AN INVESTIGATION OF PJM’S CAPACITY MARKET

Report on the Evaluation of PJM’s Capacity Market and Its Ability to Provide Reliable Service at the Lowest Cost

New Jersey Board of Public Utilities

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Executive Summary

PJM Interconnection, LLC ("PJM") is forecasted to experience significant load growth over the next two decades, largely driven by increased data center demand. These loads are expected to interconnect and ramp at a rapid pace: PJM forecasts its summer peak demand to grow from 156 gigawatts ("GW") in 2026 to 183 GW by 2030, 222 GW by 2036, and 253 GW by 2046.[1] However, non-market constraints impede the deployment of new supply resources at the speed and scale necessary to meet this demand growth. At the same time, investment in new supply resources is unappealing due to both the uncertain trajectory of data center load growth and PJM's ongoing consideration of significant capacity market reforms. These dynamics have tightened supply and demand, prompting unprecedented capacity prices: the capacity market clearing price jumped from $28.92 in the 2024/2025 Delivery Year ("DY") Base Residual Auction ("BRA") to $269.92 in the 2025/2026 BRA, $329.17 in the 2026/2027 BRA, $333.44 in the 2027/2028 BRA, and most recently, cleared at $325.00 in the 2028/2029 BRA.[2] Temporary capacity auction price caps were implemented in response to these high clearing prices and prevented even higher price spikes in the 2026/2027, 2027/2028, and 2028/2029 BRAs. Despite sending elevated price signals for multiple years, PJM's two most recent BRAs procured capacity 5.6% short of their Installed Reserve Margins ("IRM"), prompting PJM to consider broader reforms to its resource adequacy framework.[3] Against this backdrop, the New Jersey Legislature tasked the New Jersey Board of Public Utilities ("BPU" or "Board") with investigating the PJM capacity market and evaluating whether it is achieving its intended objectives of ensuring resource adequacy at the lowest possible cost to customers.

In its May 6, 2026 report titled "Powering Reliability through Market Design," PJM stated that its current capacity market construct is incompatible with achieving resource adequacy both today and in the future, because a single-year price commitment in today's market

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[1] PJM Interconnection, L.L.C., 2026 Load Forecast Report Tables Table B1 (2026) ("PJM 2026 Load Forecast Tables"), https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/2026-load-report-tables.xlsx.

[2] PJM Interconnection, L.L.C., 2028/2029 Base Residual Auction Report 5 (2026) ("PJM 2028/2029 BRA Report"), https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2028-2029/2028-2029-bra-report.pdf.

[3] PJM Interconnection, L.L.C., 2027/2028 Base Residual Auction Report 3 (2025) ("PJM 2027/2028 BRA Report"), https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2027-2028/2027-2028-bra-report.pdf.

environment fails to induce sufficient supply additions.[4] Significant non-market barriers to entry for new supply resources, including permitting, siting, and supply chain constraints, have limited the ability of new resources to respond to market signals. High global demand for equipment used to construct new generating facilities has strained supply chains and significantly increased the cost of building new natural gas-fired power plants. At the same time, uncertainty surrounding future load growth and potential changes to the capacity market design have weakened investment incentives for new supply resources. As a result, price signals that may once have been sufficient to attract and retain resources are no longer producing the supply response necessary to maintain resource adequacy. Under current conditions, PJM's capacity market revenues may be neither sufficiently high nor sufficiently durable to incentivize the construction of new supply resources. Supply resource developers require high or long-lasting price signals to counter the risk that, under the existing capacity market construct, their investments will be less profitable than planned. Profitability under the current capacity market construct is particularly dubious due to uncertainty surrounding the rules that will govern future capacity auctions and uncertainty of future load forecast levels. Because of such risks, simply implementing high or long-lasting price signals under PJM's current capacity market construct cannot result in the achievement of resource adequacy at least cost.

While our findings largely corroborate PJM's recent diagnosis of its capacity market, they are also more specific to New Jersey. Our conclusions are as follows:

- In the past, resource adequacy was achieved under PJM's capacity construct at the Regional Transmission Organization ("RTO") level, with prices that fluctuated but were relatively lower than those observed in the past three BRAs.
- Current demand- and supply-side conditions prevent PJM's existing market design from maintaining resource adequacy at least cost and will continue to do so, necessitating significant reforms to capacity procurement.
- One-year price signals alone are insufficient to attract the investment needed to develop new capacity, indicating that longer-term price signals may be necessary. At the same time, any transition toward a capacity construct that provides greater long-term revenue certainty to suppliers must carefully manage the risks such commitments impose on existing ratepayers.
- Since the data center customer class is the primary driver of current resource adequacy risks, reforms pursued at the regional and state levels should seek to

[4] PJM Interconnection, L.L.C., Powering Reliability Through Market Design 45 (2026) ("PJM's Market Report"), https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2026/20260506-powering-reliability-through-market-design.pdf.

allocate the costs and risks associated with providing service to it. The state, for its part, will begin implementing many of these reforms pursuant to P.L.2026, C.32.

This report begins by discussing New Jersey's evolving relationship with PJM. Section 3 then examines the history, assumptions, and design of the Reliability Pricing Model ("RPM"). Sections 4 through 8 evaluate market outcomes, review recent market pressures, and assess ongoing reform efforts at PJM and their implications for New Jersey. Readers who are primarily interested in current market conditions and reform discussions should skip to Section 4. The report ends with a set of recommendations for policymakers to review and consider.

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Table of Acronyms

Acronym	Full Name
ACE	Atlantic City Electric
AUCAP	Accredited Unforced Capacity
BGS	Basic Generation Service
Board	New Jersey Board of Public Utilities
BPU	New Jersey Board of Public Utilities
BRA	Base Residual Auction
Brattle	The Brattle Group
BYONC	Bring Your Own New Capacity
CC	Combined Cycle
CCM	Capacity Credit Market
CIFP	Critical Issue Fast Path
CONE	Cost of New Entry
CPQR	Capacity Performance Quantifiable Risk
CRA	Charles River Associates
CT	Combustion Turbine
C&M	Connect and Manage
D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
DER	Distributed Energy Resource
DR	Demand Response
DY	Delivery Year
EAS	Energy and Ancillary Services
EDC	Electric Distribution Company
EDECA	Electric Discount and Energy Competition Act
ELCC	Effective Load Carrying Capability
EMAAC	Eastern Mid-Atlantic Area Council
EUE	Expected Unserved Energy
E3	Energy and Environment Economics, Inc.
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
FRR	Fixed Resource Requirement
GW	Gigawatt
HHI	Herfindahl-Hirschman Index
IA	Incremental Auction
IMM	Independent Market Monitor
IRAS	Interim Resource Adequacy Service
IRM	Installed Reserve Requirement

IRP	Integrated Resource Plan
ISO	Independent System Operator
ISO-NE	Independent System Operator New England
kW	kilowatt
LCAPP	Long-Term Capacity Pilot Program
LDA	Locational Deliverability Area
LFA	Load Forecast Adjustment
LLA	Large Load Addition
LOLE	Loss of Load Event
LOLP	Loss of Load Probability
LSE	Load Serving Entity
MAAC	Mid-Atlantic Area Council
MDPSC	Maryland Public Service Commission
MOPR	Minimum Offer Price Rule
MSOC	Market Seller Offer Cap
MW	Megawatt
NEDC	National Energy Dominance Council
NLL	New Large Load
OATT	Open Access Transmission Tariff
PAI	Performance Assessment Interval
PJM	PJM Interconnection, LLC
PRD	Price Responsive Demand
PSE&G	Public Service Electric & Gas
RBO	Reliability Backstop Obligation
RBP	Reliability Backstop Procurement
RCP	Resource Clearing Price
RERRA	Relevant Electric Retail Regulatory Authority
RPM	Reliability Pricing Model
RR	Reliability Requirement
RTO	Regional Transmission Organization
SOCA	Standard Offer Capacity Agreements
Tariff	Open Access Transmission Tariff
Third Circuit	United States Court of Appeals for the Third Circuit
TPS	Three Pivotal Supplier
UCAP	Unserved Capacity
VPP	Virtual Power Plant
VRR	Variable Resource Requirement

1. A Request to Investigate PJM's Capacity Market

Approved on August 15, 2025, P.L. 2025, JR-11 directed the New Jersey BPU to investigate whether PJM's RPM, also known as its capacity market, is serving its intended purpose to provide resource adequacy and whether it is doing so at the lowest possible cost.[5] Due to recent price spikes driven by increased forecasted demand and constrained supply, policymakers are seeking to re-evaluate whether the capacity market remains aligned with state objectives.

New Jersey residents have recently experienced price shocks, due in part to PJM's capacity market prices. As a restructured state, New Jersey relies on PJM-administered markets to procure capacity, energy, and ancillary services. Therefore, New Jersey retail ratepayers are directly and fully exposed to the outcomes of PJM's wholesale market design. With average electricity bills having increased between roughly 17 and 20% in New Jersey in 2025 compared to 2024,[6] policymakers are increasingly looking to PJM's wholesale markets, especially the RPM, as recent BRA clearing prices increased roughly nine-fold between the 2024/2025 and 2025/2026 DYs.[7] These capacity market outcomes are largely due to unprecedented forecasted load growth and significant barriers to new resource entry that together create a tightening supply-and-demand balance across the region.

The central purpose of PJM's capacity market is to ensure reliability by procuring sufficient capacity to meet system demand.[8] Specifically, the RPM sends a price signal three years in advance of the DY, providing a revenue stream meant to help retain existing resources and incentivize the development of new resources when needed. These revenues are designed to address the "missing money" problem, that is, helping resources recover costs that may not be fully compensated through the energy and ancillary services ("EAS") markets alone. Furthermore, the competitive auction structure is intended to achieve these objectives at the lowest cost. Evaluating the RPM therefore requires consideration not only of whether

[5] P.L. 2025, J.R. No. 11 (2025).

[6] NJBPU Announces Conclusion of New Jersey's Annual Electricity Supply Auction, https://www.nj.gov/bpu/newsroom/2024/approved/20250212.html (last visited July 6, 2026).

[7] PJM Interconnection, L.L.C., 2025/2026 Base Residual Auction Report 4 (2024) ("PJM 2025/2026 BRA Report").

[8] PJM Interconnection, L.L.C. Capacity Market & Demand Response Operations, PJM Manual 18: PJM Capacity Market, Revision 62, 14 (2025) ("PJM Manual 18"), https://www.pjm.com/-/media/DotCom/documents/manuals/m18.pdf.

the market secures sufficient resources to maintain reliability, but also whether the costs imposed on customers result in commensurate reliability benefits.

While the Federal Energy Regulatory Commission ("FERC") regulates PJM's wholesale electricity markets, states have jurisdiction over generation policy, resource planning, siting, permitting, retail rates, and clean-energy policies. Consequently, the RPM operates at the intersection of federal and state jurisdiction, with wholesale market design and outcomes directly affecting state policy objectives and customer costs.

This report evaluates PJM's capacity market and its ability to achieve reliability and resource adequacy, affordability and cost-effectiveness, and compatibility with state policy objectives. This report evaluates both the market design and the environment in which it operates.

2. Federal and State Regulations Supporting Competitive Procurement

Federal and state regulations together create an intertwined framework that governs New Jersey's procurement of capacity. While federal law supports competition in wholesale capacity procurement, state law encourages retail customer choice and competition among electricity suppliers. This section notes provisions in the Federal Power Act ("FPA"), FERC Orders 888 and 2000, and New Jersey's Electric Discount and Energy Competition Act ("EDECA") that together facilitate the state's use of competition in capacity procurement.

The FPA grants FERC jurisdiction over the transmission of electric energy in interstate commerce and wholesale sales of electricity, while reserving authority over electric generation facilities, local distribution facilities, and retail electricity sales to states.[9] Section 205 of the FPA further provides that all rates and charges for or in connection with

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[9] Section 201(a) of the FPA states that

> [i]t is hereby declared that the business of transmitting and selling electric energy for ultimate distribution to the public is affected with a public interest, and that Federal regulation of matters relating to generation to the extent provided in this Part and the Part next following and of that part of such business which consists of the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce is necessary in the public interest, such Federal regulation, however, to extend only to those matters which are not subject to regulation by the States.

16 U.S.C. § 824(a). Section 201(b) of the FPA states that "[t]he Commission … shall not have jurisdiction … over facilities used for the generation of electric energy or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter." Id. § 824(b)(1).

interstate transmission and wholesale sales, as well as the classification, practices, and regulations affecting those rates and charges, must be filed with FERC.[10]

To comply with these requirements as a public utility regulated by FERC,[11] PJM has on file with FERC an Open Access Transmission Tariff ("OATT" or "Tariff"). In 1996, FERC issued Order 888, mandating that "all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce ... file open access non-discriminatory transmission tariffs that contain minimum terms and conditions of non-discriminatory service."[12] In establishing this requirement, FERC sought to eliminate undue discrimination in transmission access and facilitate the development of competitive wholesale electricity markets.[13] More specifically, by facilitating non-discriminatory service, FERC aimed to enable the construction of new merchant generation capacity that could be built and operated at a substantially lower cost than generation recovered through utilities' embedded costs, and to provide customers with access to lower-cost supplies from other regions through the transmission grid.[14]

New Jersey's 1999 EDECA has worked in parallel with these federal regulations, supporting competition in electricity by encouraging distribution utilities and their customers to purchase their generation on more competitive terms than under the previous regulated structure. Specifically, EDECA required electric public utilities to unbundle their rate schedules for generation, transmission, and distribution services,[15] functionally separating their non-competitive business functions from their competitive generation services.[16] EDECA additionally directed the BPU to protect competition in distribution-level electricity sales by not permitting the BPU to regulate, fix, or prescribe the rates, tolls, charges, rate structures, rate base, or cost of service of competitive services, including electric generation.[17] EDECA also directs the BPU to protect competition in generation[18] and to

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[10] Federal Power Act §§ 205(a), (c).

[11] FERC Order No. 888, 75 FERC ¶ 61,080, at n. 425 (1996) ("An ISO will operate facilities used for the transmission of electric energy in interstate commerce and thus will be subject to the Open Access and OASIS rules.").

[12] Id. at 4.

[13] Id. at 50.

[14] Id. at 48-49.

[15] Electric Discount and Energy Competition Act, N.J.S.A. § 48:3-52.

[16] Id. § 48:3-59.

[17] Id. § 48:3-56.

[18] Id. § 48:3-78.

develop standards for competitive service.[19] Electricity procurement in New Jersey is thus currently framed by competitive procurement structures at both the wholesale and retail levels.

As a retail choice state, New Jersey end-use customers may select the load serving entity ("LSE") from which they purchase their electricity supply. These LSEs procure energy, capacity, and ancillary services through PJM's wholesale markets, and the costs associated with those purchases are ultimately recovered from retail customers. End-use customers may either contract with a competitive third-party supplier that serves as their LSE or receive default service from their electric distribution company ("EDC"), which procures generation supply from LSEs selected through the Basic Generation Service ("BGS") auction administered under BPU oversight.[20]

While New Jersey's default service procurement has historically relied on shorter-term contracts that hedge energy price risk, it has generally not provided long-term hedging against changes in capacity costs.[21] PJM has noted that this approach was economically rational during a prolonged period of supply surplus, as it allowed default service providers to benefit from competitive market prices while avoiding the costs of long-term hedging.[22] However, as capacity market prices have increased, the absence of long-term hedging has exposed default service customers to significant price increases.[23]

3. PJM and Resource Adequacy: A Historical Evaluation

This section explains how PJM's current capacity market procures capacity and establishes capacity prices, as well as how the market evolved into its current form. It begins with a historical account of capacity procurement prior to the implementation of the RPM, the Board's historical concerns about the RPM, and the jurisdictional conflicts over capacity procurement, before describing how the RPM determines the quantity and price of capacity procured for each DY.

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[19] Id. § 48:3-56.

[20] Id. § 48:3-57.

[21] As explained below, in the past New Jersey tried to support more in-state generation capacity and hedge against capacity market risk by requiring a form of bilateral capacity contracting. However, federal courts ruled New Jersey's efforts pre-empted by FERC's approval of PJM's capacity market design. See infra Sections 3.2-3.3.

[22] PJM's Market Report at 5.

[23] Id. at 6.

3.1. Before The Current Capacity Market Design

Prior to PJM becoming an RTO, its vertically integrated utility members were responsible for maintaining sufficient generating capacity to meet forecasted peak demand plus a reserve margin. Utilities with excess capacity could sell capacity to utilities with capacity deficiencies through a bilateral market, allowing members to satisfy their resource adequacy obligations.[24] From 1974 to 1999, PJM formalized this arrangement by imposing a two-year forward capacity obligation under which each member utility "was required to demonstrate that it had, or would have, sufficient installed capacity to meet its load and reserve margin obligations two years ahead of the delivery year."[25] Utilities that failed to do so were subject to a capacity deficiency charge based on the estimated Cost of New Entry ("CONE") of a combustion turbine ("CT").[26] This obligation ensured that each utility remained responsible for securing adequate capacity while allowing bilateral capacity transactions to balance temporary surpluses and deficiencies.[27]

During the 1990s, states and federal policymakers increasingly sought to replace vertically integrated monopoly structures with competitive electricity markets. Under this model, generation was separated from transmission and distribution utilities, allowing independent power producers to compete to supply electricity. Rather than relying on utility ownership of generation, the competitive framework was intended to encourage private investment and innovation while reducing costs through market-based procurement.

The transition to competitive retail electricity markets fundamentally changed how resource adequacy obligations were satisfied. Rather than relying on ownership of generation resources, competitive LSE became responsible for procuring sufficient capacity to serve their customers.[28] Since LSEs generally do not own sufficient generation resources to meet their capacity obligations, the restructured retail system needed to provide LSEs with a way to "purchase and sell capacity in small increments with a short lag as they gained or lost load."[29] Restructuring thus helped create the need for an official PJM market where entities serving retail load could transact for capacity with generation-

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[24] Joseph Bowring, Capacity Markets in PJM, 2 Economics of Energy & Environmental Policy, 47-48 (2013) ("Capacity Markets in PJM").

[25] PJM's Market Report at 53.

[26] Id.

[27] Id.

[28] Id.

[29] Capacity Markets in PJM at 22.

owning utilities who were competing to serve the same load.[30] In response to the FERC filings made by the Pennsylvania Public Utility Commission, PJM created a Capacity Credit Market ("CCM") in 1999.[31] The CCM was "a daily market with a daily requirement to purchase capacity equal to each LSE's capacity obligation, subject to a penalty payment."[32]

This CCM was not heavily relied upon – less than 10% of PJM's capacity obligation was transacted on it[33] – and it was ultimately deemed inadequate for ensuring long-term resource adequacy.[34] PJM's Independent Market Monitor ("IMM") attributed the market's lack of market power mitigation rules, which resulted in near-zero daily sell offer and clearing prices, as responsible for the market's lack of success.[35] According to the IMM's reasoning, the CCM's low clearing prices could not generate sufficient revenue to cover the annualized costs of building new generation units, making entry into the market unattractive for new supply resources and threatening the sustainability of this method of capacity procurement.[36] PJM attributed this market's dysfunction to its lack of recognition of the locational value of capacity, as well as a lack of market requirements or incentives for capacity resources to commit for longer than a day.[37]

3.2. Creation of the RPM, the Board's Original Opposition, and New Jersey's Efforts to Bilaterally Procure Its Own Capacity

Due to PJM's concerns that the CCM design was failing to secure long-term reliability, PJM filed its initial RPM proposal with FERC on August 22, 2005.[38] FERC agreed with PJM's diagnosis in an April 20, 2006 order, but directed further proceedings to address issues FERC identified and further refine the design.[39] This led to a settlement that would establish

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[30] Id.

[31] Id.

[32] Id.

[33] Johannes Pfeifenberger et al., Review of PJM's Reliability Pricing Model (RPM) 6 (2008), https://www.brattle.com/wp-content/uploads/2017/10/6328_review_of_pjms_reliability_pricing_model_pfeifenberger_et_al_jun_30_2008-2.pdf.

[34] PJM's Market Report at 54.

[35] Capacity Markets in PJM at 49.

[36] Id. at 50.

[37] PJM's Market Report at 54.

[38] PJM Interconnection, L.L.C., 115 F.E.R.C. ¶ 61,079 at P 1 (2006).

[39] Ibid.

the initial rules of the RPM, which FERC approved subject to conditions on December 22, 2006,[40] enabling PJM to implement the RPM in 2007.

At the time, the Board opposed the new RPM design out of a concern that it would fail to meet New Jersey's capacity needs while nonetheless pushing up electricity prices.[41] More specifically, the Board feared that the fluctuating, annual nature of the prices produced by the RPM auction would be too volatile and uncertain to support the financing of new generation and thus ultimately fail to attract sufficient new capacity to maintain reliability.[42] The Board, along with other parties, thus sought rehearing of FERC's December 2006 order approving the RPM design.[43] However, FERC rejected the Board's central concerns and upheld its decision on rehearing in a June 25, 2007 order.[44] The Board, along with the Maryland Public Service Commission ("MDPSC"), then appealed FERC's decision to approve the RPM to the United States Court of Appeals for the District of Columbia Circuit ("D.C. Circuit").[45] However, the D.C. Circuit summarily denied the MDPSC's and Board's appeal and upheld FERC's decision in a 2011 ruling.[46]

Yet neither the Board nor the Legislature were willing to gamble that the RPM would sufficiently improve on the CCM to maintain reliability, especially since in 2010 PJM itself warned that transmission constraints and limited in-state generation could expose New Jersey to a risk of blackouts in just two to three years.[47] As such, with the Board's support, the Legislature passed an act establishing the Long-Term Capacity Pilot Program ("LCAPP") in 2011.[48] In passing the LCAPP Act, the Legislature found that "the lack of incentives under the reliability pricing model" meant that "the construction of new, efficient generation must

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[40] PJM Interconnection, L.L.C., 117 F.E.R.C. ¶ 61,331 at P 1 (2006) ("RPM Approval Order").

[41] See RPM Approval Order at 145 ("[T]he New Jersey [Board of Public Utilities] similarly argue[s] that the Settlement will raise prices without improving reliability . . . ."): PJM Interconnection, L.L.C., 119 F.E.R.C. ¶ 61,318 at P 185-86, 190 (2007) ("RPM Rehearing Order").

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

[43] RPM Rehearing Order at P 2.

[44] RPM Rehearing Order at P 1, 190-92.

[45] Hanna, F.Supp. 2d at 392-93; Md. PSC v. FERC, 632 F.3d 1283, 1284 (D.C. Cir. 2011).

[46] Hanna, F.Supp. 2d at 393; Md. PSC v. FERC, 632 F.3d at 1284.

[47] Hanna, 977 F.Supp. 2d at 393. Fortunately, these reliability concerns ultimately proved to be a false alarm driven by PJM load forecasts that failed to fully account for the economic impact of the Great Recession. Id. at 395. Subsequent downward revisions to the load forecast sufficiently alleviated the reliability concerns to enable the remainder to be resolved by new transmission lines that could facilitate additional electricity imports into New Jersey. Ibid.

[48] Ibid.; N.J.S.A. 48:3-98.2 to -98.4.

be fostered by State policy that ensures sufficient generation is available to the region, and thus the users in the State in a timely and orderly manner."[49] To that end, the LCAPP Act required the Board to issue an order directing New Jersey EDCs to bilaterally procure 2,000 megawatts ("MW") of new capacity via Standard Offer Capacity Agreements ("SOCA").[50]

To follow the ensuing litigation associated with the LCAPP, it is important to understand how LSEs obtain supply in PJM. The only way an LSE can use capacity procured wholly outside the RPM to meet its capacity needs is by electing to use the Fixed Resource Requirement ("FRR") Alternative,[51] under which it must meet *all* of its capacity needs outside of the RPM for the relevant service area.[52] However, the Reliability Assurance Agreement effectively bars LSEs in states like New Jersey that allow full retail choice from electing the FRR Alternative.[53]

Any LSE outside of an FRR meets its capacity obligations through the RPM. This is achieved by requiring an LSE to pay its share of the "Locational Reliability Charge," an amount equal to the RPM clearing price in its zone multiplied by the supply the LSE serves.[54] An LSE may, however, "self-supply" a resource into the capacity auction, provided the resource clears the market, to offset its payment obligations.[55] An LSE can self-supply by directly owning generation – as is done by a vertically owned utility, for instance – or by entering a bilateral contract with generators. An LSE self-supplying with a generator is considered the effective owner of that generation in the capacity market.

The LCAPP was designed to function similarly to a long-term bilateral contract. Under the program, the Board competitively solicited bids from developers looking to construct

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[49] N.J.S.A. 48:3-98.2(d).

[50] N.J.S.A. 48:3-98.3(c)(1). The LCAPP Act made the EDCs the counterparties, rather than the LSEs ultimately responsible for procuring the capacity sold at retail in New Jersey, because under New Jersey's BGS auction design LSEs only take on commitments to serve load for a period of three years. N.J.S.A. 48:3-98.2(c)(3).

[51] Id. § 7.2.

[52] See id., Sch. 8.1.B(2).

[53] This follows from the fact that the RAA limits FRR Alternative eligibility to entities that are "an [Investor Owned Utility, Electric Cooperative, or Public Power Entity" with "the capability to satisfy the Unforced Capacity obligation for all load in an FRR Service Area." Id., Sch. 8.1.B(1). This means an LSE can only elect the FRR Alternative for a given service area if it has a monopoly on the supply of capacity at retail in that service area. Such monopolies cannot exist in states like New Jersey that allows retail customers to choose from multiple competitive electricity providers that supply capacity at retail to the same service area.

[54] RAA Section 7.2.

[55] RAA Section 7.3; PJM, Intra-PJM Tariffs, OATT, Attach. DD, § 5.2 (Nomination of Self Supplied Capacity Resources), https://agreements.pjm.com/oatt/5142.

power plants.[56] Awarded generators were required to participate in and clear PJM's capacity market. However, the generators would not receive the auction clearing price. Instead, they obtained fixed prices for capacity over 15 years through the SOCAs signed with the EDCs.[57] Any difference in price between the capacity market and a fixed SOCA price would be credited or covered by the EDC and its ratepayers. Effective ownership of the generation unit would not change hands. This type of arrangement is called a contract for differences.

3.3. The *PPL Energyplus v. Solomon* Decision Ends New Jersey's Attempt to Bilaterally Procure Capacity and Forces Reliance on RPM Auctions.

From its inception, the LCAPP was controversial and thus was promptly challenged by Public Service Electric and Gas Company, Atlantic City Electric ("ACE"), as well as numerous companies that owned generation capacity that would compete with the new generation capacity awarded SOCAs under LCAPP.[58] In a 2013 decision, the United States District Court for the District of New Jersey held that the FPA pre-empted LCAPP in *PPL EnergyPlus v. Hanna*.[59] The United States Court of Appeals for the Third Circuit ("Third Circuit") affirmed that decision the following year in *PPL EnergyPlus v. Solomon*.[60] In 2016, the Supreme Court found that a similar program in Maryland was also pre-empted by the FPA in *Hughes v. Talen Energy Marketing*.[61]

The Third Circuit found that the FPA pre-empted LCAPP because, in its view, LCAPP constituted a form of wholesale capacity price regulation, a field where FERC has exclusive authority under the FPA.[62] The court explained that LCAPP effectively regulated capacity prices because it required LCAPP "generators to 'participate in and clear' RPM auctions and ensured each LCAPP generator would receive a "price to New Jersey's liking" instead of the "auction price they would have otherwise received."[63]

The *Hughes* Court expressed similar concerns when reviewing Maryland's version of the LCAPP. The Court found that the program "second-guess[ed] the . . . the wholesale rate" of

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[56] N.J.S.A. 48:3-98.3

[57] N.J.S.A. 48:3-98.3(c).

[58] See Hanna, 977 F.Supp. 2d at 377.

[59] See id. at 410-12.

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

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

[62] Solomon at 252-53.

[63] Id. at 252.

the capacity market.[64] The Court made clear, however, that a state is free to pursue programs "untethered to a generator's wholesale market participation" – for instance, "so long as the state does not condition payment of funds on capacity clearing the auction," a similar program would be able to survive legal scrutiny.[65]

Though the *Solomon* case only directly considered LCAPP, the precedent it and *Hughes* set create bounds on the types of programs a state can set for long-term procurements. A state cannot set a replacement rate for resources that must participate in the wholesale capacity auction. However, it is not fully clear if each element of the LCAPP – (1) that the state set a price for capacity and (2) that the generators were required to participate and clear the capacity market – was individually sufficient to trigger the legal defect.

Importantly, although *Solomon* clearly does not prohibit voluntary bilateral contracting, to date New Jersey LSEs have opted to procure the capacity they needed exclusively or nearly exclusively through RPM auctions. Therefore, in order to promote long-term contracts and price certainty for both generators and ratepayers, the state must consider the options available to it, as discussed in Section 9 and as constrained by the legal risks surrounding *Solomon* and *Hughes*. Of course, PJM and FERC can remove these constraints and uncertainty by modifying PJM's governing documents to allow more flexibility with "self-supply" arrangements.

3.4. How the RPM Procures Capacity: Reliability Metrics and Price Formation

3.4.1. Overview

As explained above, PJM replaced the CCM with the RPM in order to solve the problems created by the CCM's inability to sustain investments in supply resources.[66] To that end, PJM designed the RPM to fulfill two central objectives: (1) ensure that sufficient supply resources are committed to meet forecasted demand plus a reserve margin to maintain grid reliability,[67] and (2) solve the problem of the EAS markets failing to provide sufficient revenue to stimulate new entry and retain needed existing units, known colloquially as the

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[64] Hughes, 578 U.S. at 165.

[65] Id. at 166.

[66] Capacity Markets in PJM at 50.

[67] PJM Manual 18 at 11.

“missing money” problem.[68] The RPM was designed to accomplish these purposes through market mechanisms and without ongoing regulatory intervention.[69]

The RPM consists of a BRA that occurs three years before the DY and three Incremental Auctions (“IA”) that occur after the BRA to account for load forecast and supply-side changes. The BRA is intended to procure sufficient capacity to satisfy the Reliability Requirement (“RR”), which consists of forecasted demand plus a reserve margin based on the IRM calculated using PJM’s Loss of Load Probability (“LOLP”) Model. The RPM incorporates the Net CONE of a supply resource to set the prices needed to recover the “missing money.” It also administers a Variable Reliability Requirement (“VRR”) Curve, a downward-sloping demand curve, which aligns prices with reliability levels and provides a price signal reflective of system needs.[70] Additionally, PJM implements a locational capacity pricing mechanism that reflects transmission constraints and sends price signals to incent the retention of existing resources and construction of new resources in areas that need capacity.[71] Together, these components are intended to promote a reliable grid, transparent price formation, and efficient procurement of capacity. The following sections explore and evaluate the RPM’s assumptions and methodology.

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[68] Monitoring Analytics, L.L.C., 2024 Quarterly State of the Market Report for PJM: January through March 305 (2024), https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2024/2024q1-som-pjm-sec5.pdf.

[69] Capacity Markets in PJM at 50.

[70] PJM’s Market Report at 55.

[71] Id.

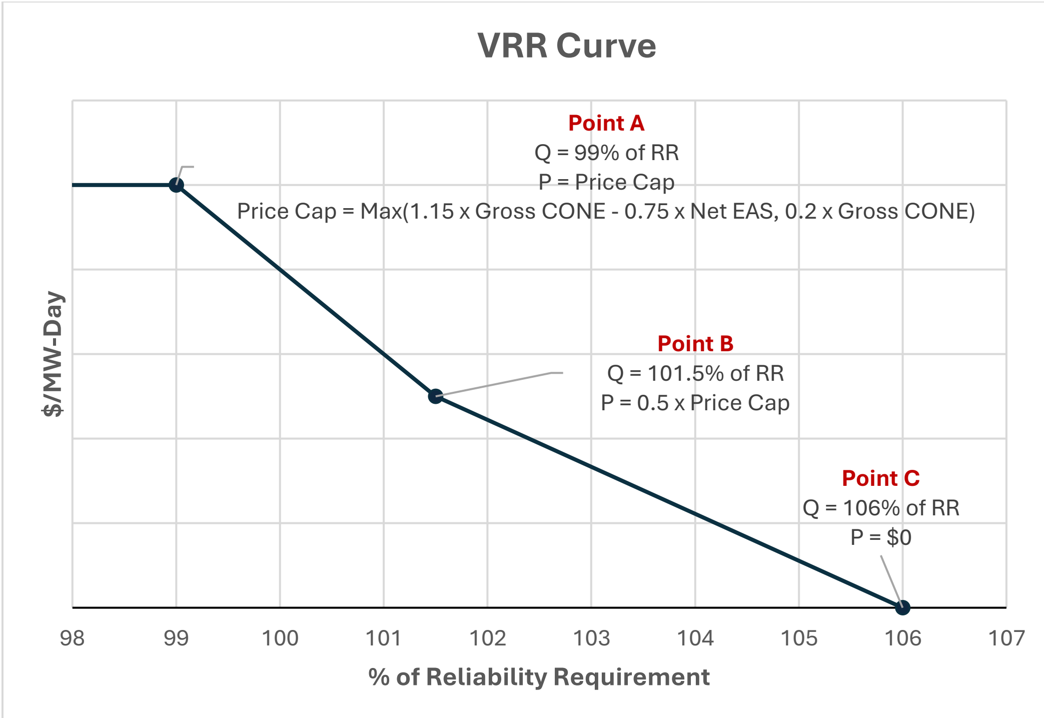

Figure 1. Illustration of the PJM Variable Reliability Requirement (VRR) Curve.

3.4.2. Load Forecasting

Since the RR is determined using annual RTO peak load forecasts, PJM's forecasting methodology directly influences the quantity of capacity that must be procured. PJM's Load Forecast Model estimates hourly peak load for each PJM zone using multiple regression models.[72] These models consider (1) historical hourly metered load data; (2) estimated load drops due to emergency or pre-emergency programs, PJM- or EDC-implemented voltage reductions, and Loss of Load Events ("LOLE"); and (3) other Load Forecast Adjustments.[73] PJM's regression models additionally consider how "trends in equipment and appliance usage, anticipated economic growth, distributed solar generation and battery storage, plug-in electric vehicles, and historical weather patterns will affect peak load and energy use growth."[74] PJM makes its Load Forecast Adjustments

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[72] PJM Interconnection, L.L.C. Resource Adequacy Planning, PJM Manual 19: Load Forecasting and Analysis, Revision 39, 12 (2026) ("PJM Manual 19"), https://www.pjm.com/-/media/DotCom/documents/manuals/m19.pdf.

[73] Id.

[74] Id. at 12. Note that PJM accounts for forecasted deployment of distributed solar and battery storage resources that do not participate in the capacity market as a reduction in the load forecast. This means increased distributed solar and/or storage deployment can reduce the amount of capacity New Jersey needs to source through the RPM.

by soliciting information from EDCs and LSEs about any large increases or decreases in load within their territories, then verifying these changes and determining whether they are captured in the PJM Load Forecast Model.[75] It is through these Large Load Adjustments that most forecasted data center load is incorporated into PJM's load forecast. Stakeholders have noted that forecasts developed through the Large Load Adjustment process are subject to considerable uncertainty, largely because the timing and magnitude of data center development remain highly uncertain.

As PJM's current method of making LFAs is largely dependent on EDC and LSE input, PJM is currently initiating an independent hourly load forecast for 2027-2047.[76] This independent forecast will also be used to review EDC and LSE Large Load Adjustment submissions.[77] PJM has commissioned Charles River Associates ("CRA") to develop it by reconciling load estimates that are determined using "bottom-up" and "top-down" methods.[78] While a bottom-up forecast considers load that is expected to be associated with individual facilities, a top-down forecast considers macro-level factors, such as economic indicators. CRA will base their forecast on 2026 PJM Load Forecast data, as well as data that they supply.[79]

Furthermore, PJM has recently made additional changes to its Load Forecast Adjustment process to improve its accuracy. First, PJM now designates as "firm" load Large Load Additions ("LLA") that are greater than or equal to 50 MW, have made a financial commitment, and have an electric service obligation, construction commitment, or long-term supply commitment.[80] PJM will include these LLAs in the load forecasts that inform the RPM auctions.[81] Load that does not meet the firm load criteria will be designated as non-firm and may not be included in the forecasts for the RPM.[82] PJM has also added a Relevant Electric Retail Regulatory Authority ("RERRA") review step whereby entities that have jurisdiction over the retail sales of the EDC or LSE submitting the forecast adjustment

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[75] Id. at 26-31.

[76] Emmanuele Bobbio, Third-Party Review of Large Load Adjustments 3 (2026), https://www.pjm.com/-/media/DotCom/committees-groups/subcommittees/las/2026/20260605/20260605-item-03---third-party-review-of-large-load-adjustments.pdf.

[77] Id.

[78] Id.

[79] Id.

[80] PJM Manual 19 at 26.

[81] Id.

[82] Id. at 28-29.

must be given a voluntary opportunity to review and provide feedback on the submitted Load Forecast Adjustment.[83] PJM will consider RERRA feedback and the independent third-party review when adjusting its preliminary load forecast total that accounts for firm load.[84]

3.4.3. Loss of Load Probability Model

3.4.3.1. Model Overview

PJM relies on the LOLP Model, its probabilistic resource adequacy model, to determine several key inputs to the RPM. The model uses historical weather patterns, load forecasts, and resource performance characteristics to evaluate system reliability under thousands of simulated conditions. By iteratively evaluating reliability under varying reserve levels, the model then determines the IRM, or the amount of installed capacity required above peak load to satisfy PJM's reliability criterion of a 1-day-in-10 years LOLE, or 0.1 days per year.

The same model is also used to evaluate the reliability contribution of each resource class by calculating its Effective Load Carrying Capability ("ELCC").[85] These ELCC values are translated into Accredited Unforced Capacity ("AUCAP") ratings, which establish the maximum amount of Unforced Capacity ("UCAP") that each resource may offer in the RPM.[86] Finally, PJM combines the pool-wide Average AUCAP factor with the IRM to calculate the Forecast Pool Requirement, the quantity of accredited capacity that must be procured to satisfy the RR.

3.4.3.2. 1-day-in-10 Loss of Load Events Reliability Standard

The 1-day-in-10 reliability standard is a central assumption and input to the LOLP Model and directly influences how much capacity PJM procures and the price at which reliability is valued. This is based on the assumption that customers are accustomed to the 1-day-in-10 standard, that is, approximately one firm load shed event every 10 years, and has been described as the "lynchpin of power system planning for decades."[87] The direct origin of

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[83] Id.

[84] Id. at 30.

[85] PJM Interconnection, L.L.C. Resource Adequacy Planning, 2025 PJM Effective Load Carrying Capability and Reserve Requirement Study (ELCC/RRS) 37-40 (2025) ("PJM 2025 ELCC/RRS Study"), https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2025-pjm-elcc-rrs.pdf.

[86] PJM Interconnection, L.L.C. Resource Adequacy Planning, PJM Manual 21B: PJM Rules and Procedures for Determination of Generating Capability 8 (2026) ("PJM Manual 21B"), https://www.pjm.com/-/media/DotCom/documents/manuals/m21b.pdf.

[87] Energy Systems Integration Group, New Resource Adequacy Criteria for the Energy Transition: Modernizing Reliability Requirements viii (2024), https://www.esig.energy/wp-content/uploads/2024/03/ESIG-New-Criteria-Resource-Adequacy-report-2024a.pdf.

this reliability metric is somewhat vague, rooted in papers from the 1940s, and many question whether this longstanding criterion is appropriate for our system today.[88]

One of the central criticisms of the 1-day-in-10 metric is that it solely measures the *frequency* of loss-of-load events and, therefore, should not be used in a silo to evaluate resource adequacy. That is, without an evaluation of the size, duration, or timing of shortfalls, the LOLE only captures a single dimension of risk for the system to plan for. The Energy Systems Integration Group has recommended that grids move beyond expected values and consider tail events, and characterize the size, frequency, duration, and timing of shortfall events.[89] While the RPM is deeply tied to this standard, PJM has started to report Expected Unserved Energy ("EUE") alongside LOLE, a more granular metric of reliability.

Another pertinent discussion surrounding resource adequacy metrics in PJM is its longstanding practice of procuring the same level of reliability for all customers and zones. In its Powering Reliability Through Market Design Workshop and Critical Issue Fast Path ("CIFP") Reliability Backstop Procurement ("RBP")/Connect and Manage ("C&M") workstreams, PJM and stakeholders are discussing the very premise of what it means to value resource adequacy and how this valuation may change in an era of scarcity. Because PJM targets a reliability standard of 1-day-in-10 and aims to procure this standard for all customers, PJM has stated that "[it] effectively introduces a demand-side proxy for the willingness to pay for reliability that society would purchase at if it could coordinate toward an efficient outcome in the absence of the demand-side flaws."[90] However, because PJM has to act as this proxy, the 1-day-in-10 metric may provide more reliability than customers are willing to pay for it.[91] As the costs associated with maintaining the 1-day-in-10 reliability standard continue to increase and the RPM has proven unable to procure sufficient accredited capacity to satisfy that standard, attention has increasingly shifted toward the appropriate trade-offs between reliability and affordability. PJM and stakeholders are contemplating a future in which certain customers can opt for less reliable service, which is discussed in greater detail later in this report.

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[88] Kevin Carden, Nick Wintermantel & Johannes Pfeifenberger, The Economics of Resource Adequacy Planning: Why Reserve Margins Are Not Just About Keeping the Lights On 2 (2011) ("Reserve Margins in Resource Adequacy Planning"), https://pubs.naruc.org/pub/FA865D94-FA0B-F4BA-67B3-436C4216F135.

[89] Ryan Deyoe, Resource Adequacy Metrics: Historical, New Metrics, and Changing Requirements 9 (2026), https://wpui.wisc.edu/wp-content/uploads/sites/746/2026/04/RTO-2026-Deyoe.pdf.

[90] PJM's Market Report at 14.

[91] Reserve Margins in Resource Adequacy Planning at 12.

3.4.3.3. Installed Reserve Margin

As noted above, PJM uses the LOLP Model to determine the IRM, or the installed capacity the system needs above peak load so that expected loss of load equals 0.1 days/year. If installed capacity were perfectly reliable and forecasted load were perfectly certain, little or no reserve margin would be needed to meet this metric. However, the IRM exists because system resources often do not perform perfectly during periods of system stress and because both load and resource availability are inherently uncertain. While a later section discusses how individual resource classes are assigned accreditation values based on their contribution to resource adequacy, this section focuses on the IRM.

PJM's LOLP Model is initialized with DY-specific inputs. In total, the model evaluates 40,300 simulated years to assess system reliability across a wide range of load, weather, and resource performance conditions.[92] Notably, the model uses 31 years of historical weather data to generate hourly load scenarios that capture a broad range of system conditions and performance.[93] These load scenarios are evaluated against a modeled generation fleet that incorporates resource availability, forced outages, demand response assumptions, and transmission limitations.[94] For each simulated hour, the model applies probabilistic resource performance assumptions and chronologically dispatches available resources to meet modeled load.[95] If available supply is insufficient to meet modeled load after dispatch in any given hour, the hour registers as a modeled loss-of-load event.[96] The model aggregates these reliability outcomes across all simulated scenarios to estimate the probability and frequency of loss-of-load events and determine whether the modeled system has sufficient reserves above forecasted load.[97] The model then evaluates reliability outcomes under varying reserve levels until the reserve level associated with the 1-day-in-10 criterion is identified. [98]

Because these inputs and assumptions used in the resource adequacy model directly influence the IRM and ultimately the amount procured in the BRA, the inputs and the methods of the model have been closely scrutinized. In 2025, PJM retained a consulting

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[92] PJM 2025 ELCC/RRS Study at 16, 35.

[93] Id. at 17.

[94] Id. at 16, 22-28.

[95] Id. at 15, 30.

[96] Id. at 30.

[97] Id. at 15, 16, 28.

[98] Id. at 15.

company to evaluate its model. In its report, Energy and Environment Economics, Inc. ("E3") identified several limitations, tradeoffs, and areas for refinement by comparing PJM's LOLP Model to other resource adequacy models and general best practices.[99] One area of active debate concerns how the model should treat historical observations from extreme weather events when operational practices and resource performance have changed over time. For example, during the 2014 Polar Vortex and the 2022 Winter Storm Elliott, natural gas-fired generating resources underperformed and PJM faced extremely tight system conditions. After the 2014 Polar Vortex, PJM implemented the Capacity Performance construct to strengthen resource performance obligations during emergency conditions, increase incentives for firm fuel arrangements, improve winterization and performance during scarcity events, and generally mitigate risks associated with extreme weather underperformance.[100] During Winter Storm Elliott in 2022, PJM and other grid operators experienced unprecedented levels of unplanned generation outages, fuel supply constraints, and extremely tight operating conditions.[101] The event reinforced concerns raised during the 2014 Polar Vortex regarding the performance of thermal resources during extreme winter weather events and prompted a series of operational and market reforms aimed at improving winter preparedness, generator performance, and gas-electric coordination.[102] Following these reforms, some stakeholders, including the IMM, have argued that historical outage observations from events such as the Polar Vortex and Winter Storm Elliott may no longer be representative of expected future performance because PJM has fundamentally changed its operational approach through conservative operations and earlier unit commitments.[103] Conversely, PJM has argued that there is insufficient evidence that large-scale correlated outages have been fully mitigated and that removing these

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[99] Zach Ming et al., PJM ELCC / RRS Model Evaluation 2-5 (2025) ("E3 2025 ELCC/RRS Study"), https://www.pjm.com/-/media/DotCom/committees-groups/task-forces/elccstf/2025/20251209/20251209-item-02---pjm-elcc-rrs-model-evaluation---e3-report.pdf.

[100] PJM Interconnection, L.L.C., 151 FERC ¶ 61,208 at P 91 (2015).

[101] Federal Energy Regulatory Commission Staff et al., Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott 7 (2023), https://www.ferc.gov/sites/default/files/2024-02/24_Winter-Storm_Elliot_0207_UPDATE.pdf.

[102] Id.; PJM Interconnection, L.L.C., Winter Storm Elliott: Event Analysis and Recommendation Report 3 (2023), https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.pdf.

[103] Memorandum from Monitoring Analytics, L.L.C. to PJM Interconnection, L.L.C. (July 24, 2025) (https://www.monitoringanalytics.com/reports/presentations/2025/IMM_ELCCSTF_IMM_Response_20250725.pdf).

observations could understate winter reliability risks and bias resource adequacy assessments.[104]

While there are additional concerns beyond those discussed here, these debates illustrate that the determination of the IRM depends upon assumptions and modeling inputs that remain actively contested. As a result, stakeholders continue to debate not only whether the model appropriately measures reliability risk, but also whether reliability is being achieved and whether it is doing so at an appropriate cost. Resource adequacy is more complicated than it may seem at first glance.

3.4.4. VRR Curve

Demand, using the IRM as an input, is represented in the RPM using an administratively determined demand curve called the VRR Curve. The VRR Curve is intended to help PJM meet its resource adequacy targets by "attract[ing] new entry of capacity resources, … provid[ing] stable and predictable pricing outcomes, and recogniz[ing] the incremental benefits of procuring additional capacity."[105]

The VRR Curve is administratively developed because demand is generally inelastic in electricity markets: the majority of end-use customers typically have no financial incentive to reduce electricity consumption during times of grid shortage because they receive service under retail tariffs or contracts that insulate them from real-time wholesale scarcity prices.[106] The VRR Curve acts as a proxy for the willingness to pay for a level of reliability that satisfies the 1-day-in-10 metric previously mentioned.

Negative Slope

The VRR Curve is comprised of three points that form a negative slope with a convex shape. The CCM that preceded the RPM used a vertical demand curve that required procurement of 115% of the peak load.[107] In 2006, FERC accepted the RPM's downward-sloping demand curve partly because the expected lower price volatility was expected to encourage greater

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[104] Memorandum from PJM Interconnection, L.L.C. (July 11, 2025) https://www.pjm.com/-/media/DotCom/committees-groups/task-forces/elccstf/2025/20250711/20250711-pjm-memo---concerns-regarding-the-removal-of-winter-storm-elliott-and-polar-vortex-1-performance-observations---informational-only.pdf.

[105] Skylar Marzewski, Affidavit of Skyler Marzewski on Behalf of PJM Interconnection, L.L.C., 7-8, Docket No. ER26-455, Nov. 7, 2025 ("Marzewski Affidavit").

[106] PJM's Market Report at 12.

[107] PJM Interconnection, L.L.C., 115 FERC ¶ 61,079 at P 105 (2006) ("April 20, 2006 Order").

investment at lower financing costs.[108] FERC also agreed that the curve's downward slope would provide additional reliability benefits by allowing for the procurement of capacity resources above the IRM, as well as lessen the incentive for resources to withhold capacity.[109] To support their determination, FERC cites a study that analyzed reliability, capacity prices, and EAS revenue outcomes of various VRR Curves.[110] The study persuaded FERC that the downward-sloping VRR Curve would result in overall lower capacity prices than the incumbent vertical CCM demand curve, despite allowing for more capacity procurement, because the VRR Curve would lower price volatility and, in turn, financing costs.[111] FERC was also persuaded that the more favorable terms of supply construction offered by the VRR Curve would result in the construction of more generation, which would lower energy market prices.[112] In its 2025 Quadrennial Review,[113] PJM maintained that a VRR Curve with a downward-slope should continue to be employed because it reduces price volatility and provides stable pricing outcomes.[114]

Price Cap

The first point on the VRR Curve ("Point 1" or "Point A") sets a maximum price ("price cap"). The current price cap is determined using a formula that considers the CONE of a reference resource and its estimated EAS revenues. A resource's CONE is "the levelized net revenues a resource owner would require to be willing to enter the market" and takes as input a plant's "installed costs, fixed Operations and Maintenance costs, the shape and timeframe of its projected future net revenue trajectory, and the risk-appropriate cost of

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[108] Id. at P 104.

[109] PJM Interconnection, L.L.C., 117 FERC ¶ 61,331 at P 75-76 (2006) ("December 22, 2006 Order").

[110] Id. at P 81.

[111] Id. at P 78.

[112] Id.

[113] Pursuant Attachment DD of PJM's OATT, PJM's Office of the Interconnection is required to produce a review of the VRR Curve shape that is "based on simulation of market conditions to quantify the ability of the market to invest in new Capacity Resources and to meet the applicable reliability requirements on a probabilistic basis." PJM, Intra-PJM Tariffs, OATT, Attach. DD, § 5.10 (Auction Clearing Requirements), https://agreements.pjm.com/oatt/5151. PJM is to then recommend either the retention or modification of the existing VRR Curve shape. PJM is required to undertake this review no later than every fourth Delivery Year after the 2018/2019 Delivery Year. *See id.* To date, the results of these Quadrennial Reviews have been published in 2008, 2011, 2014, 2018, 2022, and 2025. PJM has commissioned Brattle to review the VRR Curve and its parameters for each Quadrennial Review.

[114] Marzewski Affidavit at P 33.

capital."[115] Net CONE is determined by subtracting first-year forward EAS revenues from CONE.[116] PJM also establishes and evaluates potential reference resources using five criteria: whether the resource has a significantly higher Net CONE than other resources, whether its facilities can be built at scale by the DY, whether it can comply with all relevant regulations and operate as planned, whether its Net CONE can be accurately assessed, and whether it can make stable reliability contributions for four DYs.[117] In its 2025 Quadrennial Review, PJM selected the CT as the reference resource.[118]

The Brattle Group ("Brattle"), PJM's consultant hired to consider the shape of the VRR Curve, has stated that while lower price caps "mitigate customers' exposure to price spikes and exercise of market power," higher price caps allow for more certainty that supply will join the market when reliability needs are acute.[119] Specifically, higher price caps allow clearing prices to reflect annual variations in supply-and-demand conditions, which in turn allow the entry and exit of higher-cost resources such as demand response ("DR") and net imports when needed.[120] Central to PJM's price cap design is the principle that the market must be permitted to clear above Net CONE during periods of scarcity so that average clearing prices over time are consistent with Net CONE.[121]

Brattle has also stated that stakeholders must consider the cause of high prices. A high price due to market fundamentals should be distinguished from one that is an "artifact of market inefficiencies."[122] High CONE values "due to the underlying economic forces of supply costs and rapid demand growth" are reasons to allow an increase in the price cap.[123] Conversely, high CONE values that are "the product of barriers to entry relative to need," "transitional outcomes associated with rule changes that have not yet been accounted for

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[115] Samuel A. Newell et al., Brattle 2025 CONE Report for PJM 24 (2025) ("Brattle 2025 CONE Report"), https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2025/20250411-special/item-1-02-revised-cone-report-final.pdf.

[116] Id. at 6.

[117] Id. at 20.

[118] Marzewski Affidavit at 2.

[119] Kathleen Spees et al., Sixth Review of PJM's Variable Resource Requirement Curve 61 (2025) ("Brattle 2025 VRR Curve Report"), https://www.brattle.com/wp-content/uploads/2025/04/Sixth-Review-of-PJMs-Variable-Resource-Requirement-Curve.pdf.

[120] Id.

[121] Id. at 64.

[122] Id. at 63.

[123] Id.

in suppliers' development plans," or due to "transient shocks to the market" are not legitimate reasons to allow an increase in the price cap.[124]

3.4.5. Supply

Supply resources submit offers into the BRA representing the price at which they are willing to accept a capacity obligation for the applicable DY. Resources eligible to participate in PJM's capacity market include existing and planned generation capacity resources, bilateral contracts for unit-specific capacity resources, existing and planned demand resources, energy efficiency resources, distributed energy and capacity aggregation resources, and qualifying transmission upgrades.[125] Participation requirements vary by resource type; however, nearly all existing and planned resources are subject to RPM must-offer requirements. These resources include those that already provide capacity, those that bilaterally contract within the PJM footprint, and, beginning with 2025/2026 DY, planned generation capacity resources that submit a notice of intent to offer.[126] Notably, DR resources do not have a must-offer requirement in PJM.[127]

3.4.5.1. Resource Accreditation

To measure the marginal contribution of a resource class to system reliability, PJM uses the ELCC methodology. An ELCC class is a defined group of resources that share a "common set of operational characteristics,"[128] and these resources are accredited based on their availability during critical hours, that is, the hours where additional energy reduces EUE. ELCC ratings are expressed as the fraction of a capacity addition that could be replaced by "perfect capacity" while holding the level of reliability constant. For example, after the system is calibrated to meet PJM's LOLE reliability criterion, if adding a marginal 100 MW of 8-hour battery storage reduces EUE by the same amount as 70 MW of perfect capacity, the storage resource would receive a 70% ELCC rating.[129] It should be noted that "perfect

[124] Id.

[125] PJM Manual 18 at 13.

[126] Id.

[127] Id. at 14.

[128] RAA, Article 1 (defining "ELCC Class").

[129] For the 2027/2028 Delivery Year, 8-hr storage has an ELCC rating of 70%, though for the 2026/2027 Delivery Year, it had an ELCC of 62%. PJM Interconnection, L.L.C., ELCC Class Ratings for the 2027/2028 Base Residual Auction, (available at https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2027-28-bra-elcc-class-ratings.pdf); PJM Interconnection, L.L.C., ELCC Class Ratings for the 2026/2027 Base Residual Auction, (available at https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2026-27-bra-elcc-class-ratings.pdf).

capacity" represents a theoretical ideal and is not synonymous with "dispatchable" or "baseload" capacity. All resource types fall short of the theoretical ideal of "perfect capacity," and thus all resource types have ELCC ratings that are less than 100%.

Resource accreditation is an important component of system reliability, as resources often cannot contribute their full installed nameplate capacity during periods of system stress due to forced outages, duration limits, fuel constraints, weather conditions, and correlated performance risks. Because accreditation values directly affect the quantity that capacity resources can offer into the market, accreditation methodologies materially influence market revenues, investment incentives, and the relative competitiveness of different resources.

PJM has relied on some form of its current ELCC methodology since 2021; however, it has undergone significant changes since then. In early October 2023, following Winter Storm Elliott, PJM made a Section 205 filing to FERC reforming its resource accreditation methodology. Though this was partially to account for observed performance failures at natural gas-fired plants,[130] PJM's filing recognized the growing importance of a resource accreditation methodology that better accounts for renewable or hybrid resources and correlated outages.[131] The filing recognized the value of an enhanced model that uses a "temporally granular, hourly framework for assessing risk drivers and probabilities of resource and energy inadequacy throughout the year rather than only during periods associated with peak loads."[132]

Despite the drastic reforms that PJM has made to its resource accreditation methodology in recent years, there have been disagreements about whether all of these changes have in fact been improvements. For example, the IMM has criticized PJM's ELCC Model for lacking transparency and improperly incentivizing resource-specific reliability contributions due to class-based accreditation.[133] Meanwhile, in a March 2025 letter to PJM, Board President Guhl-Sadovy questioned whether the risk assessment for gas resource in the winter was

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[130] PJM Interconnection, L.L.C., Capacity Market Reforms to Accommodate the Energy Transition While Maintaining Resource Adequacy, 13, Docket No. ER24-99, Oct. 13, 2023.

[131] Id. at 9-10.

[132] Id. at 16.

[133] Monitoring Analytics, L.L.C., Protest of the Independent Market Monitor for PJM, Docket No. ER24-99, Nov. 9, 2023; Monitoring Analytics, L.L.C., Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER24-99.

still appropriate given PJM's increased use of conservative operations.[134] On the other hand, while the consulting company E3 – which was retained by PJM to provide an independent assessment of the ELCC Model – identified several areas for PJM to consider for improvements, it stated that the ELCC Model is generally reasonable and "fit-for-purpose."[135]

In discussions pertaining to PJM's October 2023 Section 205 filing, stakeholders raised concerns regarding the rushed process by which these reforms were considered and developed. Ultimately, FERC approved these changes, although Commissioner Christie's concurrence noted the lack of clarity in the accreditation methodology.[136] Other stakeholders have echoed this frustration by described the methodology as a "black box."[137] PJM has recently acknowledged that risk modeling and ELCC accreditation reforms warrant further consideration as part of its broader capacity market reform efforts, suggesting that these issues will be discussed as a standalone initiative or as part of its broader reforms pursued through the Powering Reliability Through Market Design Workshops.

The increased emphasis on some of these issues, like weather risk and differing seasonal availability of resources, has driven various stakeholders to advocate for a seasonal capacity market construct. PJM hired Analysis Group to evaluate this construct,[138] and PJM noted it as a potential pathway forward in its "Powering Reliability Through Market Design" paper. If implemented, a seasonal capacity market construct would substantially reform how resources are accredited in PJM's RPM.

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[134] Letter from Christine Guhl-Sadvoy, President, New Jersey Board of Public Utilities, to the PJM Board of Managers (Mar. 26, 2025), https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/2025/20250326-njbpu-president-guhl-sadovy-letter-re-capacity-market-adjustments.pdf.

[135] E3 2025 ELCC/RRS Study at 64.

[136] PJM Interconnection, L.L.C., 186 FERC ¶ 61,080 (2024) (Christie, Comm'r, concurring at P 5-7) (available at https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-pjms-capacity-market-reform-filing-docket-no).

[137] PJM Interconnection, L.L.C., 186 FERC ¶ 61,080 at P 47 (2024) ("AMP describes the proposed ELCC accreditation methodology as a "black box," arguing that implementation of the proposed ELCC accreditation methodology would be extremely complex, opaque, and highly dependent on assumptions about future system conditions.").

[138] Analysis Group formally recommended that PJM transition to a seasonal capacity market design. Todd Schatzki et al., Sub-Annual Capacity Market Construct for PJM 58 (2026) ("Analysis Group 2026 SACM Report"), https://www.analysisgroup.com/globalassets/insights/publishing/2026_sub_annual_capacity_market_for_pjm.pdf. PJM has not opened an issue charge to begin this process.

3.4.5.2. Avoidable Costs

As discussed previously, one of the primary purposes of the capacity market is to provide generators with a revenue stream that supports their continued operation. Existing generation resources rely on revenues from the energy, ancillary services, and capacity markets to recover their avoidable costs. Avoidable costs are the annual costs that a generating unit could avoid by retiring and thus must recover in PJM's markets to financially justify continued operation.[139] These costs play a central role in determining the minimum revenue a resource requires to remain in service and to continue offering into the RPM.

The IMM has provided evidence that the 2025/2026 BRA clearing price was sufficient to cover the avoidable costs for most existing units. According to the IMM's estimation of avoidable costs for existing generation units, combined cycle ("CC"), CT, diesel, solar, and wind resources could cover their 2025 avoidable costs using the 2025/2026 BRA resource clearing price ("RCP").[140] The 2025/2026 BRA clearing price likely provides sufficiently high revenue for existing generation to continue operation. Indeed, the IMM states that in 2025, "capacity revenues were sufficient to cover the shortfall between energy revenues and avoidable costs for most CC, DS, hydro, solar, and wind units in PJM."[141] However, using the 2024/2025 BRA clearing price, which was much lower, CC, CT, diesel, solar, and wind resources could not cover their 2025 avoidable costs.[142]

3.4.5.3. Single Clearing Price

Supply resources submit offers into the RPM representing the price at which they are willing to accept a capacity obligation. The RPM clears each marginal resource in order of least-cost until it intersects with the VRR Curve, and all MWs that clear receive the same clearing price. The idea of a "uniform" or "single clearing price" has long been debated, and while some argue that this practice is consistent with auction design standards aimed at achieving least-cost, others argue that a structure in which suppliers receive the amount they bid in and not more, such as pay-as-bid, is better suited for a capacity market.

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[139] Monitoring Analytics, L.L.C., 2025 State of the Market Report for PJM 442 (2026) ("IMM 2025 PJM Market Report"), https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2025.shtml.

[140] The 2025/2026 resource clearing price for the RTO and all LDAs was $269.92/MW-day. The 2025 avoidable costs for CC, CT, diesel, solar, and wind resources were $149.32/MW-day, $129.65/MW-day, $124.43/MW-day, $78.62/MW-day, and $144.88/MW-day respectively. Id.

[141] Id. at 444.

[142] The 2024/2025 DY RTO resource clearing price was $28.92/MW-day; the LDAs with the highest resource clearing prices were in EMAAC and PS, where the resource clearing price was $53.60/MW-day. Id. at 442.

Advocates for a uniform clearing price argue that under this structure, resources in an effectively competitive market have every reason to bid in at prices equivalent to their marginal cost of producing an additional MW of energy,[143] knowing that, if the price clears below their offer, it is not economically viable for them to produce energy at that price. Alternatively, if it clears above, these resources receive the difference between their avoidable costs and the clearing price which can contribute towards their fixed cost recovery and profits.[144] Advocates for a uniform clearing price predict that, over time, supply resources will seek to minimize their costs to maximize the profits they can earn, thereby maximizing system efficiency.

Meanwhile, advocates for a pay-as-bid structure have voiced concerns that under a uniform clearing price, the market cannot drive new investment in supply resources without substantial retail cost increases to ratepayers. Opponents of a uniform clearing price argue that price increases that are meant to attract new resources also increase revenues for all incumbent generators even if they do not require such high prices to continue operation. This results in substantial increases in ratepayer prices throughout a region, particularly under the conditions observed in PJM today where, due to supply chain constraints, the current cost of building the reference resource is several times higher than it was in the past.[145]

However, there are also distinct concerns with the pay-as-bid model, particularly that suppliers would have little incentive to bid at their marginal costs. Instead, suppliers would likely bid strategically by submitting offers near an estimated market-clearing price rather than at their marginal costs. Another concern is that larger market participants may have greater resources and analytical capabilities to forecast the clearing price, potentially giving them an advantage over smaller suppliers.[146] Notably, PJM's RBP, discussed in a later

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[143] Alfred E. Kahn et al., Uniform Pricing or Pay-as-Bid Pricing: A Dilemma for California and Beyond, 14 The Electricity Journal 70, 72 (2001) ("Uniform or Pay-as-Bid Pricing").

[144] Id. at 72.

[145] Specifically, current estimates of the capital cost of building a new natural gas plant are as high as $3,000 per kW due to supply chain constraints. See Bobby Noble, 5-year Waits and Rising Costs: How Demand Is Redefining the Gas Turbine Market, Util. Dive (Mar. 23, 2026), https://www.utilitydive.com/news/5-year-waits-and-rising-costs-how-demand-is-redefining-the-gas-turbine-mar/813385/. Yet the capital cost of a natural gas plant in PJM was estimated to be $1,100 per kW as recently as 2022. Samuel A. Newell, et al., Brattle Grp., PJM CONE 2026/2027 Report 27 tbl.6 (Apr. 21, 2022), https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2022/20220422-brattle-final-cone-report.pdf.

[146] Uniform or Pay-as-Bid Pricing at 75.

section, has been proposed as a pay-as-bid construct, signaling that PJM may be open to the different bid structure.

As discussed later, the uniform clearing price is intended to provide an investment signal that attracts new supply resources. However, price signals alone cannot ensure that an appropriate mix of resources is developed or that resulting rates remain just and reasonable. The effectiveness of these signals depends on both developers' ability to respond to them and confidence that elevated prices will persist long enough to support investment. For example, stakeholders have observed that volatile capacity prices may discourage investments requiring long-term revenue certainty, while barriers to entry, such as permitting constraints, may prevent new resources from responding to market signals in a timely manner.

3.4.5.4. Market Power

Electricity markets are distinct from other markets in their susceptibility to the exercise of market power. In a 2004 paper, Stanford economist Frank Wolak described the characteristics that make wholesale electricity markets particularly vulnerable:

> *It is difficult to conceive of an industry more susceptible to the exercise of unilateral market power than electricity. It possesses virtually all of the product characteristics that enhance the ability of suppliers to exercise unilateral market power. Supply must equal demand at every instant in time and each location of the network. It is very costly to store and production is subject to extreme capacity constraints in the sense that it is impossible to get more than a pre-specified amount of energy from a given generation unit in an hour. Delivery of the product consumed must take place through a potentially congested transmission network. Historically, how it has been priced to final consumers makes the wholesale demand extremely inelastic, if not perfectly inelastic, with respect to the wholesale price. The technology of electricity production historically favored large generation facilities, and in most wholesale markets the vast majority of these facilities are owned by a relatively small number of firms. Finally, generation capacity ownership also tends to be concentrated in small geographic areas within these regional wholesale markets.*[147]

PJM's markets are overseen by PJM's IMM, Monitoring Analytics, LLC, to monitor whether resources are abusing their market power to inflate prices, thereby raising revenues for all other resources and significantly raising prices for customers. The IMM is responsible for

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[147] Frank A. Wolak, Managing Unilateral Market Power in Electricity 3 (2004), https://fawolak.org/pdf/Managing%20Unilateral%20Market%20Power%20in%20Electricity_Wolak.pdf.

promoting a robust, competitive, and nondiscriminatory electric power market. Specifically, it monitors the "potential of market participants to exercise undue market power, the behavior of market participants that is consistent with attempts to exercise market power and the market performance that results from the interaction of market structure with participant behavior."[148] Using historical data and various tests, the IMM evaluates market power in PJM, determines the extent to which it affects market outcomes, and recommends reforms to market rules if necessary.

Despite the unique susceptibility of electricity markets to market power, the IMM states that competitive outcomes can be achieved so long as appropriate market power mitigation rules are in place within an effective market design.[149] The IMM explains that "in a market with endemic structural market power like the PJM Capacity Market, effective market power mitigation rules are required in order to constrain market participants to behave competitively."[150] For this reason, PJM has implemented detailed market power mitigation rules, which are found in its Tariff. These include the Minimum Offer Price Rule ("MOPR"), the Market Seller Offer Cap ("MSOC"), and the Must-Offer Requirement. In each RPM auction, the IMM evaluates whether market power was effectively mitigated and whether it produced competitive outcomes under PJM's market power mitigation framework.

Market Power Tests

The IMM relies on two key tests to assess market power: the Three Pivotal Supplier ("TPS") test and the Herfindal-Hirschman Index ("HHI"). The TPS test measures whether PJM could satisfy demand in a Locational Deliverability Area ("LDA") if the supplier being evaluated and the two largest remaining suppliers are removed from the market. If not, that supplier is deemed "pivotal" and is subject to market power mitigation. The TPS is a structural market power screen rather than a conduct test, as it does not actually measure whether a supplier has exercised market power. The IMM refers to the TPS as "the most relevant measure of market structure" because it directly incorporates ownership, supply, and demand conditions to determine whether the market can satisfy its RR without a given

[148] Monitoring Analytics, L.L.C., Our Role as PJM Market Monitor, Monitoring Analytics, https://www.monitoringanalytics.com/company/role.shtml.

[149] IMM 2025 PJM Market Report at 314.

[150] Id. at 313.

supplier.[151] In contrast, the HHI solely measures market concentration by summing the squared market shares of all market participants. Thus, while the TPS test evaluates whether the market's ability to meet demand depends on a supplier, the HHI evaluates how concentrated ownership is among market participants.

The IMM found that the market has failed the TPS test in both the RTO and applicable LDA markets,[152] however, this is not a unique finding because the PJM capacity market has failed the TPS test in nearly every auction from 2007 to the present.[153] This is largely because the RPM is designed to procure approximately the amount of capacity needed to satisfy PJM's reliability criterion, meaning there is rarely sufficient surplus capacity for the system to lose its largest suppliers and maintain reliability. In constrained LDAs, local suppliers may also be pivotal due to transmission constraints, making TPS failures even more likely. Importantly, however, failing the TPS test does not by itself indicate that market power has been exercised. Rather, the TPS test is a structural screen used to identify suppliers that may possess market power. For sellers that fail the TPS test, the IMM evaluates whether their offers exceed the applicable offer cap and whether mitigation is warranted – sellers whose offers exceed the permitted level may be subject to an MSOC, which is further discussed below.[154]

Minimum Offer Price Rule (MOPR)

The MOPR is a market power mitigation rule that was first introduced in the 2000s. Its central purpose is to protect the market from the exercise of buyer-side market power, which can occur when a net buyer of capacity offers some amount of uneconomic supply into the market well below its costs with the aim of artificially suppressing the market-clearing price. By doing so, the net buyer benefits from purchasing capacity at a lower price. The MOPR was designed with the intent of preventing a net buyer from depressing the capacity price below the competitive level by setting a minimum offer level for a net buyer.[155]

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[151] Monitoring Analytics, L.L.C., 2026 State of the Market Report for PJM: Q1 9 (2026) ("IMM 2026 Q1 PJM Market Report"), https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2026/2026q1-som-pjm.pdf.

[152] IMM 2025 PJM Market Report at 1.

[153] Id. at 306.

[154] Id. at 39.

[155] See PJM Interconnection, L.L.C., Summary of the Updated PJM MOPR Proposal 1 (2021), https://www.pjm.com/-/media/DotCom/committees-groups/cifp-mopr/2021/20210630/20210630-cifp-mopr-pjm-proposal.ashx.

However, in 2019, FERC required PJM to expand the application of MOPR to new or existing resources that received state subsidies, such as Renewable Energy Credits or Zero Emission Credits.[156] The ostensible rationale was that the requirement protected prices in the competitive market from being suppressed by state-sponsored resource planning decisions, as state policy often attracts incremental clean energy resources and displaces fossil generation, which in turn reduces capacity market prices. Indeed, in its Order, FERC ruled that the unrestricted entry of state-sponsored resources artificially suppressed market prices, and that the expanded MOPR was necessary to mitigate those price-suppressive effects.[157]

This ruling would force clean energy resources to bid in at high, uncompetitive prices, even though it was economically viable for them to bid in at much lower prices. Although these supply resources were well positioned to be price takers and submit bids near $0/MW-day, thereby providing valuable capacity to the grid at a low price to consumers, as a result of this order, these resources would be forced to submit bids that were so high that they could not clear the capacity market at all. Therefore, the implications of the MOPR expansion were sweeping: it would limit the ability for clean energy resources to generate revenues, interfere with state clean energy mandates, result in the retention of unnecessarily high volumes of uneconomic supply, and prompt higher market clearing prices.[158] As market clearing prices would exceed the level appropriate for actual supply conditions, they would result in a large wealth transfer from customers to incumbent suppliers.[159]

The MOPR expansion thus raised real concerns for states seeking to meet their policy and business objectives while remaining in the capacity market. Dominion Energy acted on its concerns by exiting the capacity market and electing the FRR Alternative for the 2022/2023 DY BRA .[160] New Jersey, Illinois, and Maryland all also considered exiting the capacity

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[156] Calpine Corporation et al. v. PJM Interconnection, L.L.C, 169 FERC ¶ 61,239 (December 19, 2019).

[157] Id.

[158] Abraham Silverman et al., Alternative Resource Adequacy Structures for New Jersey: Staff Report on the Investigation of Resource Adequacy Alternatives, Docket #EO20030203 18 (2021) ("BPU Staff Report on Alternative Resource Adequacy Structures"), https://www.nj.gov/bpu/pdf/reports/NJ%20BPU%20RA%20Investigation%20(Final).pdf.

[159] Id.

[160] Rich Heidorn Jr., Dominion Opts out of PJM Capacity Auction, RTO Insider (May 6, 2021), https://www.rtoinsider.com/articles/20192-dominion-opts-out-of-pjm-capacity-auction; see also Sarah Vogelsong, Dominion's exit from regional capacity market raises some eyebrows – and questions, Virginia Mercury (May 25, 2021), https://www.virginiamercury.com/2021/05/25/dominions-exit-from-regional-capacity-market-raises-someeyebrows-and-questions/.

market, either through administrative proceedings or legislative initiatives,[161] although doing so would require at least partially rolling back their retail choice policies.[162] The expanded MOPR essentially told restructured states that they must choose between pursuing their preferred generation mix or maintaining a retail market structure.

In July 2023, PJM made a Section 205 filing to largely revert the expanded MOPR to its original purpose of prohibiting and mitigating the exercise of buyer-side market power. Although the expanded MOPR was ultimately narrowed, it remains an important example of how PJM and stakeholders can make politically driven interventions in PJM that are substantially misaligned with New Jersey state policy goals and consumer interests. Furthermore, since the legal issues surrounding the expanded MOPR were never resolved, a future FERC could seek to reimplement it. The MOPR proceedings also delayed many capacity market auctions, temporarily shifting the system away from its three-year-forward design. The market is only expected to return to its normal cadence with the 2030/2031 DY auction scheduled for May 2027.

Market Seller Offer Cap (MSOC)

The MSOC is a market power mitigation tool used to limit market power on the supply side. It applies to resources that are determined by the IMM to possess market power, and it is designed to limit the price at which those resources may offer into the RPM. The MSOC generally reflects a resource's avoidable costs less expected EAS revenues, plus demonstrable costs associated with maintaining a capacity obligation.[163]

Must Offer Requirement

The must offer requirement generally requires existing capacity resources located within PJM to offer their available capacity into RPM auctions. The purpose of this requirement is

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[161] See State of New Jersey Board of Public Utilities Order Initiating Proceeding, Docket No. EO20030203, March 27, 2020, https://www.nj.gov/bpu/bpu/pdf/boardorders/2020/20200325/3-27-20-2H.pdf (the New Jersey Board of Public Utilities is staying its proceeding precisely because it anticipated this filing to replace the Expanded MOPR); Clean Energy Jobs Act, Ill. SB2248, 102nd Gen. Assembly, State of Ill. (Feb. 26, 2021) (introduced by Sen. Collins); Kathleen Spees, et al., Alternative Resource Adequacy Structures for Maryland, Maryland Energy Administration (March 2021), https://energy.maryland.gov/Reports/Alternative%20Resource%20Adequacy%20Structures%20for%20Maryland% 20Final%20Brattle%20Study%20March%202021.pdf.

[162] See supra § 3.2 (explaining that the only way to procure capacity outside the RPM in PJM is to elect the FRR Alternative, which requires each service territory using the FRR Alternative to be served by a single entity that has a monopoly on the supply of capacity at retail).

[163] Letter from Monitoring Analytics, L.L.C., to the RASTF/CIFP/PJM Board of Managers, (August 16, 2023) ("IMM 2023 SCM Letter"), https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_RASTF-CIFP_SCM_Executive_Summary_20230816.pdf.

to prevent physical withholding, whereby sellers withhold supply in attempt to create artificial scarcity and increase market prices. Together with the MSOC, the must offer requirement is one of the RPM's primary protections against the exercise of supply-side market power. Certain resources are exempt from this requirement, including demand resources and generation resources that are seeking retirement. Notably, PJM historically exempted intermittent resources, capacity storage resources and hybrid resources from the must offer requirement. In 2025, however, PJM adopted reforms removing this exemption and requiring these resources to participate in capacity auctions.

Some stakeholders have concerns about exempting demand resources from the must offer requirement. In particular, the IMM has argued that this asymmetry can lead to uncompetitive outcomes by allowing some resources greater discretion over whether and when to participate in the capacity market.

3.4.5.5. PAI Penalties

Although the capacity market is meant to compensate capacity resources for being available at any time during the DY, resources only incur nonperformance charges during defined emergency scarcity conditions called Performance Assessment Intervals ("PAI"). To determine the rate that these resources are penalized for nonperformance, PJM uses a formula derived from Net CONE. In May 2023, PJM filed revisions with FERC to refine the definition of an "Emergency Action," which is used to determine if an event counts as a PAI. The revisions narrowed the definition by removing pre-emergency load management reductions, emergency load management reductions, and certain alerts and warnings as automatic PAI triggers.[164] As a result, PAIs are now more closely tied to conditions that reflect actual capacity shortages, including primary reserve shortages coupled with specified emergency actions.[165]

The IMM has long criticized the PAI penalty mechanism, arguing that the Net CONE-based penalty structure creates artificial risks for supply resources and adds unnecessary complexity to the Capacity Performance Quantifiable Risk ("CPQR") calculation.[166] CPQR represents the risk premium associated with a resource's potential non-performance,[167]

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[164] PJM Interconnection, L.L.C., Transmittal Letter Re: Proposed Revisions to Prospectively Refine the Definition of Emergency Action, Request for Shortened Comment Period and Expedited Commission Action, 7-13, Docket No. ER23-1996, May 30, 2023.

[165] PJM Interconnection, L.L.C., 184 FERC ¶ 61,058 at P 34.

[166] IMM 2025 PJM Market Report at 316.

[167] PJM, Intra-PJM Tariffs, OATT, Attach. DD, § 6.8 (Avoidable Cost Definition), https://agreements.pjm.com/oatt/37226.

and is incorporated into the MSOC.[168] According to the IMM, the Net CONE-based penalty structure artificially increases CPQR, permitting higher supply offers and ultimately raising capacity prices above competitive levels.[169] More fundamentally, the IMM has questioned whether PAI-based penalties are an effective mechanism for incentivizing resource performance.[170] Following PJM's revisions to the Capacity Performance framework, the IMM argued that PJM's increasingly reliance on conservative operations that reduce the likelihood of PAIs, together with the narrowing of the PAI definition and the adoption of an annual penalty cap equal to 1.5 times a resource's BRA clearing price, have significantly weakened the remaining performance incentives.[171] As a result, the IMM concluded that "there is no effective performance incentive remaining in the capacity market."[172]

Importantly, there were also concerns regarding the PAI definition's exclusion of load management resources, such as DR and Price Responsive Demand ("PRD"): this exclusion meant that these resources did not face non-performance penalties when called upon during pre-emergency events so long as a PAI had not been declared. This meant that these resources could earn capacity market revenue for being "available" without facing any consequences for nonperformance. However, in April 2026, PJM filed revisions to its Tariff at FERC proposing that DR and PRD resources that fail to respond during Non-PAI Events would be subject to a penalty equal to 50% of the PAI penalty.[173] In June 2026, FERC approved these Tariff revisions.[174]

Despite the recent Tariff changes, disagreement over PJM's use of its Capacity Performance framework persists. The IMM argues that capacity compensation should be tied to a resource's actual availability on an ongoing basis, rather than relying on large nonperformance penalties during infrequent PAI events.[175] By contrast, supporters of PJM's Capacity Performance framework maintain that reliability is most valuable during emergency conditions and that concentrated performance incentives are necessary to

[168] PJM, Intra-PJM Tariffs, OATT, Attach. DD, § 6.4 (Market Seller Offer Caps), https://agreements.pjm.com/oatt/37221.

[169] IMM 2025 PJM Market Report at 316.

[170] Id.

[171] Id.

[172] Id.

[173] PJM Interconnection, L.L.C., Transmittal Letter Re: Proposal to Enhance Performance of Load Management Resources and Price Responsive Demand Providers During Non-Performance Assessment Interval Events, 11, Docket No. ER26-2319, April 27, 2026.

[174] PJM Interconnection, L.L.C., 195 FERC ¶ 61,253 at P 13.

[175] IMM 2023 SCM Letter.

ensure resources perform when the system is under the greatest stress. Because the Capacity Performance framework directly influences the prices at which supply resources offer into the capacity market, its design has important implications for both resource adequacy and ratepayer affordability.

4. Quantitative Historic Evolution of RPM

The following section describes the RPM's historical performance and the impact that large load participation in recent auctions has had on BRA clearing capacity quantities and prices.

PJM is currently operating in a new environment of projected energy scarcity. The largest driver of this scarcity is the projected load growth from data centers. The changing system conditions have exposed limitations in the current capacity market design that were less apparent under slower load growth and more favorable supply conditions. The remainder of this report begins by recounting the historical performance of the BRA and evaluating the market design challenges that have emerged in recent years. It then considers conceptual market reforms aimed at improving reliability while protecting consumers, including those identified by PJM in its recent market design report.

As illustrated in Figure 2, the RPM has historically procured sufficient capacity to meet resource adequacy goals: the 2027/2028 DY was the first year in which the BRA cleared more than one percentage point below the target reserve margin, as this auction and the subsequent BRA for the 2028/2029 DY both cleared 5.6 percentage points below the 20% target IRM.[176] As further discussed in a later section, the shortfall in these most recent auctions is largely attributable to data center load growth.

[176] PJM 2027/2028 BRA Report and PJM 2028/2029 BRA Report.

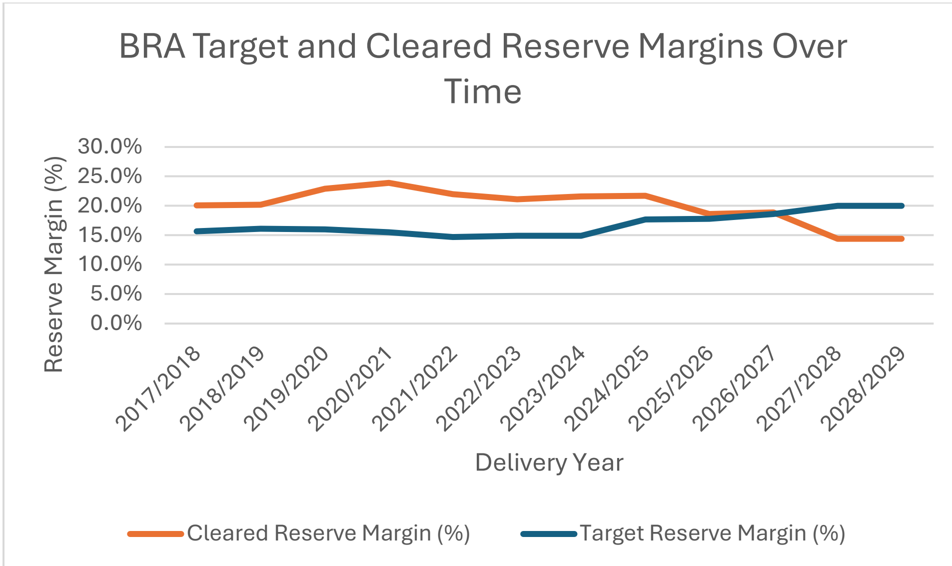

Figure 2: BRA Target and Cleared Reserve Margins for 2017/2018-2028/2029 Delivery Years.[177]

The RCP is the price received by a Capacity Resource that offered into and cleared a BRA or IA.[178] The RCP within an LDA is equal to the sum of the 1) marginal value of system capacity ("System Marginal Price") and 2) Locational Price Adder.[179] The RCP is relevant to both supply resources and consumers, since it determines the capacity payments that supply resources receive and informs the Locational Reliability Charges that LSEs are obligated to pay.

Figure 3 illustrates that BRA RCPs have been significantly higher in the 2025/2026 to 2027/2028 DYs compared to historic prices. It also demonstrates that capacity prices have historically been volatile, especially in the supply-constrained zones that include New Jersey. Historically, the PS ("Public Service") and PS-North zones, as well as the larger Eastern Mid-Atlantic Area Council ("EMAAC") and Mid-Atlantic Area Council ("MAAC")

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[177] The "Cleared Reserve Margin" corresponds to PJM's "RPM Reserve Margin" metric while the "Target Reserve Margin" corresponds to PJM's "Installed Reserve Margin" metric. PJM Interconnection, L.L.C., 2028/2029 Base Residual Auction Report 5 (2026) ("PJM 2028/2029 BRA Report"); PJM Interconnection, L.L.C., Planning Parameters for Base Residual Auction, https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2017-2018-planning-period-parameters.XLS ("Target Reserve Margin" data for the 2017/2018 BRA).

[178] PJM, Intra-PJM Tariffs, OATT, Attach. DD, § 5.14 (Clearing Prices and Charges), https://agreements.pjm.com/oatt/5156.

[179] PJM Manual 18 at 255.

zones[180] of which they are a part, have generally experienced higher RCPs than the rest of the RTO due to the application of Locational Price Adders. This is because PJM applies a Locational Price Adder to constrained areas where transmission limitations reduce the amount of electricity that can be imported during peak load conditions to maintain reliability.[181] A lack of local generation relative to load gives rise to such transmission limitations.

The amount of capacity cleared in the 2022/2023 BRA declined because a 1.6% reduction in forecast peak load, a lower IRM, and a lower Equivalent Demand Forced Outage Rate reduced the RR for this DY.[182] The amount of unforced capacity that cleared also declined in the 2025/2026 BRA due to changes in PJM's resource accreditation methodology.[183] This does not necessarily mean that higher RCPs failed to incent new supply investment in the New Jersey zones. Rather, it indicates that the price signal alone was insufficient to attract enough new capacity to eliminate the transmission constraints during the 2017/2018 through 2027/2028 DYs.

Between the 2025/26 and 2027/2028 DYs, the RCPs for the RTO, MAAC, EMAAC, and the PS as well as PS-North zones converged because capacity shortages became RTO-wide rather than being limited to individual LDAs. As a result, scarcity was reflected in the RTO-wide clearing price instead of through separate Locational Price Adders.[184] Although New Jersey's constrained zones have historically experienced higher capacity prices than the RTO due to transmission constraints, recent system-wide shortages have significantly increased capacity price obligations across the State. For example, the Zonal Capacity Price for the New Jersey zones increased from $53.31/MW-day in the 2024/2025 BRA to $333.69/MW-day in the 2027/2028 BRA.[185]

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[180] Figure A-1.

[181] PJM Manual 18 at 155.

[182] PJM Interconnection, L.L.C., 2022/2023 RPM Base Residual Auction Results 26 (2021), https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2022-2023/2022-2023-base-residual-auction-report.ashx.

[183] PJM 2025/2026 BRA Report at 3.

[184] PJM Interconnection, L.L.C., 2026/2027 Base Residual Auction Report 3 (2025), https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2026-2027/2026-2027-bra-report.pdf; PJM 2027/2028 BRA Report at 3.

[185] The Zonal Capacity Price is used to calculate the charge that each LSE that serves a zone owes for participating in the RPM. PJM Interconnection, L.L.C., Capacity Market (RPM), https://www.pjm.com/markets-and-operations/rpm ("Base Residual Auction Results" Excel sheets for the 2024/2025 and 2027/2028 BRAs).

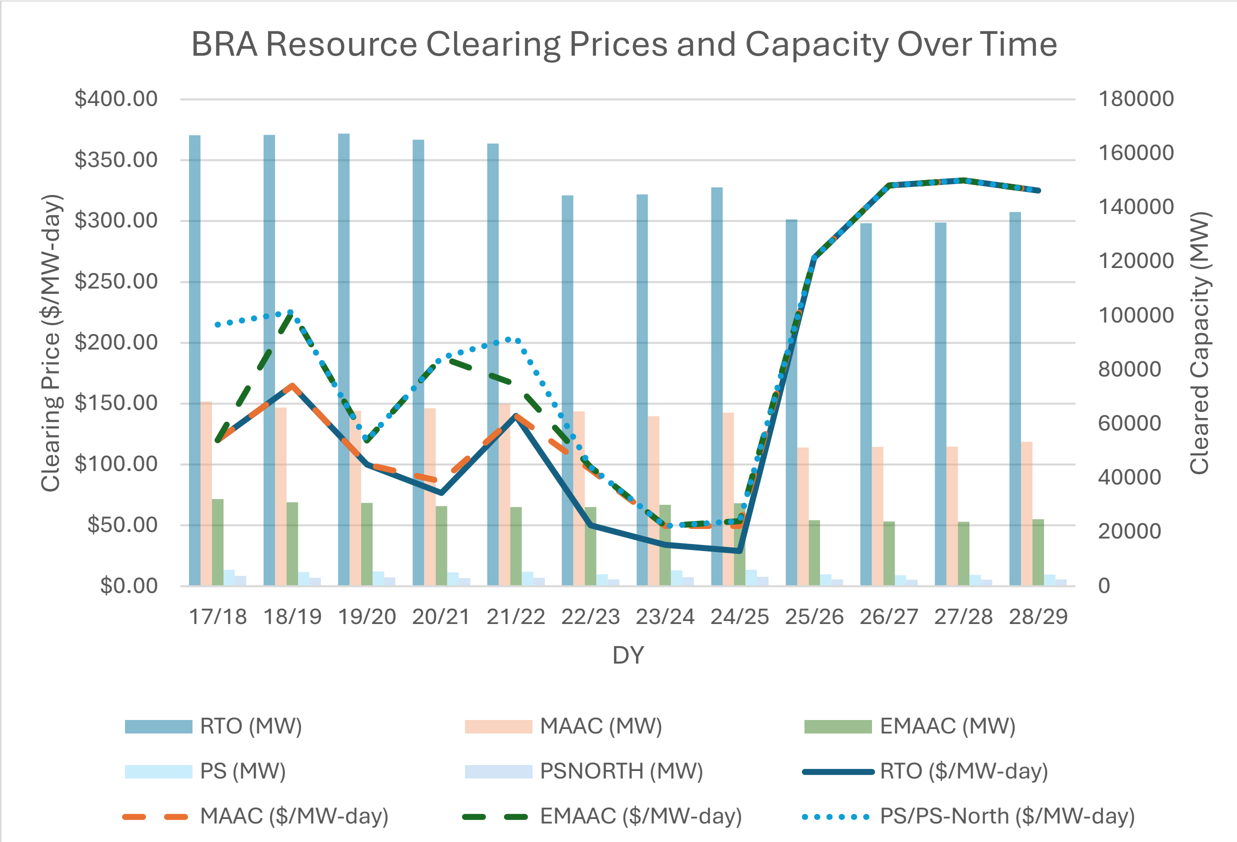

Figure 3: BRA Resource Clearing Prices ($/MW-day) and Cleared Capacity (MW) for the 2017/2018-2028/2029 Delivery Years.[186]

In its reports on the RPM for the 2025/2026 DY and beyond, the IMM has evaluated the impact of LLAs on the BRA by comparing the auction results with and without these projected load additions. Figure 4 summarizes the IMM's estimates of BRA revenue and cleared UCAP under each scenario. Across each DY, the inclusion of LLAs increased both BRA revenues and the amount of cleared capacity. However, the increase in BRA revenues substantially exceeded the increase in cleared capacity. For example, in the 2026/2027 BRA, including LLAs increased BRA revenues by 82.1% while increasing cleared capacity by only 0.7%.[187] This shows that the additional demand from LLAs had a much larger effect on capacity prices than on the quantity of capacity procured.

[186] The bars show the cleared capacity and the lines show the clearing price. Id. ("Base Residual Auction Results" Excel sheets for the 2017/2018, 2018/2019, 2019/2020, 2020/2021, 2021/2022, 2022/2023, 2023/2024, 2024/2025, 2025/2026, 2026/2027, 2027/2028, 2028/2029 BRAs).

[187] This mismatch in BRA revenue and cleared capacity percent changes due to LLAs is observed in the 2025/2026 DY and 2027/2028 DY BRAs as well. The 2025/2026 DY BRA had a revenue percent change of 174.3% and a cleared capacity percent change of 1.7%. The 2027/2028 DY BRA had a revenue percent

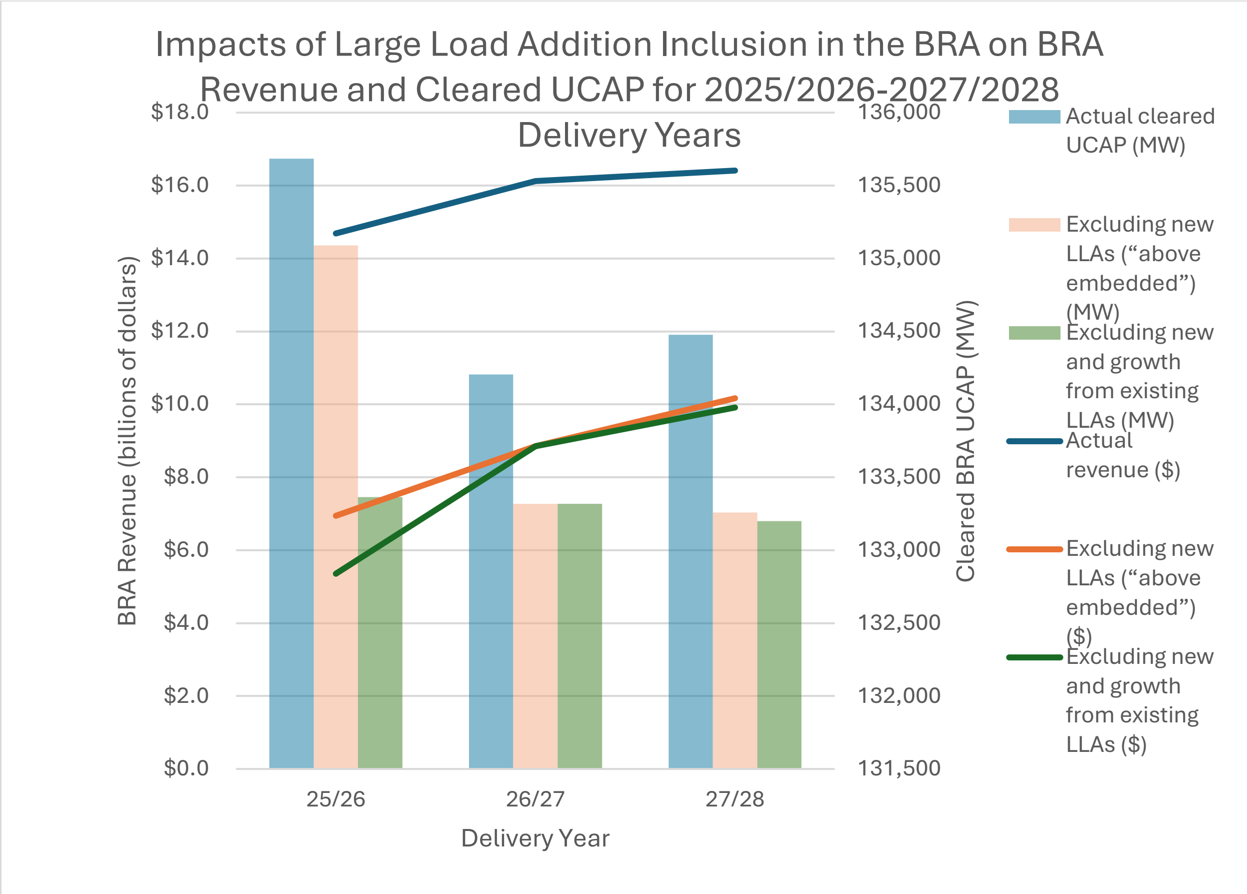

Figure 4: Impacts of Large Load Addition Inclusion in the BRA on the BRA Revenue and Cleared BRA UCAP in MW for the 2025/2026-2027/2028 Delivery Years.[188]

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change of 65.5% and a cleared capacity percent change of 1.0%. The mismatch would be even more pronounced in the 2026/2027 DY and 2027/2028 DY BRAs if the $325/MW-day price cap was not in effect. The 2026/2027 DY BRA would have had a revenue percent change of 278.0% and a cleared capacity percent change of 5.1%. The 2027/2028 DY BRA would have had a revenue percent change of 283.0% and a cleared capacity percent change of 4.9%. Monitoring Analytics, L.L.C., Analysis of the 2025/2026 RPM Base Residual Auction Part G 13, 19 (2025) ("IMM 2025/2026 BRA Analysis Part G"), https://www.monitoringanalytics.com/reports/reports/2025/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_G_20250603_Revised.pdf; Monitoring Analytics, L.L.C., Analysis of the 2027/2028 RPM Base Residual Auction Part A 23, 25 (2026) ("IMM 2027/2028 BRA Analysis Part A"), https://www.monitoringanalytics.com/reports/Reports/2026/IMM_Analysis_of_the_20272028_RPM_Base_Residual_Auction_Part_A_20260105.pdf.

[188] IMM 2025/2026 BRA Analysis Part G at 13, 19; Monitoring Analytics, L.L.C., Analysis of the 2026/2027 RPM Base Residual Auction Part A 18, 20 (2025), https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20262027_RPM_Base_Residual_Auction_Part_A_20251001.pdf; IMM 2027/2028 BRA Analysis Part A at 23, 25.

5. Recent Pressures on the RPM Due to Large Load Additions

In its May 6 report, PJM presents the recent pressures on the RPM as resulting from a mismatch between the conditions for which the RPM was designed and current system conditions.[189] PJM writes that "even if all regulatory and market processes had operated flawlessly, the sheer velocity of data center load growth combined with a sluggish supply-side response significantly increased cost . . . [and] guaranteed a severe physical mismatch" between supply and demand.[190]

The following subsections further examine the demand- and supply-side pressures that currently face the RPM, as well as how the current RPM design translates tightening supply and demand conditions into higher VRR Curve prices. While the RPM has historically provided a revenue stream that supported resource adequacy under more stable market conditions, PJM argues that unprecedented load growth, increases in the costs of new generation, supply chain constraints, and uncertainty surrounding future load forecasts have weakened the ability of one-year capacity price signals alone to attract sufficient new investment.[191] As a result, the current RPM design faces increasing challenges in procuring new capacity at the pace required to maintain resource adequacy.

5.1. Demand-Side Pressures

The main source of pressure on the RPM is the unprecedented pace of forecasted load growth. According to PJM's 2026 Load Forecast Report, summer peak demand is projected to increase 26,635 MW from 2026 to 183,008 MW in 2030, then increase to 222,106 MW in 2036 and 253,077 MW in 2046.[192] Because the RPM is a forward-looking market, these load forecasts directly influence the amount of capacity procured in each BRA. Forecasts are also used as inputs into PJM's transmission planning process, which is outside the scope of this report.

Notably, PJM projects that this load growth will not be evenly distributed across zones. Figures 5 and 6 illustrate that the Western zone, which encompasses utilities in Illinois, Ohio, Indiana, and Kentucky, is projected to experience the largest increase in summer peak demand. The Dominion zone is also expected to experience significantly higher load

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[189] "Powering Reliability Through Market Design," PJM, May 6, 2026 at 11. ("[T]he market was designed for specific conditions: slow, predictable load growth; generation buildable in roughly three years; and investors willing to accept annual auction revenues as sufficient return.")

[190] PJM's Market Report at 18.

[191] Id. at 4-5.

[192] PJM 2026 Load Forecast Tables Table B1.

growth than most other PJM zones. A map showing these different zones is included in the appendix.

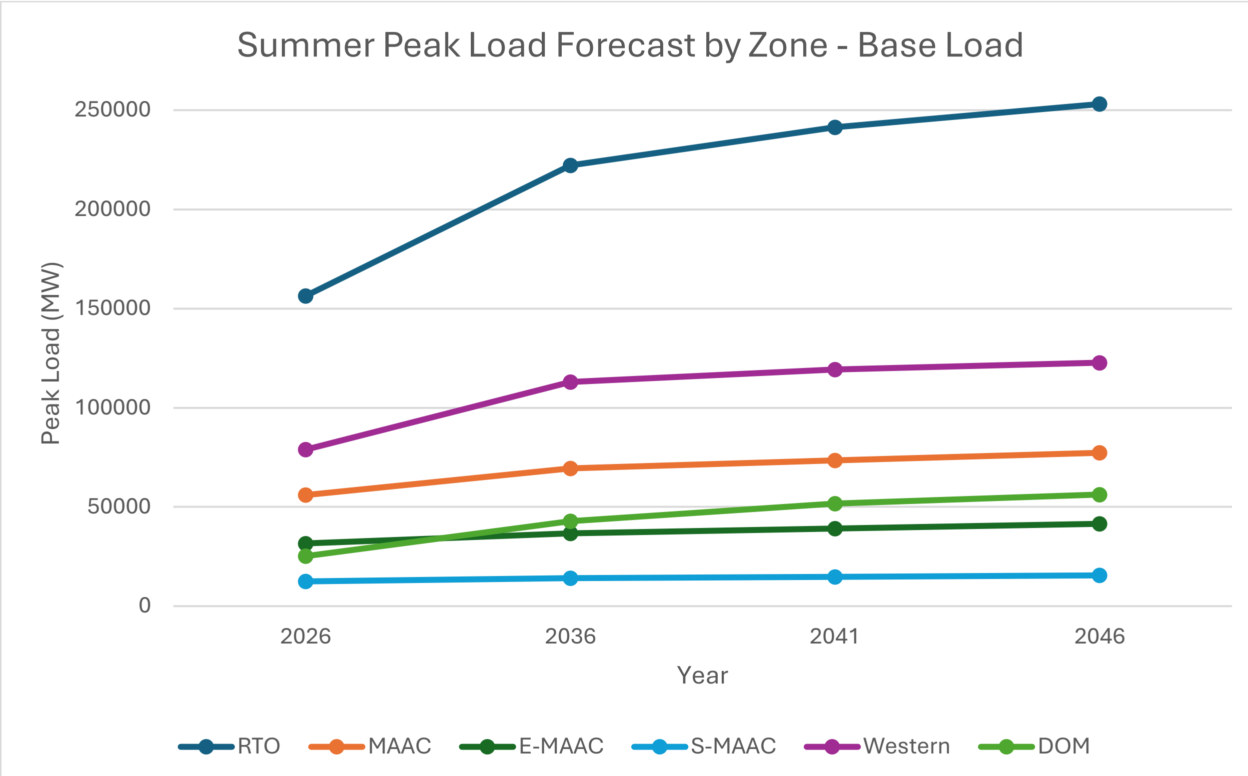

Figure 5: Summer Peak Load Forecast by Zone in Base Load in MW from years 2026 to 2046.[193]

[193] Id. Tables B1 and B2.

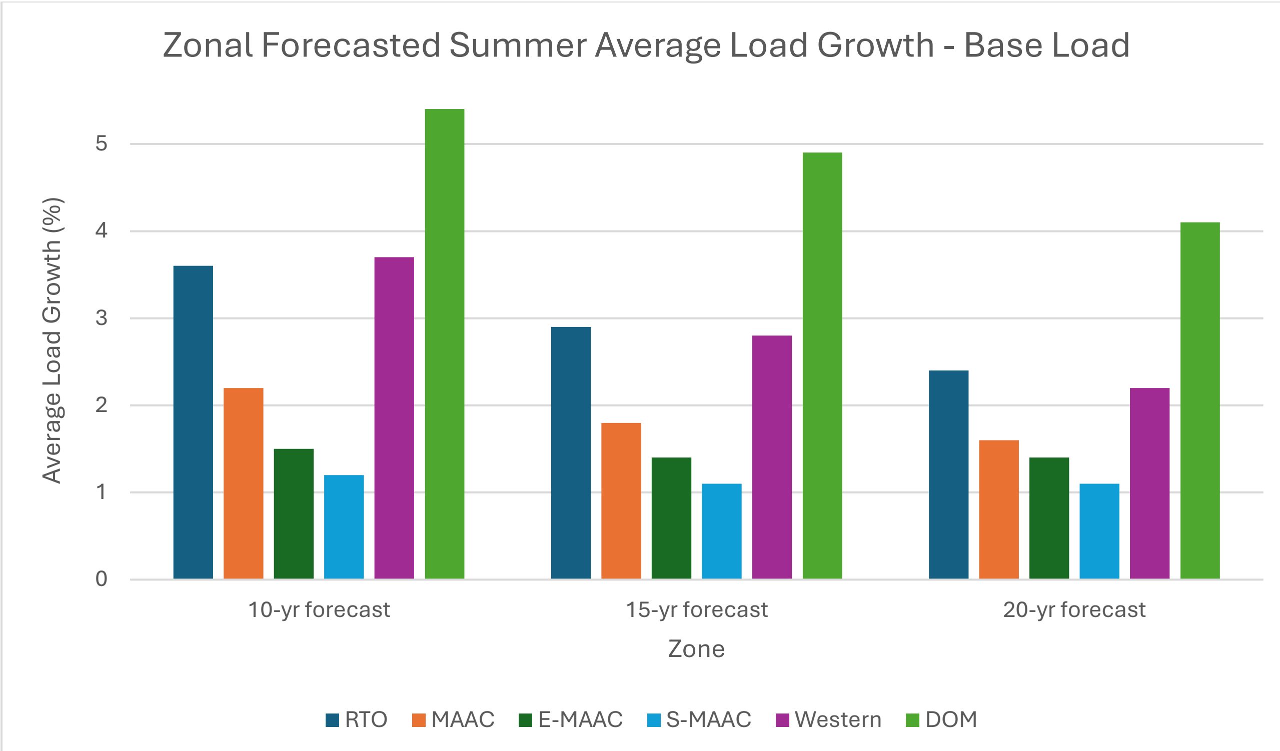

Figure 6: Zonal Forecasted Summer Average Base Load Growth.[194]

Both the IMM and PJM have identified actual and forecasted data center load growth as the primary driver of demand-side pressures on the capacity market. The IMM has stated that "[b]ut for data center growth, both actual and forecast, the PJM Capacity Market would not have seen the same tight supply demand conditions, the same high prices observed in the 2025/2026 BRA and 2026/2027 BRA or the currently expected tight supply conditions and high prices for subsequent capacity auctions."[195] Similarly, PJM has stated that approximately 30 of the 32 GW of projected peak load growth between 2024 and 2030 is attributable to data centers, and that this growth "has created significant upward pricing pressure and has raised future resource adequacy concerns."[196] Figure 7 illustrates that

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[194] PJM Interconnection, L.L.C. Resource Adequacy Planning, 2026 PJM Load Forecast Report 9-13, 34 (2026), https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2026-load-report.pdf.

[195] IMM 2025 PJM Market Report at 314.

[196] Letter from David E. Mills, Chair, PJM Bd. Of Managers, to PJM Stakeholders (Aug. 8, 2025), https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/2025/20250808-pjm-board-letter-re-implementation-of-critical-issue-fast-path-process-for-large-load-additions.pdf.

LLAs account for an increasing share of forecasted load growth across PJM in the next ten years.[197]

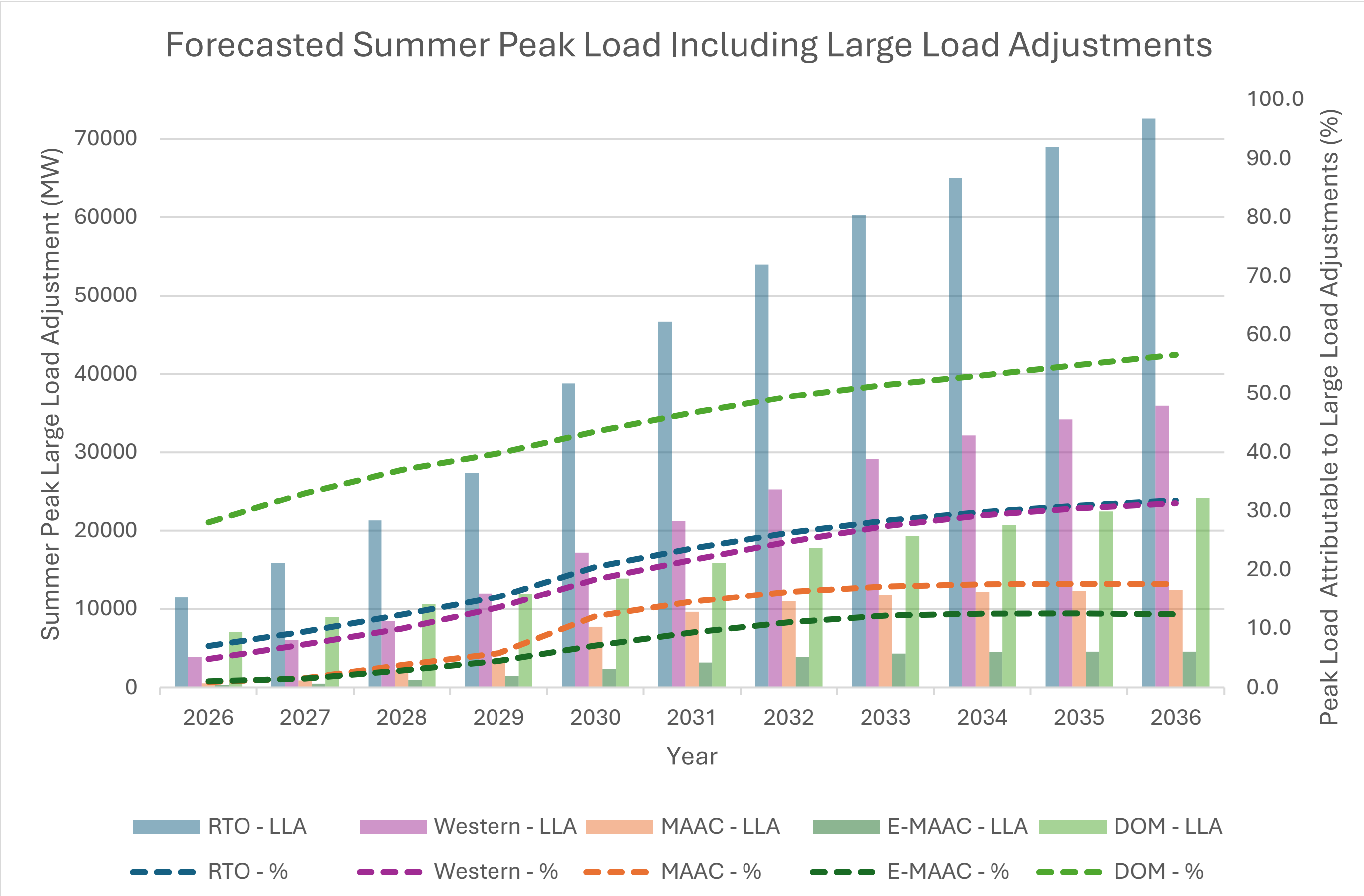

Figure 7. Forecasted Summer Peak Load Including Large Load Adjustments in MW by Zone for 2026- 2036.[198]

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[197] The accuracy of PJM's load forecasts have been a topic of discussion in PJM stakeholder settings. Recent data released by PJM indicates that there is some variation in accuracy of zones' forecasted summer 2025 peak large load adjustments: COMED and DOM's actual loads were 14% and 12% higher than their respective forecasts, PS and AEP's actual loads were 12% and 2% below their respective forecasts, and APS, ATSI, and PL didn't have their forecasted large load adjustments materialize. PJM Interconnection, L.L.C. Resource Adequacy Planning, 2026 PJM Load Forecast Accuracy Report 6 (2026), https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/2026-load-forecast-accuracy-report.pdf.

[198] Values labeled "-LLA" are adjustments to PJM's summer peak load forecasts submitted by EDCs to account for data center load growth that wasn't captured in the original forecasts. Data center load captured in PJM's existing forecast process is included in values labeled "-total". The adjustment in PS's forecast, which is reflected in RTO, MAAC, AND EMAAC values, is due to both data center load growth and port electrification. The adjustment in DOM's forecast is due to voltage optimization and data center load growth. PJM 2026 Load Forecast Tables B1 and B9b.

5.2. Supply-Side Constraints

5.2.1. Interconnection Queue Backlog

To ensure new generation can connect to the grid safely and reliably, PJM has an interconnection process in which proposed generation projects undergo a series of studies and, where necessary, grid upgrades before they are allowed to interconnect to the grid. In recent years, a significant increase in New Service Requests, combined with a time-intensive interconnection process, led to a substantial backlog of generation projects seeking interconnection. Historically, PJM used a serial, first-come, first-served interconnection process that became overwhelmed by the influx of New Service Requests during the latter half of the 2010s, many of which were speculative or otherwise failed to advance.[199] This large volume of requests increased the number of iterative system impact studies required under the serial process, significantly slowing project review timelines.[200] A 2026 study found that the average length of time between new gas project submission and Interconnection Study Agreement effective dates was 7.4 years.[201]

PJM's reformed first-ready, first-served interconnection process is intended to improve study efficiency by evaluating projects in clusters and discouraging speculative projects by requiring developers to satisfy readiness criteria and post progressively larger readiness deposits throughout the study process.[202] The 14 GW of supply projects in Transition Cycle 1 and nearly 30 GW of supply projects in Transition Cycle 2 indicate that PJM has been able to advance a significant volume of projects under the reformed framework.[203] Furthermore, 811 generation projects, representing approximately 220 GW of proposed capacity, applied to the first Cycle of the reformed interconnection process, indicating continued developer interest in pursuing projects through PJM's queue.[204] As PJM's interconnection reforms begin to alleviate one of the central barriers to new resource development, attention

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[199] PJM Interconnection, L.L.C., Tariff Revisions for Interconnection Process Reform, Request for Commission Action by October 3, 2022, and Request for 30-Day Comment Period, 20, Docket No. ER22-2110, June 14, 2022 ("PJM ER22-2110 Filing Letter").

[200] Id.

[201] Gianna Murphy and Abraham Silverman, Natural Gas Generator and Energy Storage Timelines in PJM 2 (2026), https://energyinstitute.jhu.edu/natural-gas-generator-and-energy-storage-timelines-in-pjm/.

[202] PJM ER22-2110 Filing Letter at 8.

[203] PJM's Market Report at 18.

[204] PJM Interconnection, L.L.C., Over 800 New Generation Projects Seek to Connect Under PJM's Reformed Process, PJM Inside Lines, April 29, 2026, https://insidelines.pjm.com/over-800-new-generation-projects-seek-to-connect-under-pjms-reformed-process/.

should also be directed toward the other factors that continue to delay the construction of new generation resources.

5.2.2. Permitting

Planning and permitting timelines for new generation resources are often significantly longer than the time it takes for data centers to interconnect to the grid. While data centers may become operational within two to three years, the planning and permitting phase alone can take at least three and a half years for synchronous generation resources and between two and eight years for inverter-based resources.[205] PJM has also identified permitting as a significant source of project delays, noting that 29% of generation projects that requested milestone extensions between 2023 and 2025 cited local or state permitting issues as the reason.[206]

5.2.3. Supply Chain Constraints

Supply chain issues have also slowed the development of new generation resources. PJM reports that between 2023 and 2025, 23% of projects that requested milestone changes did so because of supply chain delays.[207] Natural gas generation plants are notably facing significant supply chain constraints. Mitsubishi, GE Vernova, and Siemens, the three primary global suppliers of large industrial gas turbines, are experiencing substantial order backlogs, increasing procurement timelines and the cost of constructing new gas-fired generation.[208] A 2023 Sargent & Lundy report indicates that the typical total lead time before commercial operation of CT facilities was 40 months while that of CC facilities was 40-54 months depending on the facility type.[209] However, a 2025 GridLab white paper, based on recent Integrated Resource Plans ("IRP"), found that new CC resources often could not be brought online until at least 2030, suggesting a total lead time of 60 months or

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[205] Kyle Thomas and Julia Matevosyan, Interconnection Processes for Large Loads: Current Practices and Recommendations Figure 2 (2026), https://www.esig.energy/wp-content/uploads/2026/06/ESIG-Large-Loads-Interconnection-Process-report-2026a.pdf.

[206] PJM Interconnection, L.L.C., 2027/2028 Base Residual Auction Reserve Target Shortfall Report 8 (2026), https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2027-2028/2027-2028-bra-reserve-target-shortfall-report.pdf.

[207] Id.

[208] PJM's Market Report at 22.

[209] Sargent & Lundy, Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies 21, 27, 34, 42, 48, (2024), https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf.

longer.[210] Capital costs for new CC and CT resources have also significantly increased. While CC projects slated for completion in 2026 and 2027 were reported to have capital costs between $1,116/kilowatt ("kW") and $1,427/kW, as of 2025, projects slated to come online in later years reported costs of $2,000/kW or more.[211] By early 2026, according to some estimates, projected costs of new CC projects had risen to approximately $3,000/kW.[212]

Globally, gas turbine demand currently outpaces supply[213] because of increased global electricity demand, particularly from the rapid expansion of data centers.[214] In addition to sudden data center demand growth, a transition from oil to gas in the Middle East and coal retirements in the US and Middle East are contributing to increased demand for gas turbines.[215] Meanwhile, materials, components, and labor shortages have put upward pressure on gas turbine construction timelines and costs.[216]

Although the three primary gas turbine manufacturers have announced plans to increase production, they remain cautious about rapidly increasing manufacturing capacity because of uncertainty regarding the durability of current demand and concerns about repeating past cycles of overinvestment.[217] Manufacturers have additionally continued to maintain substantial order backlogs while charging reservation fees and premium prices for earlier delivery slots. Inflation, supply constraints, limited upstream suppliers, and

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[210] GridLab, The New Reality of Power Generation: An Analysis of Increasing Gas Turbine Costs in the U.S. 2 (2025), https://gridlab.org/wp-content/uploads/2025/09/GridLab_Gas-Turbine-Costs-Report-1.pdf.

[211] Id. at 4.

[212] See Bobby Noble, 5-year Waits and Rising Costs: How Demand is Redefining the Gas Turbine Market, Util. Dive (Mar. 23, 2026), https://www.utilitydive.com/news/5-year-waits-and-rising-costs-how-demand-is-redefining-the-gas-turbine-mar/813385/ ("In just the past six months, EPRI research shows average gas turbine prices increased from roughly $2,000/kW to $3,000/kW, a nearly 50% increase.").

[213] A recent Wood Mackenzie report found that the end of 2025 saw 110 GW of gas turbine orders globally, although only 60 GW-70 GW could be manufactured globally. Wood Mackenzie, Gas turbine prices soar 195% as market faces supply-demand crisis, April 1, 2026, https://www.woodmac.com/press-releases/gas-turbine-prices-soar-195-as-market-faces-supply-demand-crisis/.

[214] Id.

[215] International Energy Agency, Electricity 2025: Analysis and forecast to 2027 10 (2025), https://iea.blob.core.windows.net/assets/0f028d5f-26b1-47ca-ad2a-5ca3103d070a/Electricity2025.pdf; Sam Reynolds, Global gas turbine shortages add to LNG challenges in Vietnam and the Philippines 5 (2025) ("IEEFA 2025 LNG Shortages Report"), https://ieefa.org/sites/default/files/2025-10/IEEFA%20Report_Global%20gas%20turbine%20shortages%20add%20to%20LNG%20challenges%20in%20Vietnam%20and%20the%20Philippines_October2025.pdf.

[216] IEEFA 2025 LNG Shortages Report at 5.

[217] Id. at 14-15.

labor are also expected to continue placing upward pressure on manufacturing costs and production timelines.[218] Therefore, elevated gas turbine prices and manufacturing backlogs are expected to persist in the medium term.

5.2.4. Uncertain Long-Term Outlook

Stakeholders have emphasized that developers require reasonably predictable revenue streams to support investment decisions. However, rapid load growth, uncertainty surrounding future market conditions, and long development timelines have created an increasingly uncertain investment environment in which one-year capacity price signals alone may be insufficient to support new resource development.

5.2.4.1. Policy Interventions

PJM's capacity market has recently been subject to a series of market design changes and supplemental procurement proposals, such as the Reliability Resource Initiative and the introduction and extension of a price collar for the 2026/2027 - 2029/2030 BRAs. While these measures were intended to address near-term reliability and affordability concerns, they also contribute to uncertainty regarding the long-term design of PJM's capacity market and the revenues that new resources may ultimately receive. This is particularly important because developers of merchant generation projects rely significantly on capacity market revenues when making investment decisions. In its 2025 Annual State of the Market Report for PJM, the IMM reported that 82.1% of the MWs that cleared in the 2025/2026 through 2027/2028 DY BRAs are market-funded.[219] Among the resources that had not yet entered commercial operation at the time they cleared, 96.3% are market-funded.[220] This indicates that most new resources depend primarily on market revenues over alternative funding sources.

5.2.4.2. Load Forecast Uncertainty

The current market structure and uncertainty surrounding future load forecasts may also impede the development of new supply resources. Because merchant developers rely heavily on future market revenues, they must evaluate whether expected prices will remain sufficiently high over the life of a project to justify investment. Although projected load growth creates opportunities for new entry, it also introduces the risk that actual load growth may fall short of expectations or that competing projects will add sufficient

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[218] Id.

[219] IMM 2025 PJM Market Report at 327.

[220] Id.

capacity to depress future market prices. Although PJM's 2026 Load Forecast largely corroborates its 2025 forecast, long-term load projections remain inherently uncertain, particularly given the pace of technological change, evolving artificial intelligence deployment, and the possibility that data center investment may not materialize as currently projected. While this uncertainty may not materially affect the market's ability to support existing resources, it might reduce developers' willingness to invest in the quantity of new supply needed to maintain resource adequacy at a reasonable cost. PJM's proposed enhancements to its Load Forecast Adjustment process may help reduce this uncertainty, but it cannot eliminate the risk entirely.

5.3. Quantified Potential RPM Impacts of Demand- and Supply-Side Pressures

PJM and Brattle have both attempted to quantify how current demand- and supply-side conditions may affect the CONE, the key input used to establish the maximum price of the VRR Curve. In its "Powering Reliability Through Market Design" paper, PJM distinguishes between Administrative CONE and Empirical CONE. Administrative CONE is based on a "bottom-up estimate of the capital and fixed costs to build a reference technology" and is intended to represent a stable, long-run average cost that is "representative of normalized market conditions rather than today's spot realities, and deliberately smoothed to insulate the demand curve from short-run volatility."[221] By contrast, Empirical CONE estimates the cost of new entry using observed market data, including Certificates of Public Convenience and Necessity, IRPs, project finance disclosures, and original equipment manufacturer pricing. Consequently, Empirical CONE reflects current supply chains, financing markets, and the revenue risk premiums faced by developers.[222]

PJM recognizes that current Empirical CONE values are higher than current Administrative CONE values, largely because the overnight capital cost estimates it used to calculate current Administrative CONE values are outdated. For the 2028/2029 DY BRA, PJM translated overnight capital cost values of $1,361/kW for CTs and $1,419/kW for CC resources[223] into levelized first-year revenue requirements of $663/MW-day and $813/MW-day, respectively.[224] By comparison, recent estimates place the overnight capital costs of new CC projects with 2028 through 2031 Commercial Operation Dates at $2,000/kW or

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[221] PJM's Market Report at 19.

[222] Id.

[223] Id. at 20.

[224] Id.

more.[225] Because Empirical CONE reflects substantially higher capital costs than Administrative CONE, it would correspond to higher first-year revenue requirements than those implied by the Administrative CONE values. These estimated revenue requirements substantially exceed the $325/MW-day price cap that PJM extended for the 2028/2029 and 2029/2030 DYs that is further discussed in Section 6.1.

In its "2025 CONE Report for PJM," Brattle also evaluates how current estimates of new resource construction costs translate into the VRR Curve reference price. Brattle's lower-end Net CONE estimates for CC and CT estimates for the 2028 DY ranged from below $200/MW-day to slightly above $350/MW-day,[226] while its higher-end estimates ranged from nearly $400/MW-day to more than $500/MW-day.[227] Brattle additionally estimated short-term reservation prices that ranged from $633/MW-day to $3,040/MW-day. [228] Both Brattle's higher-end Net CONE estimates and its estimated short-term reservation prices substantially exceed the $325/MW-day price cap.

The analyses presented by PJM and Brattle suggest that higher expected revenues may be necessary to attract investment in new generation under current market conditions. At the same time, the demand- and supply-side constraints discussed above indicate that higher prices alone are unlikely to be sufficient to attract new resource development, particularly within a market that relies primarily on one-year capacity price signals. PJM argues that exposing ratepayers to sustained scarcity pricing invites political intervention, thereby weakening the credibility of future market price signals.[229] However, one may interpret such interventions as reflecting the legitimate concern that the aforementioned non-market barriers prevent new resources from responding to short-term price signals with sufficient speed to maintain resource adequacy.

6. PJM-Led Reforms Underway

The conclusion of PJM's 2025 LLA CIFP initiated several workstreams intended to address the demand- and supply-side pressures discussed in the previous sections. The stakeholder process concluded with the issuance of PJM's Board Decisional Letter. On the

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[225] Id. at 21.

[226] Net CONE values are calculated by netting out expected energy and ancillary services market revenue from the CONE.

[227] Brattle 2025 CONE Report at 13.

[228] The short-term reservation price is the "price at which investors would be willing to enter in the 2028/29 auction, if we assume that they face temporarily high prices due to current high costs to build but they expect lower-cost resources to set market clearing prices over the long term." Id. at 10-11.

[229] PJM's Market Report at 26.

same day, the National Energy Dominance Council ("NEDC") and the 13 Governors within PJM jointly issued a Statement of Principles.[230] Together, these documents outlined complementary approaches for addressing rapid data center-driven load growth, resource adequacy concerns, and rising capacity prices.

The Board Decisional Letter called for new LLAs to either provide new capacity through the Bring Your Own New Capacity ("BYONC") framework or accept less reliable service under the C&M framework. It also directed the immediate initiation of the RBP and a holistic review of PJM's market design to improve investment incentives for new supply resources and sought stakeholder feedback on extending the $325/MW-day price collar through the 2028/2029 and 2029/2030 DYs.

The NEDC and Governors' Statement of Principles similarly emphasized the need to restore effective market signals while protecting consumers from the costs associated with rapid data center-driven load growth. It encouraged PJM to conduct a backstop procurement mechanism that would provide new generation with revenue commitments of up to 15 years and to allocate costs from this procurement to LSEs that serve data centers who have not procured new capacity or agreed to be curtailable. It also committed the states to develop policies that protect residential customers, ensuring that the states' LSEs would allocate these procurement costs to new data center loads.

Underlying PJM's market reform initiatives is the concern that the region is unable to attract new supply at the pace and scale needed to meet forecasted demand growth from new large loads ("NLLs"). In its Section 205 filing to extend the price collar, PJM acknowledged that siting, permitting, interconnection, supply chain constraints, and an uncertain investment environment are key reasons why high BRA clearing prices are not resulting in timely new supply entry.[231] These non-market barriers have weakened the ability of capacity market price signals to induce timely new investment, creating a disconnect between rising capacity prices and improvements in resource adequacy.[232] Similarly, the

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[230] National Energy Dominance Council, Statement of Principles Regarding PJM (Jan. 16, 2026), https://www.energy.gov/documents/statement-principles-regarding-pjm; Letter from David Mills, Interim President & CEO, PJM Bd. Of Managers, to PJM Stakeholders (January 16, 2026) ("PJM Board Decisional Letter on CIFP-LLA"), https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/2026/20260116-pjm-board-letter-re-results-of-the-cifp-process-large-load-additions.pdf.

[231] PJM Interconnection, L.L.C., Transmittal Letter Re: Proposal to Extend The Price Cap and Price Floor for the 2028/2029 and 2029/2030 Delivery Years, And Request for a Waiver of the 60-Days' Notice Requirement to Allow for a March 31, 2026 Effective Date 8, 12, Docket No. ER26-1556, Feb. 27, 2026 ("PJM 2026 Price Collar Extension Transmittal Letter"), https://elibrary.ferc.gov/eLibrary/filedownload?fileid=7D1A2A2E-6F76-CBA8-9DCB-9CA09BA00000.

[232] Id.

single-clearing price structure for the entire market results in most market revenues going toward existing generators instead of the new generators that are desperately needed: In fact, the Natural Resource Defense Council found that only 7% of the projected $163 billion in capacity payments through 2033 would support new supply, with the rest going toward existing generators.[233] Accordingly, PJM characterized the extension of the price collar as only "one component of a larger set of initiatives to address resource adequacy concerns stemming from large loads" and directed staff to undertake a Holistic Review of Investment Incentives in PJM's Markets in 2026.[234]

6.1. Price Collar Extension

Following a Section 206 complaint by Pennsylvania Governor Shapiro alleging that the capacity market was producing unjust and unreasonable rates, FERC accepted a settlement establishing a BRA price cap of approximately $325/MW-day and a price floor of approximately $175/MW-day.[235] In January 2026, the PJM Board requested stakeholder feedback on whether to extend the price collar for two additional DYs. The ensuing stakeholder process generated significant support, as well as opposition to, the proposed extension.[236] Supporters argued that ongoing reforms addressing LLAs, together with the planned implementation of the RBP, created an uncertain investment environment that justified maintaining the existing price collar until those reforms could take effect. Stakeholders who opposed the price cap, however, advocated that because the grid has not been able to attract new supply at the scale and pace needed, prices should be permitted to rise to the scarcity price point of the VRR Curve, Point A, which is intended to signal the need for new capacity during periods of scarcity. Ultimately, PJM submitted a Section 205 filing in February 2026 requesting that the existing price collar be extended

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[233] Tom Rutigliano and Claire Lang-Ree, Large Load CIFP NRDC Solution Components 8 (Oct. 14, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/cifp-lla/2025/20251014/20251014-item-03c---nrdc-proposed-options.pdf.

[234] PJM 2026 Price Collar Extension Transmittal Letter at 1.

[235] PJM Interconnection, L.L.C., 191 FERC ¶ 61,066 (2025) (April 21, 2025 Order); Governor Josh Shapiro and the Commonwealth of Pennsylvania, Complaint of Governor Josh Shapiro and the Commonwealth of Pennsylvania, 39, Docket No. EL25-46, December 30, 2024, https://www.pjm.com/-/media/DotCom/documents/ferc/filings/2024/20241230-el25-46-000.pdf.

[236] PJM Interconnection, L.L.C., Board Questions Regarding Capacity Auction Price Collar - Stakeholder Survey Responses (Feb. 4, 2026), https://www.pjm.com/-/media/DotCom/committees-groups/cifp-lla/postings/20260204-board-questions-re-capacity-auction-price-collar-stakeholder-survey-responses.pdf.

through the 2028/2029 and 2029/2030 DYs.[237] FERC approved the extension in April 2026.[238]

PJM characterizes this dynamic as a "credibility trap," arguing that while scarcity pricing is economically necessary to support investment, the resulting affordability impacts prompt political intervention that weakens future market signals.[239] This dynamic is greatly exacerbated by the capacity market's single-clearing price design that provides all generators the scarcity price only needed by new generation. A lack of bilateral contracting that hedges against capacity market price volatility further compounds the affordability challenges produced by relying on capacity market scarcity pricing to incentivize new entry. At the same time, the non-market constraints discussed in Section 5 suggest that scarcity pricing alone may be insufficient to induce timely new supply entry.

In any event, the 2026/2027 and 2027/2028 DY price collar is estimated to save customers approximately $18 billion, while the extension through the 2028/2029 and 2029/2030 DYs is projected to save customers an additional $27 billion across the PJM region.[240] Because New Jersey accounts for roughly 10-12% of PJM peak load, New Jersey ratepayers are expected to realize roughly $5 billion of these savings. These projected savings illustrate the significant affordability benefits of the price collar during a period in which non-market constraints limit the extent to which higher capacity prices can produce commensurate reliability benefits.

6.2. Reliability Backstop

The PJM Board's January 2026 Decisional Letter directed PJM to expedite[241] an RBP proposal in light of the region's emerging reliability risks.[242] In the 2027/2028 and 2028/2029

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[237] PJM 2026 Price Collar Extension Transmittal Letter.

[238] PJM Interconnection, L.L.C., 195 FERC ¶ 61,076 (2026).

[239] PJM's Market Report 5.

[240] Commonwealth of Pennsylvania, Governor Shapiro Secures Extension of PJM Price Cap, Saving Consumers $27 Billion More — and $45 Billion in Total — on Energy Bills, Commonwealth of Pennsylvania (Feb. 12, 2026), https://www.pa.gov/governor/newsroom/2026-press-releases/gov-shapiro-secures-extension-pjm-price-cap-saving-consumers--45.

[241] PJM's current tariff would only trigger a Reliability Backstop Procurement after three consecutive auctions clear at short of 99% of the reliability requirement. PJM, Intra-PJM Tariffs, OATT, Attach. DD, § 16 (Reliability Backstop), https://agreements.pjm.com/oatt/5170.

[242] PJM Board Decisional Letter on CIFP-LLA.

DY BRAs, PJM procured 6,516.6 MW[243] and 6,831.3 MW of UCAP,[244] respectively, below the RTO RR. PJM projects that the region's capacity shortfall could grow to between 50 and 60 GW over the next decade.[245] Nevertheless, PJM characterized the RBP as a "one-time, transitional procurement of capacity designed to begin to address the unprecedented load growth in the region," rather than a long-term solution to resource adequacy.[246] PJM describes the RBP as a "transitional mechanism to safeguard resource adequacy, support the C&M interim posture, and advance reforms to be discussed in the investment incentive work planned for later this year."[247]

On July 27, 2026, PJM released its Board Decisional Letter with its final proposal on the RBP and C&M, renaming C&M to Interim Resource Adequacy Service ("IRAS").[248] The PJM Board's final RBP proposal was a departure from the joint EDCs-Data Center Coalition proposal, the only proposal to receive the required two-thirds, sector-weighted threshold required to pass the Members Committee, which proposed that the procurement target is set using LSE buy bids on behalf of the NLLs that they will serve.[249]

The PJM Board's RBP proposal largely reflects the PJM Stage 4 proposal and consists of central procurement and facilitated bilateral matchmaking paths.[250] Initial bilateral matches are proposed to be released in August 2026, although the matchmaking may continue for another 6-9 months afterwards. The PJM Board proposes to simultaneously

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243 PJM 2027/2028 BRA Report.

244 PJM 2028/2029 BRA Report.

245 PJM Interconnection, L.L.C., Critical Issue Fast Path – Reliability Backstop Procurement PJM Proposal 1 (April 16, 2026) ("PJM April 16 CIFP-RBP Proposal"), https://www.pjm.com/-/media/DotCom/committees-groups/cifp-rbp/2026/20260416/20260416-item-05---pjm-reliability-backstop-procurement-proposal---paper.pdf.

246 Id.

247 PJM Interconnection, L.L.C., Critical Issue Fast Path – Reliability Backstop Procurement PJM Proposal 1 (May 27, 2026), https://www.pjm.com/-/media/DotCom/committees-groups/cifp-rbp/2026/20260527/20260527-item-05---cifp--reliability-backstop-procurement-pjm-proposal---paper.pdf; PJM April 16 CIFP-RBP Proposal at 1.

248 Letter from Paula Conboy, Chair, PJM Bd. Of Managers, to PJM Stakeholders (July 27, 2026) ("Board Decisional Letter on Critical Issue Fast Path – Reliability Backstop Procurement and Connect and Manage"), https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/2026/20260727-board-decisional-letter-on-cifp-reliability-backstop-procurement-and-connect-and-manage.pdf.

249 PJM Interconnection, L.L.C., CIFP - Reliability Backstop Procurement - Options and Packages Matrix – Updated (June 29, 2026), https://www.pjm.com/-/media/DotCom/committees-groups/cifp-rbp/2026/20260630/20260630-cifp---reliability-backstop-procurement---options-and-packages-matrix---updated.xls.

250 Id.

run a central procurement for the 6.8 GW capacity shortfall from the 2028/2029 BRA; the central procurement is proposed to be conducted between September and October 2026 and have its results released in December 2026. The central procurement is aimed to give new generation resources a fixed price for 15 years.

To avoid procuring double for NLLs that receive supply outside the market, the PJM Board proposes reducing the initial procurement target by 1) load matched with bilateral supply contracts; 2) load with matching approved IRP supply; or 3) load willing to commit to demand-side participation.[251] Additionally, EDCs and zones will be allowed a limited opportunity to opt their load out of the Reliability Backstop under two conditions. The first condition is mainly for EDCs and zones whose rates are not regulated by the state and that demonstrate a documented inability to address cost allocation from the backstop. In the second condition, however, an EDC zone may opt out if it addresses its capacity needs through Peak Shaving Adjustment ("PSA") programs that are codified in state law. New Jersey and its EDCs may be able to benefit from this second condition under P.L.2026, C.32.

The costs of this procurement will be allocated to each zone or area based on its pro rata share of the procurement target MW. This calculation relies on the 2026 Load Forecast and is based on the difference between the forecasted 2028 and 2026 summer peak loads in each zone. The zone or area costs may then be allocated to LSEs based on their Reliability Backstop Obligation ("RBO"). Importantly, states and EDCs must establish a framework for assigning RBOs to NLLs. Otherwise, PJM will apply its default allocation methodology in each zone, which may result in procurement costs being allocated broadly among LSEs based on their shares of zonal peak load.

this cost allocation methodology, New Jersey's share of RBP costs could be significantly lower than its share of traditional RPM costs because the State accounts for a much smaller share of projected PJM NLL growth than of total PJM load. However, the ultimate allocation will depend on the quantity and location of qualifying NLL BYONC and other adjustments reflected in the procurement target.

The bilateral matchmaking path most directly allocates the cost of procuring new supply to NLLs and reduces the risk that costs associated with serving large loads that ultimately do not materialize, or cease operations, are borne by exiting ratepayers. The central procurement, however, presents a greater risk that procurement costs could ultimately be

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[251] Id. at 2.

allocated more broadly among retail customers. Accordingly, the BPU should continue to work with New Jersey EDCs and LSEs to develop cost allocation mechanisms that ensure costs attributable to data center-driven load growth are borne by the responsible customers rather than existing ratepayers.

6.3. Interim Resource Adequacy Service, Formerly Known as Connect and Manage

Concurrently with its Reliability Backstop workstream, PJM has proposed an RTO-wide framework to prioritize the curtailment of NLLs when necessary to maintain system reliability. The proposal is intended to allow NLLs to interconnect before sufficient new capacity is available while maintaining system reliability by requiring those loads to accept priority curtailment until sufficient new capacity enters service. The July 27, 2026, Board Decisional Letter proposes an Interim Resource Adequacy Service ("IRAS") framework under which NLL MW entering service after June 1, 2027, that are not offset through BYONC commitments would be subject to priority curtailment before PJM initiates Pre-Emergency Load Management actions. The proposal would require EDCs and TOs, in coordination with state regulatory bodies, to implement this procedure.

To facilitate the implementation of this procedure, PJM has proposed developing a Large Load Registry in which LSEs will designate the BYONC supply associated with NLLs for the duration required to maintain BYONC status. Beginning with the 2027/2028 DY, PJM would then use the registry to assign IRAS responsibility according to the quantity of NLLs in each zone or area that are not offset by BYONC. An NLL that has procured BYONC for a future DY will remain subject to IRAS until the associated capacity resource enters commercial operation.

Notably, unless and until sufficient new supply resources are offered into an RPM auction to cover NLL demand, the PJM Board proposes to exclude any NLL MW that were not included in the 2028/2029 BRA forecast from RPM demand stacks beginning with the 2029/2030 DY. Although PJM has not yet made a FERC filing – as of July 30 – detailing the technical aspects of this framework, the Board Decisional Letter suggests that PJM intends to exclude these NLL MW from future RPM demand forecasts until sufficient new supply is available to serve that load. This approach would reduce the extent to which these NLLs contribute to future BRA price increases and the resulting capacity costs borne by existing customers. However, the Board Decisional Letter proposes to retain in the RPM demand stack any NLL MW that were designated IRAS but included in the 2028/2029 BRA forecast.

The PJM Board's IRAS proposal is a departure from PJM's Stage 4 C&M proposal, which lacked an RTO-driven curtailment strategy and an incentive structure for individual states to develop and implement curtailment policies The IRAS procedure strengthens the incentive for NLLs to bring new capacity to the grid through bilateral arrangements. By encouraging bilateral contracting between NLLs and new supply resources, IRAS protects against capacity price spikes and mitigates the socialization of wholesale-level cost and reliability risks that are attributable to these customers. This regional standard ensures that region-wide impacts from NLL can be minimized.

6.4. Powering Reliability Through Market Design

PJM's May 6, 2026 "Powering Reliability Through Market Design" paper responds to the directives set forth in both the Statement of Principles and the PJM Board's Decisional Letter. Unlike the reforms discussed in the previous sections, which are intended to address near-term resource adequacy concerns, the pathways outlined in "Powering Reliability Through Market Design" consider more fundamental changes to PJM's capacity market. The paper explains the history and objectives of the RPM, examines how recent changes in electricity demand and supply conditions have altered the environment in which it operates, and argues that the current market design no longer functions as effectively under today's operating conditions as it once did. Rather than recommending a single preferred market design, PJM presents three conceptual pathways that states and stakeholders may consider to "help confront the resource adequacy and investment challenges facing the region today."[252] These pathways include: 1) increasing the use of long-term capacity contracts at either the LSE- or PJM-level to provide more stable investment signals and customer rates; 2) allowing customers to choose different levels of reliability rather than applying the 1-day-in-10-years reliability standard for every customer; and 3) gradually shifting a larger share of generator revenues from the capacity market to the energy and ancillary services markets. Importantly, these reforms require different implementation timelines and are not mutually exclusive. PJM also identifies several complementary reforms, including a sub-annual or seasonal market design, a reevaluation of the auction forward period, and continued enhancements to risk modeling and ELCC accreditation.

6.4.1. Path A: Stabilized Markets and Long-term Contracts

The first pathway that PJM introduced seeks to stabilize customer costs and investment signals by procuring a greater share of capacity through long-term contracts rather than relying primarily on annual capacity auctions. PJM argues that long-term contracting would hedge customers against short-term scarcity pricing and would help avoid the "credibility

[252] PJM's Market Report at 28.

trap" by reducing affordability shocks during scarcity pricing that can prompt political intervention in market outcomes.[253] PJM introduced this pathway because the current capacity market's one-year commitment, procured three years in advance of a DY, may no longer provide sufficient revenue certainty for developers seeking to finance new generation in an environment characterized by extended project timelines and investment uncertainty.[254] PJM suggests that these long-term capacity commitments could be implemented either through bilateral procurements by LSEs or through centralized procurements made on behalf of LSEs.[255]

PJM is already moving toward longer-term commitments by encouraging LLAs to enter into bilateral agreements with new capacity resources and by proposing capacity contracts of up to 15 years through its RBP central procurement.[256] Longer-term contractual commitments, such as power purchase agreements, provide developers with greater revenue certainty during the initial years of a project's operation, thereby reducing financing risk and supporting debt recovery. For states such as New Jersey that have ambitious emissions reductions and clean energy goals, long-term contracting with clean energy resources may encourage additional in-state investment by providing the revenue certainty needed to finance new projects.

However, long-term contracting poses a fundamental question regarding which party should bear investment risks. Under PJM's current market structure, supply resources bear much of this risk while customers benefit from competition in spot capacity markets. However, an increased reliance on long-term commitments shifts a greater share of investment risk to customers. Like with PJM's proposed 15-year term lengths in the RBP, if PJM pursues long-term capacity commitments, states may need to develop cost allocation frameworks that protect existing customers by ensuring the costs and risks of those commitments are allocated to the customers driving the need for new generation, which are primarily data centers.

6.4.2. Path B: Differential Reliability

Although PJM has historically met the 1-day-in-10 years reliability standard for all customers, the growing imbalance between supply and demand, together with rapidly

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[253] Id. at 29.

[254] Id.

[255] Id.

[256] Board Decisional Letter on Critical Issue Fast Path – Reliability Backstop Procurement and Connect and Manage.

increasing capacity prices, has prompted PJM and stakeholders to reconsider whether all customers should continue to receive and pay for the same level of reliability. PJM's second path assumes that "the investment needed to return the PJM system to its desired reliability level" will either require considerable time or may not occur at all.[257] Accordingly, it proposes explicitly providing different customers with different levels of reliability while the system remains capacity constrained.[258] PJM notes that cost causation-based service differentiation already exists at the distribution level through interruptible tariffs, curtailable service contracts, and demand response programs.[259] Extending this concept to the transmission level, however, would be novel because it would apply to a much larger volume of load and require the development of new transmission-level operational curtailment capabilities.[260]

Most wholesale electricity capacity markets, including PJM's RPM, are designed to procure a common reliability standard that applies uniformly across customers and LSEs. PJM describes the RPM being underpinned by a social "shared reliability compact" under which it is "a pooled procurement design . . . by ensuring everyone who benefits also contributes to a common standard."[261] A characteristic of this pooled design is that PJM has historically directed emergency involuntary firm load shed to substations and geographic zones according to the physics and engineering of the system, regardless of the commercial arrangements within these zones or the type of load therein.[262] This approach made sense when it was difficult to distinguish loads and their causative impact on system upgrades.

As previously mentioned, PJM has already begun pursuing a form of differential reliability through its Connect and Manage ("C&M") and IRAS. However, PJM's June 10, 2026 C&M proposal treated differential reliability as a transitional operational tool rather than a fundamental change to the capacity market. Specifically, C&M load remained in the capacity market demand curve, meaning that the BRA would have continued to procure capacity for that load even though it may have ultimately been subject to curtailment under C&M. This inclusion would have put upward pressure on BRA clearing prices for all market participants while reducing the incentive for C&M customers to procure their own capacity. In March 2026, the BPU President expressed concern over this design, noting that including

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[257] PJM's Market Report at 37.

[258] Id.

[259] Id.

[260] Id.

[261] Id. at 15.

[262] Id. at 14.

C&M load in the capacity market demand stack increases costs for all market participants while weakening incentives for NLLs to secure their own supply.[263] I

In its Board Decisional Letter released July 27, 2026, PJM changed course and suggested that its proposal would exclude incremental NLLs with IRAS that were not included in the forecast used for the 2028/2029 BRA from the demand stack.[264] If PJM includes this in their FERC filing and FERC approves this framework, PJM will not continue to procure capacity for this load. Rather, incremental NLLs must BYONC under PJM's qualifications or choose to receive IRAS and be excluded from the RPM demand stack. In other words, differentiated reliability should not be viewed in a vacuum; it can also be used as a tool to segregate the customers that must and are willing to pay their incremental system costs.

The implementation of differential reliability would also require significant coordination between PJM and the states to ensure that transmission-level curtailment obligations are assigned to the intended retail customers. Although an RTO registry to track individual NLLs that procure their own capacity has been proposed in PJM's final IRAS proposal,[265] PJM currently lacks a mechanism to ensure that specific customers receive differentiated curtailment treatment during system emergencies – states must direct the curtailments to specific customers. New Jersey's new law at P.L. 2026, C.32 aims to give state stakeholders the tools to do this.

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[263] PJM responded to the Board's letter arguing that C&M load should remain in the capacity demand stack because removal would allow this load to enjoy largely reliable service without paying for capacity and would mute the price signal for resource entry. PJM also emphasized that it is within the purview of states to allocate capacity costs among customers as they see fit. Letter from Christine Guhl-Sadvoy, President, New Jersey Board of Public Utilities, to the PJM Board of Managers (Mar. 27, 2026), https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/2026/20260401-njbpu-letter-re-connect-and-manage-issue-charge.pdf; David E. Mills, President & CEO, PJM Board of Managers, to Christine Guhl-Sadvoy, President, New Jersey Board of Public Utilities (June 1, 2026), https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/2026/20260602-board-response-to-njpbu-connect-and-manage-scope.pdf.

[264] PJM Interconnection, L.L.C., CIFP Framework for Service During Periods of Insufficient Resource Adequacy – PJM Proposal 5 (July 27, 2026), https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/2026/20260727-cifp-framework-for-service-during-periods-of-insufficient-resource-adequacy-executive-summary.pdf.

[265] Abe Silverman, Katya Evans, and Sue Glatz proposed a mechanism by which new large loads avoid C&M curtailment eligibility through the purchase of credits issued by new capacity suppliers. Abe Silverman, Katya Evans and Sue Glatz, Updated Proposal: A Registry to Track New Load & Supply Commitments 2-7 (June 10-11, 2026), https://www.pjm.com/-/media/DotCom/committees-groups/cifp-rbp/2026/20260611/20260611-item-03c---silverman-glatz-presentation.pdf). The Illinois Office of the Attorney General and the Maryland Office of People's Counsel are supportive of a large load registry. Joint Consumer Advocates, JCA Preferred Approach for Reliability Backstop/Connect & Manage and Modifications to PJM's May 27 Proposal 4 (June 10-11), https://www.pjm.com/-/media/DotCom/committees-groups/cifp-rbp/2026/20260611/20260611-item-03i---joint-consumer-advocates-presentation.pdf.

New Jersey's new law also provides data centers an opportunity to work to offset their load additions by engaging in voluntary demand reduction trade programs. Through these programs, data centers can contract with third parties to reduce load in place of data centers during tight system conditions. Tools in this vein, such as the Peak Shaving Adjustments recognized by PJM, can help identify more economically efficient ways to manage load growth through demand reductions where adding new capacity is a slower and more costly alternative. PJM's RBP and IRAS proposals both recognize New Jersey's new law as a valid mechanism to offset data center load additions in the state.

As indicated above, differential reliability may provide benefits to New Jersey if thoughtfully implemented. For instance, it could facilitate the interconnection of new load by allowing certain customers to accept a lower level of reliability rather than requiring sufficient new capacity to maintain the same reliability standard for all customers. In doing so, it could enable more efficient utilization of existing generation and transmission infrastructure.[266] To the extent that these efficiencies reduce system costs, they may also translate into lower costs for ratepayers.[267]

6.4.3. Path C: Energy Market Transition

This pathway focuses on shifting a greater share of generator revenue recovery from the capacity market to the energy and ancillary services ("EAS") markets. PJM argues that suppressed energy market prices during periods of grid stress weaken the price signals needed to economically dispatch large flexible loads, reduce incentives for demand-side flexibility, and increase reliance on the capacity market as a source of generator revenue.[268] PJM therefore proposes increasing reliance on EAS markets so that generators recover a larger portion of their revenues during scarcity conditions, when they provide the greatest

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[266] A 2025 study used historical seasonal peaks to calculate the additional load that could've been interconnected to the grid if PJM allowed curtailments. It found that significant load additions could be accommodated if modest load curtailments occurred: 76 GW of new load could be added if an average annual load curtailment rate of 0.25% is accepted, 98 GW could be added if an average annual load curtailment rate of 0.5% is accepted, and 126 GW could be added if an average annual load curtailment rate of 1.0% is accepted. Norris 2025 Load Flexibility at 2.

[267] A March 2026 study that calculated investment, operations, and non-compliance costs under different data center development and supply interconnection scenarios found that load interconnection on a non-firm basis resulted in total system costs that were $15-16 billion lower annually than systems that only allowed firm load interconnection. Yury Dvorkin and Abraham Silverman, Data Center Flexibility and Grid Infrastructure Needs in PJM: Data Center Flexibility Policies Can Substantially Reduce Energy Infrastructure Investments Necessary to Keep the PJM Grid Reliable 1 (2026), https://energyinstitute.jhu.edu/wp-content/uploads/2026/03/Data_Center_Analysis_PJM-March-20-2026.pdf.

[268] PJM's Market Report at 40.

value to the system.[269] PJM characterizes this approach as a rebalancing of revenue recovery rather than an increase in total generator revenues, stating that "[i]nstead of consumers paying a high, flat 'insurance premium' (capacity) every day of the year regardless of grid conditions, they pay a lower baseline premium and only pay high energy prices when the system is actually stressed."[270] Under this framework, scarcity pricing becomes the primary mechanism for rewarding resource performance and encouraging new investment.[271] PJM further contends that LSEs would increasingly manage their exposure to price volatility through bilateral energy and capacity procurement rather than relying as heavily on the administratively determined capacity market.[272]

Supporters of this approach argue that EAS markets rely on fewer administrative constructs than capacity markets and therefore reduce regulatory uncertainty and disputes over market design.[273] Furthermore, PJM argues that increased reliance on bilateral forward energy contracts would provide a more attractive financing mechanism for new generation than bilateral forward capacity contracts because the energy market revenues are less dependent on administratively determined market rules that are subject to change.[274] In addition, compensation under this approach is more directly tied to actual production and performance under scarcity conditions rather than resource availability alone, strengthening incentives for both generators and flexile loads to respond during periods of system stress. Finally, because capacity markets rely heavily on resource accreditation methodologies and reserve margin determinations, a greater share of revenue recovered through EAS markets could reduce the importance of these administrative judgments as variable renewable and storage resources comprise an increasing share of the resource mix. PJM is already pursuing reforms consistent with this pathway through the Reserve Certainty Senior Task Force, which is evaluating changes to better compensate resources that provide energy and ancillary services during system stress.

However, shifting a greater share of revenue recovery from the capacity market to the energy market would require substantial reforms to PJM's energy market design and is

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[269] Id.

[270] Id. at 43.

[271] Id. at 42.

[272] Id. at 43.

[273] Id.

[274] Id.

therefore likely to require many years to implement.[275] Such a long implementation timeline may be difficult to reconcile with the near-term need to attract new generation resources. Furthermore the IMM argues that shifting revenue recovery from the capacity market to the energy market does not change the underlying economics associated with connecting large volumes of data center load without corresponding generation.[276] The IMM contends that greater reliance on energy market revenues could still result in high costs to ratepayers and maintains that requiring NLLs to provide or procure their own generation is the most effective way to prevent these costs from being socialized.[277]

7. Additional Proposed Reforms to the RPM

As PJM remains the only US Independent System Operator ("ISO") or RTO that relies on an annual capacity market with a three-year-forward auction, stakeholders have increasingly advocated for reforms that better reflect the high penetrations of renewable generation, rapid and uncertain load growth, and prolonged generation development timelines. Therefore, in addition to the three conceptual pathways discussed in the previous section, several complementary market reforms, including a sub-annual capacity market and a prompt auction, may be simultaneously advanced.

7.1. Sub-Annual Capacity Market

PJM's reliance on an annual capacity market increasingly distinguishes it from the procurement approaches used by other organized electricity markets. The New York ISO, the California ISO, and the Midcontinent ISO all employ sub-annual resource adequacy or capacity procurement mechanisms, while the ISO New England ("ISO-NE") is considering transitioning to a seasonal capacity auction through its Capacity Auction Reforms Key Project.[278]

PJM's RPM was designed when reliability risk was primarily associated with summer peak demand and thermal units exhibited consistent performance throughout the year. Under

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[275] Walter Graf, Powering Reliability Through Market Design: Addressing Rising Demand and Constrained Supply, and Stimulating Investment To Support Durable Reliability 10 (June 12, 2026), https://www.pjm.com/-/media/DotCom/committees-groups/workshops/prtmdw/2026/20260612/20260612-item-02---powering-reliability-through-market-design---pjm-presentation.pdf.

[276] Maeve Allsup, Is PJM too big to function?, Latitude Media, June 16, 2026, https://www.latitudemedia.com/news/is-pjm-too-big-to-function/.

[277] Id.

[278] Chris Geissler, Capacity Auction Reforms: Overview of Prompt Capacity Market 4 (March 11-12, 2025), https://www.iso-ne.com/static-assets/documents/100021/a03_mc_2025_03-11-12_prompt_iso_presentation.pdf.

those conditions, assigning a single annual accreditation value to each resource was generally sufficient. Today, however, reliability risks are becoming increasingly seasonal, with growing winter reliability concerns and a larger share of resources whose performance varies significantly across seasons. As a result, a single annual accreditation value may overvalue resources during some seasons while undervaluing them during others. A seasonal capacity market would help address this issue by establishing separate summer and winter prices that more accurately reflect seasonal reliability needs and provide investment signals where additional capacity is more valuable. The IMM has suggested that PJM transition toward an even more granular sub-annual market design – an hourly capacity market – which it states is an essential step forward, given the increased heterogeneity of resources.[279]

After a PJM Sub-Annual Capacity Market Senior Task Force was initiated in August 2025, PJM retained the Analysis Group to evaluate the costs and benefits of transitioning from an annual to a sub-annual capacity market. The Analysis Group concluded that the benefits of a sub-annual market would substantially outweigh the implementation costs.[280] PJM likewise identified a sub-annual capacity market as a reform warranting further consideration in its "Powering Reliability Through Market Design" paper.[281]

7.1. Prompt Auction

When approving PJM's RPM in 2006, FERC recognized that a forward procurement exposed customers to the risk of forecast error[282] but nonetheless concluded that this risk was outweighed by the benefits associated with providing developers with a longer forward investment signal.[283] Today, however, unprecedented uncertainty surrounding projected load growth has increased the likelihood that forecasts made three years in advance will differ from actual system needs.

Stakeholders are considering a prompt auction – where a capacity auction is held one year or less before delivery – because they recognize that the assumptions underlying the current three-year-forward market have changed. PJM recognizes that the development timeline for its reference resource, a new CT, has substantially increased. At the same time, growing uncertainty surrounding load forecasts has made it more difficult for capacity

[279] IMM 2023 SCM Letter at 11.

[280] Analysis Group 2026 SACM Report at 58.

[281] PJM's Market Report at 45.

[282] April 20, 2006 Order at P 71.

[283] Id.

market prices established three years in advance to accurately reflect future system needs.[284] A prompt auction would allow procurement decisions to incorporate more current information, thereby reducing the effects of forecast uncertainty. However, PJM has cautioned against simply reverting to a prompt auction that resembles the CCM, the RPM's predecessor, which was widely viewed as providing insufficient incentives for new resource development.[285]

Others have likewise advocated for a transition from a forward to a prompt auction in light of the challenges PJM has experienced under its current market design. In dissenting from PJM's 2023 Section 205 filing to delay the upcoming BRA, Commissioner Clements stated that "PJM's three-year forward capacity market structure may be broken" and added that "a structural move to a more prompt auction design is very likely warranted."[286] She added that a prompt auction would provide PJM with greater certainty regarding auction inputs and help break the cycle of repeated auction delays and uncertainty. [287] Following the implementation of ISO-NE's Capacity Auction Reforms, PJM would remain the only US ISO/RTO relying on a centralized capacity auction conducted three years before the applicable DY.

8. Discussion and Implications for New Jersey

New Jersey relies on PJM-administered markets to procure capacity, energy, and ancillary services, and New Jersey ratepayers are therefore directly exposed to the outcomes of PJM's market design. While the preceding sections demonstrate that the assumptions underlying PJM's capacity market have changed substantially in recent years, this section discusses the implication of those changes for New Jersey and evaluates how the market reforms currently under consideration may better support the state's affordability, reliability, and clean energy goals.

8.1. Affordability and Reliability

Although BRA clearing prices for New Jersey's LDAs have historically been volatile and often exceeded the RTO clearing price, they have reached new highs in the past three BRAs. The BRA clearing price for New Jersey LDAs increased fivefold, from $53.60/megawatt-day (MW-day) in the 2024/25 DY to $269.92/MW-day in the 2025/26 DY, and the capacity cost

[284] PJM's Market Report at 46.

[285] Id.

[286] PJM Interconnection, L.L.C., 183 FERC ¶ 61,172 (2023) (June 9, 2023 Commissioner Clements Dissent) at P 19.

[287] Id.

market clearing price are expected to remain elevated through at least the 2028/2029 DY. At the same time, the additional demand created by NLLs has increased capacity market costs far more than the quantity of capacity procured. Therefore, under current market conditions, higher capacity prices are not producing commensurate increases in resource adequacy.

As BRA clearing prices have increased, capacity market costs have accounted for an increasingly large share of the total cost of wholesale power. Capacity market costs jumped from 6.5% of the total cost of wholesale power costs in 2024 to 15.8% in 2025, the first year that included a DY with a BRA clearing price above $250/MW-day.[288] Consequently, capacity market outcomes are becoming an increasingly large driver of retail electricity rates. In New Jersey, retail electricity rates increased by roughly 20% in 2025[289] as higher BRA clearing prices flowed through to customers. Recognizing the growing importance of affordability, Governor Sherrill issued Executive Order No. 1 on her first day in office, reaffirming the State's commitment to affordable electricity and directing the BPU to study how to modernize the electric distribution utility business model.[290]

Short-Term Reforms

As discussed in previous sections, the recent increase in BRA clearing prices has not produced a commensurate increase in new supply resources. Instead, most of this capacity revenue has flown to incumbent generators while resource adequacy concerns persist. Under these circumstances, the extension of the temporary price collar through the 2029/2030 DY aligns with New Jersey's affordability objectives by limiting ratepayer exposure to scarcity prices that current non-market constraints prevent from translating into timely new investment.

PJM's RBP/C&M CIFP provided an important opportunity to address both reliability and affordability, and PJM's Board Decisional Letter reflected the broad stakeholder support for robust changes in the capacity market to implement protections for residential customers. While this proposal is a step in the right direction, states and PJM should continue to coordinate to support mechanisms that facilitate bilateral contracting between data centers and new supply or load reductions. Bilateral arrangements most directly allocate the costs and risks of new generation to the NLLs that are creating the need for that

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[288] Monitoring Analytics, L.L.C., Market Monitor Report 20 (Jan. 22, 2026), 20260122-item-06---market-monitoring-report---presentation.pdf.

[289] New Jersey Board of Public Utilities, NJBPU Announces Conclusion of New Jersey's Annual Electricity Supply Auction (Feb. 12, 2025), https://www.nj.gov/bpu/newsroom/2024/approved/20250212.html.

generation, while also minimizing the risk that those costs are socialized across existing ratepayers. These mechanisms are most effective when implemented throughout the PJM footprint in coordination with states.

The principle of cost causation should extend beyond PJM's near-term reforms. The costs and risks associated with serving NLLs should be borne by the customers creating those reliability challenges rather than existing ratepayers. New Jersey, for its part, took an aggressive step to control data center costs and service by passing P.L.2036, C.32.

Medium and Long-Term Reforms

In the medium-term, ongoing PJM workstreams to modify the capacity market generally support the aim of providing reliable service at the lowest reasonable cost. Although these reforms are unlikely to resolve the current supply shortage on their own, they may improve the efficiency with which the market procures and values capacity.

The implementation of a sub-annual capacity market design may improve both affordability and reliability by more accurately reflecting seasonal differences in resource performance, transmission system performance, and resource value.[291] The Analysis Group argued that seasonal procurement allows market prices to better reflect the marginal value of UCAP in each period, such that resource entry and retention in the market is better informed.[292] A sub-annual construct may therefore improve resource adequacy without requiring repeated administrative market modifications.[293] However, because today's barriers to new resource development are largely outside of the capacity market itself, a sub-annual capacity market construct alone is unlikely to attract sufficient new supply or prevent continued high capacity prices.

A prompt, instead of the current three-year-forward auction, may also facilitate more affordable and reliable resource procurement by allowing procurement decisions to rely on current information regarding load forecasts, resource availability, and system conditions. By reducing the time between the auction and the applicable DY, a prompt auction may mitigate the risk of over- or under-procuring capacity due to forecast error; the former would unnecessarily increase ratepayer costs, while the latter could threaten reliability. Nevertheless, as with the sub-annual market, a prompt auction alone is unlikely to resolve the widening gap between supply and projected demand.

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[291] Analysis Group 2026 SACM Report at 48-55.

[292] Id. at 56.

[293] Id. at 48.

Beyond these incremental improvements, PJM's three pathways in "Powering Reliability Through Market Design" require more fundamental decisions regarding how reliability should be procured and how the costs and risks of meeting growing demand should be allocated. Regardless of which framework is pursued, it is important that, where possible and prudent, higher prices and long-term commitments to attract additional capacity are ultimately borne by those who are causing the shortall – data centers – not existing ratepayers.

Aspects of differential reliability, as contemplated under Path B, may help New Jersey improve both affordability and reliability. PJM's July 27, 2026 IRAS proposal, for example, proposes to establish a form of differential reliability by requiring NLLs to either procure additional capacity or accept a lower level of reliability. IRAS could therefore serve as a core reliability and affordability tool for the system. New Jersey's new law at P.L. 2026, C.32, builds upon this framework by giving data centers tools to offset their load by contracting with third parties to provide demand flexibility. Programs such as these are cost effective means to serve new load while shielding ratepayers from the negative reliability and cost impacts associated with rapid data center load growth.

Energy market reforms must also be pursued, in conjunction with Path B, to limit potential scarcity energy market costs resulting from IRAS data center load. As data center load increases, even if it is subject to curtailment, the frequency of tight supply and demand conditions will increase, driving up the average energy market prices throughout the year due to more scarcity price events.

Expanding the differential reliability concept under Path B to additional customer classes is worth exploring as well. Existing demand response programs and similar mechanisms demonstrate how market incentives can be used to provide differential reliability. Data centers can also be encouraged to participate in these programs to offset their load additions to the grid. The Board Decisional Letter suggests PJM will encourage NLLs to participate in DR or load reduction programs, as doing so may fulfill the BYONC requirement needed to avoid IRAS.[294] The State, in coordination with PJM, should work to ensure these opportunities are unlocked to their fullest extent, as it is often quicker and cheaper to unlock demand-side flexibility than to construct new generation.

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[294] PJM Interconnection, L.L.C., CIFP Framework for Service During Periods of Insufficient Resource Adequacy – PJM Proposal (2026), https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/2026/20260727-cifp-framework-for-service-during-periods-of-insufficient-resource-adequacy-executive-summary.pdf.

Path C, as defined by PJM, would gradually shift a greater share of generator revenue recovery from the capacity market to the energy and ancillary services markets. PJM recognizes that such a transition would be substantial, likely requiring a decade to implement. Under this approach, generators would recover a larger portion of their revenues through scarcity pricing in the energy market than they currently do. That said, reforming the market in such a large way creates speculative risks, and it is likely prudent to explore other alternatives first. It is also important to recognize that states would have more limited tools to implement this pathway than the other pathways.

Employing more long-term capacity and energy contracts, as contemplated under Path A, presents a few clear benefits. As electricity demand grows, long-term contracts can provide developers with the revenue certainty needed to support investment and operation while reducing price volatility for consumers. However, given the present high construction costs and market prices, it is important to strike an appropriate balance between shifting investment risk to consumers and preserving the benefits of competitive market procurement. Accordingly, there is no need to wholly abandon the current market – rather, a targeted amount of long-term contracts can supplement the existing market. The state may require its LSEs to enter a limited amount of long-term bilateral contracts – note, the legal risks for this workstream, as constrained by *PPL EnergyPlus, LLC v. Solomon*, will need due consideration.

Of course, in bringing new supply to the grid under Path A, consumers can be best protected if the new data center load most directly bears the costs and risks of new generation construction. For instance, states can implement requirements or incentivize NLLs to BYONC beyond PJM's proposal in its July 27, 2026 proposal.[295] If PJM explores additional market constructs to solicit new supply for NLLs through long-term central procurements outside of the RBP, PJM and the states will need to ensure those costs get allocated to NLLs.

Regardless of the broader market pathway ultimately pursued, additional action at both the RTO and state levels will be necessary to ensure that the costs and risks associated with serving LLAs, including stranded-asset risks, are allocated to those customers rather than existing ratepayers.

[295] Board Decisional Letter on Critical Issue Fast Path – Reliability Backstop Procurement and Connect and Manage.

8.2. Clean Energy Programs and Market Reforms

Although PJM does not have an explicit obligation to advance clean energy or reduce emissions, New Jersey relies on PJM-administered markets to procure energy, capacity, and ancillary services while simultaneously pursuing ambitious clean energy and emissions reduction goals. Accordingly, it is important to consider whether PJM's capacity market design aligns or conflicts with the State's policies. Resource adequacy frameworks that incorporate targeted long-term procurement and differentiated reliability may better align with these objectives. Furthermore, many of these approaches can be coordinated with data center load growth by encouraging investment in new clean generation or load reduction programs.

Governor Sherril's Executive Orders Two and Five reaffirm the New Jersey's commitment to in-state clean energy infrastructure development. Executive Order Two directs the accelerated development of distributed and utility-scale solar, community solar, transmission-scale battery storage, a virtual power plant ("VPP") program, electricity generation and grid stabilization projects, and existing gas plant modernization.[296] Meanwhile, Executive Order Five supports the construction of such projects through the creation of a Cross-Agency Permitting Team and initiation of permitting reforms that may facilitate the construction of clean energy generation infrastructure.[297]

At the state-level, New Jersey can directly support or encourage EDCs and LSEs to bilaterally contract with renewable resources. New Jersey's Garden State Energy Storage Program, Community Solar Energy Program, and Competitive Solar Incentive program already foster the development of in-state renewable capacity resources. New Jersey can also consider the construction of new in-state nuclear facilities; Governor Sherrill's signing of S3870/A4528 in April 2026, which will remove permitting impediments to the construction of new nuclear facilities, is one step in this direction. Although these resources have to effectively participate in the RPM since New Jersey is a restructured state, with state assistance, they may enter the capacity market as price-takers and hedge or reduce costs for New Jersey and PJM-wide ratepayers.

Under the jurisdiction reserved for the states, New Jersey can also lead efforts to speed up siting and permitting efforts in the state that expedite the development of clean energy resources; assist in VPP aggregation efforts so that smaller, distributed energy resources ("DERs") can still benefit from revenues in the capacity market; and build utility incentive

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[296] NJ Exec. Order No. 2 (January 20, 2026), https://nj.gov/infobank/eo/057sherrill/pdf/EO-2.pdf.

[297] NJ Exec. Order No. 5 (January 20, 2026), https://nj.gov/infobank/eo/057sherrill/pdf/EO-5.pdf.

programs to deploy more energy efficiency and DERs, some of which Governor Sherrill has already initiated since coming into office.

While PJM markets have delivered power to New Jersey consumers reliably and at competitive prices over the past few decades, these markets are not designed to achieve New Jersey's emissions reduction objectives. As a result, New Jersey and other PJM states with aggressive carbon reduction mandates are forced to develop workarounds to the market to meet their clean energy goals.

One reason why states with aggressive carbon reduction mandates must, at times, work around PJM's markets is that PJM and FERC have the ability to make sweeping decisions at the wholesale-level that fundamentally misalign with and even impede New Jersey state policy goals and consumer interests. The aforementioned expansion of the MOPR in 2019, which required clean energy resources to bid into the capacity market at high prices that could not account for additional revenue streams from state clean energy investments, is one such example. Even though it was re-narrowed soon after, this policy demonstrated that PJM's decisions can substantially impact the participation and accreditation of renewable energy resources at the wholesale level. It shows that there always remains a risk that a future FERC administration and PJM can revisit the MOPR, or make similar changes, to impede clean energy programs.

As LLAs increasingly seek 24/7 firm service, resource adequacy reforms should remain focused on reliability outcomes rather than favoring any particular resource types. Although thermal resources currently provide important reliability attributes, renewable resources are generally quick to construct and provide broader consumer benefits that are not fully reflected in today's capacity market. As PJM continues reforming its accreditation and market design, it should recognize the value of a diverse resource mix and the consumer benefits provided by clean energy resources.

PJM's proposed pathways in "Powering Reliability Through Market Design" may align with New Jersey's clean energy and emission reductions goals. Under a bilateral hedging pathway, for example, New Jersey could establish procurement requirements or selection criteria that favor resources consistent with the State's energy policies. More broadly, greater state involvement in long-term procurement decisions may provide opportunities to better align wholesale market outcomes with state policy objectives. Differential reliability may likewise support New Jersey's clean energy objectives if implemented thoughtfully. Additional market reforms, including a sub-annual capacity market, may also improve the valuation and accreditation of clean energy resources by more accurately reflecting their seasonal reliability contributions.

9. Recommendations and Options

Since the PJM capacity market is not fulfilling its objectives of ensuring reliability at least cost, it is prudent for New Jersey to consider the tools available to it. This report aims to explain the forces affecting the capacity market, as they must be understood before solutions can be considered. The recommendations and options outlined below are not intended to represent a comprehensive list, but they suggest ways that the State can protect ratepayers. Additionally, these recommendations and options do not address tools that the state currently employs to incent new generation or load side management, such as clean energy initiatives, storage program incentives, and demand-side programs. To be clear, these state programs are generally effective and should be continued. Additionally, we are not recommending that PJM pursue an energy-only market at this time.

Many actions also require PJM and FERC involvement. New Jersey must continue to advocate in these spaces, using the PJM stakeholder process and litigation options at FERC to further New Jersey's priorities.

1. **Data centers, or their LSEs, should be required to bear the costs and risks associated with their new load.**

   The main driver behind high market prices is the rapid pace of load growth associated with a narrow class of customers, data centers. New supply cannot be built fast enough to respond to the load growth. Further, market price signals are muted when new data center load forecasts are uncertain and will remain so despite improvements to the forecasting methodology.

   The New Jersey Legislature passed a data center tariff bill, P.L.2026 C.32, that will implement or require the BPU to implement much of the following three recommendations. That law, however, cannot reach other states and solve regional market problems on its own. PJM's IRAS program, if implemented well, can help achieve some of these regional protections.

   a. A State BYONC Mandate
      i. Explanation and Benefits: Data center-financed capacity protects consumers and generation developers from stranded asset risks associated with uncertain load forecasts. If data center load, without BYONC, is removed from the capacity market demand stack, existing ratepayers can be protected from socialized stranded asset costs.
      ii. Risks: Other states in PJM may not implement similar programs, exposing New Jersey customers to regional market forces.

b. Stave-Level Priority curtailments
    i. Explanation and Benefits: Priority curtailment does not prevent data centers from interconnecting to the grid. It can, however, be implemented under a C&M framework to force data centers to pay for their own new supply or accept a lower level of reliability. Priority curtailment, whether it successfully incents new supply or not, protects ratepayers from load loss.
    ii. Risks: Other states in PJM may not implement similar programs, exposing New Jersey customers to regional market forces. Additionally, New Jersey data centers would be subject to curtailment before others in the region.
c. Regional Interim Resource Adequacy Service
    i. Explanation and Benefits: PJM and FERC can set a baseline standard and incentive for data centers throughout the region. States would have to implement priority curtailment rules to protect non-data center consumers from these curtailments, but a regional solution ensures that customers can be better protected from the effects of out-of-state data centers. To protect customers from regional market forces, the data center loads without BYONC must be removed from the capacity market demand stack. PJM proposed this in its July 27, 2026, Board Decisional Letter.[298]
    ii. Risks: New Jersey cannot implement this type of program on its own. However, it is the strongest tool available to the region and many stakeholders have advocated for it.

It is important to note that a regional IRAS solution can alleviate the strain on PJM's capacity market, especially if non-BYONC data center load is removed from its demand stack. However, scarcity price outcomes may continue and grow in the energy market – the timing of any priority curtailment and any associated price triggers will have a substantial effect on customers through wholesale energy prices.

2. PJM should implement market reforms to improve the capacity market

[298] Board Decisional Letter on Critical Issue Fast Path – Reliability Backstop Procurement and Connect and Manage.

Irrespective of data center load growth, the evolving generation mix and investment environment warrant changes to the capacity market.

a. Seasonal Market Construct
    i. Explanation and Benefits: Resources have different operational profiles in the summer and winter. Separating the market into a seasonal design can better value the risks and benefits of each resource through changing weather patterns over the year.
b. Prompt Auction
    i. Explanation and Benefits: A prompt auction can reduce the effects of an uncertain load forecast and system generation profile on capacity market price outcomes.
    ii. Risks: A prompt auction loses some of the forward-looking benefit of a price signal. However, given that the supply chain and other factors have slowed resource development timelines, the forward nature of the price signal arguably provides little benefit today. At the same time, a prompt auction provides existing generators with less advanced price certainty when making decisions regarding continued operation, retirement, or deactivation. Furthermore, as New Jersey's BGS currently procures retail supply through staggered three-year contracts that are aligned with PJM's forward capacity market, transitioning to a prompt auction may necessitate adjustments to the BGS procurement structure or additional hedging mechanisms to mitigate increased price volatility.
c. PJM Directed and Centralized Long-term Procurements
    i. Explanation and Benefits: PJM can run markets to secure long-term revenue streams for capacity. The Reliability Backstop Auction is a form of this. These long-term procurements can be directed to specific customer classes, such as large-load data centers. Alternatively, they can be aimed at establishing a persistent bifurcated market that separates existing and new capacity. A PJM-directed long-term procurement removes transaction costs associated with bilateral contracts and can give investors the long-term price certainty they need.
    ii. Risks: Centralized long-term procurements will rely upon projected load needs, which are inaccurate, and the system may invest in resources that are not needed. Long-term procurements

solely targeted at new resources may also diminish the revenue streams for existing resources, leading to premature economic retirements. Whether centralized procurements are needed and prudent will depend on whether state-directed long-term procurements are pursued and successful.

3. States should direct long-term procurements

New Jersey customers are currently exposed to capacity market volatility and generator developers are seeking greater price certainty. The state has many tools to incent long-term contracting for new resource development. Other tools, such as mandated bilateral contracts, warrant consideration as well. PJM and FERC may also enable more flexible arrangements in this space.

a. State-mandated Bilateral Contracts for its LSEs
    i. Explanation and Benefits: An LSE can serve retail load through third-party supplier contracts or the BGS. Currently, LSEs do not generally hedge by entering into long-term capacity contracts before supplying retail service. The State may require all in-state LSEs, or LSEs that serve load through the BGS, to ensure that a portion of their supply is obtained through supply ownership of long-term bilateral contracts. Long-term supply arrangements can provide a hedging mechanism for ratepayers and minimize retail price spikes associated with wholesale rates.
    ii. Risks: There is an economic risk and a legal risk. The economic risk is that long-term procurements – ones that are not made with and on behalf of new large loads – will shift risk away from investors and toward ratepayers and may expose ratepayers to market power concerns or locked-in prices made during a high-priced market. While a more balanced approach toward risk sharing can be explored, decision makers must be careful to not overcorrect either. On the legal front, state-directed long-term procurements under the LCAPP were deemed illegal under *Solomon* and *Hughes*. To avoid a legal defect, a state-directed program (1) cannot set capacity prices and (2) cannot require load to participate and clear in the capacity market. To mitigate the legal risk, an LSE serving BGS load must be allowed to procure long-term supply arrangements through their own efforts and negotiations. The state should not require any resource procured

this way to participate in the capacity market. However, a competitive LSE will still be incented to participate in it to ensure they obtain the self-supply offsets available to it through PJM's FERC-approved governing documents. Still, the lack of a requirement for the LSE bilaterally contracted capacity to clear the capacity market presents a theoretical risk that New Jersey customers may end up having to pay for *both* bilaterally procured capacity that does not clear the market *and* duplicate replacement capacity that managed to clear the market.

b. PJM Governing Document Reform
    i. Explanation and Benefits: Some state-directed procurements, such as the LCAPP, do not fit within PJM's FERC approved rules. PJM and FERC can therefore allow more flexibility for states by reforming its rules. A Partial FRR, for instance, would allow the state (through its utility zone) to remove a part of its load from the capacity market to serve as the state and its utility best see fit. Alternative, a less aggressive reform would simply ensure that PJM's "self-supply" provisions expressly allow for state directed long-term bilateral contracts, which would fully circumvent the *Solomon* decision. PJM and FERC have it within their authority to give states more ownership over long-term procurements.

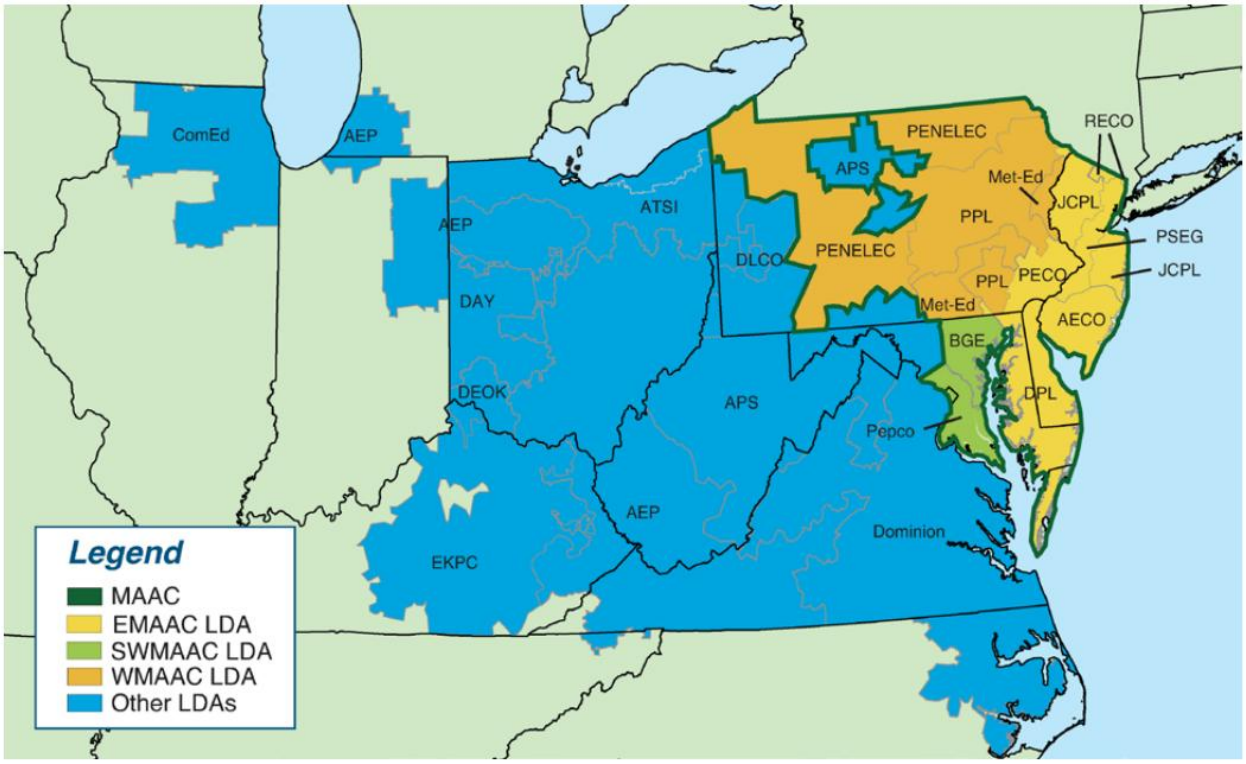
10. Conclusion

States restructured their electricity sectors and entered into competitive electricity markets expecting that market-based procurement of generation would achieve reliability at a lower cost than traditional vertically integrated monopoly structures. Within this market structure, however, affordability depends on wholesale markets' ability to produce efficient investment signals and reliable outcomes.

While the RPM largely succeeded under conditions of slow load growth and adequate supply, those assumptions are being challenged by unprecedented demand growth, supply constraints, and changing resource characteristics. In other words, markets alone cannot address the pace of rapid load growth where supply chains constraints, permitting challenges, and forecasting uncertainty create risk and volatility for all stakeholders. Therefore, stakeholders across the region, including states and PJM itself, have recognized that the current market structure no longer fully serves its intended purpose. Capacity market prices in PJM are increasing substantially without a commensurate increase in reliability, and states are grappling with growing affordability challenges despite having limited authority over the underlying market design.

Acknowledging the shortcomings of the current capacity market, PJM is pursuing significant reforms to its market design. Those reforms must address the growing imbalance between supply and demand, improve investment incentives for new capacity, and establish wholesale market mechanisms that allocate the costs and risks associated with data center-driven load growth to the customers creating that demand. States must also employ the tools available within their own jurisdictions, including long-term contracts, demand flexibility programs, and mechanisms that require new data center load to pay for the new capacity needed to serve it. Ultimately, restoring confidence in the competitive market framework will require coordinated action by PJM, the states, and FERC, with clearly defined responsibilities and an equitable allocation of the costs and risks associated with meeting future electricity demand.

Appendix



Map of PJM LDAs.[299]

[299] https://www.monitoringanalytics.com/reports/pjm_state_of_the_market/2017/2017-som-pjm-volume2-appendix.pdf