

Every four years, PJM reviews its VRR curve in its Quadrennial Review. Since 2011, PJM has defined the maximum auction price (i.e., maximum point on the VRR curve) as the higher of either Gross CONE or 1.5 times Net CONE.[54] For all previous auctions, PJM estimated Net CONE using a gas-fired simple-cycle CT plant. As described in Section 1.2 (Supply and Demand Curves), Net CONE is a key parameter in defining the shape of the VRR curve. When Net CONE changes, the VRR curve shifts up and down. For instance, when there is a higher cost of new entry, Net CONE increases, which pushes point A and B on

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[51] PJM Interconnection. December 9, 2024. Revisions to Reliability Pricing Model, Docket No. ER25-682, page 33.

[52] Comments of the Independent Market Monitor for PJM. January 6, 2025. Docket No. ER25-682-000.

[53] PJM Interconnection. December 9, 2024. Revisions to Reliability Pricing Model, Docket No. ER25-682, page 28.

[54] Complaint of Governor Josh Shapiro and the Commonwealth of Pennsylvania, Docket No. EL-25-46. December 30, 2024, at page 8.

VRR curve upwards and increases the steepness of the VRR curve's slope. This could lead to more price volatility and/or higher prices. When Net CONE is at zero (which can occur if the E&AS offsets are higher than gross CONE), Point B falls to zero, creating a steep two-point VRR curve (known as a "collapsed" curve).

In recent years, PJM's capacity market was consistently over-procuring capacity above the reliability requirement (the target level of capacity to meet PJM's reliability standard). As a result, FERC had originally approved PJM's shift of its reference source to a combined-cycle (CC) plant and set the maximum price at the larger of Gross CONE or 1.75 times Net CONE (instead of using a 1.5 multiplier), starting in the 2026/2027 delivery year. These two changes produce a steeper VRR curve "that more strongly controls RPM quantity clearing outcomes, increasing certainty that sufficient quantity will be procured while guarding against over procurement."[55] However, a steeper VRR curve trades controlling quantity over more volatile prices.

Today, over-procurement of capacity is no longer the primary concern for PJM's wholesale markets. As discussed elsewhere in this report, increasing demand along with changes to supply (e.g., new ELCC accreditation, etc.) and a clogged interconnection queue has led to increasingly eroding reserve margins across PJM. Instead of over-procurement, PJM now faces potential capacity shortfalls.[56] As a result, in February 2025, PJM received approval from FERC to *not* switch to a CC plant as its reference resource and instead maintain the CT reference resource. However, in that same PJM reform package proposed in December 2024, PJM did not address the 1.75 multiplier for Point A on the VRR curve. In February 2025, PJM and the Pennsylvania Governor's Office jointly proposed to add a price cap and floor to the VRR curve; this is recently approved by FERC at the end of April 2025.[57]

VRR Curve Price Cap and Price Floor

In response to over-procuring capacity in recent years, PJM previously made adjustments to both the reference resource and point A on the VRR curve (the 1.5 vs 1.75 multiplier to Net CONE). However, despite their correlation, in its more recent capacity market reforms for the 2026/2027 and 2027/2028 auctions, PJM only adjusted the reference technology. It did not address the maximum price; Point A on the VRR curve is still set to either Gross CONE or 1.75 Net CONE, whichever is larger. However, the multiplier does not affect the shape of the VRR curve for the RTO and the majority of modeled LDAs, including Pepco, and its parents SWMAAC and MAAC. In all these cases, Gross CONE is larger than 1.75 times Net CONE, and thus defines the top point on the demand curve. As seen below in Figure 5, using Gross CONE creates a very steep curve, with maximum prices as high as $505.73/MW-day for the RTO instead of $371.25/MW-day (1.75 times Net CONE) or $318.21/MW-day (1.5 times Net CONE).

[55] PJM Recommendations – Quadrennial Review. Available at: https://www.pjm.com/-/media/DotCom/committees-groups/committees/mrc/2022/20220824/item-02---3-pjm-position-on-2022-quadrennial-review-recommendations.ashx.

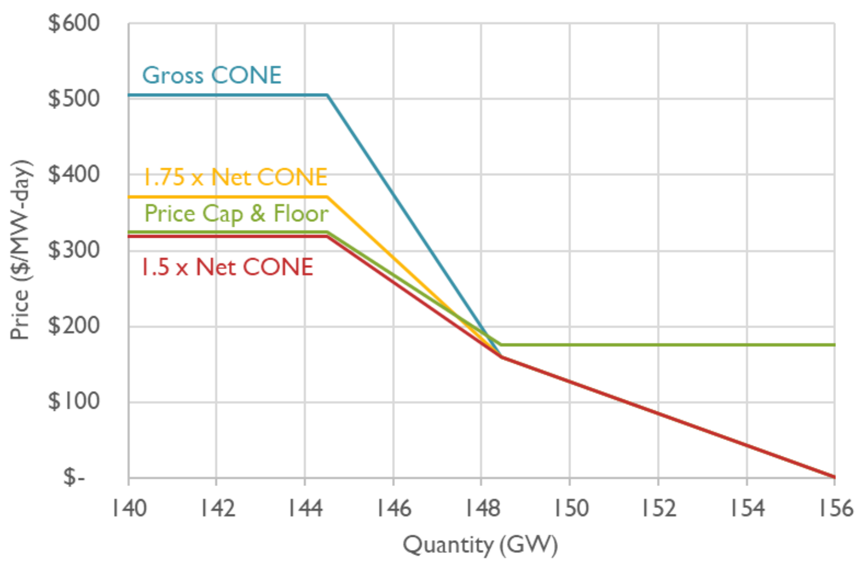
[56] PJM Interconnection. December 9, 2024. Revisions to Reliability Pricing Model, Docket No. ER25-682, page 40.

[57] Order Accepting Tariff Revisions and Dismissing Complaint, April 21, 2025. FERC ER25-1357.

Pennsylvania Governor Shapiro issued a complaint to FERC arguing that PJM should remove Gross CONE from the maximum VRR calculation and restore the 1.5 multiplier to Net CONE. The governor's office argued that if the market was functioning as intended, the record-setting prices would encourage investment in new generation. Yet due to the severely clogged interconnection queue and the compressed auction schedule, market participants are not able to respond to these high prices, and customers are saddled with the bill.

PJM and the Governor of Pennsylvania's Office engaged in confidential settlement discussions and on January 23, 2025, introduced a new proposal for a price cap and price floor for the upcoming two BRAs. The price cap and floor would be set at $325/MW-day UCAP and $175/MW-day UCAP, respectively (Figure 5). They argue that the floor protects suppliers while the cap protects consumers.

Figure 5. RTO VRR Curve permutations for the 2026/2027 delivery year



The maximum price of $325/MW-day is higher than the weighted average historical clearing price (prior to the 2025/2026 BRA) of $116.30/MW-day.[58] It is also 14 percent higher than the average of 1.5 times Net CONE values for all the LDAs.[59] Nonetheless, the independent market monitor has estimated that

[58] Monitoring Analytics. February 7, 2025. PA/PJM Agreement re Maximum and Minimum RPM Prices. Special Member Committee meeting. Available at: https://www.monitoringanalytics.com/reports/Presentations/2025/IMM_MC_PA_PJM_Agreement_Max_Min_RPM_Prices_20250207.pdf.

[59] Monitoring Analytics. February 7, 2025. PA/PJM Agreement re Maximum and Minimum RPM Prices. Special Member Committee meeting. Available at: https://www.monitoringanalytics.com/reports/Presentations/2025/IMM_MC_PA_PJM_Agreement_Max_Min_RPM_Prices_20250207.pdf.

the price cap of $325/MW-day could save electricity customers across PJM $8.7 billion per year, relative to the initial maximum price of the greater of Gross CONE or 1.75 times Net CONE.[60]

The Joint Consumer Advocates protested both the price cap and floor at FERC, arguing that they were too high and ultimately unjust and unreasonable.[61] PJM's independent market monitor also opposed the price floor and PJM's proposed VRR shape, arguing there is no economic logic or support in the tariff to justify these changes.[62] FERC approved the VRR curve price cap and floor for the 2026/2027 and 2027/2028 delivery years in April 2025.[63]

Reference Technology and the VRR Curve

CC plants have longer run times over the course of a year relative to a CT plant, and thus they typically make more money in the energy market. As a result, they have much higher E&AS offsets in the Net CONE calculation; using a CC plant reference technology would mean that Net CONE falls to $0/MW-day in the RTO and in certain LDAs. Point B on the VRR curve is 0.75 times Net CONE; if net CONE falls to zero, so does point B on the curve. This results in a very steep 2-point VRR "curve," which can lead to substantial price volatility. Since FERC has approved maintaining a CT reference resource, this effect will no longer occur (until at least the upcoming Quadrennial Review, scheduled for the third quarter of 2025).[64]

Non-Performance Charges

Net CONE is not just used in determining the points on the VRR curve; it also defines non-performance charges. The non-performance charge rate ($/MW-5-minute interval) is a penalty charged to generators who do not fulfil their capacity commitment during grid emergencies (called Performance Assessment Intervals (PAI)). In other words, generators are charged a penalty if they are not able to provide the amount of capacity they are contracted to provide through the capacity market. The charge is based on Net CONE and their capacity shortfall during PAIs. With the switch to a CC plant reference technology, where Net CONE falls to zero (for the RTO and in certain LDAs), the non-performance charge would also fall to zero. If this were to happen, power plants could lose their incentive to fulfil their capacity commitments, yet they would still be paid the clearing price for the entire delivery year. This scenario poses a potential risk to the reliability of the grid. To minimize this risk going forward, in addition to retaining a CT as the reference resource, PJM will implement a uniform RTO-wide non-performance

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[60] The independent market monitor updated CONE values and the higher forecasted peak load but otherwise kept all parameters the same as the 2025/2026 BRA. Ibid.

[61] Protest of Joint Consumer Advocates. FERC ER25-1357-000. March 17, 2025.

[62] Comments of the Independent Market Monitor for PJM. FERC ER-25-1357-000. March 17, 2025.

[63] Order Accepting Tariff Revisions and Dismissing Complaint, April 21, 2025. FERC ER25-1357.

[64] PJM Interconnection. December 9, 2024. Revisions to Reliability Pricing Model, Docket No. ER25-682, page 37.

charge (rather than LDA-specific charges). According to PJM, an RTO-wide non-performance charge is less likely to drop to $0 than LDA-specific non-performance charges.

Net CONE and Reactive Power

PJM is removing Reactive Power compensation from E&AS offsets for the Net CONE calculation effective for the 2026/2027 delivery year. Unlike real power, reactive power is not consumed by the load; instead, it is power that oscillates between load and the source within a circuit and is crucial in maintaining voltage levels. In Order No. 904, FERC determined that it was unreasonable and unjust for transmission providers to charge for reactive power within the standard power factor range.[65] In response to this final order, PJM is now eliminating the $2,546 per megawatt-year revenue from reactive power services from the EAS offsets to determine the Net CONE for the 2026/2027 BRA.[66] This change will increase Net CONE and affect the shape of the VRR curve.

4. Potential Electric Bill Impact of 2026/2027 Capacity Auction

We assessed the bill impacts for four scenarios for the upcoming 2026/2027 BRA (currently scheduled for July 2025). These scenarios are not definitive or fully accurate predictions of the next BRA clearing price, as there are numerous factors that are changing and impossible to accurately predict. Nonetheless, these scenarios can help estimate a range of possible bill impacts for electricity customers in DC associated with upcoming changes to PJM's capacity market.

All scenarios account for updated ELCC values; as shown in Table 5, in Section 2.3 above, ELCC values are decreasing for the majority of resource types for the 2026/2027 BRA. This will shrink supply by about 4,600 MW across the RTO. All scenarios also include Brandon Shores and Wagner RMRs participating as supply-side resources, increasing supply by roughly 1,580 MW, along with the resources that were previously exempt from participating. We used PJM's "RPM Existing Resource List" for the 2025/2026 delivery year[67] and added in planned retirements from PJM's list of "Generation Deactivations."[68] The scenarios are as follows:

1. The **No Additional New Builds** scenario includes all PJM existing and new resources (as per PJM's Existing Resource List), including the previously exempt wind, solar, storage,

[65] Compensation for Reactive Power Within the Standard Power Factor Range, Order No. 904, 189 FERC ¶ 61,034 (2024)

[66] Revision to Reliability Pricing Model FERC docket No. ER25-628-000, at 81.

[67] PJM. Capacity Market (RPM): 2026/2027. Available at: https://www.pjm.com/markets-and-operations/rpm.

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

and hybrid resources. When including the RMR units alongside the updated ELCC ratings and retirements, there is a *reduction* of supply of approximately 1,500 MW UCAP.

2. The **Some New Entry** scenario includes an additional 2,000 UCAP of new builds (planned resources).[69] This scenario also includes all the resources included in Scenario 1, resulting in an addition of 500 UCAP.

3. The **Price Floor** scenario examines what it would take to reach the recently approved clearing price minimum of $175/MW-day. We estimate that the region would need approximately 15,000 MW UCAP more supply (generation capacity and/or demand response) to reach the price floor. This quantity of new capacity is nearly impossible, given the current queue constraints and the current capacity under construction.

4. The **No Price Cap** scenario is a sensitivity on scenario 2, to better understand the bill impact if the price cap had not been approved (i.e., it demonstrates potential bill savings of the price cap to DC consumers). The inputs for this scenario are the same as scenario 2 ("some new entry").

For each of these scenarios, we estimated the VRR curve based on the 2026/2027 planning requirements[70] (the forecasted peak load, installed reserve margin, and Net CONE were released on March 31, 2025, without the VRR curve itself). We assume no changes to demand response resources relative to the 2025/2026 BRA.

For the supply curve, we used the smoothed supply curve from the 2025/2026 BRA.[71] The supply curve is not smoothed in reality; it is instead a step-wise function representing discreet offer bids (quantity and price). We added in Brandon Shores and Wagner's estimated UCAP as price takers (shifting the supply curve to the right roughly 1,600 MW). Without having any offer price data, we assumed that all additional new supply resources were added as price takers (though this is unlikely to be true in reality). New supply (beyond Brandon Shores and Wagner) was allocated proportionally to each LDA relative to peak demand. We also shifted the supply curve to the left by roughly 1,400 MW to account for the planned retirements, and again by 4,600 MW to account for new ELCC ratings. In reality, it is likely that the supply curve would also shift downward with reductions in supply, not just leftward; however, without offer prices and specific bid data, we could not include that adjustment in the analysis. This analysis is simply a best guess and provides a possible range of bill impacts for DC electricity customers that could be seen as a result of the upcoming capacity market changes in PJM.

As described in Section 2, DC electricity customers could see an additional $10 on their monthly bills starting around June 2025 as a result of the latest BRA for the 2025/2026 delivery year, incremental from the previous 2024/2025 BRA. We estimate that residential electricity bills in DC could increase by

[69] There are roughly 1,500 MW of UCAP (thermal, intermittent, ant storage) resources that are reporting to EIA as "planned" resources that are expecting to be online by the beginning of the 2026/2027 delivery year.

[70] Assuming the VRR curve maximum is the greater of Gross CONE or 1.75 Net CONE.

[71] PJM Interconnection. September 13, 2024. 2025/2026 BRA Supply Curves. Available at: https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-bra-supply-curves.pdf.

an additional $1 for the 2026/2027 delivery year (incremental to the $10 price increase expected in the 2025/2026 delivery year (Table 7).[72] If there was approximately 15,000 MW more supply available in all of PJM for the upcoming auction (a highly unrealistic scenario), average residential monthly bills could decrease by $5 per month, relative to the 2025/2026 delivery year (Table 7). If the price cap had not been approved, and some new resources had still been built, average residential bills could have increased by an additional $9 for the 2026/2027 delivery year. Without substantially more supply, the RTO could clear at the price maximum.

Table 7. DC bill impacts for potential results of the 2026/2027 capacity auction relative to 2025/2026 results

	No Additional New Builds	Some New Entry	Price Floor	Some New Entry with No Price Cap
Estimated RTO Clearing Price	$325/MW-day	$325/MW-day	$175/MW-day	$506/MW-day
Residential Average Monthly Bill Change (relative to previous year)	+ $1	+ $1	- $5	+ $9
Commercial Average Monthly Bill Increase (relative to previous year)	+ $26	+ $26	- $172	+ $321

Source: Synapse analysis; see description in text.

We assume that neither the DOM LDA nor the BGE LDA will separate from parent LDAs as they did in the 2025/2026 BRA. This is due to transmission upgrades which will increase the DOM LDA's import capacity, and as a result Brandon Shores and Wagner returning to the BGE LDA's supply curve. Other LDAs could separate, such as the MAAC LDA, as it has done in recent years. However, without recent supply curves available for the MAAC LDA, we are unable to estimate the clearing price for MAAC, or other LDAs. As a result, for the sake of this bill impact analysis, we assume that no other LDA separates. MAAC has also only cleared above the RTO by a few dollars in recent years (and did not separate at all in the 2025/2026 BRA), therefore we do not expect this assumption to substantially affect the results. It is unlikely that the SWMAAC LDA would separate from the MAAC LDA, or that the PEPCO LDA would sperate from SWMAAC, given the amount of local capacity and import capability currently available for both LDAs.

We used the same methodological approach for estimating the 2025/2026 incremental bill impacts (as described in Section 2.2). In this case, we also estimated the Capacity Transfer Rights (CTR) to estimate the cost for consumers for the 2026/2027 BRA, a key part of the customer impact analysis. When an LDA

[72] For DC residential customers, the total capacity costs translate to approximately $3 per month for 2024/2025 and $13 per month for 2025/2026. For commercial customers, 2024/2025 and 2025/2026 capacity costs are on average $107 and $452 per month respectively.

has a higher clearing price than its parent LDA, there is a "locational price adder" to represent the higher clearing price relative to the RTO clearing price. CTRs are allocated to consumer loads within an LDA that experiences price separation. The CTRs are payments equal to the locational price adder times the load's *pro rata* share of the lower-priced capacity imported into that LDA. CTRs serve to offset a portion of the higher capacity prices for customers in that constrained LDA. We used the CTR allocation and annual capacity market costs for customers provided in PJM's 2025/2026 Base Residual Auction Results (Excel workbook), adjusted to be reflective of our expectations for the 2026/2027 BRA.

4.1. Potential Impacts for the 2027/2028 Delivery Year

As PJM has stated itself, we will likely continue to see a tightening of supply and demand for the foreseeable future.[73] As described above, a substantial amount of capacity is needed to maintain capacity prices close to the proposed floor of $175/MW-day. This suggests the clearing price and associated bill impacts will remain high until the implementation of more substantial reforms, particularly those focused on the interconnection queue. As long as load forecasts continue to rise in PJM, and other market factors (already present in the last auction) persist, we expect that clearing prices will remain high.

5. INTERCONNECTION QUEUE REFORMS

Delays with PJM's interconnection queue have prompted concerns about the region's resource adequacy. In addition, PJM's interconnection queue issues have raised concerns about DC and PJM states' ability to meet their renewable energy targets. The capacity market is designed to send a price signal: when prices are high, plant owners and operators should build more plants for new entry into the market. However, currently, the PJM interconnection queue is clogged and not operating as designed, thereby limiting the market's ability to function properly and fairly. This section explores the barriers to interconnecting new clean energy resources and ongoing changes to PJM interconnection queue process.

The clogged queue could have a major impact on electricity customers in DC and throughout the region. On behalf of Evergreen Action, Synapse conducted power sector analysis, bill impact analysis, and job impact analysis to understand the benefits of resolving these queue constraints to customers and residents in the PJM states. Our analysis shows that if PJM continues down its current path, residential electricity bills in the region are expected to increase by nearly 60 percent by the 2036–2040 period compared to historical levels. However, if PJM adequately implements interconnection reforms to

[73] PJM Interconnection. December 9, 2024. Revisions to Reliability Pricing Model, Docket No. ER25-682, page 5.

enable the deployment of more cost-effective energy generation, largely comprised of clean energy sources, electricity bills are projected to decrease 7 percent within the same time period.[74]

5.1. Background on DC's Renewable Energy Portfolio Standards

DC first established renewable energy targets in 2005 when it passed the Renewable Energy Portfolio Standard (REPs) Act.[75] The District has updated these targets several times since. Most recently the Local Solar Amendment Act of 2022 set the following targets (effective March 10, 2023): under the RPS, electricity suppliers must buy 100 percent of their power from renewable sources by 2032, with 15 percent coming from local solar power by 2041.[76] This is one of the highest renewable energy targets in the country.[77] Pepco, the distribution utility serving DC, estimated that the RPS resulted in a monthly bill impact of $22 to $26 on the average residential bill, in May and June 2025.[78]

5.2. Current PJM Interconnection Queue

PJM's queue currently has 290 GW of potential generating capacity awaiting interconnection.[79] The capacity primarily consists of renewable resources that could help DC and other states in the PJM region make substantial progress toward their renewable energy goals, as well as bring in much needed capacity to mitigate potential shortfalls across PJM. The queue is made up of 94 percent renewables and storage, and only 6 percent gas-fired resources, in MW terms.[80] There are currently no solar resources in DC in the PJM queue, though smaller projects interconnecting at the distribution level will likely be used to meet the solar carve-out requirement and avoid the PJM queue altogether.

Resources in PJM's queue have faced long wait times and expensive network upgrades over the past several years. Between 2000 and 2018, only 24 percent of projects in PJM's interconnection queue were completed, and withdrawal rates were higher for solar and battery storage projects than for gas or wind

[74] Chavin, S., Knight, P., Shenstone-Harris, S., Zeng, A., Fuzaylov, A., Hittinger, J. April 15, 2025. Tackling the PJM Electricity Cost Crisis. Prepared for Evergreen Collective by Synapse Energy Economics. Available at: https://www.synapse-energy.com/tackling-pjm-electricity-cost-crisis.

[75] Renewable Energy Portfolio Standards Act (REPS Act) Code of the District of Columbia § 34–1432.

[76] District of Columbia Department of Energy & Environment. Renewable Energy in the District. Available at: https://doee.dc.gov/service/renewable-energy-district#:~:text=Under%20the%20RPS%2C%20electricity%20suppliers,its%20projected%202032%20GHG%20emissions.

[77] Clean Energy States Alliance. "Table of 100% Clean Energy States." Available at: https://www.cesa.org/projects/100-clean-energy-collaborative/guide/table-of-100-clean-energy-states/.

[78] Pepco Holdings. May 21, 2025. PJM Taskforce Bill Impacts Summary.

[79] PJM. Planning: Service Requests. Available at: https://www.pjm.com/planning/service-requests.

[80] Energy Transition in PJM: Resource Retirements, Replacements & Risks, PJM Interconnection, L.L.C., 2 (Feb. https://www.pjm.com/-/media/library/reports-notices/special-reports/2023/energytransition-in-pjm-resource-retirements-replacements-and-risks.ashx ("Four Rs Report").

projects.[81] Since 2020, 45 percent of projects added to the queue have withdrawn before completing the interconnection process, and 64 projects (over 5 GW of capacity) currently in the queue submitted their interconnection requests before 2020. Meanwhile, interconnection costs reached an average of $240/kW in 2020 to 2022, a substantial increase from the $29/kW average in 2017 to 2019.[82]

5.3. Interconnection Queue Reforms

General Interconnection Reforms

PJM has been making efforts to improve the interconnection queue in recent years. In 2020, PJM initiated a stakeholder process to explore interconnection reforms, which led to a pause of the queue in 2022 to allow PJM to implement the approved reforms.[83] This primarily included a transition from a serial first-come, first-served process of reviewing interconnection requests to a first-ready, first-served cluster study process. This approach allows the grid operator to review more requests in a shorter amount of time and focuses on projects that are prepared to move forward rather than speculative projects or projects that are less likely to be built. These reforms included:

- a fast lane for certain projects to address the backlog;
- new requirements for commercial readiness deposits and improved site control procedures;
- an expedited process to memorialize interconnection agreements for projects that do not require network upgrades or further studies; and
- transition from conducting studies on a serial-basis to a cluster-process.[84]

In July of 2023, the FERC issued Order 2023, which required all RTOs across the country to address interconnection barriers, which are experienced nationwide. Many of the reforms required in that Order are similar to reforms already underway in PJM. PJM submitted a compliance filing on May 16, 2024, requesting that its previously filed reforms be considered sufficient to comply with Order 2023 objectives and that FERC should grant "independent entity variations" where it does not meet specific Order requirements that would allow PJM to be compliant in the eyes of the FERC without having to

[81] Rand, Joseph, Manderlink, Nick, Gorman, Will, Wiser, Ryan, Seel, Joachim, Mulvaney Kemp, Julie, Jeong, Seongeun, Kahrl, Fritz.. 2024. Queued Up: 2024 Edition. Lawrence Berkeley National Laboratory. Available at: https://emp.lbl.gov/sites/default/files/2024-04/Queued%20Up%202024%20Edition_R2.pdf.

[82] Joachim, Rand, Joe, Gorman, Will, Millstein, Dev, Wiser, Ryan. 2023. Interconnection Cost Analysis in PJM Territory. Lawrence Berkeley National Laboratory. https://eta-publications.lbl.gov/sites/default/files/berkeley_lab_2023.1.12-_pjm_interconnection_costs.pdf.

[83] PJM Interconnection, L.L.C., Tariff Revisions for Interconnection Process Reform, Docket No. ER22-2110-000 (June 14, 2022).

[84] PJM Interconnection, L.L.C., Tariff Revisions for Interconnection Process Reform, Docket No. ER22-2110-000 (June 14, 2022).

deviate from its ongoing reforms.[85] Order 2023 litigation is still ongoing, as PJM continues to move ahead with the interconnection reforms already in motion.

PJM's transition to this new process established in its 2022 filing is already underway. PJM began the Transition Period to finish clearing the backlog of interconnection requests on July 10, 2023 (of which PJM had previously paused its review, while it sought to develop and implement the abovementioned queue reforms). The interconnection process is still complicated and lengthy: it requires projects to move through feasibility, system impact, and facilities studies—sometimes multiple rounds of each—before getting interconnection agreements and achieving commercial operation. The first of the Transition Cycles (TC1) of projects in the queue began its Phase II System Impact Study on June 21, 2024, and was reportedly completed on December 20, 2024.[86] At that stage, 204 projects totaling roughly 30 GW of mostly renewable or hybrid generation decided to continue through the interconnection process to the next stages of facilities studies needed to receive interconnection agreements.

Meanwhile, 284 additional projects qualified for an Expedited "Fast Lane" Process. Both TC1 and the "Fast Lane" projects are expected to complete the interconnection queue process by late 2025. PJM plans to complete the Transition Cycle #2 by the third quarter of 2026. Since PJM has been implementing its reform processes, there are already another 38 GW of projects that have completed the queue process but have not yet been built.[87]

Resource Reliability Initiative

Following to calls for interconnection queue reform after the sky-high 2025/2026 auction results, PJM proposed its Reliability Resource Initiative (RRI)[88] in a filing to the FERC on December 2023. FERC approved the RRI on February 2025.[89] PJM described this initiative as a "one-time expansion of eligibility criteria for Transition Cluster #2 to add more resources" to the grid and address resource adequacy concerns in the region in the 2029/2030 delivery year and beyond.[90] With RRI, PJM aims to improve resource adequacy and encourage new entry into the market, but it may create challenges for PJM states and the District as they strive to meet RPS targets. Consumer advocates in the region called for

[85] PJM Interconnection, L.L.C., Order Nos. 2023 and 2023-A Compliance Filing, Docket No. ER24-2045-000 (May 16, 2024).

[86] PJM, "Transition Cycle #1 Phase II System Impact Study Posting Date" (December 16, 2024).

[87] PJM. August 2024. "PJM Reaches Next Interconnection Milestone", available at: https://insidelines.pjm.com/pjm-reaches-next-milestone/.

[88] PJM. 2024. "PJM Capacity Auction Procures Sufficient Resources to Meet RTO Reliability Requirement, Tighter Supply/Demand Balance Drives Higher Pricing Across the Region." Available at: https://insidelines.pjm.com/pjm-capacity-auction-procures-sufficient-resources-to-meet-rto-reliability-requirement/.

[89] Order Accepting Tariff Revisions. FERC ER25-712-000. February 11, 2025, at 9.

[90] Order Accepting Tariff Revisions. FERC ER25-712-000. February 11, 2025, at 3.

reforms to prioritize ready-to-study projects that will be sited in LDAs that are more likely to be constrained. However, RRI will focus on different criteria.[91]

The RRI will expand eligibility for its second Transition Cycle of projects, TC2, based on the following criteria and point scale:

- Ability to provide substantial amounts of unforced capacity (35 out of 100 points)
- High ELCC ratings (20 out of 100 points)
- Location in areas where capacity is scarce (10 out of 100 points)
- Location in areas with headroom on the transmission system to accommodate new generation (5 out of 100 points)
- Ability to be constructed and achieve commercial operation quickly to meet PJM's near-term resource adequacy needs, specifically a commercial operation date between 2028 and 2031 (10 out of 100 points)
- Uprating of projects already in commercial operation, that have interconnection-related service agreements, or are already under study (10 out of 100 points)
- Secured permits, siting, financing, etc. (10 out of 100 points)

The RRI raises several concerns. PJM claimed in its filing that the initiative would likely accelerate interconnection of gas and storage projects, but that there was the potential that some other resource types could qualify. However, environmental groups are worried that RRI is unduly discriminatory against non-dispatchable resources in favor of gas, which has a high reliability rating. The potential impact of this expansion of TC2 on primarily renewable resources already in the cluster is unknown, but PJM does not plan to hold them harmless should any upgrade costs increase.[92] In other words, if resources in the TC2 cluster face shifting costs from the addition of these RRI resources, the resources already in TC2 would not be responsible only for their initial cost expectations. Others are concerned that this initiative will not improve resource adequacy, particularly as it does not have any requirements that these projects are actually put in service by 2030. In her dissent, FERC Commissioner Chang said "By facilitating queue jumping for large generators, which are the most challenging to develop, acquire the necessary environmental permits, and obtain adequate material supplies and labor for construction and focusing primarily on large generators over speed of development, PJM's proposal may not actually resolve its impending capacity shortage."[93] Additional delays beyond the queue also suggest that these resources may not be in service by 2030. Long interconnection processes in PJM are "exacerbating siting and permitting challenges and leading to knock-on delays in equipment procurement and financing decisions," which mean that once developers have their Interconnection Service Agreements, it will still likely be at least two years before projects can enter service, if not more.[94]

[91] Complaint of Joint Consumer Advocates. FERC EL25-18, page 5.

[92] Tariff Revisions for Reliability Resource Initiative. FERC ER25-712-000. December 13, 2024, page 29-30.

[93] Order Accepting Tariff Revisions, Commissioner Chang's Dissent. FERC ER25-712-000. February 11, 2025, page 4.

[94] Complaint of Joint Consumer Advocates. FERC EL25-18, page 12.

Prioritization of gas resources will likely create a new barrier to achieving RPS targets. The federal GRID Power Act introduced on February 6, 2025, would broadly allow grid operators to prioritize dispatchable power plants in their interconnection queues. If passed, this Act could worsen the challenges associated with the RRI.[95]

Clean Repowering

Clean repowering, or connecting new resources through surplus interconnection or generator replacement, can help bring more renewable resources online and ultimately help the District meet its RPS goals. Through surplus interconnection, a resource can connect at the same point of interconnection (POI) as an existing resource and dispatch energy when the existing resource is not operating to its full capacity. Generator replacement is when an existing resource retires and a new resource can make use of its transmission infrastructure by taking over its CIRs and connecting to the transmission system at its POI. PJM is exploring how to reduce barriers for these two pathways.

PJM filed a proposal with FERC on December 2024 to remove barriers for surplus interconnection, which FERC approved in February 2025.[96] The filing makes the following changes:

- It adds language to the Tariff to explicitly allow for the construction of additional physical interconnection facilities where surplus project developers need them to accommodate the requested surplus interconnection service.
- It eliminates the current restrictions on surplus interconnection service in instances where the service:
    i. affects the determination of Network Upgrades for projects already in the interconnection process; or
    ii. results in material adverse impacts on short circuit capability limits, steady-state thermal and voltage limits, or dynamic system stability and response
- It expands the availability of surplus interconnection service to projects that have an Interconnection Service Agreement or Generator Interconnection Agreement but are not yet constructed and operating.

PJM is also exploring ways to enhance the transfer of CIRs from retiring resources to new generation resources to enable smoother, more efficient generator replacement. Together, these two interconnection pathways can help more clean resources interconnect.

[95] Howland, Ethan. February 7, 2025. "RTOs could fast-track dispatchable generation under House, Senate bills." *Utility Dive*. Available at: https://www.utilitydive.com/news/fast-track-grid-interconnection-ferc-pjm-house-senate-bill/739523/?utm_source=Sailthru&utm_medium=email&utm_campaign=Issue:%202025-02-07%20Utility%20Dive%20Newsletter%20%5Bissue:70277%5D&utm_term=Utility%20Dive.

[96] Order Accepting Tariff Revisions. FERC ER25-778-000. February 11, 2025.

Going Forward

As capacity market issues worsen, and as DC and states around the country try to make progress in meeting their RPS targets, there is much uncertainty about PJM and other RTOs' ability to interconnect sufficient new resources fast enough. DC can support efforts by PJM to make surplus interconnection and the transfer of CIRs for generator replacement easier and more broadly available. The DC OPC can also work with other consumer advocates and PJM stakeholders to advocate for interconnection processes and other policies that do not place renewable generators at a lower priority.

There is an opportunity for DC to explore district-level changes to ensure smoother interconnection processes. The District could conduct a study to determine how local permitting and siting constraints impact interconnection timelines and how to reform them. Furthermore, the District may want to focus on the potential to connect renewable resources at the distribution-system-level, particularly solar resources that could satisfy the solar carve-out of the RPS requirement. Interconnections at that level can be managed outside of the PJM process and under greater direct control by DC and Pepco.

6. Ongoing Reform Discussions

6.1. Seasonal ELCC Adjustments for Gas-Fired Generators

In the November 2024 filing from consumer advocate offices, the group requested that PJM be required to adjust ELCC calculations for gas-fired generators.[97] ELCC accreditation for thermal resources are currently based on summer ratings, rather than winter ratings. The independent market monitor has stated that CC and CT generators can produce at higher levels in colder temperatures during the winter weather, which suggests that PJM undercounts their contribution. Consumer advocates, including the DC OPC, argue that using the lower summer ratings and accounting for the winter risks suppresses the available market supply.[98] The independent market monitor estimated that holding everything else constant, the use of summer ratings rather than winter ratings in the marginal based ELCC accreditation for CC and CT resources resulted in market revenue increases of 22.7 to 118.1 percent increase (or $2.72 billion to $7.95 billion) for the 2025/2026 BRA (depending on the reserve margin and holding all else constant).[99] PJM has not filed updates on this item to date, but this issue will likely arise again as additional reforms are discussed.

[97] Complaint of Joint Consumer Advocates. FERC EL25-18, page 5.

[98] Complaint of Joint Consumer Advocates. FERC EL25-18, page 27.

[99] Monitoring Analytics, Analysis of the 2025/2026 RPM Base Residual Auction Part A. Available at: https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_A_20240920.pdf.

6.2. Load Forecasting Issues

PJM's capacity market is highly sensitive to PJM's load forecast: when demand increases, PJM procures more power in the market. PJM's 2025 long-term load forecast projects a sharp rise in electricity demand across its footprint (Figure 4), driven primarily by the anticipated expansion of data centers, particularly in northern Virginia.

Growing scrutiny from consumer advocates, PJM stakeholders, and independent experts suggests these projections may be speculative and overstated, especially beyond the short-term horizon. PJM's previous load forecasts overpredicted peak demand in 17 out of the last 18 years, raising concerns about the credibility of its projections.[100] The consistent historical over-forecast bias led to over-procuring capacity when compared to actual demand.[101] The over-procurement bias is also visible within the reserve margin metric. While PJM has one of the lowest reserve margin requirements of any RTO, due to consistent over-procurement of capacity, the actual procured reserves are some of the highest of any RTO.[102]

Current projections incorporate utility-supplied inputs that vary widely in methodology. Peak load forecasts for the Dominion LDA (in Virginia) have drawn attention for its rapidly escalating data center load projections.[103] While data center load in Dominion's territory reached about 4 GW in 2024, Dominion Energy (which provides local load projections for PJM's forecast) now expects that figure to exceed 15 GW within the decade.[104] These expectations are based on speculative development plans for data centers, many of which lack financial commitment and firm timelines. Trends such as higher energy prices in Dominion's service territory, increased geographic flexibility for data centers, and tax incentives in other regions could slow or end the existing trend of consistent data center growth in northern Virginia.[105] In addition, in January 2025, Chinese company DeepSeek's AI model was reported to require a fraction of the energy used for other AI models, while achieving the same results,[106] which

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[100] James F. Wilson, *Session 4: What's With the PJM Load Forecast?*, presented to the Organization of PJM States, Inc. (OPSI), October 22, 2024, https://opsi.us/wp-content/uploads/2024/10/4.-Wilson-OPSI-10-22-24-draft-10-18-24.pdf.

[101] The Brattle Group, April 2022, *Fifth Review of PJM's Variable Resource Requirement Curve.* Available at: https://www.brattle.com/wp-content/uploads/2022/05/Fifth-Review-of-PJMs-Variable-Resource-Requirement-Curve.pdf.

[102] Federal Energy Regulatory Commission (FERC), *2023 Common Metrics Report* (Washington, DC: Federal Energy Regulatory Commission, January 2024), 9, https://www.ferc.gov/sites/default/files/2024-01/2023_Common_Metrics_Report.pdf.

[103] James F. Wilson, *Session 4: What's With the PJM Load Forecast?*.

[104] Aurora Energy Research, *Impacts of Virginia datacenter demand growth on the power system*, June 2024. https://go.auroraer.com/l/885013/2024-06-19/n7nbj/885013/1718806706gUvUPURq/Aurora_Jun_2024_PJM_Load_Growth_Report.pdf.

[105] Aurora Energy Research, *Impacts of Virginia datacenter demand growth on the power system.*

[106] Ma, M., and Chediak, M. January 28, 2025. "DeepSeek's AI Model Just Upended the White-Hot US Power Market." *Bloomberg News*. Available at: https://www.bloomberg.com/news/articles/2025-01-28/deepseek-s-ai-model-just-upended-the-white-hot-us-power-market?embedded-checkout=true.

suggests that the current PJM data center energy forecasts could be overstated. AI technology is still evolving and may become more efficient over time.

Furthermore, consumer advocates from five PJM states caution that PJM's current load forecasting approach does not differentiate between "firm" load growth and hypothetical future demand.[107] The consumer advocates suggest that PJM adopt a more cautious forecasting framework that incorporates only high probability loads backed by contracts (e.g., data center development contract), or a demonstrated need, and using scenario-based planning. These changes would better reflect uncertainty in sectors such as data centers where development is sensitive to factors such as land use, water availability, local opposition, and computational advancements. Without such reforms, PJM risks basing long-term infrastructure and capacity market decisions on unreliable assumptions, and leaving existing customers paying for the resulting over procurement.

6.3. RMR Reforms: Pro Forma RMR Arrangements

PJM currently handles RMR arrangements on a case-by-case basis, lacking the standardized *pro forma* framework seen in other RTOs. This ad hoc approach has raised concerns among stakeholders about transparency, predictability, and efficiency, particularly as aging resources and low-capacity factor plants face economic pressure to retire. ISO New England, CAISO, and MISO each have clear tariff-defined RMR structures while PJM remains the only RTO with a capacity market that does not yet have a *pro forma* RMR agreement in place.[108] Compounding the issue, PJM also has one of the shortest generator retirement notice periods among its peers, increasing the risk of last-minute reliability issues and the risk that PJM will implement reactive rather than proactive solutions.[109]

Recognizing these challenges, PJM has stated its intent to explore the development of standardized *pro forma* RMR arrangements, targeting implementation by the 2028/2029 delivery year.[110] Developing a *pro forma* RMR agreement could significantly improve consistency in how reliability resources are retained and compensated, while providing market participants greater clarity. For example, this could include formalizing the compensation structure for retained resources. Given PJM's access to detailed operational and market data, including insights into aging infrastructure and underperforming plants, it is well-positioned to identify reliability risks ahead of time. This raises the question of whether PJM could also explore extending its generator retirement notice period or actively engaging with at-risk resource owners earlier in the process. Such forward-looking measures, in tandem with a formalized

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[107] Maryland Office of People's Counsel. *Letter to the PJM Board of Managers*. July 18, 2024. Available at: https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/2024/20240718-med-opc-letter-to-pjm-board.ashx.

[108] America's Power, *Reliability Must Run Agreements* (Washington, DC: America's Power, October 13, 2022), https://americaspower.org/wp-content/uploads/2022/10/RMR-Agreements-1.pdf.

[109] America's Power, *Reliability Must Run Agreements.*

[110] Revisions to Reliability Pricing Model. FERC ER-682-000. January 6, 2025, page 8.

RMR structure, could better safeguard reliability while reducing reliance on emergency, non-standardized interventions.[111]

6.4. Energy Efficiency and its Treatment in the Capacity Market

In November 2024, FERC approved PJM's plan to omit energy efficiency resources from the capacity market effective November 6, 2024, a change that would impact the capacity auction for the 2026/2027 delivery year.[112] FERC found that this change would benefit consumers by reducing capacity prices without impacting resource adequacy. However, the overall impact on capacity prices remains to be seen, and many stakeholders opposed this change, asserting that load would no longer receive the demand-side benefits.

7. CONCLUSION

The recent PJM BRA for the 2025/2026 delivery year resulted in a seven-fold increase in RTO-wide clearing prices, with maximum prices in the BGE zone in Maryland and the DOM zone in Virginia. The auction resulted in the highest RTO-wide capacity prices ever seen in the region.

The price surge was driven by several factors, including resource retirements, RMR agreements, a clogged interconnection queue, and ongoing market rule changes—such as updates to resource accreditation. These developments, alongside increasing electricity demand, contributed to limited available supply and higher clearing prices.

In response, PJM and stakeholders have proposed reforms to better reflect changing market dynamics, several of which have already received FERC approval. In addition, ongoing implementation of queue reforms will help accelerate the interconnection of generation resources. Despite these reforms, PJM's capacity market could see prices that would be among the highest in PJM's history. Moreover, forecasted load growth, mainly driven by the rapid expansion of data centers, will likely result in capacity prices continuing to be high for the foreseeable future.

[111] Monitoring Analytics, *Comments of the Independent Market Monitor for PJM, Docket No. ER25-682-000* (Eagleville, PA: Monitoring Analytics, January 6, 2025), https://www.monitoringanalytics.com/filings/2025/IMM_Comments_Docket_No_ER25-682_20250106.pdf.

[112] Order Accepting Tariff Revisions. FERC ER24-2995-000. November 5, 2024.

8. GLOSSARY

BRA	Base Residual Auction	The PJM capacity auction, called the Base Residual Auction, procures “capacity” power supply resources in advance of the delivery year to meet electricity “resource adequacy” needs in the PJM service area, which includes all or part of 13 states and the District of Columbia. Auctions are usually held three years in advance of the delivery year. Due to recent changes in market design, among other factors, PJM held the most recent BRA, in July, 2024, for the delivery year starting June 1, 2025 (the BRA 25/26), with the auction held only about one year in advance of the beginning of the delivery year. PJM currently intends to conduct subsequent BRAs on an accelerated basis to enable returning to the 3-year forward schedule. The BRA is the first auction, in a cycle of several auctions for each delivery year underPJM’s Reliability Pricing Model (RPM), or capacity market, where the majority of the RPM capacity is procured for a particular delivery year.
CONE	Cost of New Entry	CONE represents the total annual net revenue (net of variable operating costs) that a new generation resource would need to recover its capital investment and fixed costs, given reasonable expectations about future cost recovery over its economic life. CONE is the starting point for estimating the Net Cost of New Entry (Net CONE). Net CONE represents the first-year revenues that a new resource would need to earn in the capacity market, after netting out energy and ancillary service (E&AS) margins from CONE. This metric is used in calculating the VRR Curve (see below) which is used to define the administrative cost cap to the BRA.
CTR	Capacity Transfer Rights	A method of allocating the economic value of transmission import capability that exists into a constrained Locational Deliverability Area (LDA) to Load Serving Entities (LSE).
DY	Delivery Year	The PJM capacity auction procures commitments for a delivery year, beginning June 1 and ending May 30th. The RPM was and is intended to provide for the conduct of each annual capacity auction (or BRA) three years in advance of the beginning of the running of the delivery year commitment procured through the auction. Currently due to slippage resulting from multiple causes, PJM just completed the most recent BRA, in July, 2024, for the 25/26 delivery year, which begins at the same time (June 1, 2025) as the scheduled beginning of the Brandon Shores and Wagner RMR arrangements. The 24/25 delivery year was already procured through a previously completed auction.
E&AS	Energy & Ancillary Services Revenues	Revenues from the energy and ancillary services markets, which are unit-specific. E&AS are historically netted out of Market Seller Offer Caps, and/or Net Cost of New Entry calculations.
ELCC	Effective Load Carrying Capability	ELCC provides a way to assess the capacity value (or reliability contribution) of a resource (or a set of resources) that is tied to the loss-of-load probability concept. ELCC can be defined as a measure of the additional load that the system can supply with a particular generator of interest, with no net change in reliability. ELCC can be based on any reliability metric (e.g., Loss of Load Expectation (LOLE), Loss of Load Hours (LOLH), or Expected Unserved Energy (EUE)). PJM shifted from its prior use of LOLE to an EUE metric for the most recently completed BRA (2025/2026) which was conducted in July, 2024.
EUE	Expected Unserved Energy	This is defined as a measure of the resource availability to continuously serve all loads at all delivery points while satisfying all planning criteria. The EUE is

		energy-centric and analyzes all hours of a particular year. Results are calculated in megawatt hours (MWh). The EUE is the summation of the expected number of MWh of load that will not be served in a given year as a result of demand exceeding the available capacity across all hours.
FERC	Federal Energy Regulatory Commission	The federal agency that regulates wholesale electric power sales and transmission rates.
ICAP	Installed Capacity	A MW value based on the summer net dependable capability of a unit and within the capacity interconnection right limits of the bus to which it is connected.
IMM	Independent Market Monitor	PJM's Independent Market Monitor is responsible for guarding against the exercise of market power in PJM's markets and assisting in the maintenance of competitive and nondiscriminatory markets in PJM. The IMM operates independently from PJM staff and members to objectively monitor, investigate, evaluate, and report on PJM's markets. Monitoring Analytics serves as PJM's independent market monitor.
IRM	Installed Reserve Margin	Percentage value used to establish the level of installed capacity resources that provide an acceptable level of reliability.
LDA	Locational Deliverability Area	Sub-regions of PJM's "footprint" used to evaluate locational constraints of the electric grid. An LDA is an area or zone within the wholesale electric markets administered by PJM, in which local effects of transmission, load, and generating resources are separately accounted for in the operation of PJM's markets. In this report, costs described as allocated to or incurred by a LDA mean costs flowed through to the end-use customers located within that LDA.
LOLE	Loss of Load Expectation	Loss-of-load expectation defines the adequacy of capacity for the entire PJM footprint based on load exceeding available capacity, on average, only once in 10 years. This is generally defined as the expected number of days per year for which the available generation capacity is insufficient to serve the daily peak demand.
MSOC	Market Seller Offer Cap	PJM uses Market Seller Offer Caps to ensure that resources are submitting competitive offers into the capacity market, thus preventing sellers from exerting market power and setting artificially high prices. A resource's MSOC is equivalent to the costs it would avoid if it retired or if it did not clear in the capacity market and did not operate for the delivery year. It is the minimum capacity price a resource needs to take on a capacity obligation and continue operations for another year.
RMR	Reliability Must-Run	A generating unit slated to be retired by its owners but that is needed for reliability reasons. Typically, PJM requests that the unit remain operational beyond its proposed retirement date until transmission upgrades are completed.
RRI	Reliability Resource Initiative	The RRI represents a narrowly tailored, limited-duration proposal designed to expedite the interconnection of a limited number of shovel-ready generating resources that are not presently in the Transition Cycle #2 (TC2) interconnection queue. This proposal reflects the growing urgency to connect generating resources that have a high likelihood of being able to materially support resource adequacy and maintain grid reliability in the near term.
RPM	Reliability Pricing Model	PJM's capacity market design that includes a series of auctions to satisfy the reliability requirements of the PJM region for a delivery year. The majority of capacity is procured in the first auction for a particular delivery year, which is

		known as the Base Residual Auction. This auction is intended to be conducted three years in advance of a given delivery year. The RPM model works in conjunction with PJM's Regional Transmission Expansion Planning process to ensure the reliability of the PJM region for future years.
RTO	Regional Transmission Organization	The organization that coordinates, controls, and monitors a multi-state electric grid. In this report, RTO refers to PJM Interconnection, LLC (or PJM) which operates a competitive wholesale electricity market and manages the high-voltage electricity grid to ensure reliability in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.
UCAP	Unforced Capacity	The megawatt (MW) value of a capacity resource in the PJM Capacity Market. PJM currently uses different methods to accredit the amount of UCAP specific resource types may offer into the PJM capacity market but was shifted to a marginal ELCC approach for the recently completed BRA (for delivery year 2025/2026).
VRR Curve	Variable Resource Requirement	A downward sloping demand curve used in the conduct and settlement of the BRA, both PJM wide and for individually constrained LDAs, that relates the maximum price for a given level of capacity resource commitments relative to reliability requirements.

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