2025 RTO
Membership Analysis

PPL companies

October 2025

Contents

1 Overview and Summary

Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively "Companies") have performed an evaluation of whether joining a regional transmission organization ("RTO") would be in the best interest of customers.[1] This 2025 RTO Membership Analysis builds on work performed in the previous RTO reports, the most recent of which was filed with the Companies' 2024 Integrated Resource Plan ("IRP") in Case No. 2024-00326. The primary conclusions of this year's analysis are:

1. **Continuing and controversial market reforms drive ongoing uncertainty.** Midcontinent Independent System Operator, Inc. ("MISO") and PJM Interconnection, L.L.C. ("PJM") continue to modify their market rules to address concerns about resource adequacy, capacity market volatility, and interconnection delays. Some of these reforms and their results, including increased capacity auction prices, have created significant controversy, including a threat from Pennsylvania Governor Shapiro: "If PJM is not willing to look in the mirror and really reform itself, then I'm willing to go my own way."[2] Unless and until MISO and PJM consistently demonstrate their markets are capable of attracting new generation resources to maintain reliability—and the stability of RTO members' long-term membership increases—the Companies can neither practically model RTO membership nor support initiating detailed discussions with MISO or PJM regarding membership.

2. **Rising reliability risks and costs.** NERC in its 2024 Long Term Resource Assessment highlighted MISO's and PJM's expected resource adequacy challenges, driven by retirements of dispatchable generation and inadequate incentives for new builds in the RTOs' flawed market constructs. In particular, PJM's most recent capacity auction results announced on July 22, 2025, showed continued high capacity prices for Delivery Year 2026/2027, reaching the price cap that was designed to promote affordability, but it will likely be insufficient to incentivize the new generation needed to address reliability concerns.

3. **Loss of local system control.** As a standalone utility, the Companies maintain full control over generation planning, fuel procurement, and reliability decisions. In contrast, RTOs operate through complex stakeholder processes where the Companies would have limited influence and could be subject to rules that conflict with Kentucky's energy priorities. PJM in particular is facing a "crisis of confidence" among member states, with governors demanding reforms and even considering exit strategies.[3]

4. **Policy preference for utility ownership.** In its final order in Case No. 2022-00402, the Commission stated, "This Commission has no interest in allowing our regulated, vertically-

[1] *See Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates*, Case No. 2018-00294, Order (Ky. PSC Apr. 30, 2019); *Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates*, Case No. 2018-00295, Order (Ky. PSC Apr. 30, 2019).

[2] https://www.bloomberg.com/news/articles/2025-09-22/pennsylvania-governor-says-biggest-us-power-grid-needs-overhaul?srnd=phx-technology&sref=cBoeoIOm

[3] https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/2025/20250717-nine-governors-letter-regarding-board-vacancies.pdf, at 1

integrated utilities to effectively depend on the market for generation or capacity for any sustained period of time."[4] Additionally, the Kentucky legislature has expressed a similar stance in KRS 164.2807(1)(f), stating, "It is in the interest of the Commonwealth that it be able to generate sufficient electricity *within its borders* to serve its own industrial, residential, and commercial demand and to power its own economy[.]"

5. **No capacity savings.** Finally, RTO capacity accreditation reforms have increased the amount of capacity the Companies would need in PJM and MISO compared to prior studies and have eliminated the potential for capacity and energy savings that previously were a primary benefit from joining an RTO.

This report focuses on the reliability and market issues that are ongoing in both MISO and PJM and the challenges each RTO faces in addressing its future capacity and energy needs. It also describes the fundamental differences between operating as a standalone utility and operating inside an RTO (e.g., capacity planning, fuel planning and procurement, unit commitment and dispatch).

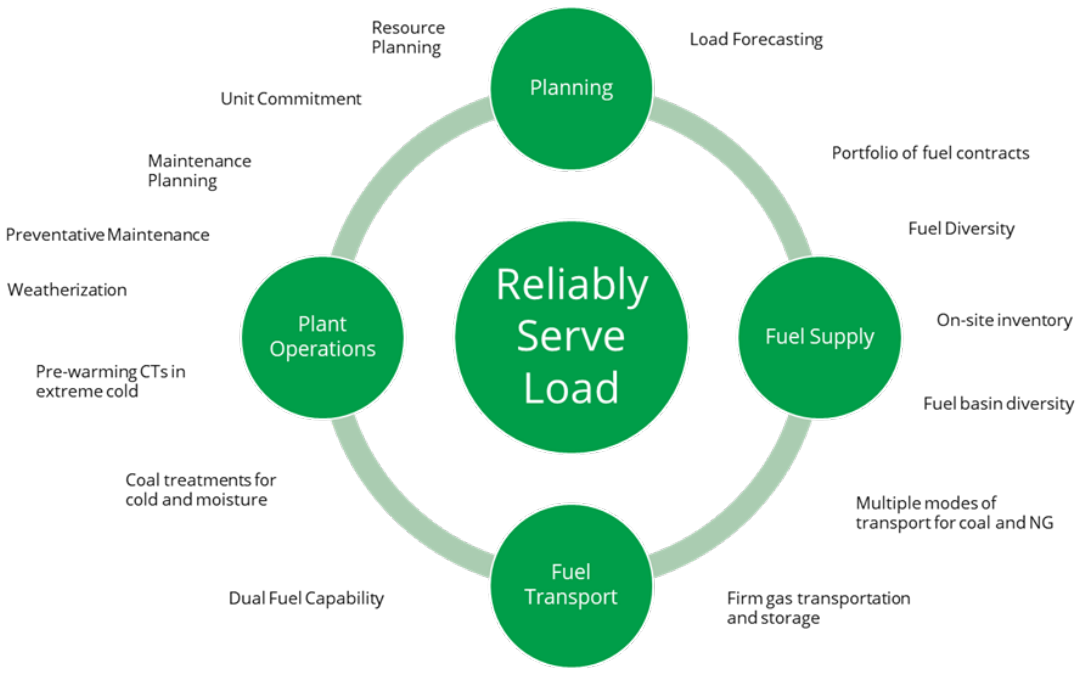
The Companies remain open to the possibility of future RTO membership, and they believe that continuing to study it, albeit perhaps less frequently than the current annual requirements (e.g., only in conjunction with the triennial IRP filing), is entirely appropriate. Less frequent study would allow more time between studies for RTOs to work through their lengthy governance and stakeholder processes to address the numerous issues related to resource adequacy and EPA regulations and to demonstrate some degree of stability. Stability and certainty are important in a decision to join an RTO because it is likely to be challenging and costly to undo such a decision. Therefore, prudence requires that the benefits be clear and durable before making such a decision and commitment on behalf of the Companies' customers.

2 Key Differences in Operating as a Standalone Utility versus in an RTO

A decision to join an RTO must include a thorough consideration of the vast differences between operating as an independent vertically integrated utility (as the Companies currently operate) and an RTO member.

As a standalone, vertically integrated utility, the Companies are solely responsible for all aspects of planning and operating their generation portfolio to reliably serve the Companies' customers' energy needs 8,760 hours a year across a broad range of possible future conditions. The following figure illustrates, at a high level, the continuous cycle of long-term and short-term resource-related planning and operating activities in which the Companies engage to ensure reliable service to customers.

[4] *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan*, Case No. 2022-00402, Order at 177 (Ky. PSC Nov. 6, 2023).



Notably, the Companies evaluate all resource-related decisions (e.g., decisions related to fuel inventory levels, fuel contracts, fuel transportation contracts, environmental compliance, and the need for new resources) (1) in the context of their generation portfolio as a whole and (2) with a singular focus on serving customers reliably and at the lowest reasonable cost. For example, when the Companies identify a need for new capacity, they evaluate the economics and operating characteristics of all available resource options in the context of their generation portfolio to determine which resource contributes optimally to reliable service at the lowest reasonable cost.

Operating as an independent, vertically integrated utility offers distinct strategic and operational advantages over participation in an RTO. Chief among these is the ability to proactively manage the commitment and dispatch of the generation fleet without being constrained by market rules or performance incentive mechanisms.[5]

RTO markets are structured mechanisms whose rules are set through stakeholder processes approved by the Federal Energy Regulatory Commission ("FERC"). Functionally, MISO and PJM do not own generation resources nor transmission lines but coordinate the flow of electricity across their respective geographical footprints over the high-voltage transmission system. They are both responsible for maintaining a fair and competitive wholesale market for electricity, where buyers and sellers can have equal access to the grid. They, however, are not responsible for the distribution of electricity to end consumers, as this is handled by local distribution companies or utilities.

Furthermore, the RTOs do not possess the power to mandate the construction of new generation resources. Their primary mechanism for supporting resource adequacy is through market-based incentives—namely, facilitating the rational entry and exit of generation via the capacity market. RTOs

[5] Mark C. Christie, "It's Time to Reconsider Single-Clearing Price Mechanisms in U.S. Energy Markets," Energy Law Journal Vol. 41.1 at 15-16 (May 2, 2023), available at https://www.eba-net.org/wp-content/uploads/2023/05/3-Commr-Christie1-30-1.pdf.

pursue this objective through extensive stakeholder processes for designing and reforming complex market rules. PJM, for instance, is overseen by a nine-member independent Board of Managers and governed through a complex stakeholder structure. Its Members Committee—comprising approximately 500 voting members out of over 1,000 in total—serves as the final authority on changes to governing documents and market reforms.[6] This structure involves more than 400 stakeholder meetings annually, spanning committees, subcommittees, task forces, forums, and workshops. MISO has 550 Market Participants, and 219 members made of 56 transmission owners and 173 non-transmission owners.[7] The various RTO stakeholder groups include generation resource owners, independent power providers, power marketers, Independent Market Monitors, consumer advocacy groups, state regulators, utilities, and others. While this collaborative model aims to ensure transparency and inclusivity, it can also slow decision-making and dilute strategic focus.

To maintain a reliable balance between electricity supply and demand across their respective service territories, PJM and MISO employ four distinct market structures. These markets are designed to competitively incentivize electricity generation, ensuring that load is served reliably and at the lowest cost. In these markets, load pays market prices, and generation receives market prices. Thus, an important activity for a load-serving entity ("LSE") in an RTO is to financially balance and hedge load's market price risk with generation revenues.

2.1 Capacity Market

PJM's capacity market provides financial signals to generation owners to make investments in existing generation resources, build new generation resources, and retire generation resources that have reached the end of their useful life while meeting long-term reliability objectives. Each capacity auction, known as a Base Residual Auction ("BRA"), is held three years in advance of the Delivery Year, using BRA-specific peak load forecast and expected resource mix. Capacity owners economically bid into the capacity auction, taking into consideration, among other things, long-term fixed costs, operations and maintenance costs, fuel costs, environmental regulation compliance costs, and profitability margin. The bidders that clear the auction receive capacity revenue based on their location for every MW of capacity they commit to be available to supply energy when needed by PJM.

MISO's capacity market provides financial signals to market participants representing LSEs to make investments in existing generation resources, build new generation resources, and retire generation resources that have reached the end of their useful life while meeting resource adequacy objectives. Known as the Planning Resource Auction ("PRA"), it is a seasonal resource adequacy construct that was originally approved by FERC in August 2022 and implemented by MISO beginning the 2023/2024 Planning Year. The new seasonal approach was adopted to provide better clarity into the seasonal resource adequacy needs in each Local Resource Zone and match that more precisely to the seasonal performance attributes of generation resources. It is conducted in April every year to establish a separate auction price for each season (summer, fall, winter, and spring) of the next Planning Year, which begins June 1.

[6] https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/oversight-and-transparency-fact-sheet.pdf

[7] https://cdn.misoenergy.org/MTEP25%20Chapter%201%20-%20Transmission%20Planning%20Overview720401.pdf?v=20250929111625, at 4

2.2 Day-Ahead Energy Market

Generation owners bid their electricity supply into the day-ahead market to meet forecast demand for the following day, providing enough time for resources that clear the market to make the necessary preparations to generate electricity. Individual generators are incentivized to minimize costs and maximize profitability. Among other costs, depending on the generation resource, bid considerations include the cost of fuel, fixed and variable operations and maintenance, natural gas pipeline transportation, transmission, emission allowances, and profit margin. Note that the Day-Ahead Energy Market is just a financial settlement because no actual load is served on a day-ahead basis; actual load is served only in real-time.

2.3 Real-Time Energy Market

Differences between forecast and actual demand during the operating day and as cleared in the Day-Ahead market are resolved in the real-time market. RTOs remedy any supply shortages by procuring the lowest cost supply from generators that are synchronized to the grid and able to immediately supply energy. Just as in the day-ahead market, generators are incentivized to minimize costs and maximize the profitability of their units when bidding into the real-time market. Essentially, load and generation pay or receive differences in the volumes that cleared the Day-Ahead market at the real-time LMP.

2.4 Ancillary Services Market

PJM and MISO have other specialized products and services they procure to control the critical balance of supply and demand on their respective grids (such services are "ancillary services"). Ancillary services markets help "ensure that there are adequate electric reserves to maintain reliability and sufficient voltage to enable the grid to operate."[8]

2.5 Conclusion

The primary difference between the Companies' planning and operating as a standalone utility versus planning and operating in an RTO can be summarized in one word: control. As a standalone utility, the Companies are a one-stop shop for planning and operating their generation fleet. The Companies interact with regional energy markets to optimize energy costs and off-system sales benefits for customers, but they do not depend on regional markets. Customers pay the prudently incurred costs for the Companies' generation fleet, and the Commission has clear oversight and authority over those costs. Conversely, because RTOs have many stakeholders, as RTO members the Companies would have limited influence over the RTO's market tariffs and rules that may or may not be beneficial to the Companies' customers.

A key flaw in the RTO market construct is its inability to provide sufficient and stable revenue signals to support investment in dispatchable generation needed for long-term reliability. Capacity markets offer only short-term visibility, which can be inadequate for financing long-lived assets. The resulting volatility and uncertainty in capacity revenues discourage investment in capital-intensive generating resources, undermining the reliability of the grid over time.

[8] FERC, "Participation in Midcontinent Independent System Operator (MISO) Processes: An Introductory Guide to Participation in Midcontinent Independent System Operator (MISO) Processes," available at https://www.ferc.gov/participation-midcontinent-independent-system-operator-miso-processes (accessed Oct. 12, 2024).

3 Markets in Transition: RTO Resource Adequacy Concerns

Growing concerns regarding resource adequacy in PJM and MISO are receiving increasing attention by the RTOs themselves, industry observers, and regulators. With different stakeholder groups and different existing market tariffs, MISO and PJM are taking somewhat different approaches to their market redesigns to attempt to address future capacity and resource adequacy concerns. One of the consequences of each RTO's efforts is that capacity prices have risen dramatically from recent levels. This is as should be expected because each RTO is trying to send a price signal via each capacity market that existing generation should consider remaining operational and that new generation (particularly non-intermittent generation) is urgently needed. However, because load always pays the market price, the increase in prices has not been well received by many, despite the need for future generation capacity and energy.

3.1 PJM

3.1.1 PJM's Growing Reliability Concerns

PJM is facing a growing set of challenges that threaten its ability to maintain long-term resource adequacy and system reliability.

Resource Retirements Outpacing Additions

Between 2020 and 2024, PJM saw 15,896 MW unforced capacity ("UCAP") of unit retirements, compared to only 8,518 MW UCAP of additions.[9] The majority of new additions have been intermittent renewable resources, which cannot replace dispatchable thermal generation on a one-to-one basis due to their limited availability during certain hours and seasons. Moreover, renewables often lack essential reliability services such as frequency response and voltage support, further complicating system planning.

Rapid Load Growth Driven by Data Centers

PJM is experiencing unprecedented load growth, particularly from large-scale data centers. PJM's 2025 load forecast projects nearly 12,000 MW of data center load by 2026, representing 93% of large load additions. The summer peak is expected to rise by approximately 70,000 MW over the next 15 years,[10] with 32,000 MW of peak load growth projected between 2024 and 2030, of which 30,000 MW is due to data centers.[11]

PJM is facing mounting reliability challenges that could impact its ability to serve load as early as the 2026/2027 Delivery Year. On December 9, 2024, the PJM Board formally alerted stakeholders to the potential risk of a capacity shortage, signaling a shift in tone toward more urgent reliability planning.[12]

[9] https://www.pjm.com/-/media/DotCom/library/reports-notices/testimony/2025/20250325-asthana-testimony-us-house-subcommittee-on-energy.pdf, at 6

[10] https://www.pjm.com/-/media/DotCom/library/reports-notices/testimony/2025/20250305-haque-testimony-us-house-committee-on-energy-commerce.pdf, at 6

[11] 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

[12] https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/2024/20241209-board-letter-outlining-action-on-capacity-market-adjustments-rri-and-sis.pdf

This warning was echoed in the North American Electric Reliability Corporation's ("NERC") 2024 Long-Term Reliability Assessment, released on December 31, 2024.[13] NERC noted that PJM had significantly scaled back its projections for generator additions in 2025 and 2026 compared to its 2023 outlook. The report concluded that PJM could face resource adequacy challenges, particularly during winter months, where poor thermal performance and low solar output could lead to loss-of-load events.

Operational Stress and Emergency Alerts

The first half of 2025 saw a notable increase in NERC Energy Emergency Alert Level 1 ("EEA-1") events, most of which occurred during the summer.[14] An EEA-1 is issued when all available generation resources are committed, and there are concerns about maintaining contingency reserves. This uptick in emergency alerts reflects growing stress on PJM's system and the narrowing margin between supply and demand.

A particularly concerning incident occurred on August 11, 2025, when Baltimore Gas and Electric ("BGE") was forced to shed approximately 20 MW of load to prevent a cascading failure of 1,200 MW in the zone.[15] The event was triggered by a complete shutdown of the Brandon Shores 230kV substation, causing the two Brandon Shores coal units to trip offline.[16] The BGE zone was already an area of concern as the two units' original retirement date was May 31, 2025, but was extended to May 31, 2029, under a Reliability Must Run ("RMR") agreement with PJM to allow time for network upgrades to resolve transmission violations.

Federal Emergency Orders to Maintain Reliability

In response to the reliability concerns, the U.S. Department of Energy ("DOE") invoked Section 202(c) emergency authority to extend operations of critical generation units in PJM:

- Wagner Unit 4: On July 21, 2025, the DOE extended operating hours due to an "imminent electric reliability emergency."[17]
- Eddystone Units 3 and 4: Originally scheduled to retire on May 31, 2025, these units were ordered to remain online through August 28 and later extended to November 26, 2025.[18] These units were utilized to support grid reliability during the summer 2025 heat waves.[19]

3.1.2 PJM Governance, Stakeholders, and Rising Member State Engagement

PJM is undergoing a period of significant governance strain, marked by leadership turnover, contested decision-making, and increasing pressure from member states seeking a more active role in shaping the future of the regional grid.

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[13] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf, at 89

[14] https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2025/20250805/20250805-item-07---1-expansion-of-provisional-service---problem-statement.pdf, at 1

[15] https://www.pjm.com/-/media/DotCom/committees-groups/committees/oc/2025/20250911/20250911-item-04---bge-load-shed-event.pdf

[16] https://www.rfirst.org/wp-content/uploads/2025/10/August-2025-Baltimore-Load-Shed-Event-RF-Analysis.pdf. At 4

[17] https://www.energy.gov/sites/default/files/2025-07/PJM%E2%80%99s%20202%28c%29%20Application%20202-25-6.pdf, at 1

[18] https://www.energy.gov/ceser/federal-power-act-section-202c-pjm-interconnection

[19] https://www.energy.gov/articles/energy-secretary-issues-order-secure-grid-reliability-mid-atlantic

Leadership Turnover and Governance Tensions

On April 14, 2025, PJM President and CEO Manu Asthana announced his intention to step down at the end of the year, signaling a major leadership transition.[20] This was followed by a notable governance shakeup on May 12, 2025, when PJM Board Chairman Mark Takahashi and incumbent nominee Terry Blackwell failed to secure reelection to the Board—an unexpected outcome that reflects growing dissatisfaction among stakeholders.[21]

Further tensions emerged when the PJM Board approved the Installed Reserve Margin ("IRM") and Forecast Pool Requirement ("FPR) for the upcoming 2027/2028 BRA despite the proposal failing to achieve a supermajority vote among stakeholders.[22] This decision intensified concerns about the Board's responsiveness to member input.

Member State Pushback and Calls for Reform

State-level frustration reached a new peak on July 16, 2025, when nine governors, including Kentucky Governor Andy Beshear, issued a joint letter warning of a "crisis of confidence" in PJM.[23] They noted that while PJM was once a model for regional coordination, discussions of exiting PJM are now becoming increasingly common across the region.

To restore confidence in PJM, the governors proposed several reforms, including:

- Meeting with PJM's Nominating Committee to share their slate of Board candidates.
- Reserving two PJM Board seats for state-nominated candidates.
- Creating a formal governors' group within PJM's stakeholder structure.

On August 11, 2025, the governors of Virginia and Pennsylvania formally nominated two candidates to the PJM Board.[24] However, on August 25th, PJM's Nominating Committee selected Robert Ethier and Le Xie for the vacant seats, bypassing the governors' nominees.[25] This prompted a strong response: On September 10, seven governors expressed disappointment, warning that PJM's refusal to collaborate could accelerate efforts to explore alternative reliability strategies outside the RTO framework.[26]

[20] https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/2025-releases/20250414-ceo-manu-asthana-to-step-down-at-years-end.pdf

[21] https://insidelines.pjm.com/pjm-members-elect-new-board-member-two-seats-unfilled/

[22] https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/2025/20250804-board-correspondence-re-irm-and-fpr.pdf

[23] https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/2025/20250717-nine-governors-letter-regarding-board-vacancies.pdf

[24] https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/2025/20250811-pa-va-govs-letter-re-board-candidates.pdf

[25] https://www.pjm.com/-/media/DotCom/committees-groups/committees/nc/postings/2025-supplemental-nc-announcement-re-board-candidates-with-cvs.pdf

[26] https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/2025/20250911-govs-of-pjm-member-states-letter-to-pjm-board-related-to-nc-decision-regarding-open-seats-on-bom.pdf

Multi-State Technical Conference and Legislative Action

Pennsylvania Governor Josh Shapiro convened a Multi-State Technical Conference on September 22, 2025, titled *Summit on the State of PJM Interconnection.*[27] The summit launched a public process to consider structural reforms to PJM governance, including:

- Granting states the right to file PJM-related proposals at FERC.
- Establishing a formal role for states in Board member selection.

Governor Shapiro warned, "If PJM is not willing to look in the mirror and really reform itself, then I'm willing to go my own way."[28]

Similarly, Virginia Governor Glenn Youngkin criticized PJM's demand forecasts as "fundamentally wrong" and driven by "hope and ideology," citing delays and bottlenecks that harm economic development and raise costs. He indicated that Virginia lawmakers are also considering legislation to reassess the state's participation in PJM.

The summit led to a formal request by 11 states (excluding Kentucky and West Virginia) to form a PJM Governors' Collaborative, aimed at increasing state representation and influence within PJM.[29]

State-Level Legislative Actions

Several states have already taken legislative steps to increase transparency and explore alternatives to PJM's market structures:

- **New Jersey:**
  - On August 15, 2025, the Governor signed two bills requiring utilities to disclose PJM voting records and investigate PJM's capacity market.[30]
  - On June 27, the Assembly passed Bill A5902, directing the New Jersey Board of Public Utilities to collaborate with other states on alternatives to PJM's capacity auction.
- **Delaware**:
  - On July 16, SB 61 was signed into law, mandating public utilities disclose their PJM stakeholder votes.[31]
- **Maryland**:
  - On April 14, 2025, the Maryland Office of People's Counsel ("OPC"), joined by consumer advocates from Illinois and New Jersey, filed a formal complaint with FERC challenging the results of PJM's 2025/2026 BRA. The complaint alleged that PJM's auction design and execution led to unjust and unreasonable outcomes, significantly inflating costs for consumers and undermining market integrity. The complaint requested that FERC either

[27] https://www.pa.gov/governor/newsroom/2025-press-releases/ahead-of-historic-13-state-summit--energy-leaders-call-on-pjm-to

[28] https://www.bloomberg.com/news/articles/2025-09-22/pennsylvania-governor-says-biggest-us-power-grid-needs-overhaul?srnd=phx-technology&sref=cBoeoIOm

[29] https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/2025/20250925-pjm-governors-collaborative-joint-statement-of-intent.pdf

[30] https://www.nj.gov/governor/news/news/562025/approved/20250815a.shtml

[31] https://legis.delaware.gov/BillDetail?LegislationId=141865

re-clear the auction with the previously excluded resources included or reset prices using a just and reasonable methodology.[32]

- On May 3, 2025, HB 121 was signed into law mandating public utilities disclose their PJM stakeholder votes.[33]

- **Pennsylvania**:
  - On April 21, 2025, FERC approved PJM's capacity auction price cap and floor proposal, resolving a complaint filed by Governor Shapiro.[34]
  - On July 28, 2025, PJM launched an effort to explore a sub-annual capacity auction model, following a proposal from the Governor's office.[35]
  - Legislation (HB 1272 & SB 897) is under deliberation to allow regulated utilities to build and own generation, signaling a potential shift toward more state-directed resource planning.

Stakeholder Communications: Edison Electric Institute

In a letter dated October 7, 2025, the Edison Electric Institute ("EEI"), which represents all U.S. investor-owned electric companies, addressed the PJM executive team with a strong call for reform in the capacity market.[36] EEI expressed deep concerns over PJM's ability to ensure reliable electricity supply amid rising demand, the retirement of dispatchable generation, and increasing risks of supply shortfalls while criticizing the lack of accountability and effectiveness in PJM's current market structure.

To steer PJM toward a more resilient and responsive energy system, EEI proposed a new guiding framework, signifying a major shift in perspective for investor-owned utilities in PJM. The framework includes:

- Empower states to lead generation planning, with PJM actively supporting and coordinating efforts.
- Reduce dependence on PJM's centralized capacity market by promoting integrated resource planning and alternative procurement methods.
- Encourage varied approaches like regulated generation, bilateral contracts, and improved self-supply mechanisms.
- Prioritize proactive and strategic transmission planning to support evolving grid needs.
- Reform PJM's governance to be more responsive, transparent, and aligned with the interests of customers and load-serving entities.

3.1.3 Kentucky PJM Member Status

Kentucky regulated utilities that are members of PJM are responding to growing uncertainty in PJM's capacity market by reassessing their planning strategies and market participation. Reliability of the PJM

[32]https://opc.maryland.gov/Portals/0/Files/Publications/Others/Joint%20Consumer%20Advocate%20Complaint%20(2025-2026%20BRA).pdf

[33] https://mgaleg.maryland.gov/mgawebsite/Legislation/Details/hb0121

[34] FERC docket EL25-46-000

[35] https://www.pjm.com/-/media/DotCom/committees-groups/committees/mrc/2025/20250723/20250723-item-05---3-revised-sub-annual-auction-issue-charge---clean.pdf

[36] https://s3.documentcloud.org/documents/26182749/final-letter-eei-to-opsi-pjm-100725-pjm-execs.pdf

system is a shared concern among them, especially in light of extreme weather events, generator retirements, and shifting market rules. The transition to PJM's marginal Effective Load Carrying Capability ("ELCC") methodology has significantly reduced accredited capacity for these entities, prompting increases in reserve margins, more conservative planning, and requests to build new generation. Rising costs—particularly transmission expenses, capacity performance penalties, and capacity costs—are adding financial pressure, while regulatory unpredictability and "stroke of the pen" risk associated with frequent changes in market rules have introduced new uncertainties around PJM's long-term stability.

East Kentucky Power Cooperative, Inc.

East Kentucky Power Cooperative, Inc. ("EKPC") is a not-for-profit, rural electric cooperative corporation that has been a fully integrated member of PJM since June 1, 2013, and participates in the capacity market as a Reliability Pricing Model ("RPM") entity. In two recent case proceedings before the Kentucky Public Service Commission ("PSC"), EKPC outlined a number of challenges they face as a member of PJM.

As part of the reasoning for filing a Certificate of Public Convenience and Necessity to construct new generation in Case 2024-00310 before the Kentucky PSC, EKPC stated the need to significantly increase their Winter and Summer Reserve Margins compared to those published in their 2022 IRP. Due to the risks of extreme cold weather events as experienced during Winter Storms Elliott and Gerri, and the associated high probabilities for generator outages (which entail substantial PJM non-performance penalties and lower future capacity accreditation), EKPC stated it was increasing its Winter Reserve Margin significantly from 0% to 7%. It would also provide an enhanced hedge against the risks of high energy prices experienced during those extreme winter weather events.[37]

EKPC also increased its Summer Reserve Margin from 3% to 7%, which it stated would provide a hedge to the recent volatility seen in the historically high capacity auction price for the 2025/2026 Delivery Year of $270/MW-day. With respect to its own generation portfolio, EKPC stated its fleet accredited capacity to sell into PJM fell by 17% on average due to the recent adoption of marginal ELCC, supporting its decision to increase Reserve Margins across the board and stating it could not ignore ELCC risk moving forward.

In Rate Case Application 2025-00208, EKPC President and Chief Executive Officer Anthony S. Campbell expressed his reliability concerns with respect to PJM and the recent challenges faced by the RTO:

> EKPC experienced many benefits since joining PJM. However, in the last few years, the PJM capacity market was beset by a series of complaints and controversies that made the market less predictable and, from EKPC's perspective, less conducive to promoting long-term grid reliability.[38]

In his view, two factors resulted in the current tight conditions of the PJM capacity market raising doubts to the resiliency of the PJM system:

- Retirement of dispatchable coal-fired resources due to strict environmental regulations; and

[37] https://psc.ky.gov/pscecf/2024-00310/allyson%40hloky.com/09202024100053/Application_with_Exhibits.pdf, at 7.

[38] https://psc.ky.gov/pscecf/2025-00208/allyson%40hloky.com/08012025124816/Volume_1_Exhibits_1-14_Redacted.pdf, at 91.

- Utilities in deregulated electricity market states have relied too much on PJM's system, failing to build new generation due to adequate incentives.

EKPC further noted that its share of PJM Regional Transmission Expansion Plan ("RTEP") expenses has not exceeded $14.2 million annually since joining PJM. But in 2025 those expenses dramatically increased to $29.5 million. EKPC went on to say it anticipates "additional significant increases due to anticipated large load growth and [generation] deactivation trends across the entirety of the PJM region."[39]

Duke Energy Kentucky

On May 16, 2025, the Kentucky PSC approved Duke Energy Kentucky's ("DEOK") request to withdraw from the Fixed Resource Requirement ("FRR") alternative and transition to full participation in PJM's RPM beginning with the 2027/2028 Delivery Year.[40] This marks a significant shift in DEOK's capacity market strategy, as the utility had previously joined PJM in 2010 under the condition that it operate as an FRR entity.

DEOK cited several compelling factors driving its decision to exit the FRR construct:

- Load Growth Risk: The potential for rapid and unpredictable load increases could outpace DEOK's ability to procure sufficient generation capacity, exposing the utility to costly FRR deficiency penalties.
- Supply-Demand Balance Uncertainty: Ongoing unit retirements within the DEOK zone have created volatility in the local supply-demand balance.
- Limited Bilateral Capacity: DEOK faces challenges in securing adequate bilateral capacity to meet its FRR obligations.
- Anticipated FRR Rule Changes: PJM is expected to revise the FRR framework in ways that could disadvantage DEOK's continued participation.
- Energy Transition Pressures: The broader shift away from fossil generation across PJM is contributing to shrinking reserve margins and rising capacity prices.
- Regulatory Risk: DEOK expressed concern over PJM's ability to unilaterally alter planning reserve margin requirements or market rules ("stroke of the pen" risk).
- Penalty Structure Changes: The FRR shortfall penalty has increased to the greater of 1.75 times the Net Cost of New Entry ("Net CONE") or Gross CONE, raising the financial stakes of any capacity shortfall.
- RPM Advantages: As an RPM participant, DEOK will no longer be subject to the 3% holdback constraint on selling excess capacity and will gain flexibility to optimize reserve procurement in response to high capacity prices.

With DEOK's departure from the FRR designation, the subsidiaries of American Electric Power ("AEP") will become the sole PJM FRR entities operating in regulated states.

[39] https://psc.ky.gov/pscecf/2025-00208/allyson%40hloky.com/08012025124816/Volume_2_Exhibits_15-29_Redacted.pdf, at 46.

[40] https://psc.ky.gov/pscscf/2024%20Cases/2024-00285//20250516_PSC_ORDER.pdf.

Kentucky Power Company

Kentucky Power Company ("KPCO"), part of AEP's eastern transmission zone, joined PJM on October 1, 2004. It participates in PJM's capacity market under a joint FRR plan alongside Appalachian Power Company ("APCo"), Indiana Michigan Power ("I&M"), and Wheeling Power Company.

KPCO is also facing challenges under PJM's evolving capacity market rules. In Case No. 2025-00175, KPCO reported a 15% reduction in accredited capacity for the Mitchell coal plant due to PJM's marginal ELCC reforms compared to what the company planned in its most recent IRP.[41] To mitigate future risks, the company has incorporated an additional reserve margin above the required winter reserve margin, anticipating the possibility that PJM may adopt a seasonal capacity construct.

3.1.4 PJM 2026/2027 Base Residual Auction

The 2026/2027 BRA, originally scheduled for December 2024, was delayed until June 2025 to allow time for evaluating and implementing significant market rule changes. These changes were designed to address evolving reliability concerns and improve price discovery following record high capacity prices clearing in 2025/2026 BRA.

Among the most notable reforms were the introduction of a price cap and price floor, the inclusion of RMR units in the supply stack, a new must-offer requirement for intermittent resources, and a shift in the reference resource from a natural gas combined cycle unit to a simple cycle combustion turbine.

The auction results continued to indicate a tightening market. All zones cleared at the price cap of $329.17/MW-day (UCAP), a sharp increase from the previous year's clearing price of $269.92/MW-day (UCAP). A sensitivity analysis revealed that, absent the price cap, prices would have reached $388.57/MW-day, underscoring the scarcity conditions and strong demand signals.

Despite the high prices, supply offered declined by 500 MW (UCAP) compared to the 2025/2026 BRA, continuing concerns about resource adequacy.[42] However, the auction did see a reversal of a three-year trend, with 2,669 MW (UCAP) of new generation and uprates entering the market—suggesting that elevated prices may be beginning to incentivize new investment.

Still, PJM procured 209 MW less than the Reliability Requirement, highlighting ongoing resource adequacy challenges in meeting the "1 day in 10" Loss of Load Expectation ("LOLE") reliability standard.[43]

3.1.5 PJM Interconnection Queue Status and Reforms

In July 2023, PJM implemented a major reform to its interconnection process, shifting from a first-come, first-served serial queue to a first-ready, first-served cluster-based model. This change was designed to streamline the queue and accelerate project processing.[44] PJM has studied approximately 160 GW of

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[41] https://psc.ky.gov/pscecf/2025-00175/mmcaldwell%40aep.com/06302025034730/03_KPCO_DT_Wolffram.pdf, at 16

[42] https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2026-2027/2026-2027-bra-report.pdf, at 6

[43] https://www.monitoringanalytics.com/reports/Presentations/2025/IMM_MC_Webinar_Market_Monitor_Report_20250731.pdf, at 3

[44] https://www.pjm.com/-/media/DotCom/library/reports-notices/testimony/2025/20250325-asthana-testimony-us-house-subcommittee-on-energy.pdf, at 7

generation interconnection projects since then, reducing the active queue to about 46 GW. These remaining projects are scheduled to be processed by the end of 2026 as part of Transition Cycle 2.[45] PJM recently paused studying new interconnection projects to clear the current queue backlog. They intend to reopen the queue by spring of 2026 once the new reformed process is in place. Moving forward, the time to process generation interconnection agreements will be reduced to one to two years.

On September 22, 2025, PJM announced it had completed Transition Cycle 1 Interconnection Studies, which included draft agreements for 130 New Service Requests.[46] These agreements, representing 17.4 GW of capacity, are expected to be finalized or withdrawn by year-end. However, these projects are mostly intermittent resources with scarce additions from dispatchable generation (56% solar, 25% wind, 10% storage, 5% hybrid, 3% natural gas).

Outside of Transition Cycle 1, as of June 2025, approximately 46 GW of generation projects had signed interconnection agreements to connect to the grid that have yet to construct due to factors outside of PJM's control, including state and federal permitting, supply chain, and financing.[47] These projects are also dominated by intermittent solar resources: 27.8 GW solar, 5.9 GW natural gas, 5.6 GW wind, 4.1 GW storage, 3.0 GW renewable hybrid, 0.2 GW hybrid.

While efforts to reduce the interconnection queue have yielded results, the challenge of bringing resources online in a timely manner remains a critical concern. To address this issue, PJM is working on several urgent interconnection reforms to bring resources online as quickly as possible.

On February 11, 2025, FERC approved PJM's Reliability Resource Initiative ("RRI")—a one-time emergency measure that reopens Transition Cycle 2 to allow select generation projects with high resource adequacy value and commercial readiness to join earlier queued projects. This initiative aimed to expedite the integration of critical resources through the interconnection process by 18 months to prevent a reliability crisis.[48]

On May 2, 2025, PJM selected 51 generation projects from 94 applications, totaling 9,361 MW UCAP.[49] These projects include 39 uprates (2,108 MW UCAP) of existing generation and 12 new construction proposals consisting of 6 natural gas, 5 battery storage, and 1 nuclear project, which contributed 7,253 MW UCAP. While these projects represent critical resource additions to address future resource adequacy concerns, there remains uncertainty around how many will ultimately be built. Additionally, project in-service dates are a key concern, as the majority of new capacity under the RRI is not expected to be online until later in the decade, further complicating planning efforts. Uprate projects benefit from existing infrastructure, allowing them to enter commercial service more quickly. In contrast, the new generation projects are experiencing significant delays due to supply chain constraints and extended

[45] https://insidelines.pjm.com/pjm-completes-interconnection-reform-transition-cycle-1-studies/
[46] Id.
[47] https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/interconnection-reform-progress-fact-sheet.pdf
[48] https://www.ferc.gov/news-events/news/commissioner-phillips-and-commissioner-rosner-concurrence-regarding-pjms
[49] https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/2025-releases/20250502-pjm-chooses-51-generation-resource-projects-to-address-near-term-electricity-demand-growth.pdf

manufacturer lead times. As a result, over 90% of these projects are currently estimating commercial operation dates no earlier than 2029, with approximately half projected to come online in 2030 or 2031.[50]

Another key initiative is the Capacity Interconnection Rights Transfer, a stakeholder-endorsed reform designed to expedite the interconnection process for replacement resources. This mechanism allows new generation assets to assume the capacity interconnection rights of retiring units, significantly reducing administrative hurdles and ensuring continuity in system reliability and capacity planning.

Complementing this effort is the Surplus Interconnection Service reform, which introduces a streamlined pathway for facilities to utilize unused portions of their interconnection service. This is particularly beneficial for resources that do not operate continuously throughout the year, such as peaking units or intermittent renewables. By enabling the transfer or sharing of surplus capacity, PJM enhances grid flexibility and promotes more efficient use of existing infrastructure.

PJM has also partnered with Google and Tapestry to integrate AI-enhanced tools into its planning and interconnection workflows. This collaboration allows PJM to use advanced automation and data analytics to accelerate project evaluations and improve decision-making, which is a significant step toward modernizing PJM's operational capabilities and supporting the growing complexity of grid planning.

To further accelerate resource integration, PJM has proposed an Interim Deliverability Study "quick fix" for the 2026/2027 Delivery Year.[51] This proposal, which is currently being deliberated in the stakeholder process, would allow certain new generation projects to operate on an energy-only basis under specific conditions even before required network upgrades are completed. This initiative underscores PJM's concern that near-term energy shortfalls are a legitimate threat.

In parallel, PJM is developing a longer-term reform to expand Provisional Service, enabling partially completed generation projects to begin energy-only operations prior to the completion of full interconnection studies.[52] These reforms aim to urgently unlock desperately needed generation to mitigate reliability risks associated with delayed project integration.

3.1.6 PJM's Ongoing Market Reform Initiatives

In response to evolving reliability needs, resource adequacy concerns, and stakeholder pressure, PJM has launched a series of market reform initiatives aimed at enhancing its capacity market construct. These reforms reflect PJM's efforts to adapt to changing system dynamics, including rapid load growth, increasing penetration of intermittent resources, and the need for more flexible and responsive market structures.

[50] https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2025/20250506/20250506-rri-addendum---post-meeting.pdf

[51] https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2025/20250909/20250909-item-03a---manual--14h---interim-deliverability-study-procedure---issue-charge.pdf

[52] https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2025/20250909/20250909-item-04---expansion-of-provisional-services.pdf

Sub-Annual Capacity Auction Exploration

On July 28, 2025, PJM initiated a stakeholder process to explore the feasibility of a sub-annual capacity auction model, following a proposal from the Pennsylvania Governor's office.[53] This model could offer more granular procurement options and better align capacity commitments (reliability attributes) with seasonal reliability needs.

ELCC Accreditation Methodology Changes

PJM's transition to marginal ELCC methodology for resource accreditation in the 2025/2026 BRA had significant financial implications. According to the IMM, the switch from the previous EFORd method resulted in a 49% increase in RPM revenues (cost to load), totaling $4.4 billion more than the prior auction.[54]

Stakeholders have continued to express concerns regarding the transparency and replicability of the ELCC calculation methodology. The ELCC calculations are a critical component of PJM's capacity market as they have direct implications for how the supply-demand balance is assessed and how unit performance is held accountable within the energy and capacity markets.

At the heart of the issue is a perceived lack of clarity around the assumptions, inputs, and modeling techniques used to derive ELCC values. Without a transparent and repeatable methodology, stakeholders face challenges in validating results, understanding resource adequacy implications, and making informed investment decisions.[55]

Stakeholder discussions are ongoing to refine the ELCC methodology ahead of the 2028/2029 BRA. On August 4, 2025, the PJM Board directed staff to engage an independent consultant to identify further enhancements to be implemented after the 2028/2029 BRA and to publish a detailed description of the ELCC model.[56] One potential reform includes seasonal ELCC accreditation, which could better account for resource performance across different times of year.

The IMM has raised concerns that current ELCC values—particularly for thermal resources—are understated due to their reliance on performance data from extreme events like Winter Storm Elliott and the 2014 Polar Vortex.[57] Additionally, the IMM has acknowledged that summer 2025 unit performance exceeded accredited UCAP, suggesting that ELCC-based UCAP may no longer accurately represent seasonal expectations.[58]

PJM's Response to Large Load Integration

Recognizing the urgency to address the meteoric data center demand forecasts, PJM initiated the Critical Issue Fast Path ("CIFP") stakeholder process on August 8, 2025, to streamline the interconnection of large

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[53] https://www.pjm.com/-/media/DotCom/committees-groups/committees/mrc/2025/20250723/20250723-item-05---3-revised-sub-annual-auction-issue-charge---clean.pdf

[54] https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_A_20240920.pdf, at 2

[55] https://opsi.us/wp-content/uploads/2025/08/08.27.25-ELCC-letter.pdf

[56] https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/2025/20250804-board-correspondence-re-irm-and-fpr.pdf.

[57] https://ferc.gov/media/joe-bowring-monitoring-analytics-president-and-independent-market-monitor, at 14.

[58] https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2025/20250910/20250910-item-05---2025-heat-waves-capacity-performance.pdf, at 14.

loads.[59] A FERC filing is anticipated by December 2025. The PJM Board has emphasized the need for reliability-focused solutions to ensure large loads can be integrated rapidly and reliably without compromising resource adequacy.

3.2 MISO

MISO is facing a rapidly evolving reliability landscape shaped by shifting resource dynamics, accelerating retirements, and increasing dependence on intermittent renewable energy. Recent reports and assessments underscore the growing urgency to address systemic challenges threatening the region's ability to maintain reliability.

3.2.1 MISO's Growing Reliability Challenges

MISO's 2025 Summer Readiness Report highlights a troubling trend: New capacity additions are failing to keep pace with retirements, suspensions, and declining resource accreditation.[60] Compared to the Summer 2024 PRA, the system saw 3.3 GW of retirements and 4.9 GW in reduced offers due to capacity accreditation losses. This imbalance signals a tightening resource margin heading into future Planning Years.

Long-Term Resource Adequacy Risks

The 2024 Regional Resource Assessment ("RRA") paints a stark picture of the next two decades. To meet future demand and policy goals reliably, MISO members and states may need to add capacity at a rate of 17 GW per year — more than triple the recent average of 4.7 GW/year.[61] The changing resource mix, particularly the growth in solar, is shifting net load ramps from morning to evening, increasing ramping needs by two to three times by the early 2030s. This shift also introduces new risks of loss-of-load events during previously low-risk hours and seasons, such as winter mornings and evenings.

As solar and wind penetration increases, the region's net load profile is expected to resemble a "duck curve," intensifying the need for dispatchable, fast-ramping resources that can respond quickly when renewables are unavailable.

OMS-MISO Survey: Growing Uncertainty

The June 2025 OMS-MISO survey reinforces concerns about resource adequacy. It reveals a wide range of potential outcomes for the 2027/2028 Planning Year — from a 1.4 GW deficit to a 6.4 GW surplus in Summer Accredited Capacity.[62] Reliability risks are expanding into winter, with a projected 5 GW decline in winter surplus capacity by 2030/2031. Load growth, driven by economic development, is outpacing previous forecasts at a compound annual growth rate of 2.2%.

Meanwhile, the report notes the generation interconnection queue remains a bottleneck. Of the 296 GW in the queue, 54 GW have signed interconnection agreements but are not yet online — 71% of which are

[59] 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.
[60] https://cdn.misoenergy.org/20250508%20Summer%20Readiness%20Workshop%20Items%2002-04%20Presentation695282.pdf, at 23.
[61] https://cdn.misoenergy.org/2024%20RRA%20Report_Final676241.pdf, at 1.
[62] https://cdn.misoenergy.org/2025%20OMS-MISO%20Survey%20Fact%20Sheet702641.pdf, at 1

wind and solar. Delays are exacerbated by supply chain disruptions, labor shortages, permitting challenges, and regulatory hurdles.

NERC Reliability Assessment and Elevated Risk

NERC reclassified MISO as an elevated risk region for 2025–2027,[63] meaning resources are sufficient under normal conditions, but extreme weather and above-normal generator outages could lead to unserved energy or load loss. But NERC has classified MISO as a high-risk area in 2028–2031,[64] meaning MISO is likely to experience a shortfall in electricity supplies at the peak of an *average* summer or winter season, with extreme weather posing an even greater threat to reliability.[65]

MISO Futures: Scenarios of Declining Capacity

MISO's Futures modeling explores three scenarios with varying degrees of thermal resource retirements. Across the 20-year study period:[66]

- Future 1A projects an 18 GW decline in accredited capacity.
- Future 2A projects a 32 GW decline in accredited capacity.
- Future 3A projects a 53 GW decline in accredited capacity.

Such reductions could result in load interruptions lasting 3–4 hours for 13–26 days per year, particularly during hot summer evenings and cold winter mornings when renewable output is low.

Recent Emergency Highlights System Vulnerability

On May 25, 2025, MISO declared a Transmission System Emergency in Southeast Louisiana, directing controlled load shedding of approximately 600 MW to prevent cascading outages.[67] The emergency was triggered by a damaged 500kV transmission line, over 50% of local generation offline, limited transmission import capability, and high temperatures driving demand.

Interconnection Queue

MISO's interconnection queue has long been a bottleneck for resource additions. The queue has experienced a large number of interconnection requests in recent years that has exceeded MISO's load projections. However, this increased the size of interconnection study cycles, which extended the time required to conduct the interconnection studies. The delays further complicated the resource adequacy planning process for states and utilities. As of early 2025, the queue included 1,584 projects totaling 293 GW, later reduced to 215 GW and 1,127 projects following the phaseout of renewable energy tax

[63] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf (NERC 2024 LTRA") at 41

[64] NERC, "Statement on NERC's 2024 Long-Term Reliability Assessment" (June 17, 2025) available at https://www.nerc.com/news/Pages/Statement-on-NERC%E2%80%99s-2024-Long-Term-Reliability-Assessment.aspx.

[65] NERC 2024 LTRA at 6.

[66] https://www.ferc.gov/media/todd-ramey-miso-senior-vice-president-markets-and-digital-strategy, at 16

[67] https://cdn.misoenergy.org/May%2025%20Load%20Shed%20Event%20Report%20-%20August%202025711584.pdf, at 3

incentives. Solar and wind projects make up 59% of the projects on a nameplate capacity basis.[68] Over 50 GW of projects with signed Generator Interconnection Agreements ("GIA") remain offline, with more than half signaling delays.[69]

Despite this, the 2025 queue cycle saw 44 GW of new submissions, 26% of which are natural gas—a notable shift in resource mix. However, due to queue backlogs and delays, these projects may wait years for interconnection agreements.

Interconnection study cycles currently take over three years, more than three times the queue process timeline in MISO's tariff.[70] Delays are primarily attributed to transmission owner supply chain issues, regulatory processes, and lack of power purchase agreements ("PPA").[71] MISO previously skipped the 2024 queue cycle entirely due to existing delays. On June 3, 2025, MISO announced a second postponement of the 2022, 2023, and 2025 queue cycles as it works to implement Suite of Unified Grid Analyses with Renewables, an automated interconnection study tool designed to accelerate the process.[72] However, it is expected to take four years to fully implement it into the interconnection study process.

To address these issues, FERC approved MISO's interconnection queue cap proposal on January 30, 2025, limiting requests to 50% of each region's non-coincident peak load.[73]

In a significant step to expedite the interconnection of new resources, FERC approved MISO's Expedited Resource Addition Study ("ERAS") proposal on July 21, 2025.[74] ERAS creates a fast lane for projects identified by state regulators as necessary to ensure resource adequacy. On September 4, 2025, MISO selected the first 10 ERAS projects totaling 5,300 MW with natural gas accounting for 4,300 MW of the total.[75] Of the selected projects, the earliest commercial operation date is in 2027, but the vast majority are expected to be in service by 2028. To further accelerate progress, MISO filed tariff revisions with FERC on September 26, 2025, proposing to increase the number of ERAS projects studied per quarter from ten to fifteen.[76]

Load Growth

Peak electric load in the MISO region is projected to grow at a 1.6% compound annual growth rate ("CAGR"), a sharp increase compared to the 0.5% CAGR observed between 2009 and 2024.[77] Data center demand alone accounts for 11 GW of load growth over the next five years.[78] This surge, driven by

[68] https://cdn.misoenergy.org/06_2025-09-16_SPC_Open_Long%20Term%20Resource%20Adequacy%20%20Interconnection%20Queue%20Update_FINAL717559.pdf, at 7
[69] Id. at 26
[70] Id. at 10
[71] https://www.ferc.gov/media/todd-ramey-miso-senior-vice-president-markets-and-digital-strategy, at 12
[72] https://www.rtoinsider.com/107212-miso-2022-2023-queue-study-cycles-delayed-again/
[73] https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250130-3083&optimized=false
[74] https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250721-3077
[75] https://cdn.misoenergy.org/ERAS%20Cycle%201717096.pdf?v=20250904134938
[76] https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250926-5169
[77] https://www.ferc.gov/media/todd-ramey-miso-senior-vice-president-markets-and-digital-strategy, at 3
[78] https://cdn.misoenergy.org/20250626%20Markets%20Committee%20of%20the%20BOD%20Item%2004%20State%20of%20the%20Market%20Report703831.pdf, at 43

economic development, electrification, and data center trends, threatens to outpace new resource additions unless urgent action is taken. The combination of rising demand and lagging capacity additions is intensifying pressure on system reliability.

Unit Retirements and Resource Additions

Between 2015 and 2024, MISO retired 22 GW of Unforced Capacity (UCAP) while adding only 13 GW—a net reduction of 9 GW.[79] Though new generation increased by 7.5 GW of nameplate capacity (3 GW of accredited capacity) and 5.9 GW of nameplate capacity (3.2 GW of accredited capacity) in 2024 and 2025, respectively, it did not keep pace with increasing demand.[80] Furthermore, these additions, which are mostly intermittent resources, only exacerbate the shift in system risks. This imbalance reflects the accelerated pace of thermal generation retirements driven by aging infrastructure, regulatory pressures, and economic factors.

Shifting System Risk and Net Load Ramp Challenges

MISO's reliability risks are no longer driven solely by peak load. The evolving resource mix and increasing frequency of extreme weather events are reshaping the nature and timing of system stress.[81] Reliability challenges are now emerging during periods of steep net load ramps. The integration of renewables brings operational challenges, primarily due to the uncertainty in forecasting wind and solar output. Forecast errors are most pronounced during periods of rapid change in generation, which can strain grid reliability, increase congestion, and require quick-ramping resources.

In 2024, MISO's wind and solar resources served more than 17% of the load on average across all hours, and renewables supplied nearly 43% of the load in the highest-share hour. This was up from 9% and 25%, respectively in 2019.[82] Due to MISO's rapid increase in renewable resources, it experienced total solar and wind output fluctuations greater than 15 GW on 20 days in winter 2025, significantly more than the ten days of such fluctuations in winter 2024 and just two in winter 2023.[83]

Solar capacity in MISO has grown 44% since summer 2024, with peak summer output doubling to a record 14.1 GW in 2025.[84] Notably, nearly all solar resources were added to MISO within the past three years. As a result, the largest summer net load ramp period has shifted from hour 16 in 2023 to hour 18 in 2025, with cumulative evening ramp increasing from 1,000 MW in 2023 to nearly 6,000 MW in 2025.[85] This shift has led to a doubling of Operating Reserve ("OR") shortage intervals in the summer of 2025 compared to the previous year, with 24 shortage intervals mostly occurring during hour 18 as solar production ramped

[79] https://ferc.gov/media/pjm-miso-accredited-capacity-2015-present, at 3
[80] https://cdn.misoenergy.org/MTEP25%20Chapter%201%20-%20Transmission%20Planning%20Overview720401.pdf?v=20250929111625, at 5
[81] https://cdn.misoenergy.org/2025-08-27%20Docket%20No.%20ER25-3307-000715742.pdf, at 2

[82] https://cdn.misoenergy.org/20250626%20Markets%20Committee%20of%20the%20BOD%20Item%2004%20State%20of%20the%20Market%20Report703831.pdf, at 47
[83] https://www.potomaceconomics.com/wp-content/uploads/2025/03/IMM-Quarterly-Report_Winter-2025.pdf, at 27
[84] https://cdn.misoenergy.org/20250916%20Markets%20Committee%20of%20the%20BOD%20Item%2007%20IMM%20Quarterly%20Report717460.pdf, at 7
[85] Id.

down.[86] MISO expects the pace of solar additions to continue through 2028, ultimately reaching 41.7 GW.[87]

Rethinking Reliability Metrics

MISO's shifting resource mix has introduced significant complexities in how future resource adequacy is assessed. The traditional LOLE standard of 1-day-in-10-years is increasingly being questioned as an adequate gauge for future systems dominated by variable and energy-limited resources. MISO and stakeholders are currently exploring alternative metrics such as Expected Unserved Energy ("EUE") and other multi-metric approaches to better capture the complexity and variability of their evolving grid operations.[88]

Transmission Expansion Costs and Allocation

On July 31, 2025, the public service commissions of Arkansas, Louisiana, Mississippi, Montana, and North Dakota filed a formal complaint with FERC challenging the cost allocation of MISO's recently approved Tranche 2.1 transmission portfolio. This portfolio, part of MISO's Long Range Transmission Planning ("LRTP") initiative, represents the second of five planned tranches and carries an estimated cost of $21.8 billion, contributing to a total projected investment exceeding $100 billion.

The MISO Board of Directors unanimously approved Tranche 2.1 in December 2024, designating the projects as Multi-Value Projects ("MVPs"). This designation enables MISO to spread the costs across all ratepayers in its footprint, including those in regions that may not directly benefit from the transmission upgrades. The projects are primarily located in MISO Midwest, which includes states with aggressive clean energy goals and anticipated reliability challenges.

However, MISO South states—notably Arkansas, Louisiana, and Mississippi—argue they should not bear the financial burden for infrastructure that does not support their resource adequacy or reliability needs. These states contend that MISO's benefit-cost analysis relied on inflated metrics, including an exaggerated social cost of carbon and unrealistic assumptions about future generation and reliability risks.

The complaint calls for FERC to:

- Reclassify Tranche 2.1 to remove its MVP status, thereby eliminating its eligibility for regional cost sharing. The states argue the benefits of the projects are concentrated in MISO Midwest, and MISO South ratepayers should not be obligated to subsidize infrastructure that does not serve their reliability or resource adequacy needs.
- Require MISO to submit future MVP business cases to FERC for review prior to board approval. This procedural change would introduce federal oversight to ensure that modeling assumptions, benefit calculations, and stakeholder input are thoroughly vetted before any cost allocation decisions are made.
- Ensure transparency and regulatory oversight over the analytical foundations of transmission planning. The states emphasized the need for greater scrutiny of the metrics used—such as the

[86] Id.

[87] https://cdn.misoenergy.org/20250312%20Board%20of%20Directors%20Item%2002%20MISO%20Strategy%20Update683072.pdf, at 3

[88] https://cdn.misoenergy.org/Resource%20Adequacy%20Metrics%20and%20Criteria%20Roadmap%20-%20Executive%20Summary667167.pdf, at 2

social cost of carbon and reliability risk scenarios—which they claim were inflated or unrealistic in MISO's justification for Tranche 2.1.

- Allow state commissions and stakeholders to challenge flawed assumptions before transmission projects are finalized and costs are distributed. This would create a formal mechanism for affected parties to contest the validity of MISO's planning models and benefit projections, potentially preventing unjustified financial burdens on ratepayers.

Adding to the criticism, MISO's IMM, Potomac Economics, has also raised concerns. The IMM argues that MISO overstated the reliability and decarbonization benefits and used speculative modeling assumptions, including extreme load shedding scenarios and unproven technologies. MISO attempted to limit the IMM's role in transmission planning, but FERC rejected this move, reaffirming the IMM's authority to review transmission planning impacts on market competitiveness.

The outcome of this complaint could have far-reaching implications for how transmission projects are planned, justified, and funded across regional transmission organizations. It may also influence future regulatory oversight and stakeholder engagement in large-scale infrastructure development.

3.2.2 MISO 2025/2026 Planning Resource Auction

The 2025/2026 PRA marked a significant shift in MISO's approach to capacity procurement, as it was the first year the Reliability-Based Demand Curve ("RBDC") was used in place of the traditional vertical demand curve. This new methodology allows for clearing incremental capacity above the reserve margin requirement based on its marginal reliability value, better aligning procurement with system risk.

However, the auction revealed a tightening supply-demand balance, resulting in a dramatic price increase. Summer season clearing prices surged to $666.50/MW-day, up from just $30/MW-day the previous year. This spike reflects the declining surplus capacity:[89]

- Summer surplus fell from 6.5 GW in 2023, to 4.6 GW in 2024, and 2.6 GW in 2025.[90]
- Surplus above the Planning Reserve Margin ("PRM") target dropped 43% year-over-year, despite a slightly lower PRM target (7.9% vs. 9.0%).

The shortfall was driven by the inability of new capacity additions to keep pace with reduced accreditation, retirements, suspensions, and slightly lower imports.

Despite these challenges, renewable participation in the auction increased:

- 9.1 GW of solar cleared, an 88% increase from the previous year.
- 6 GW of wind cleared, an 17% increase from last year.

LOLE Calculation Error and Market Impact

In June 2025, MISO discovered a software coding error dating back to 2017 that had incorrectly used "all hours" instead of the tariff-defined "daily peak hours" for LOLE calculations, which is a critical input for determining auction PRMs, including the PRM used in the 2025/2026 auction. This error led to the

[89] https://www.misoenergy.org/meet-miso/media-center/2025---news-releases/misos-planning-resource-auction-indicates-sufficient-resources/

[90] https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf

overestimation of reliability needs and caused additional capacity to clear at higher prices, with an estimated $280 million market impact.[91]

However, the IMM noted that the "daily peak hours" methodology corresponds to a lower reliability standard (less than 1 day in 5 years), while the "all hours" method aligns with a higher standard (1 day in 10 years).[92] MISO has proposed to formalize the "all hours" approach going forward, citing the shifting risk profile due to intermittent resources. Tariff revisions have been filed with FERC to adopt this methodology starting with the 2026/2027 Planning Year.[93]

3.2.3 MISO Future Market Reforms

MISO is implementing significant reforms to its capacity accreditation and reserve requirement methodologies to better align with evolving system risks.

Direct Loss of Load ("DLOL") Accreditation Methodology

A marginal ELCC framework approved by FERC on October 25, 2024, the DLOL capacity accreditation methodology, introduces a two-step process to determine resource class UCAP values:[94]

1. Step 1: Measures a resource's expected marginal contribution to reliability using resource class-level performance during LOLE analysis based on 30 years of correlated load and weather data across five probabilistic load forecasts.
2. Step 2: Evaluates historical resource-level performance during high-risk hours.

This approach will result in lower capacity accreditation for most resources compared to the current methodology. DLOL will be implemented in the 2028/2029 capacity year.

LSE Reserve Requirement Reform

MISO's risk modeling reveals that system risk is increasingly occurring outside traditional peak load conditions, particularly during periods of low availability of weather-dependent resources. Reforms under discussion with stakeholders would allocate LSEs' reserve requirements based on their load during the highest risk hours, rather than the conventional 50-50 coincident peak load.[95] This proposal is currently being deliberated by stakeholders with a tentative FERC filing expected in early-to-mid 2026.

4 Capacity Position Analysis

The Companies assessed their future capacity position as full capacity market participants in PJM and MISO. Using the Companies' expected generation fleet in 2032-2033, the installed capacity ("ICAP") was

[91] https://cdn.misoenergy.org/20250820%20RASC%20Item%2005%20LOLE%20Continuing%20Error714224.pdf
[92] https://cdn.misoenergy.org/20250916%20Markets%20Committee%20of%20the%20BOD%20Item%2007%20IMM%20Quarterly%20Report717460.pdf, at 61
[93] https://cdn.misoenergy.org/2025-08-27%20Docket%20No.%20ER25-3307-000715742.pdf
[94] https://cdn.misoenergy.org/Fact%20Sheet%20Accreditation%20Approach%20Approved666869.pdf
[95] https://cdn.misoenergy.org/20250709%20RASC%20Item%2006%20PRMR%20Allocation%20(RASC-2020-4%20and%202019-2)705843.pdf

converted using the respective RTO's expected capacity accreditation values. The load forecast values were calculated in accordance with the methodologies outlined in each respective RTO's tariff.

4.1 MISO

For MISO, the Companies used the indicative seasonal DLOL capacity accreditation values published for the 2025/2026 Planning Year. Though this marginal capacity accreditation methodology won't be implemented until the 2028/2029 Planning Year, the values provide valuable insight into how generation capacity will be accredited in future Planning Years.

The load obligation value known as the Planning Reserve Margin Requirement ("PRMR") was derived by taking the Companies' load forecast in 2032/2033 coincident with the MISO system peak for all four seasons. Each seasonal load forecast was then grossed up by the seasonal PRM and transmission losses which were assumed to be 2.1%. For this assessment, the PRM (UCAP) forecast for the 2032/2033 Planning Year included in MISO's 2025/2026 Planning Year Loss of Load Study Report were assumed: Summer 8.7%, Fall: 16%, Winter: 22.4%, Spring: 28.3%.

The analysis results showed a varied capacity position across the seasons largely due to the reserve margin and capacity accreditation differentials. Summer showed a surplus of approximately 208 MW given the lowest seasonal reserve margin and most generous capacity accreditation values. However, the fall season capacity position declined sharply to a deficit of approximately 140 MW as the seasonal reserve margin rose significantly to 16%. Winter and spring, with the highest seasonal reserve margins and least generous capacity accreditation values, produced capacity positions deeply in deficit that would require procuring more capacity in the PRA, building new generation, contracting through bilateral supply agreements, or choosing to pay the Capacity Deficiency Charge, which is 2.748 times the seasonal CONE.

2032/2033 PY Projected Capacity Position (UCAP MW)						
		Summer	**Fall**	**Winter**	**Spring**	
A	Transmission Losses	2.1%	2.1%	2.1%	2.1%	
B	PY 2032-2033 Planning Reserve Margin (UCAP)	8.7%	16.0%	22.4%	28.3%	
C	UCAP Generation - DLOL	8,593	8,528	7,407	7,253	
D	Load Forecast (MISO Coincident Peak)	7,555	7,319	7,692	6,832	
E	LSE Load Obligation	8,385	8,668	9,613	8,950	E=D*(1+A)*(1+B)
F	**Surplus/(Deficit)**	**208**	**(140)**	**(2,206)**	**(1,697)**	**F=C-E**

4.2 PJM

For PJM, a capacity position analysis was conducted on the assumption of a full RPM capacity market participant rather than a FRR participant. The FRR construct includes constraints that do not apply to RPM participants. FRR entities must abide by locational constraints with respect to contracting for bilateral capacity as well as a higher threshold of reserves required before the FRR entity can sell excess capacity into the RPM auction, limiting its ability to monetize excess capacity in a high capacity price environment. FRR entities could also be exposed to capacity deficiency penalties if large and sudden load growth occurs faster than new generation could be constructed or bilateral capacity acquired. Similarly, future ELCC

reforms could result in a sudden reduction in capacity accreditation, potentially exposing FRR entities to capacity deficiency penalties.

The Companies used the published forecast of annual ELCC capacity accreditation values for the 2032/2033 Delivery Year to convert the expected generation fleet ICAP to UCAP. The load obligation was derived by taking the Companies' 2032/2033 load forecast coincident with the average of the five highest peak load hours in PJM in the summer of 2024. This load obligation value was then multiplied by the 2027/2028 Delivery Year Forecast Pool Requirement of .926 and a scaling factor (assumed to be 1) to produce the UCAP load obligation. Netting the future generation UCAP from the UCAP load obligation produces a capacity deficit of 151 MW. This scenario assumes all offered units cleared the capacity auction. In the event any uncompetitive units fail to clear the auction, the capacity deficit would worsen. To avoid buying any capacity to remedy a shortfall in a potentially high-priced capacity market, new generation would need to be built, or other bilateral supply agreements would need to be secured.

2032/2033 DY Projected Capacity Position (UCAP MW)			
A	Summer ICAP (MW)	9,803	
B	Summer UCAP (MW)	7,024	
C	Summer Peak (MW)	7,748	
D	2027/2028 FPR	0.9260	
E	Scaling Factor	1	
F	Capacity Obligation (UCAP MW)	7,175	F=C*D*E
G	**Surplus/(Deficit)**	**(151)**	**G=B-F**

5 Continued uncertainty and cost attributable to transmission expansion cost within the RTOs

Transmission planning and the allocation of transmission expansion cost are major activities for each RTO. Under current PJM policy, the cost of new high voltage transmission projects approved under its annual Regional Transmission Expansion Planning ("RTEP") process is allocated based on a combination of zonal load ratio share and flow-based calculations. These charges are recovered under Schedule 12 of the PJM tariff. In MISO, the costs of long term expansion are recovered from a charge on energy sourced within the distinct subregion where each project is located, per Schedule 26A of their tariff. Since adoption of this process in 2022, MISO's Board of Directors have approved over $32 billion of expansion projects within the adjacent, Midwest subregion, which alone could add hundreds of millions of dollars of cost to the Companies if they joined MISO.

6 Update on SEEM Activities

The Southeast Energy Exchange Market ("SEEM") has been operational for almost three years, and it has been beneficial for the Companies' customers by providing a means of participating in energy trading that has none of the rule uncertainties or reliability and cost risks of RTOs.[96]

From January 2023 through August 2025, the Companies have sold 113,544 MWh at an average price of $48.90/MWh and purchased 60,566 MWh at an average price of $14.65/MWh. The Companies have been active SEEM participants, accounting for 4.4% of total SEEM transactions over this period. The resulting off-system sales margins and power purchase savings have benefited customers through the Companies' Fuel Adjustment Clause mechanisms. Indeed, the Companies estimate that customers have benefited by approximately $2,193,240 from sales and purchases since market inception through the second quarter of 2025, which is over *seven times* the estimated cost of SEEM participation during that period ($315,000).[97]

The Companies seek to participate in every 15-minute market and have a systematic process that determines the Companies' incremental costs and volume available for sale and the decremental costs and volumes for purchase. This process is similar to that used for making "over-the-counter" off-system sales and purchases from MISO, PJM, and TVA. See Appendix 2 for a detailed description of the Companies' SEEM bid and offer process.

Finally, the litigation noted in the 2024 RTO analysis concerning FERC's approval of the SEEM construct, the subsequent appeal to the U.S. Court of Appeals for the District of Columbia ("D.C. Circuit"), and the court's remand to FERC have all concluded, with FERC having affirmed its prior approval of the SEEM construct.[98]

7 De-pancaking Litigation Update

The Companies currently provide merger mitigation de-pancaking ("MMD") credits to certain entities importing from MISO under Rate Schedule 525 currently on file with FERC. The Companies had been crediting MISO transmission charges for imports from MISO for certain customers pursuant to a FERC filed agreement, LG&E/KU FERC First Revised Rate Schedule No. 402, relating to the Companies' 1998 merger and 2006 exit from MISO.[99] The Companies received FERC approval to eliminate MMD subject to the implementation of a transition mechanism for certain power supply arrangements.[100] A decision from the D.C. Circuit largely affirmed FERC's analysis in the 2019 Removal Order, but it ultimately vacated the

[96] See Southeast Energy Exchange Market (southeastenergymarket.com) for more information on SEEM and Appendix 1 for August 2025 audit report.
[97] See Appendix 1 for the most recent SEEM Independent Market Monitor monthly report, which provides various SEEM market data.
[98] *See Alabama Power Co.*, FERC Docket Nos. ER21-1111-006 *et al.*, Order on Remand and Addressing Rehearing Requests (FERC Mar. 14, 2025); *Alabama Power Co.*, FERC Docket Nos. ER21-1111-006 *et al.*, Order Granting Clarification and Denying Rehearing Request (FERC June 13, 2025).
[99] *See E.ON U.S., LLC, et al.*, FERC Docket No. ER06-1279-000.
[100] *Louisville Gas & Elec. Co.*, 166 FERC ¶ 61,206 ("2019 Removal Order"), *order on reh'g & clarification*, 168 FERC ¶ 61,152 (2019), *aff'd sub nom. Ky. Mun. Energy Agency v. FERC*, 45 F.4th 162 (D.C. Cir. 2022) ("KYMEA").

decision and remanded the matter back to FERC.[101] In its order on remand, FERC reversed its decision allowing for the termination of MMD and required the Companies to reinstitute the MMD provisions of Rate Schedule 402.[102] The Companies complied with this directive by filing Rate Schedule 525. The Companies appealed FERC's orders on remand and the compliance filing to the D.C. Circuit. On August 8, 2025, the D.C. Circuit vacated FERC's orders primarily due to FERC's failure to consider the transition mechanisms. The matter is currently back before FERC on remand. Due to the status of the ongoing litigation on MMD, it is not possible to identify how the Companies' MMD obligation might be impacted by RTO membership or to quantify such hypothetical impact. The Companies will revisit the potential impact of and to MMD in performing the next RTO analysis.

8 Conclusion

The current landscape of the MISO and PJM markets reveals two regional transmission organizations under mounting stress, grappling with a convergence of reliability risks, market volatility, governance tensions, and an unpredictable reform process—all occurring amid unprecedented load growth. Both RTOs are facing accelerating retirements of dispatchable generation and evolving reliability needs that traditional planning and market structures are struggling to address.

Neither RTO is successfully incentivizing the development of new generation resources through current market constructs. This issue is compounded by rising capital costs and long lead-times for new generation equipment, making investment in new resources a risky and uncertain endeavor for market participants. The slow and inefficient interconnection queue process further delays the deployment of new generation, creating a bottleneck in the system's ability to respond to growing demand.

The regulatory landscape presents significant uncertainty for stakeholders. Tariffs, tax credit structures, and legislative volatility all contribute to unpredictability in project economics and construction timelines. Additionally, evolving state and federal environmental policies are creating barriers to the development of new thermal resources. These policies often require costly retrofits for existing units and introduce siting and permitting delays that the RTOs are not equipped to mitigate directly.

In PJM, the mismatch between supply and demand is becoming increasingly acute. Capacity prices are surging, emergency alerts are rising, and regulated utilities in Kentucky and across the region are responding by reassessing planning strategies, increasing reserve margins, and reconsidering their market participation models. At the same time, frustration with PJM's governance and responsiveness is escalating at the state and stakeholder level, prompting calls for reform, legislative action, and even discussions about alternatives outside the RTO construct.

[101] The D.C. Circuit stated, "In short, the Commission's conclusion that sufficient competition would continue after [MMD] was based on substantial evidence from which it drew sensible inferences employing its expert knowledge of electricity markets. That is the 'kind of reasonable agency prediction to which we ordinarily defer.'" However, the D.C. Circuit faulted FERC for failing to evaluate the impact of the removal of MMD on rates and vacated the decision. *KYMEA,* 45 F.4th at 177.

[102] *Louisville Gas & Elec. Co.*, 183 FERC ¶ 61,122 (2023).

MISO faces similar challenges, including forecasts of persistent capacity shortfalls, chronic interconnection delays, and shifting system risks driven by the rise of intermittent renewables.

While both RTOs are pursuing market and procedural reforms, the pace of change may not be sufficient to avert a reliability crisis—especially as they attempt to balance stakeholder demands and maintain affordability for ratepayers.

This instability has direct implications for modeling future RTO membership. The continued evolution of market rules, capacity accreditation methodologies, the adoption of one-off interconnection initiatives, unprecedented capacity price volatility, and capacity auction delays have made it impractical to conduct modeling with the level of confidence required to inform a strategic decision to join an RTO at this time.

Without coordinated reform and investment, both PJM and MISO risk falling short of their reliability mandates. Until greater clarity and consistency emerge in their market structures, any attempt to quantify the financial impacts of future RTO participation remains speculative and insufficiently robust to guide long-term planning. This uncertainty underscores the need for caution and adaptability as utilities, regulators, and stakeholders navigate an increasingly complex and volatile energy landscape.

The Companies continue to monitor the market design activity of each RTO, the results of their capacity auctions, and their various reports regarding future resource adequacy. As the Companies have stated on numerous occasions, they are not opposed to RTO membership, but because it is likely a one-way option, exercising that option should only be done when it is clearly in the best long-term interest of customers.

The Companies continue to be open to possible future RTO membership. The Companies are actively monitoring market developments in MISO and PJM to help inform their analysis and future decisions. However, given the uncertainty in RTO market design, large fluctuations in capacity market prices, and pressing resource adequacy concerns, it is clear that RTO membership at this time would introduce significant unquantifiable risks for the Companies' customers without a clear quantification of possible benefits.