CRA Charles River Associates

Utility-Owned Generation as a Solution:

An Analysis of Economic & Reliability Impacts of Increased State-Regulated Generation in PJM Delivery Year 2028/29

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Disclaimers and acknowledgements

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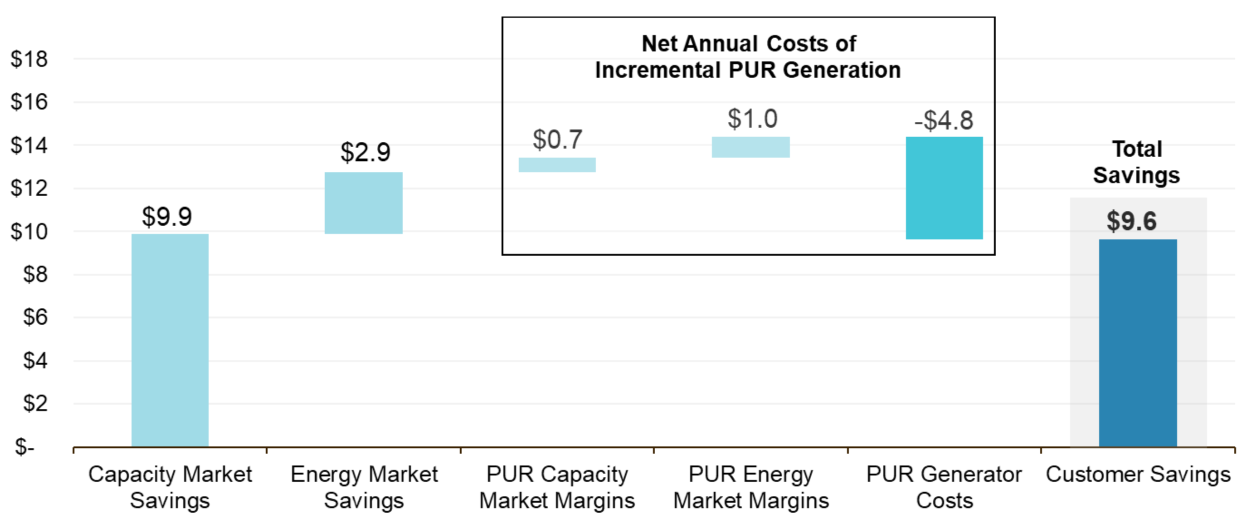
Executive Summary

Surging demand for electricity has driven sharp increases in customer electric supply costs and raised reliability concerns in PJM. The market construct currently employed by PJM relies on price signals to stimulate development of new generation by Independent Power Producers (IPPs). However, data increasingly suggests that these signals, and the IPP response to them, may be inadequate in the face of broader market conditions, regulatory challenges, and the pace of load growth. This paper examines the benefits to customers in PJM that could be realized in a scenario in which utility-owned generation were more extensively used as a state-regulated complement to IPP-developed generation.

Charles River Associates (CRA) analyzed and compared customer costs in PJM Delivery Year (DY) 2028/29 for a Business as Usual (BAU) case and a hypothetical Planned Utility Resources (PUR) case. The BAU case represents likely real-world outcomes given expected generation and load developments prior to mid-2028, the start of the DY. The hypothetical PUR case supplements projected available generation in the BAU case with additional utility-owned generation resources, assuming they were planned and developed over recent years as load growth expectations materialized.

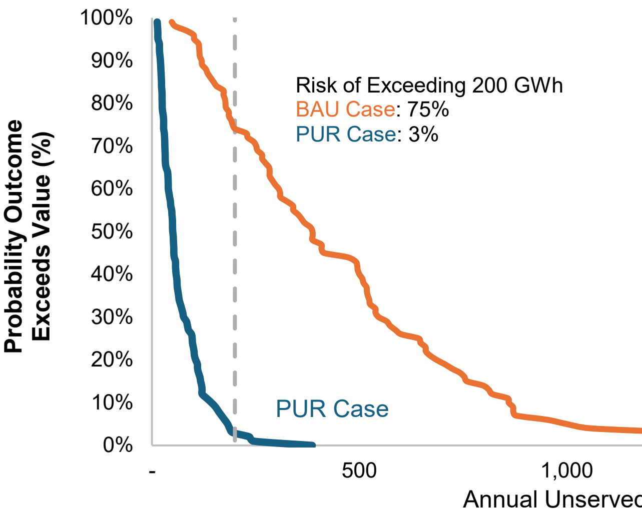
The PUR case results in $9.9 billion to $20.3 billion in lower capacity costs, as the PJM market moves from a deficit in the BAU case to levels of supply availability aligned with historical actual reserve margins, with the savings range driven by upcoming decisions on the capacity market price cap. It also results in $2.9 billion in lower annual energy costs in the PJM region, as efficient new resources displace older less-efficient generation. These benefits far outweigh the estimated net annual costs of the incremental utility-owned generation of approximately $3.1 billion across PJM. Net savings range from $9.6 billion to $20.0 billion for PJM customers. Figure 1 shows net savings in a sensitivity with lower capacity costs.

Figure 1: Net Costs/Savings of Planned Utility Resources (PUR), $ billion



The move from a shortfall of generation to reserve margins aligned with historical levels also improves reliability. Using its proprietary model, CRA evaluated reliability expectations for the two scenarios under a range of possible system conditions. By adding utility-owned generation, the annual amount of demand that fails to be met due to insufficient electricity generation, referred to as Expected Unserved Energy (EUE), declines 85% (398 GWh) in the PUR case, resulting in over $10 billion in customer reliability benefits. As shown in Figure 2, in higher-risk conditions - with extreme weather or elevated generator outages - the difference can be much larger.

Figure 2: Annual Unserved Energy Outcomes



How to Read This Figure

- Each curve shows the probability that annual unserved energy will exceed a given level.
- Lower curves indicate improved reliability and reduced outage risk.

CRA's analysis demonstrates that, in the current environment of rapid demand growth and the inability of market signals to deliver adequate new generation, expanding the role of utility-owned generation with state regulatory oversight has the potential to reduce electric supply costs and improve reliability.

Key Takeaway: Utility-Owned Generation Drives Customer Value

By keeping pace with load growth, portfolios that include utility-owned generation reduce energy and capacity costs while providing a materially more reliable electricity system**.** Based on analysis for Delivery Year 2028/29, utility-owned generation can deliver **$9.6 billion to $20.0 billion in supply cost reduction and an 85% reduction the risks of outages due to insufficient generation.**

1. Introduction

PJM Interconnection (PJM) is the largest and one of the oldest organized wholesale electricity markets in the United States. PJM coordinates the movement of wholesale electricity across all or parts of 13 states and the District of Columbia, serving more than 67 million people.[1] This Regional Transmission Organization (RTO) spans much of the Mid-Atlantic and Midwest, including the Chicago metropolitan area.[2]

Despite decades of successful operation, PJM faces significant near-term reliability and affordability challenges as new generation investment continues to lag behind rapid load growth. Regulators across the region increasingly worry that the timing, location, and characteristics of new resources cannot keep pace with overall system needs.[3,4] To help remedy this situation, policymakers in the PJM region could look to increase the prevalence of utility-owned generation alongside merchant/IPP generation. For the purposes of this whitepaper, CRA defines "utility-owned generation" to mean electric generators as well as Battery Energy Storage System (BESS) assets that are owned and operated by state-jurisdictional public utilities. These resources are built pursuant to state planning processes or plans and are subject to state oversight, state prudence review, and state approved cost recovery on a cost-of-service basis.

States can expand the role of utility-owned generation alongside market-driven developments by IPPs. PJM currently operates, and always has operated, in states with varying regulatory environments for generation. In some states, only IPPs develop new resources. In other states, vertically integrated utilities do so in parallel to IPPs. In these hybrid states, new utility-owned generation is planned through state commission regulated resource planning processes that include significant public stakeholder engagement which can better align investment decisions with long-term system needs, policy objectives, and citizens' concerns.

Expanding the use of utility-owned generation could provide states with a more deliberate mechanism to ensure **resource adequacy**[5] and support affordability. Under this framework, utilities would site and develop new generation under state guidance, based on long-term load forecasts, reliability requirements, and state policy goals, consistent with standard practices

1 PJM Interconnection, LLC. "PJM At a Glance". Audubon, PA: PJM Interconnection, 2025. https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/pjm-at-a-glance.pdf.

2 PJM Interconnection, LLC. "Territory Served." PJM Interconnection accessed January 2026. https://www.pjm.com/about-pjm/who-we-are/territory-served.

3 North American Electric Reliability Corporation (NERC), *2025 Long-Term Reliability Assessment* (Atlanta, GA: NERC, January 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

4 U.S. Department of Energy, *Report on Evaluating U.S. Grid Reliability and Security* (Washington, DC: U.S. Department of Energy, July 7, 2025), https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

5 **Resource adequacy** focuses on ensuring that the bulk electricity generation system, subject to transmission constraints, can deliver sufficient power to meet all end-use demand across all weather conditions (see Appendix for further detail).

across much of the country, which were more common in PJM prior to restructuring in the 1990s and 2000s.

The regulated framework also offers tools to manage investment and cost-recovery risk, promote bill stability, and support diverse resource portfolio development that can be purposefully aligned with public policy objectives. Regulated cost recovery could encourage development of resources with higher levels of capacity contribution, or **Effective Load Carrying Capabilities (ELCCs),**[6] such as natural gas or nuclear generation, as well as newer technologies such as offshore wind, long-duration storage, and next-generation nuclear reactors because utilities have more long-term revenue certainty provided by regulated cost recovery under state oversight and can diversify their resource pipeline. Given inadequate and uncertain market signals, IPPs have mostly focused on development of renewable resources (primarily wind and solar, with lower ELCC values) that meet state Renewable Portfolio Standard (RPS) requirements, rather than new higher ELCC resources that have a more meaningful impact on reliability.

Structured planning processes can align investment decisions with state policy goals. They can also enable regulators to directly address risks of under-procurement (leading to shortages) and avoid over-procurement (leading to unnecessary costs), while explicitly recognizing under-procurement entails greater risks (i.e., reliability shortfalls). It also allows policymakers to assess and address asymmetric risks, as costs associated with resource adequacy shortfalls, whether reflected through extreme market price spikes or power outages for customers,[7] can substantially exceed the costs of modest over-procurement.[8]

In summary, the benefits of expanding utility-owned generation in PJM include:

- **Long-term planning** aligns resource development with long-term system needs rather than short-term market outcomes;
- **More predictable and lower customer supply costs** tied to portfolio-based planning rather than scarcity pricing with a potential for \$9.6 billion to \$20.0 billion in savings for customers;[9]
- **Clear accountability for reliability** enables earlier intervention when reserve margins are expected to tighten or load uncertainties increase;

6 **Effective load carrying capabilities (ELCC)** is a 0% to 100% number capturing the portion of a resource's seasonal capacity that can be counted as an accredited supply and used toward meeting target reserve margins. It is a measure of the portion of the resource's generation that be counted on to meet grid stress hours.

7 Power outages can result from load shedding – intentionally disconnecting service to customers during periods when demand exceeds the capacity of available generators, subject to transmission constraints.

8 The Brattle Group, *Sixth Review of PJM's Variable Resource Requirement Curve: For Planning Years 2028/29 through 2031/32*, prepared for PJM Interconnection, LLC (Boston, MA: The Brattle Group, April 2025), https://www.brattle.com/wp-content/uploads/2025/04/Sixth-Review-of-PJMs-Variable-Resource-Requirement-Curve.pdf.

9 CRA analysis documented in the remainder of this white paper.

- **Reduced exposure to price volatility** by replacing short-term market outcomes with regulated decisions with clear performance obligations and transparent cost-recovery; and
- **Greater ability to develop high-ELCC** capital-intensive resources and emerging technologies**,** which are increasingly difficult for merchant developers to finance. Relatedly, states will have more control over achievement of energy policies.

To provide insight into the potential benefits of expanding utility-owned generation in PJM, this study evaluates impacts on capacity prices, energy prices, and reliability outcomes for PJM Delivery Year (DY) 2028/29.[10] The analysis compares CRA's forecasted Business as Usual (BAU) trajectory for DY 2028/29 with an alternative scenario for that period, the Planned Utility Resources (PUR) case, in which utilities had developed additional resources in advance of emerging reliability challenges consistent with when those challenges were becoming better understood (i.e., in the early 2020s when the data center and large load phenomena was first recognized). Focusing on a single delivery period – rather than an extended forecast period or a period further in the future – provides a clear, discrete, policy-relevant benchmark at a time when PJM is projected to face heightened reliability and cost pressures.

The analysis also focuses only on a single element of grid reliability: resource adequacy. A grid is resource adequate if it has sufficient generation to withstand all grid conditions. It does not consider other aspects of grid reliability, including transmission and distribution outages, which are measured separately even though customers experience both events as loss of service. To quantify the impact of the incremental generation in the PUR case, we compare the Expected Unserved Energy (EUE) between the cases. The EUE is the average amount of customer demand not served due to lack of generation.

The remainder of this paper presents the current challenges facing PJM, describes modeling approaches, reports findings, and discusses the implications for PJM and policymakers in the PJM region.

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10 DY 2028/29 is defined as June 1, 2028 – May 31, 2029.

2. Current Market and Supply Conditions in PJM and Emerging Challenges

PJM has historically delivered reliable service at low costs across a diverse group of states with different regulatory frameworks and policy priorities. For much of the past two decades, PJM operated with surplus generation, modest demand growth, and a steady pipeline of new resources. These conditions allowed its market design to function effectively and keep prices relatively low, even as older and less efficient resources retired.[11]

That dynamic has shifted in recent years. Rapid load growth, driven primarily by data center development as well as electrification, combined with accelerated generator retirements and limited development of new generators, has produced tightening reserve margins, rising capacity prices, and growing concerns about PJM's ability to maintain resource adequacy.[12] At the same time, policy uncertainty, supply-chain constraints, and complex interconnection processes increased the challenges in the development environment for new generation.[13]

This section describes how PJM's market design has historically operated, how conditions have changed, and why current trends may be straining the resource development model.

PJM Operations and Historical Conditions

PJM operates a set of integrated markets – for energy, ancillary services, and capacity – that collectively are designed to ensure reliable, economically efficient operations. PJM also operates the bulk power transmission system and orchestrates its expansion to connect generation needed to meet load growth.

In restructured states, IPPs own the majority of generation. In vertically integrated states, utilities own and operate generation alongside competing IPPs. Across the region, utilities maintain the transmission and distribution systems, regardless of regulation structure. See Figure 3 for further discussion.

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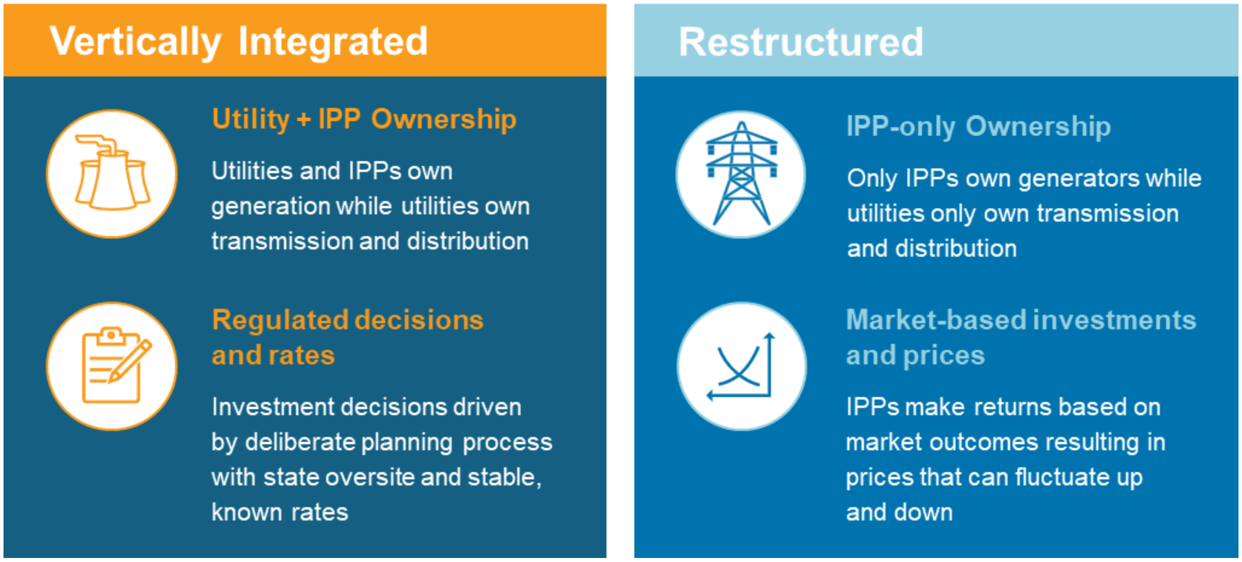
11 PJM Interconnection, LLC, *PJM Details Resource Retirements, Replacements and Risks* (Audubon, PA: PJM Interconnection, LLC, February 24, 2023), https://insidelines.pjm.com/pjm-details-resource-retirements-replacements-and-risks/

12 Ibid.

13 Joseph Rand, Nick Manderlink, Will Gorman, Ryan Wiser, Joachim Seel, Julie Mulvaney Kemp, Seongeun Jeong, and Fritz Kahrl, *Queued Up: 2024 Edition* (Berkeley, CA: Lawrence Berkeley National Laboratory, April 2024), https://emp.lbl.gov/sites/default/files/2024-04/Queued%20Up%202024%20Edition_1.pdf.

Figure 3: Comparison between Regulatory Frameworks for Electricity Markets



Day-to-day, PJM operates energy and ancillary services markets to minimize generation production costs, while procuring sufficient **operating reserves**[14] to ensure reliable operations. PJM estimates it has delivered up to $5 billion annually in savings for customers[15] through efficient dispatch, robust competition, and operational expertise.

In addition to day-to-day operations, PJM runs a **capacity market**[16] that provides capacity resource owners (mostly electric generators) with payments that are intended to support new entry and continued operations of enough existing plants to serve load under most possible system conditions. The Base Residual Auction (BRA) – the core procurement mechanism of the PJM capacity market – secures **accredited capacity**[17] to meet forecasted peak demand plus a **target planning reserve margin**.[18] Capacity prices rise as accredited supply tightens relative to the target reserve margin, providing a market signal intended to attract new investment and to retain cost-efficient existing resources while allowing inefficient, older resources to retire.

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14 **Operating reserves** are resources that are not generating at full output, which can rapidly be dispatched by PJM to respond to changes in electric demand or renewable output and generator/transmission outages.

15 PJM Interconnection, LLC. "The Value of PJM." Audubon, PA: PJM Interconnection, LLC, n.d. https://www.pjm.com/-/media/DotCom/about-pjm/the-value-of-pjm.pdf.

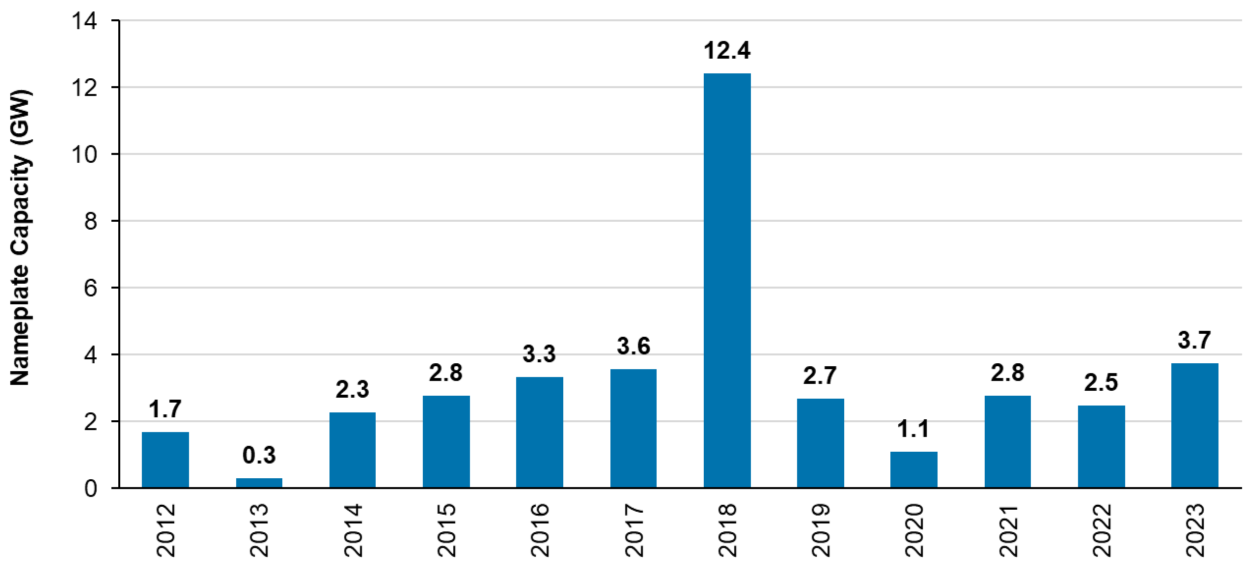
16 In this market, **capacity** can be provided by generators, storage resources, demand response, and imports. Capacity sellers that clear in the market earn capacity payments in exchange for obligations to sell into the energy and ancillary service markets and agree to expose themselves to non-performance penalties.

17 **Accredited capacity** as defined in PJM is the portion of total generation that can be counted toward meeting reserve margins. It adjusts a resource's summer-rated PJM capacity based on ELCCs to reflect expected performance during periods of grid stress, accounting for planned and unplanned outages, correlated failures, and weather-driven reductions in output under high-stress conditions.

18 **Target planning reserve margin** is the excess capacity needed, above peak demand forecast, to maintain resource adequacy.

For years, capacity prices remained relatively low because accredited supply exceeded PJM's reliability requirement. Reliability remained high even as PJM experienced significant retirements - 47.2 GW between 2012 and 2022, mostly coal, diesel, and older natural gas units[19] - because these retirements were offset by 35.3 GW nameplate of highly accredited new natural gas generation (See Figure 4) and growing quantities of renewable resources. Further, modest load growth during this period resulted in comfortable reserve margins.

Figure 4: PJM Natural Gas Generation Additions from 2012 – 2022



A Rapidly Changing Load Outlook

This historical paradigm in PJM no longer aligns with current or future conditions. After years of minimal growth, PJM's **load**[20] forecasts have risen sharply, driven by the data center boom and smaller, but material, impacts of electrification of heating and transportation and evolving policy goals. According to the *2026 Load Forecast Report*, PJM peak demand is expected to increase from 153 GW to 222 GW over the next decade, a 3.6% annual growth rate,[21] a dramatic shift compared to the historical annual growth rate of approximately 0.7% over the last decade.[22]

Earlier vintages of PJM's load forecast did not anticipate the magnitude of recent load growth. However, some utilities within PJM, most notably Dominion, identified higher load growth driven

19 PJM Interconnection, LLC, *PJM Details Resource Retirements, Replacements and Risks* (Audubon, PA: PJM Interconnection, LLC, February 24, 2023), https://insidelines.pjm.com/pjm-details-resource-retirements-replacements-and-risks/.

20 **Load** is demand for electricity. For a given period, the term can refer to either the peak demand in megawatts (MW) or the total energy demanded in megawatt-hours (MWh).

21 PJM Interconnection, LLC, *2026 Load Forecast Report* (Audubon, PA: PJM Interconnection, LLC, January 14, 2026), https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2026-load-report.pdf.

22 CRA analysis.

by localized economic activity, particularly data center development, as early as 2018-2020.[23] Under the regulatory construct, Dominion was able to pre-build resources in response.[24] This underscores the complementary roles of utilities and the RTO in the load forecasting process: utilities, through close engagement with local customers, can anticipate and plan for localized growth, while PJM captures system-wide dynamics and establishes best practices.

Slower-than-Desired Generation Builds

Across PJM, new generator additions have not kept pace with retirements and load growth in recent years. For example, less than 20 MW of new natural gas generation came online in 2024 and 2025, while approximately 1,700 MW of capacity retired over the same period.[25] Factors explaining the slower-than-desired generation builds may include, but are not limited to: [26]

- **Energy regulatory uncertainty:** Capacity market rules change regularly, creating uncertainty around future market outcomes;
- **Environmental policy changes:** Regular changes to state and federal environmental policies further dampen the investment outlook;
- **Pricing uncertainty:** Because PJM's capacity market commitments last only one year, long-lived capital investments face significant pricing and revenue uncertainty;
- **Development environment that does not support construction of high and rising capital cost resources:** IPPs depend on capacity market earnings to support the development of generating resources. In particular, market-driven natural gas and storage development has become difficult given rising input costs, pricing constraints, and a regulatory environment in a near constant state of flux;[27]

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23 Virginia Electric and Power Company d/b/a Dominion Energy Virginia, *2018 Integrated Resource Plan*, RD249, Reports to the General Assembly (Richmond, VA: Virginia General Assembly, May 1, 2018), https://rga.lis.virginia.gov/Published/2018/RD249.

24 Virginia Electric and Power Company d/b/a Dominion Energy Virginia, *2024 Integrated Resource Plan* (Richmond, VA: Dominion Energy, Inc., 2024), https://www.dominionenergy.com/-/media/content/about/our-company/irp/pdfs/2024-irp-w_o-appendices.pdf.

25 Hitachi Energy, *Energy Market Insights Software Solution (Velocity Suite)* (energy analytics and market data platform), accessed December 2025, https://www.hitachienergy.com/us/en/products-and-solutions/energy-portfolio-management/energy-analytics-software-solutions/energy-market-insights-software-solution.

26 PJM Interconnection, LLC, *PJM Details Resource Retirements, Replacements and Risks* (Audubon, PA: PJM Interconnection, LLC, February 24, 2023), https://insidelines.pjm.com/pjm-details-resource-retirements-replacements-and-risks/.

27 Jesse Dakss, Oliver Stover, Ryan Chigogo, Ryan Israel, Charles Merrick, Chloe Romero Guliak, Dean Koujak, Abdul Mohammed, and Spencer Hurst, *Synergies between Offshore Wind and Natural Gas* (Boston, MA: Charles River Associates, January 29, 2026), https://www.crai.com/insights-events/publications/synergies-between-offshore-wind-and-natural-gas/.

- **Extended generator interconnection timelines:** Despite reforms,[28] interconnection studies and transmission upgrades can take years, limiting how quickly new resources can come online;[29] and
- **Supply chain challenges:** Since 2020, supply chains have been constrained, leading to increased costs and prolonged wait times for critical power generation hardware.[30]

Market and affordability impacts

As a result of these changing dynamics, PJM now faces material resource adequacy risks and increasing affordability pressures. Recent capacity auctions have seen reserve margins tightening and consistently high prices, as shown in Figure 5. The prices shown are for the broad "RTO" capacity pricing region of PJM, while there was some inter-zonal variation in several of the auctions. The 2026/27 BRA cleared only slightly above PJM's reliability requirement, with prices hitting administrative caps.[31] The 2027/28 BRA also cleared at the administrative cap, but it fell over 6 GW short of the reliability requirement, raising the specter of future power outages.[32] The administrative caps on capacity prices for the past two BRAs were constrained by a price collar. Without the collar, prices would have cleared higher. The 2028/29 BRA will likely fall even shorter of the reliability requirement.

[28] Federal Energy Regulatory Commission, *Order Accepting Tariff Revisions Subject to Condition*, PJM Interconnection, L.L.C., Docket Nos. ER22-2110-000 and ER22-2110-001 (Washington, DC: Federal Energy Regulatory Commission, November 29, 2022), Accession No. 20221129-3092.

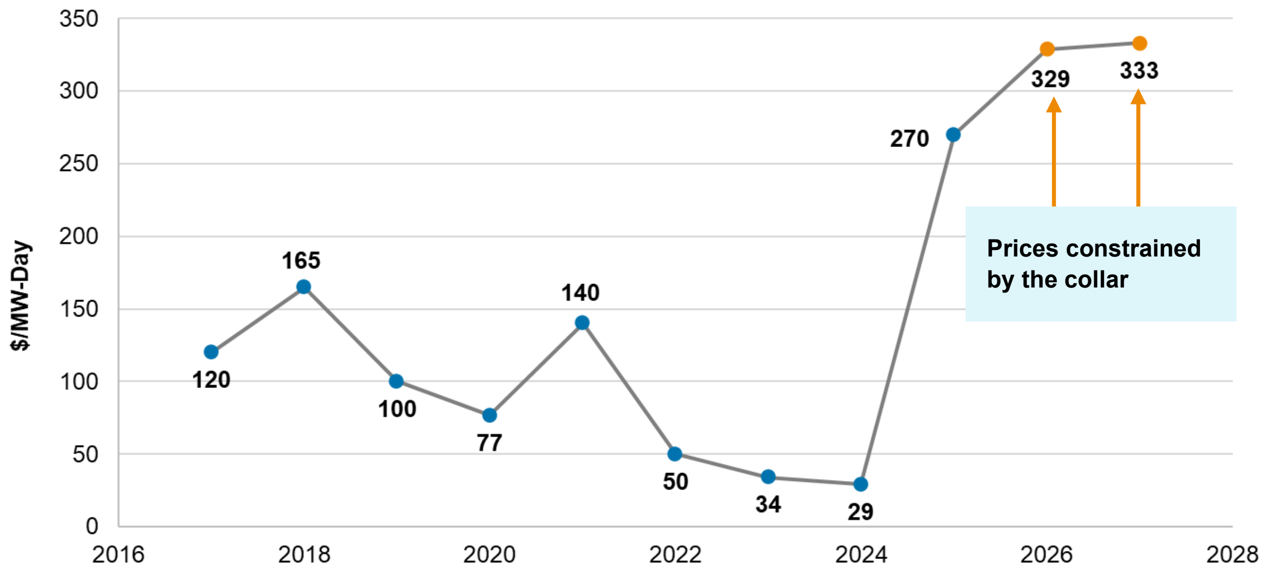
[29] Joseph Rand, Nick Manderlink, Will Gorman, Ryan Wiser, Joachim Seel, Julie Mulvaney Kemp, Seongeun Jeong, and Fritz Kahrl, *Queued Up: 2024 Edition* (Berkeley, CA: Lawrence Berkeley National Laboratory, April 2024), https://emp.lbl.gov/sites/default/files/2024-04/Queued%20Up%202024%20Edition_1.pdf.

[30] Sophie Yeo, "Costs to Build Gas Plants Triple, Says CEO of NextEra Energy," *Gas Outlook*, March 25, 2025, https://gasoutlook.com/analysis/costs-to-build-gas-plants-triple-says-ceo-of-nextera-energy/.

[31] PJM Interconnection, LLC, *2026/2027 Base Residual Auction Report* (Audubon, PA: PJM Interconnection, LLC, July 22, 2025), https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2026-2027/2026-2027-bra-report.pdf.

[32] PJM Interconnection, LLC, *2027/2028 Base Residual Auction Report* (Audubon, PA: PJM Interconnection, LLC, December 17, 2025), https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2027-2028/2027-2028-bra-report.pdf.

Figure 5: PJM Historical Capacity Prices



Despite market outcomes signaling scarcity, there have not been meaningful amounts of new accredited capacity additions. Instead, customers face higher costs while reliability risks remain elevated. These pressures highlight the need to explore complementary approaches, such as incremental utility-owned generation, that could address tightening reserve margins, reduce customer exposure to price volatility, and support more predictable resource development even under conditions of high uncertainty.

3. Approach and Results

This section summarizes the scenario design, analytical tools, and resulting findings used to evaluate two alternative resource development scenarios for PJM in DY 2028/29: Business as Usual (BAU) and Planned Utility Resources (PUR). The BAU case represents a likely real-world outcome for DY 2028/29. The hypothetical PUR case supplements available generation with additional utility-owned generation resources, assuming they had been developed over recent years as load growth expectations materialized. This case assumes that the expanded resource mix would be available on or before the start of the DY.

These findings offer insight into how different development approaches shape customer costs and reliability under the same market construct. CRA performed this analysis for DY 2028/29. This DY corresponds to the capacity auction, known as the BRA, scheduled for summer 2026. While CRA only analyzed a single year, the quantified benefits should be durable as long as grid tightness continues, and benefits to customers would accrue with each additional year of operation.

3.1 Summary of Findings

Across the energy and capacity markets, the PUR case delivers $9.6 to $20.0 billion in customer savings during DY 2028/29. Over the same period, it reduces EUE, service interruptions due to insufficient generation, by 398 GWh, which equates to the annual electricity consumption of approximately 38,000 American households,[33] and a reliability benefit of $10 billion under assumptions described below.

Based on our analysis, several themes emerged:

- **BAU operates under generator shortage conditions, resulting in elevated prices and poor reliability outcomes.**
  Elevated capacity prices in the BAU case reflect insufficient accredited capacity in DY 2028/29. Long development timelines, interconnection constraints, and investment uncertainty limit the extent to which price signals can attract new capacity additions by IPPs alone. As a result, customers face higher capacity costs while reliability risks from insufficient generation grow.

- **PUR achieves lower capacity prices and better reliability.**
  In addition to lower capacity and energy costs, the PUR case achieves an almost a seven-fold reduction in load shedding[34] risk driven by insufficient electricity generation. Even if load

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33 U.S. Energy Information Administration, *Electricity Use in Homes* (Washington, DC: U.S. Energy Information Administration, December 18, 2023), https://www.eia.gov/energyexplained/use-of-energy/electricity-use-in-homes.php.

34 **Load shedding** is intentionally disconnecting electricity service during periods of grid stress when there is insufficient electricity supply to meet demand. Load shedding steps are taken by operators to preserve overall reliability and result in power outages for customers. This analysis does not consider outages due to transmission and distribution events.

shedding were to occur in the PUR case, events would be materially smaller and shorter than in the BAU case.

- **PUR case reduces day-to-day energy prices by reducing reliance on high-cost units.** Incremental gas and storage additions exert downward pressure on energy prices by expanding lower marginal cost supply and by reducing the hours in which expensive units and scarcity conditions set the market price.

- **PUR case better positions the grid to balance multiple policy objectives, including state storage targets and economic development goals.**
By enabling incremental additions of resources aligned with state policy objectives and under state oversight, the PUR case supports the achievement of storage targets that lag behind schedule in the BAU case.

3.2 Scenario Design

To better understand the impact of reforming state policies to allow and plan for utility-owned regulated generation, we project PJM market conditions and outcomes under two scenarios:

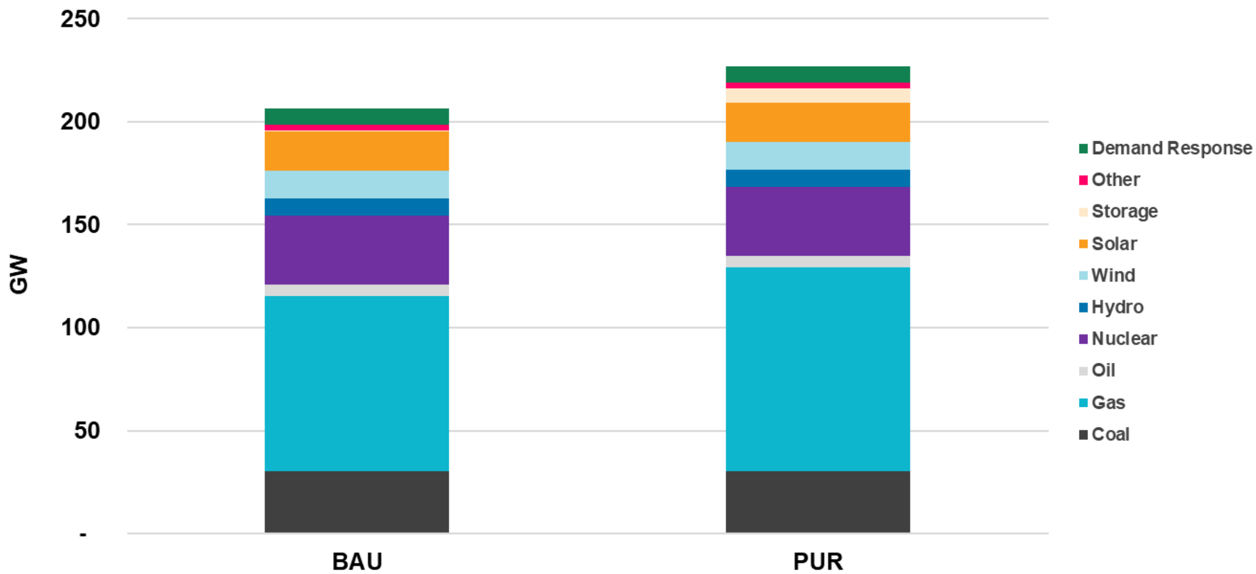
- The BAU case simulates the most likely real-world resource mix for DY 2028/29.

- The PUR case represents a scenario in which additional states permitted or directed utilities to invest in utility-owned generation ahead of emerging reliability challenges.

Other macroeconomic and electrical operating assumptions are held constant. By changing only the incremental generation resource mix resulting from the increase in utility-owned generation, the analysis highlights key differences in system performance, reliability outcomes, and customer cost impacts across the two scenarios to quantify the potential benefits of adopting the PUR framework.

Figure 6 shows the installed capacity of generators in the PUR case, compared with the BAU case.

Figure 6: 2028/29 Capacity Mix under BAU and PUR Cases



3.2.1 Business as Usual (BAU) Case

For the BAU case, CRA included generator additions likely to be online prior to the start of DY 2028/29. As illustrated in Figure 7, some additions are already *under construction* or testing. *Announced resources* are still in earlier stages of development, but can be considered likely to enter operation prior to DY 2028/29. Also, the BAU included additions and uprates selected in PJM's **Reliability Resource Initiative (RRI)**[35] and scheduled to enter service by June 1, 2028, though we note that some of the selected projects have been delayed or withdrawn, which indicates actual conditions could be less reliable than our BAU case.[36] CRA assumed that all currently scheduled and announced retirements would be delayed to preserve near-term reliability, consistent with current trends.[37,38] The US Department of Energy (DOE) would delay retirement until after DY 2028/29 through the use of its Section 202(c) authority.[39] Given the short-term nature of 202(c) extensions, CRA assumed these resources would not participate in

35 **Reliability Resource Initiative (RRI)** is a one-time, fast track opportunity created to enable 51 resources to quickly interconnect to the grid. See https://insidelines.pjm.com/pjm-chooses-51-generation-resource-projects-to-address-near-term-electricity-demand-growth/.

36 PJM Interconnection, LLC, *Reliability Resource Initiative (RRI) Addendum – Post Meeting*, presented to the Planning Committee (Audubon, PA: PJM Interconnection, LLC, May 6, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2025/20250506/20250506-rri-addendum---post-meeting.pdf.

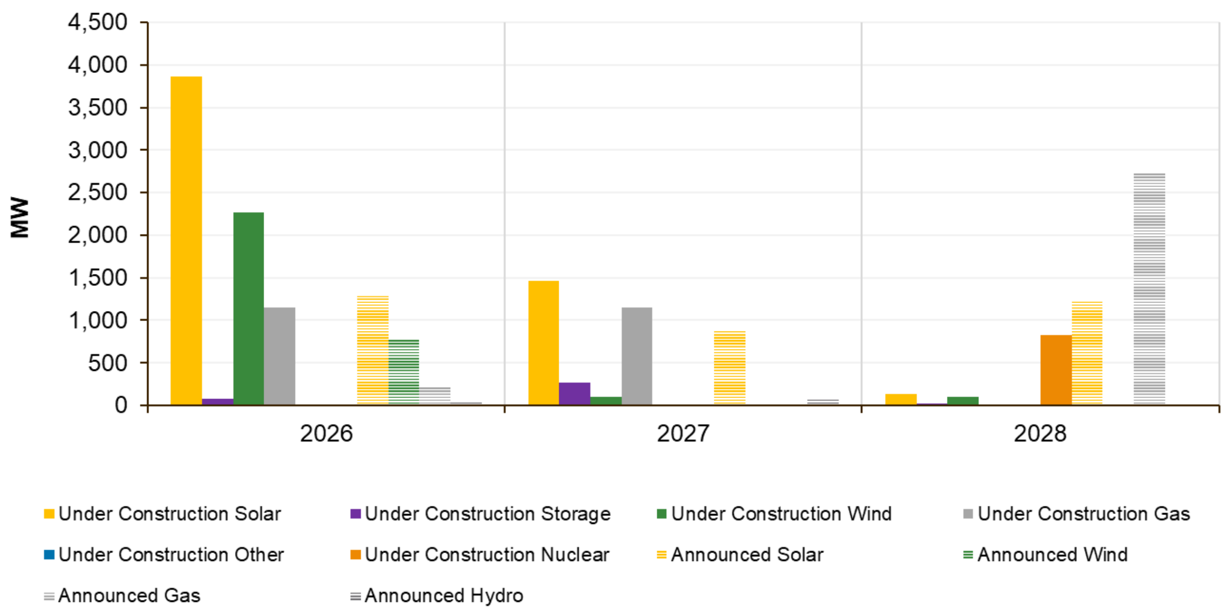
37 North American Electric Reliability Corporation (NERC), *2025 Long-Term Reliability Assessment* (Atlanta, GA: NERC, January 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

38 U.S. Department of Energy, *Report on Evaluating U.S. Grid Reliability and Security* (Washington, DC: U.S. Department of Energy, July 7, 2025), https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

39 The DOE has already delayed the retirement of 4.5 GW of coal capacity under its section 202(c) authority. Sonal Patel, "DOE Uses Emergency Powers to Freeze More Than 2 GW of Coal Retirements as Opposition Intensifies," *POWER Magazine*, December 31, 2025, https://www.powermag.com/doe-uses-emergency-powers-to-freeze-more-than-2-gw-of-coal-retirements-as-opposition-intensifies/.

the BRA. CRA also assumed load growth, fuel costs, outage behavior, and other system fundamentals followed PJM's most recent projections.

Figure 7: Annual Under Construction and Announced Additions



3.2.2 Planned Utility Resources (PUR) Case

For the PUR case, CRA created an alternative scenario in which utilities across a broad range of PJM states developed utility-owned generation under state regulatory oversight to meet forecasted system needs and state storage targets by DY 2028/29. The PUR case assumes states began planning for utility-owned generation well in advance of current supply pressures, enabling additional generation development prior to the start of DY 2028/29. Under this framework, long-term system planning and thorough public regulatory processes - supplemented by market signals where relevant - would guide utility-owned generation planning. As in the BAU case, additions under development would continue on schedule and retirements would be delayed.

As shown in Table 1, the PUR case includes a larger and more diversified resource portfolio across the PJM footprint relative to the BAU case. These resources are incremental to those included in the BAU case, and resource additions are designed to, among other things, ensure that states with storage policy targets achieve those goals. For the remaining capacity, CRA assumed that equal amounts of natural gas combined cycles and simple cycle combustion turbines constitute the remaining incremental capacity needed to achieve a return to historical PJM reserve margins. This assumption balances the combined cycles, which deliver low-cost energy as well as capacity, with less capital-intensive simple cycle combustion turbines, which primarily generate only during times of system tightness. All other assumptions, including load growth, fuel costs, capacity market design, and retirements are held constant, allowing the analysis to isolate the effects of a planned, utility-led resource development approach.

Table 1: Resource Additions (MW)

Resource Type	BAU Case	PUR Case
Gas Combined Cycle	2,090	9,762
Gas Combustion Turbine	168	7,840
Battery Storage	368	6,793
Solar	5,664	5,664
Wind	2,475	2,475
Nuclear	829	829
Total	**11,594**	**33,363**

CRA estimated the cost of utility-owned generation in the PUR case by calculating the **Gross Cost of New Entry (Gross CONE)**[40] for each technology. Gross CONE provides an annualized estimate of the cost of long-lived assets and closely reflects annual customer charges for utility-owned generation. CRA relied on PJM CONE reports for DYs 2025/26 and 2028/29[41] to reflect overnight capital costs and fixed operations and maintenance costs that utilities would have incurred had they begun planning approximately four years earlier and continued through to the present. Under the PUR framework, customers would pay for the cost of constructing and maintaining utility-owned generation over the useful life of the assets (approximately 15 – 30 years), consistent with well-established practice in cost-of-service rate design.

To estimate costs specific to utility-owned generation, CRA created its own model to calculate annual CONE values assuming 45% debt capitalization, an interest rate of 5.10%, and a utility **Return on Equity (ROE)**[42] of 10%. Under the utility-owned generation framework, customers receive credit for the energy and capacity market earnings of the resources, offsetting costs.

40 **Gross Cost of New Entry (Gross CONE)** is defined as the total, levelized cost of constructing and operating a new generation unit each year, without deducting market revenues.

41 Annual costs are based on the average Rest-of-RTO overnight capital costs and fixed operations and maintenance (O&M) costs reported in the *Brattle 2025 CONE Report for PJM* and the *PJM CONE 2026/27 Report*, combined with CRA estimates of utility capital structure and the cost of debt and equity. Sources: The Brattle Group and Sargent & Lundy, *2025 CONE Report for PJM* (Boston, MA: The Brattle Group, April 2025), https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2025/20250411-special/item-1-02-revised-cone-report-final.pdf. Gordon Newell, et al., *PJM CONE 2026/27 Report: Cost of New Entry Analysis*, prepared for PJM Interconnection, L.L.C. (Boston, MA: The Brattle Group, 2022), https://www.brattle.com/insights-events/publications/pjm-cone-2026-27-report/.

42 **Return on equity (ROE)** is the rate at which utilities earn a return on capital they deploy. The ROE is subject to regulatory approval.

Table 2 shows that CRA estimated the gross costs of utility-owned generation to be $4.8 billion, but after capacity and energy market offsets, the net cost to customers falls to $3.1 billion.

Table 2: Projected Costs of Incremental Utility-Owned Generation for DY 2028/29

Metric	Utility-owned Generation Costs ($ million)
Gross Annualized Costs	$4,780
Capacity Market Earnings	$(683)
Energy Market Earnings	$(968)
Net customer costs	$3,128

3.3 Capacity Costs (Capacity Market Modeling)

CRA forecasted PJM capacity prices for DY 2028/29 based on projected supply-demand conditions, recent auction outcomes, and known market design parameters. The BAU case capacity price forecast incorporated PJM's proposed updates to the administratively-determined capacity demand curve, or the Variable Resource Requirement (VRR) curve,[43] applicable to the DY. It also included the BAU case resource portfolio and the net revenue from the production cost modeling of the case.

The PUR case applies the same capacity market modeling methodology and assumes that utility-owned generation participates in the BRA for DY 2028/29.[44] All other assumptions, including demand levels, reliability requirements, and market clearing mechanics, are held constant, enabling a focused comparison of capacity price and cost impacts across scenarios.

Given regulatory uncertainty regarding BRA maximum prices, CRA examined BAU case capacity costs under two sensitivities that define a likely range of potential capacity price outcomes. The "lower capacity price" sensitivity assumes an extension of the price collar that has been in place for the past two auctions, which would be approximately $337/MW-day in DY 2028/29.[45] This sensitivity is aligned with ongoing policy developments, including a major recent

[43] PJM Interconnection, LLC, *PJM Files Joint Periodic Review Proposal to FERC* (Audubon, PA: PJM Interconnection, LLC, June 20, 2025), https://insidelines.pjm.com/pjm-files-joint-periodic-review-proposal-to-ferc/.

[44] CRA assumes the incremental utility-owned generation participates in the BRA rather than the Fixed Resource Requirement option. This assumption does not materially impact the results.

[45] This accounts for inflation from the current cap of $333.44/MW-day, assuming PJM's previous BRA inflation rate of 1.28%

policy directive,[46] that suggest a reasonable likelihood that the current price collar with a lower price cap is extended.[47] In the "higher capacity price" sensitivity, the collar is assumed to expire, leaving a price cap of $550/MW-day as set by the VRR curve.

Results

Consistent with recent auction outcomes and projected reserve margins, the BAU case reflects a system with capacity shortages, and thus insufficient supply relative to PJM's reliability requirement. Modeled results indicate BAU case capacity prices for DY 2028/29 will clear at the respective price caps for both sensitivities, meaning $337/MW-day for the lower capacity price sensitivity and $550/MW-day for the higher capacity price sensitivity. In each sensitivity, the BAU case results in significant capacity cost impacts to customers. CRA estimates total PJM-wide capacity costs for DY 2028/29 between $16.6 billion and $27.0 billion in the BAU case, depending on policy outcomes related to the price collar.

In the PUR case, modeled capacity prices for DY 2028/29 return to levels broadly consistent with historical norms, clearing at approximately $120/MW-day. This outcome reflects a system in which utility-owned generation meets a majority of incremental reliability needs. Lower clearing prices translate directly into reduced capacity costs for customers. CRA estimates total PJM-wide capacity costs at approximately $6.7 billion in DY 2028/29 for the PUR case.

Table 3 presents a comparison of capacity price outcomes and aggregate customer capacity costs for the BAU and PUR cases. It shows the extent to which utility-owned generation moderates capacity prices and reduces customer costs in DY 2028/29.

46 U.S. Department of Energy, *Trump Administration Calls for Emergency Power Auction to Build Big Power Plants Again* (Washington, DC: U.S. Department of Energy, January 16, 2026), https://www.energy.gov/articles/trump-administration-calls-emergency-power-auction-build-big-power-plants-again.

47 Ibid.

Table 3: Capacity Price and Cost Comparison

Resource Scenario	BAU Case		PUR Case
Capacity Market Design Sensitivity	Higher Price (no collar)	Lower Price (with collar)	
2028/29 (UCAP $/MW-Day)	$550.00	$337.77	$125.89
UCAP MW Cleared (GW)	134	134	146
Capacity Costs ($ billion)	$27.0	$16.6	$6.7
PUR Capacity Cost Savings (Lower, $ billion)			$9.9
PUR Capacity Cost Savings (Higher, $ billion)			$20.3

3.4 Energy Costs (Production Cost Modeling)

To estimate wholesale energy supply costs, CRA ran production cost modeling simulations with Aurora, a widely accepted energy market modeling tool. This model simulates the hourly, chronological dispatch of generating resources to meet system demand, producing zonal energy prices and generator operations across PJM.

Under the BAU case, the production cost model reflects current expectations for the BAU resource mix, fuel and emissions costs, demand, and interzonal transfer capabilities. Under the PUR case, the same modeling framework is applied using the expanded resource portfolio associated with planned development. This comparison allows CRA to quantify annual savings in energy costs under the PUR case relative to the BAU case.

Results

The modeling results illustrate how changes in the resource mix affect dispatch patterns, marginal pricing outcomes, and overall energy costs. The monthly projection for the energy costs in both scenarios is shown in Figure 8. Higher prices in the BAU case reflect relatively tighter system conditions, particularly during peak hours, when higher marginal cost resources are dispatched more frequently. In contrast, the PUR case benefits from a broader pool of lower-cost resources, reducing reliance on higher marginal cost units and lowering overall energy costs. The annual weighted average energy costs for the BAU case are $54.9/MWh versus $52.9/MWh under the PUR case, a 3% reduction.

Figure 8: Projected Average Monthly Energy Prices for DY 2028/29 under the BAU and PUR Cases

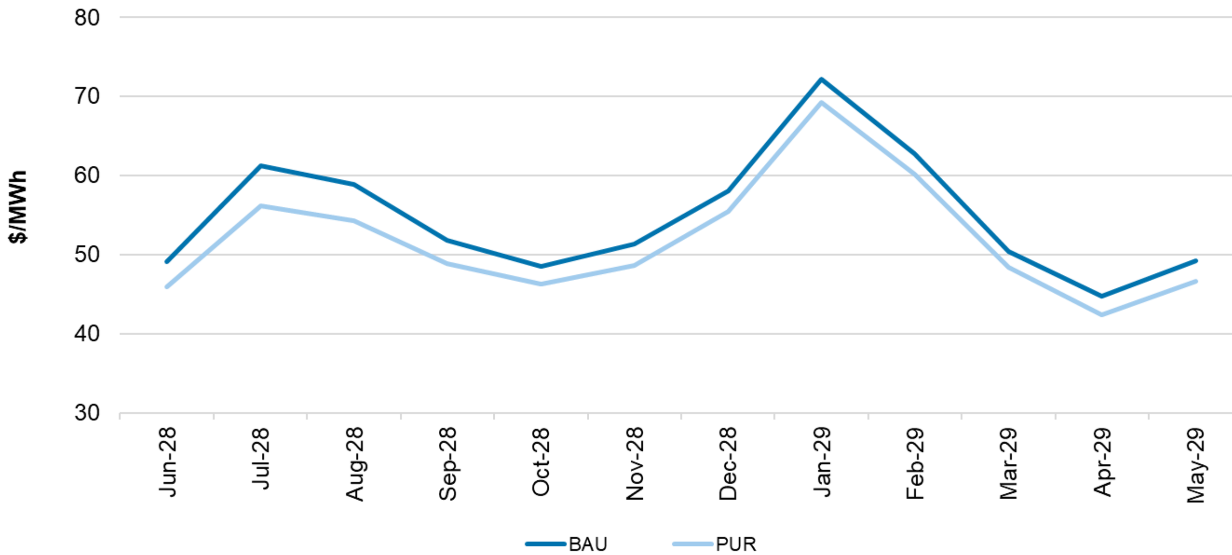


Table 4 shows the total cost of wholesale energy procurement in the BAU and PUR cases. Modeling results indicate that load and energy production costs result in total wholesale energy costs of $54.5 billion in the BAU case. In the PUR case, the prevalence of efficient new generation and BESS drives total wholesale energy costs below $51.6 billion, for a PUR case customer savings of $2.9 billion in wholesale energy supply costs. CRA notes that, although we analyzed only a single year, these savings would likely continue to accrue for years until the supply demand balance in the BAU case returns to historical PJM levels.

We also note that although utilities “lock in” wholesale energy procurement costs months, and even years, in advance, over the long-term customers ultimately pay the full cost of wholesale energy. This means cost savings from the PUR case would ultimately result in lower customer bills, but these impacts may not be felt immediately.

Table 4: Wholesale Energy Cost Comparison

Metric	Wholesale Energy Costs ($ million)
BAU Case	$54,478
PUR Case	$51,590
PUR Energy Cost Savings	$2,888

3.5 Total Financial Benefits to Customers from Utility-Owned Generation

To understand the total financial cost or benefit to PJM customers from the additional utility-owned generation in the PUR case, the energy and capacity savings are compared to the net costs of the generation (i.e., the annualized gross cost less margins from market sales that would revert to customers). If the savings are greater than the costs, the generation has a net benefit, and vice versa. CRA finds that the utility-owned generation in the PUR case saves PJM customers between $9.6 billion and $20.0 billion in DY 2028/29.

Figure 9 shows the composition of the customer benefits, focusing on the lower capacity price sensitivity in which the price collar is extended to DY 2028/29. In this sensitivity, the $9.9 billion in capacity savings that result from returning to historical PJM reserve margin levels and the $2.9 billion in energy savings caused by the displacement of higher marginal cost units more than offset the net customer costs of incremental generation of $3.1 billion. Figure 10 shows the same chart for the higher capacity price sensitivity that includes $20.3 billion in capacity savings. The higher capacity price sensitivity assumes that the proposed VRR curve price cap, rather than the price collar, will limit capacity prices in DY 2028/29.

Figure 9: PUR Net Financial Costs/Savings, Lower (Collared) Capacity Price Sensitivity, $ billion

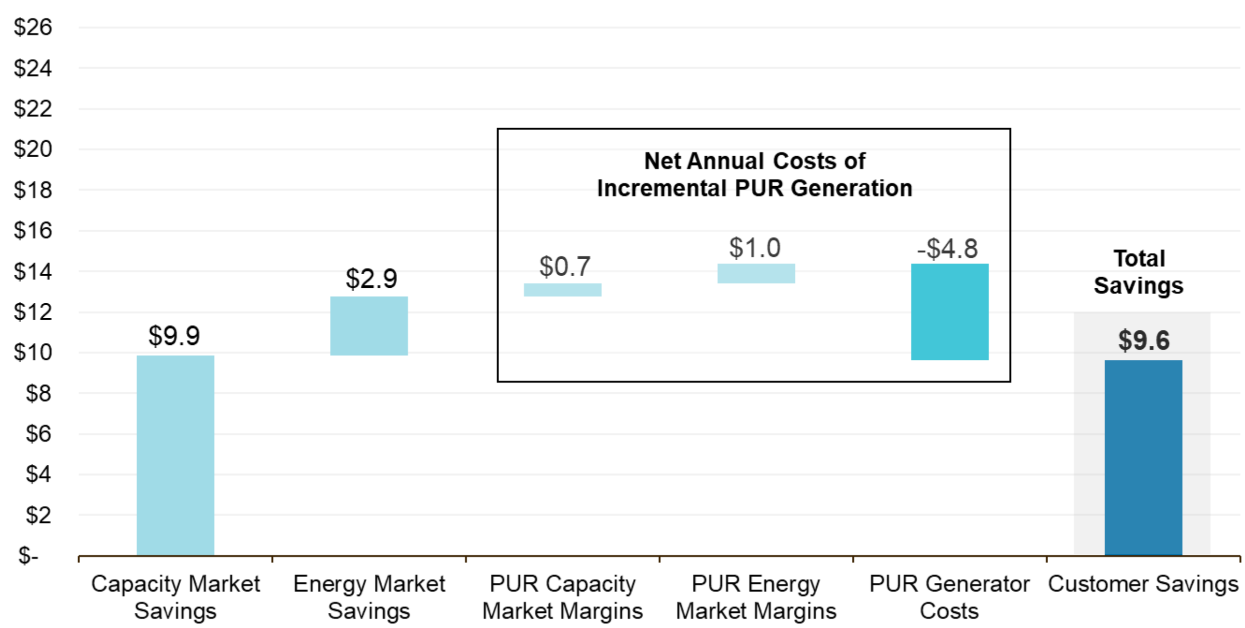
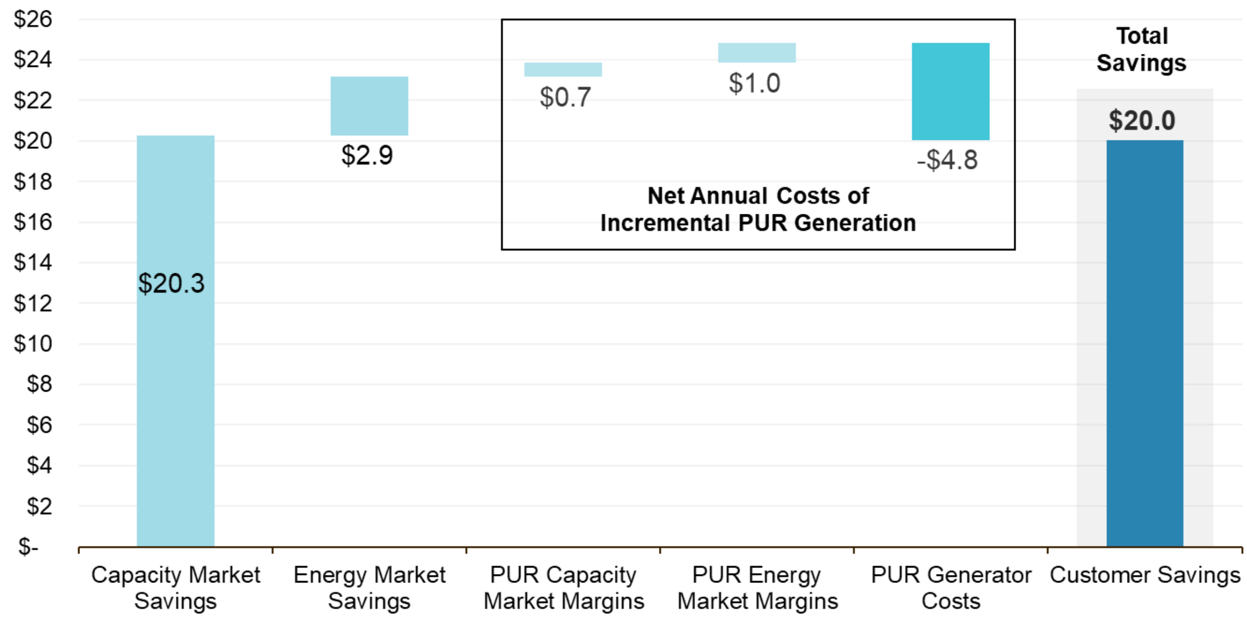


Figure 10: PUR Net Financial Costs/Savings, Higher (No Collar) Capacity Price Sensitivity, $ billion



3.6 Resource Adequacy Risk (Loss of Load Modeling)

To evaluate the resource adequacy benefits of the PUR case, CRA forecasted the resource adequacy outlook for DY 2028/29 based on projected supply-demand conditions, electricity load, and generator outage rates. This analysis focused on physical reliability outcomes, rather than the direct supply costs paid by customers. This analysis was performed using CRA's probabilistic loss of load modeling framework, AdequacyX.[48]

This analysis evaluated one key element of overall grid reliability: resource adequacy, which refers to ensuring there is sufficient and deliverable electricity generation to meet demand across all grid conditions. Resource adequacy is typically assessed with loss of load modeling, simulations that estimate the likelihood and severity of conditions in which electricity demand exceeds available supply, leading to power outage events – known as load shedding.

This analysis did not consider other elements of reliability, such as outages caused by damage to local transmission and distribution systems, including downed power lines from storms or vegetation interactions.[49] These types of transmission and distribution outages have historically been the largest driver of customer interruptions and are expected to be similar across the BAU and PUR cases. While periods of insufficient generation and transmission and distribution

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48 More detail is provided in the appendix.

49 National Renewable Energy Laboratory, *Bulk Electric System Reliability Considerations in the U.S. Transmission Planning and Operational Horizon, 2023–2032*, NREL/TP-6A40-87297 (Golden, CO: National Renewable Energy Laboratory, 2023), https://docs.nrel.gov/docs/fy24osti/87297.pdf.

events both result in customer outages, they are evaluated separately and require different interventions to mitigate risk.

At its core, the resource adequacy modeling recognizes that grid outcomes - including customer demand, generator planned and unplanned outages, availability of fuel, [50] and impacts of weather - are uncertain. The model simulated 100 possible outcomes for DY 2028/29. Each of these simulations captured a single outcome from the wide range of possible outcomes for load, generation availability, and generator outages, and together they are collectively used to quantify resource adequacy, that is outage risk due to insufficient generation. Consistent with industry practice, the model simulated correlated system stresses, such as extreme weather jointly driving the outcomes of all these variables.

This analysis also enabled CRA to identify when, why, and to what extent the grid is most stressed under the two cases. CRA also examined the seasonal distribution of outages, which has important implications for both the cause, consequence, and potential mitigation of load shedding due to insufficient electricity generation. As shown in

Table 3, both winter and summer risk can result in substantial health and economic disruptions, with winter generally providing more immediate health risks.[51,52]

Metrics

From the 100 simulations produced in AdequacyX, CRA evaluated reliability risk using several complementary metrics. CRA calculated total **annual unserved energy** in each simulated year and reported the EUE,[53] along with a range of outcomes to illustrate uncertainty and tail risk. EUE is a resource adequacy risk metric that measures the expected (average) amount of energy demand that cannot be served due to insufficient generation (with transmission and distribution outages are not included). These events represent periods when customers would experience power interruptions. Power systems are typically planned such that EUE represents less than about 0.001–0.002% of total annual electricity demand, reflecting very high reliability standards. Other resource adequacy metrics exist - including loss of load probability, load of load expectation, and others - but we selected EUE as it is more interpretable to a wider range of audience than other metrics. Furthermore, it does a better job capturing not just frequency of

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50 In line with other loss of load modeling, this analysis does not consider transmission outages.

51 Joan A. Casey et al., "Power Outages and Community Health: A Narrative Review," *Current Environmental Health Reports* 7, no. 4 (2020): 371–383, https://doi.org/10.1007/s40572-020-00295-0.

52 L. Chu, R. Dubrow, and K. Chen, "Heat- and Cold-Related Mortality Burden in the US From 2000 to 2020," *JAMA Network Open* 8, no. 11 (2025): e2542269, https://doi.org/10.1001/jamanetworkopen.2025.42269.

53 **Expected unserved energy** is the average amount of total load shedding in a given year due to insufficient or undeliverable power generation. It does not consider transmission and distribution outages. Alternative metrics, including loss of load expectation, loss of load probability, and others are all suitable for evaluating resource adequacy. EUE was selected due to its ability to capture magnitude and duration of events and its interpretability. Other metrics, like System Average Interruption Frequency Index, are most commonly used for distribution reliability and not typically used to measure shortfalls due to insufficient generation.

generation shortfalls, but volume of energy not served.[54] We also report the 95th-percentile annual unserved energy outcomes to understand the tail risk.[55]

From these simulations, CRA estimated the economic impact of outages using a Value of Lost Load (VOLL) of $25,000/MWh. VOLL is an estimate of the price a customer would be willing to pay to prevent a disruption, and its value varies materially across studies.[56][57] We chose an intermediate estimate for the purposes of this study, one that is neither on the low or high end of VOLL estimates. Of note, this is a theoretical estimate and generally an expression of economic losses from unavailability of electricity, rather than a cost directly borne by customers. As such, while we calculated the cost of unserved load in our analysis, we do not add the avoided costs of lost load to our estimate of customer cost savings.

To illustrate what outages might actually look like, CRA reports when outages occur and how severe they are. Results are broken out by month and hour of day. From these month-hour segregations, we computed 99th-percentile outcomes to highlight credible grid-stress conditions. Because each hour occurs many times in a month (for example, there are 31 separate 3:00 PM hours in July), these outcomes represent plausible stress events that would occur approximately once every three years, with inter-year variability driven by weather

54 North American Electric Reliability Corporation (NERC), *Probabilistic Adequacy and Measures Report* (Atlanta, GA: North American Electric Reliability Corporation, n.d.), accessed February 5, 2026, https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/pawg/probabilistic_adequacy_and_measures_report.pdf.

55 These are **quantiles**, which represent the nth-percentile outcome when all possible outcomes are ordered by magnitude and assigned a cumulative percentage. For example, the 95th-percentile reflects an outcome that is exceeded in only 5 percent of cases.

56 Michael J. Sullivan, Robert T. McDermott, and Shmuel S. Oren, “The Value of Lost Load (VoLL) for Electricity Supply Reliability: An Econometric Analysis of U.S. Outage Cost Data,” *Utilities Policy* 78 (December 2022), https://doi.org/10.1016/j.jup.2022.101403.

57 Thomas Schröder and Wilhelm Kuckshinrichs, “Value of Lost Load: An Efficient Economic Indicator for Power Supply Security? A Literature Review,” *Frontiers in Energy Research* 3 (December 24, 2015), https://www.frontiersin.org/articles/10.3389/fenrg.2015.00055/full.

variability and natural randomness. This approach helps identify when the grid is most vulnerable and the scale of resources needed to reduce risk.

Table 3: Illustration of Seasonal Risk Factors [58,59,60,61]

Summer versus Winter Outages			
What causes grid stress in the summer?	Extreme heat drives high cooling demand while thermal generators operate less efficiently and wind output can be lower.	**What causes grid stress in the winter?**	Extreme cold drives high heating demand that coincides with higher generator outages, fuel constraints, low solar output, and weather-related operational challenges.
Summer outage impacts	Loss of air conditioning during extreme heat, creating public health risks and business disruptions.	**Winter outage impacts**	Extended loss of heat during freezing conditions, leading to frozen pipes, water outages, and public safety risks along with business disruptions.
Recent examples of summer outage	California heat-waves in 2020 and 2022. Emergency load shedding in 2020; no load shedding in 2022 despite similar heat stress.	**Recent examples of winter outage**	Winter Storm Uri (Texas, 2021) and Winter Storm Elliott (Eastern U.S., 2022), which caused widespread and prolonged outages.

Results

Resource adequacy risk outcomes were modeled for both the BAU and PUR cases. Table 6 summarizes the expected outcome[62] along with the 95th-percentile high-risk outcome.[63] The

58 California Independent System Operator, *Final Root Cause Analysis: Mid-August 2020 Extreme Heat Wave* (Folsom, CA: California Independent System Operator, July 19, 2021), https://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf.

59 California Independent System Operator, *Summer Market Performance Report for September 2022* (Folsom, CA: California Independent System Operator, December 20, 2022), https://www.caiso.com/documents/summermarketperformancereportforseptember2022.pdf.

60 Federal Energy Regulatory Commission and North American Electric Reliability Corporation, *Lessons Learned from Winter Storm Elliott* (Washington, DC: Federal Energy Regulatory Commission and North American Electric Reliability Corporation, August 3, 2023), https://www.ferc.gov/news-events/news/ferc-nerc-release-final-report-lessons-winter-storm-elliott.

61 Federal Energy Regulatory Commission, *Final Report: February 2021 Freeze Underscores Winterization Recommendations* (Washington, DC: Federal Energy Regulatory Commission, February 18, 2022), https://www.ferc.gov/news-events/news/final-report-february-2021-freeze-underscores-winterization-recommendations.

62 **Expected** outages is determined as the mean (i.e. average) of the scenarios.

63 It is important to note that P95 outcomes will often exceed risk metric targets. Electricity grids are not planned to P95 outcomes, but they provide useful context for extreme tail risk, which is increasingly factoring in resilience evaluations.

total annual unserved energy and associated reliability costs are shown. Note that EUE in the PUR case marginally exceeds the target reliability metric even though reserve margin targets are met. This result likely reflects modeling assumptions that exclude imports from neighboring regions. Incorporating regional risk pooling and transfer capability would be expected to lower resource adequacy risk to target levels.

Across the range of possible outcomes, the additional generation in the PUR case provides significant additional reliability value, between **$1.1 billion and $21.9 billion**, depending on annual conditions, with an expected benefit of approximately **$10 billion**.[64] The PUR case also yields meaningful reductions in the severity of extreme (tail-risk) reliability events.

Table 6: Resource Adequacy Outcomes

	BAU Case			PUR Case		
	Unserved Energy (MWh)	Share of Demand not met	Value of Lost Load ($ billion)	Unserved Energy (MWh)	Share of Demand not met	Value of Lost Load ($ billion)
Expected	467,441	0.048%	$11.7	69,534	0.007%	$1.74
95% Outcome	1,003,225	0.104%	$25.08	182,832	0.019%	$4.57

The majority of total unserved energy, approximately 68% in the BAU case and 65% in the PUR case, occurs in the summer months. However, both scenarios show non-trivial winter contributions to EUE risk. Less than 1% of risk occurs during spring or fall. This phenomenon and the relative split between summer and winter is largely driven by the frequency of winter events: very hot conditions occur in most years, while very cold conditions occur a few times a decade. However, when winter outages do occur, they tend to be longer and larger and can sometimes result in more severe adverse health outcomes for the public.[65]

This summer-forward pattern differs from recent PJM ELCC modeling results, which emphasize winter reliability risk. This difference is not a critique of PJM's approach; rather, it reflects differences in modeling assumptions and purposes. Further discussion can be found in the appendix.

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64 Note, this value is driven by economic and health losses avoided by preventing a power outage, rather than a direct bill payment.

65 L. Chu, R. Dubrow, and K. Chen, "Heat- and Cold-Related Mortality Burden in the US From 2000 to 2020," *JAMA Network Open* 8, no. 11 (2025): e2542269, https://doi.org/10.1001/jamanetworkopen.2025.42269.

To understand the timing of load shedding events, CRA reports the 99th-percentile (high-risk) outcome among all samples in a given hour and month for the BAU case (Figure 11) and the PUR case (Figure 12). In these figures, a deeper red color represents higher risk. Some hours and months show zero values, representing very low likelihood of grid stress in these time periods. In both the BAU and PUR cases, reliability risk appears in summer and winter, indicating that grid stress is possible in both seasons with minimal risk in shoulder seasons. Winter events tend to occur in the early morning and evening, while summer events are concentrated in the late afternoon and early evening.

Figure 11: 99% Load Shedding Risk Outcome in BAU Case

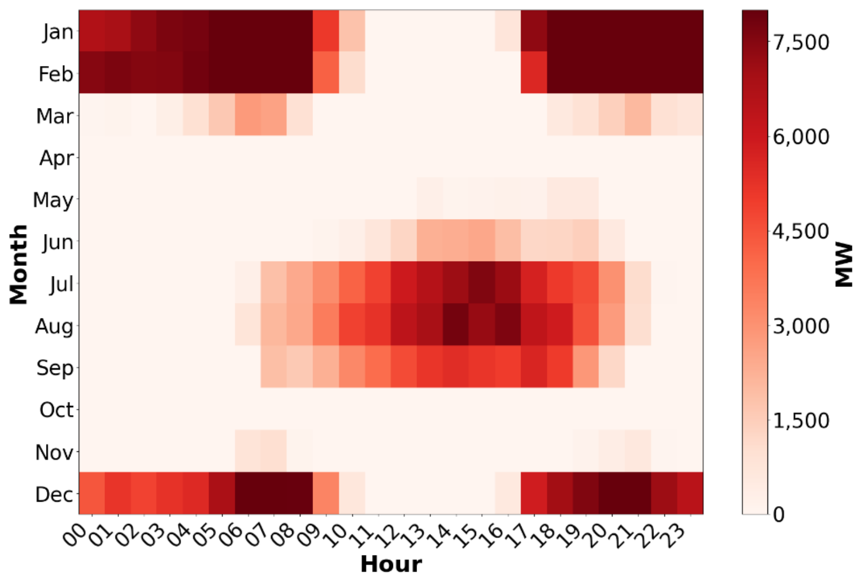
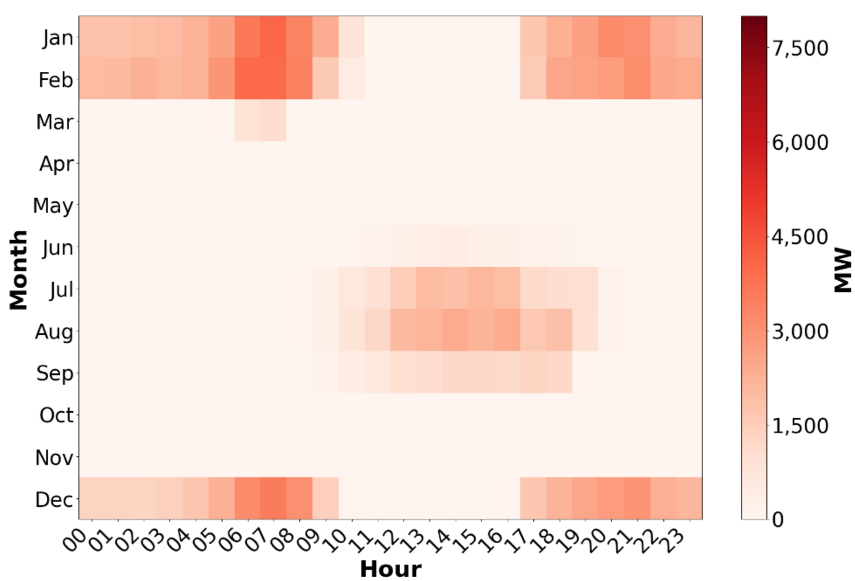


Figure 12: 99% Load Shedding Risk Outcome in PUR Case



The average and 95th-percentile outcomes for the duration and size of outages are shown in Table 4. The PUR case substantially reduces both the frequency and severity of outages.

Table 4: Outage Duration and Size Statistics

	BAU Case		PUR Case	
	Duration of Outages (hr)	Size of Outages (MW)	Duration of Outages (hr)	Size of Outages (MW)
Expected	3.2 hr	1,305 MW	2 hr	463 MW
95% Outcome	10 hr	5,423 MW	5 hr	2,028 MW

Overall, the modeling results show that the PUR case has material resource adequacy benefits. The PUR case results in a substantially higher degree of reliability, smaller and shorter outages if they occur, and more robust performance across a wider range of grid conditions. The PUR case reduces 85% of overall load shedding risk due to insufficient generation and would reduce the size of these outage events by 65% and their duration by 37%. Further, the vast majority of load shedding events in the PUR case are small relative to the total size of PJM and could be solved with emergency actions and imports from other regions. The BAU case would also benefit from such actions, but the relatively larger outages would be substantively more challenging to solve without load shedding.

4. Conclusions

The PJM region has entered a period of significant demand growth, rising supply costs, and tightening reserve margins, conditions that challenge the ability of the current regulatory and market framework to deliver the new resources needed to maintain reliability at reasonable cost. This study assesses the extent to which additional utility-owned generation, illustrated in the PUR case, could have brought affordability, reliability, and other benefits to PJM customers in a near-term period (Delivery Year 2028/29) where the current trajectory for new generation, the BAU case, is expected to bring shortfalls in generation supply relative to increasing demand.

Our analysis finds that the PUR case consistently outperforms the BAU case in delivering value for customers across multiple dimensions:

- **Affordability (energy and capacity costs)**: Utility-owned generation creates substantial total direct customer financial savings, even after accounting for the cost of developing and owning the incremental regulated generation. The additional gas generation and storage resources in the PUR case lower annual energy system costs, reduce the frequency of high-priced dispatch hours, and dampen price volatility, creating billions of dollars in energy cost savings for PJM customers. Most notably, the additional accredited supply relieves capacity scarcity, shifting clearing prices from administratively capped levels toward their historical range and reducing total capacity costs by $9.9 billion to $20.3 billion in a single year.

- **Reliability**: The PUR case also delivers significant improvements in reliability, when considering outage events due to insufficient generation. The EUE metric falls by roughly 85% relative to the BAU case, with meaningful reductions in the likelihood of load shedding during extreme events. The additional, diversified utility-owned generation also reduces the frequency, as well as the magnitude and duration, of outage events, delivering over $10 billion in reliability benefits.

- **Other**: The PUR case facilitates the full achievement of state policy objectives, an outcome not achieved in the BAU case. Other benefits, such as emissions reductions or economic growth, are likely but were not studied.

These findings were based on analysis of a single PJM Delivery Year but can be reasonably applied to subsequent Delivery Years (i.e., periods starting June 1, 2029, and beyond), given the projected ongoing tightness in the PJM market. Without major constructive policy and regulatory developments, PJM is projected to continue to experience tight reserve margins due to elevated peak-load growth and slow entry rates of new accredited capacity. The extent and costs of the shortfall in future years depends on a variety of factors, including evolving market design, fuel price trajectories, supply chain dynamics, siting and interconnection timelines, and the pace of technological change. However, it is clear that utility-owned generation offers the potential to address market tightness while delivering affordability and reliability benefits to customers.

Appendix: Reliability Risk Modeling (AdequacyX)

Resource adequacy

Resource adequacy focuses on ensuring that the bulk electricity generation system, subject to transmission constraints, can deliver sufficient power to meet all end-use demand. It represents a single, but critical element of overall grid reliability, which includes transmission and distribution reliability.

Resource adequacy analysis considers the ability of the generator fleet to:

- Serve all end-use hourly demand, with an acceptable level of reliability, typically defined by reliability standards (discussed further below);
- Accommodate uncertainty and variability in load, variable renewable output, and unplanned generator outages, including weather-correlated events;
- Provide sufficient operating reserves and flexibility, including ramping capability, start times, minimum run times, and multi-hour duration needs;
- Ensure deliverability to load, accounting for internal transmission constraints;
- Manage seasonal variability, recognizing differing summer/winter risk drivers and shifting net load[66] dynamics;
- Withstand fuel assurance and common-mode risks, such as gas supply disruptions or cold/heat-related deratings; and
- Reflect energy-limited characteristics, including storage discharge duration limits.

If a system does not have sufficient generation to meet demand in a given period, operators will perform load shedding, an intentional disconnection of certain customers to preserve the stability of the overall system. In practical terms, maintaining resource adequacy means ensuring that such events are exceedingly rare, so that households, businesses, and critical infrastructure can depend on a continuous and reliable supply of electricity.

To meet the resource adequacy standards that the public expects, system planners and regulators rely on quantitative risk metrics to define the likelihood, duration, and magnitude of load shedding events. The most widely used metric in North America is the Loss of Load Expectation (LOLE), which measures the expected number of days per year with at least one instance of load shedding. North American planning standards typically target a LOLE value of less than 0.1 days/year - meaning that system planners design their system so that load shedding occurs at most once every ten years (i.e., “1-Day-in-10-Years”). While LOLE calculates the frequency of load shedding events, it does not consider the magnitude of events.

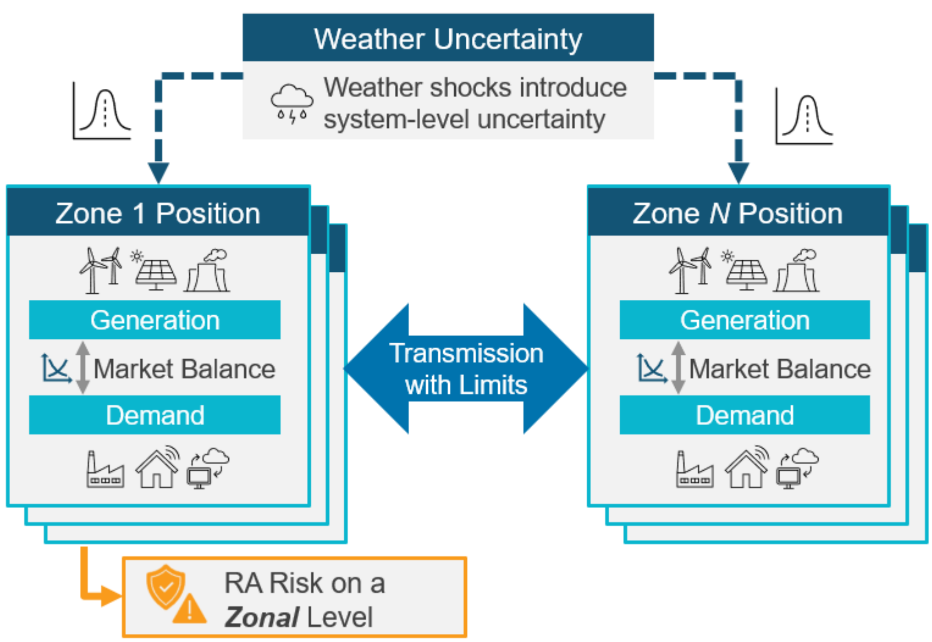
66 Net demand equals gross demand less intermittent renewable generation. This represents the amount of demand that needs to be met by dispatchable generation.

Grid planners and regulators are adopting auxiliary metrics to improve resource planning that quantify the magnitude of potential outages. Planners are increasingly utilizing EUE - the anticipated amount of energy that will not be served due to load shedding.[67]

To assess the resource adequacy of a generator resource mix, we employ loss of load modeling using *AdequacyX,*[68] a Monte Carlo-based simulation tool that quantifies the probability, magnitude, and duration of load-shedding events. Loss of load modeling is a probabilistic approach used to estimate the likelihood and severity of situations where electricity demand exceeds available supply. It accounts for uncertainties in load, generation, and outages to quantify reliability risk.

AdequacyX simulates correlated system “shocks” in load, renewable generation, and thermal outages, explicitly capturing how electrification of heating and transportation reshapes hourly load shapes and increases risk during the coldest hours. The structure of AdequacyX is shown in Figure 13 From the loss of load modeling, we can quantify the resource adequacy of the grid mix by measuring the EUE as well as the range of possible total annual unserved energy outcomes.

Figure 13: Structure of AdequacyX



67 National Renewable Energy Laboratory, *Explained: Fundamentals of Power Grid Reliability and Clean Electricity*, NREL/FS-6A40-85880 (Golden, CO: National Renewable Energy Laboratory, January 2024), https://www.nrel.gov/docs/fy24osti/85880.pdf.

68 Charles River Associates, *Introducing CRA AdequacyX: CRA’s Resource Adequacy Model* (Boston, MA: Charles River Associates, October 2024), https://media.crai.com/wp-content/uploads/2024/10/17133654/Introducing-CRA-AdequacyX-whitepaper-October2024.pdf.

Our modeling did not include further emergency actions, like voluntary reductions in load and imports from other regions. This would further mitigate the load shedding risks.

PJM Modeling versus AdequacyX

In our loss of load modeling, we found that summer risk is more prominent, but winter events still drive a material portion of risk. Meanwhile, in PJM's modeling, it finds that winter risk is the dominant mode. This is driven by differing underlying assumptions and modeling objectives including:

- **Thermal generator capability:** Our model allows thermal generators to operate above their nameplate ratings during winter months, reflecting historical evidence that many units perform more efficiently in colder conditions. This approach also assumed that some generators will have sufficient transmission headroom to exceed their nameplate rating, which reflects summer operating conditions. In practice, we expect that many units would have this headroom, and incorporating it provides a conservative estimate of reliability benefits. If additional winter derates were imposed, risk would increase[69] and be concentrated in winter months.

  PJM did not make this assumption because it cannot verify that individual generators will have transmission headroom above their nameplate limit at any given time. PJM has noted that removing winter capacity caps would reduce its modeled winter reliability risk by approximately 33%.[70] However, PJM retained these caps in its ELCC framework to avoid assigning ELCC credit for output above capacity limits and to ensure that resources without available headroom are not disadvantaged. Incorporating this cap into the modeling shifts the risk profile so that approximately 75% of unserved energy occured during winter events,[71] consistent with PJM's modeling, which indicates a winter-dominant reliability risk.

- **Weather dataset emphasis:** Our modeling placed more weight on recent weather years while PJM equally weighs the last 31-years of weather. Both approaches have value but can shift the distribution of seasonal risk. Our weather data, thus, had slightly fewer very cold years than PJM's weather data which relies on 31-years of weather.[72] As a result, very hot conditions occured in most years, while cold-weather events still occur, but occur marginally less frequently. However, when cold-weather events do occur, they are more likely to result in longer and deeper outages and could result in a greater risk to human life due to extreme weather conditions.

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69 Energy and Environmental Economics, Inc. (E3), *PJM ELCC / RRS Model Evaluation*, prepared for PJM Interconnection, LLC (San Francisco, CA: Energy and Environmental Economics, Inc., December 2025), https://www.pjm.com/-/media/DotCom/committees-groups/task-forces/elccstf/2025/20251209/20251209-item-02---pjm-elcc-rrs-model-evaluation---e3-report.pdf.

70 Ibid.

71 CRA analysis.

72 Energy and Environmental Economics, Inc. (E3), *PJM ELCC / RRS Model Evaluation*, prepared for PJM Interconnection, LLC (San Francisco, CA: Energy and Environmental Economics, Inc., December 2025), https://www.pjm.com/-/media/DotCom/committees-groups/task-forces/elccstf/2025/20251209/20251209-item-02---pjm-elcc-rrs-model-evaluation---e3-report.pdf.

- **Model calibration:** PJM calibrated its model to reflect a target reliability level prior to performing ELCC analysis.[73] Our modeling did not pre-calibrate to a reliability target; instead, it evaluates raw system risk under each scenario. This reflects the differing purposes for our modeling: raw resource adequacy assessment versus ELCC calculation. As shown in our modeling results, the risk profile shifted toward winter risk as overall risk reduces, reflecting the more durable nature of winter risk.

73 Ibid.