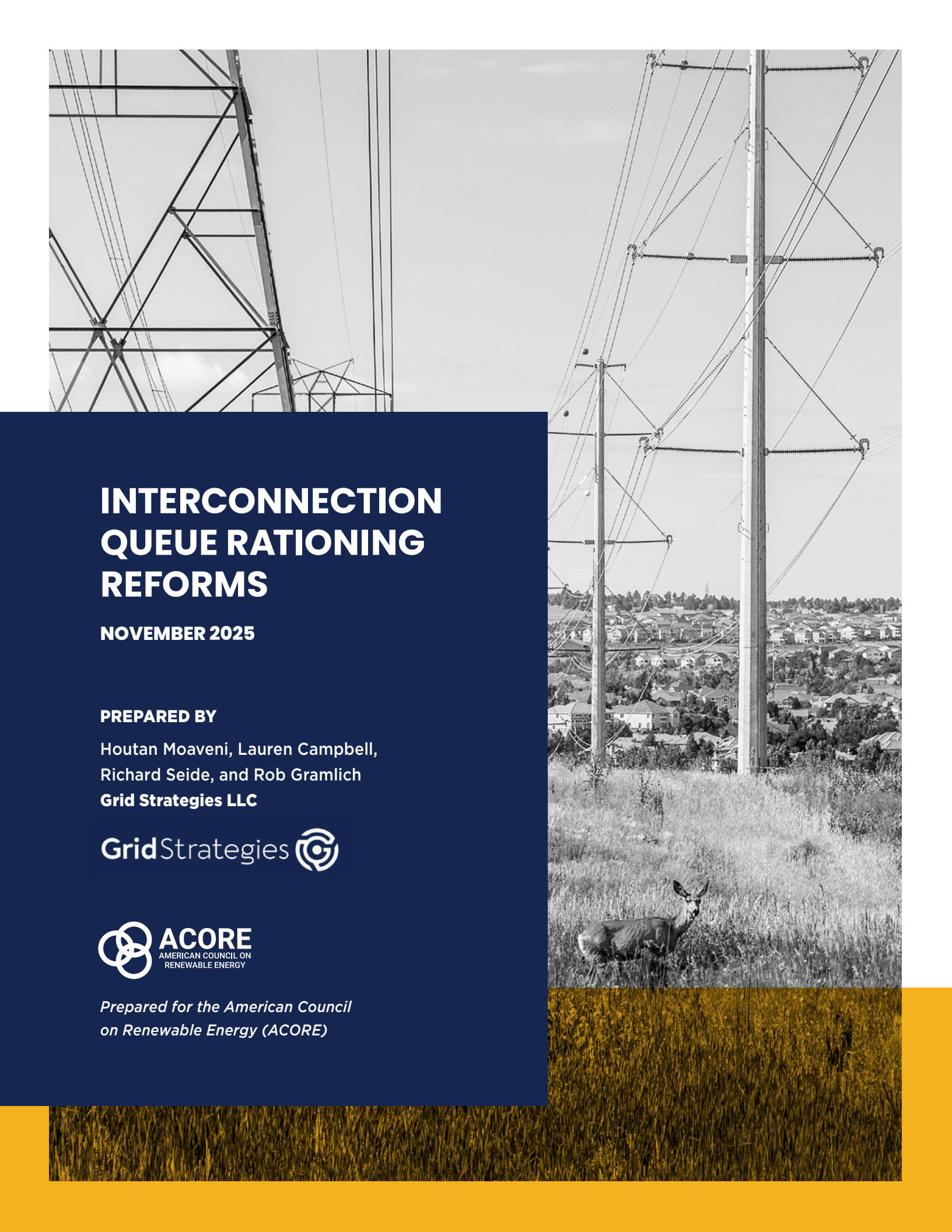




INTERCONNECTION QUEUE RATIONING REFORMS

NOVEMBER 2025

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EXECUTIVE SUMMARY

Open access is the cornerstone of competitive wholesale electricity markets, a principle enshrined in the Energy Policy Act of 1992¹ and reinforced in the Federal Energy Regulatory Commission (FERC) Orders No. 888² and No. 2003.³ These orders require utilities to provide non-discriminatory, comparable transmission and interconnection services. By remaining technology-neutral, they opened markets to all generation types and continue to serve as the benchmark for today's interconnection processes.

In the industry's effort to accelerate interconnection, after years of slow adaptation to queue backlogs, some reforms have introduced limits on project intake, either at the outset or during later stages of the process. While priority processing can be designed to be consistent with long-standing open-access principles, in many cases, core tenets of fairness and competition are being compromised. Discriminatory queue processing undermines fair competition among technologies and interconnection customers, introducing regulatory uncertainty that ultimately harms consumers.

¹ Energy Policy Act of 1992, Public Law 102-486, October 1992.

² FERC, Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities (Order No. 888), April 1996.

³ FERC, Standardization of Generator Interconnection Agreements and Procedures (Order No. 2003), July 2003.

Prior to the implementation of recent discriminatory practices, reforms aimed at improving standard interconnection processes appeared to be making an impact across regions. According to the latest data from Lawrence Berkeley National Laboratory (LBNL), interconnection queue volume has declined by approximately 12% over the past year.⁴ Smaller queues enhance grid operators' ability to process project proposals and streamline interconnection. These technology-neutral structural reforms should be allowed time to take effect before turning to extraordinary measures or creating alternative queues.

This report explores the growing trend of interconnection queue rationing⁵ across four major regional transmission organizations (RTOs) and independent system operators (ISOs)—PJM Interconnection LLC (PJM), the Midcontinent Independent System Operator (MISO), Southwest Power Pool (SPP), and the California Independent System Operator (CAISO). Each has adopted distinct approaches to prioritize projects and manage limited transmission capacity, ranging from temporary fast-track programs to permanent structural changes:

- ▶ **PJM's Reliability Resource Initiative (RRI)**⁶: a one-time process to fast-track projects with high accredited capacity and commercial readiness to address a projected near-term capacity shortfall, while sidestepping the regular queue order.
- ▶ **MISO's Expedited Resource Addition Study (ERAS)**⁷: a one-time process to prioritize projects certified by state regulators as necessary for near-term reliability, with strict eligibility and financial requirements. MISO asserted that the program would prevent undue discrimination, but opponents argue it shifts risk to other interconnection customers and non-participating load.
- ▶ **SPP's ERAS**⁸: a one-time process to prioritize projects nominated by Load Responsible Entities (LREs) to meet identified near-term resource adequacy needs. SPP asserted that the ERAS qualification requirements would prevent unfair treatment, but critics see the process as enabling LRE-sponsored generation to jump in front of pre-existing interconnection requests based on need determinations that may not be fully transparent or independently verifiable.
- ▶ **CAISO's Interconnection Process Enhancements (IPE)**⁹: a permanently restructured queue intake using zonal deliverability caps and scoring criteria aligned with state procurement and transmission planning. CAISO frames this as aligning interconnection with policy goals rather than rationing headroom, though some stakeholders worry it disadvantages newer entrants.

This report concludes that while certain rationing mechanisms may accelerate generation projects, some of them sacrifice fairness, transparency, and adherence to open-access

4 LBNL, Queued Up: 2025 Edition – Characteristics of Power Plants Seeking Transmission Interconnection as of the End of 2024, April 2025.

5 For purposes of this report, "rationing" refers to a deliberate allocation of scarce, contested grid or processing-capacity, interconnection and transmission headroom, when requests exceed availability. Rationing determines which projects get priority or even access to the queue at all, in what order, and under what criteria such as time of filing, project readiness, financial commitment or willingness to pay, demonstrated customer or system value, or preference of a state or offtaker. First-come first-served, first-ready first served, and other forms of prioritizing some projects over others are all forms of rationing. They can be technology-neutral or technology-biased and discriminatory.

6 FERC, Order Accepting Tariff Revisions (PJM Interconnection, L.L.C.: Resource Rationing Initiative), 190 FERC ¶ 61,084, February 2025. (hereinafter "hereinafter RRI Order")

7 FERC, Order Accepting Tariff Revisions (Midcontinent Independent System Operator, Inc.: Expedited Resource Addition Study), 192 FERC ¶ 61,064, July 2025. ("hereinafter MISO's ERAS Order")

8 FERC, Order Accepting Tariff Revisions (Southwest Power Pool, Inc.: Expedited Resource Addition Service), July 2025. ("hereinafter SPP's ERAS Order")

9 FERC, Order Accepting Tariff Revisions, 188 FERC ¶ 61,225, September 2024. ("hereinafter CAISO's IPE Order")



principles. Notably, FERC’s two-year Order No. 2023¹⁰ reform docket only briefly considered technology-based rationing, yet it is now active in PJM, MISO, and SPP. Early evidence suggests that these emergency mechanisms produce portfolios heavily weighted toward thermal resources that are not immune from high network upgrade costs, and may require ongoing program design changes, raising doubts about their ability to deliver the promised near-term capacity gains without eroding confidence in the standard interconnection process.

Although these programs are labeled “one-time only,” they could be extended or repeated. Independent renewable developers and regulators should closely examine these trends and develop a long-term strategy that upholds open access and competition, both of which are essential for the health of power markets and consumer benefit. To address these challenges, the report proposes a two-path framework for interconnection queue reform:

- ▶ **Enhanced Readiness Fast Lane:** a narrowly tailored, transparent pathway for projects that address verified near-term reliability needs, activated only under specific conditions and governed by transparent, objective, and non-discriminatory criteria.
- ▶ **Proactive Integration with Transmission Planning:** a restructured baseline queue that aligns project intake with available and planned transmission capacity, using scoring systems to prioritize commercially ready and policy-aligned resources.

This dual-track approach aims to fundamentally improve the standard interconnection queue while reducing reliance on emergency rationing mechanisms. By aligning interconnection with proactive transmission planning, grid operators and policymakers can build a more resilient, efficient, and equitable electric grid.

¹⁰ FERC, Improvements to Generator Interconnection Procedures and Agreements (Order No. 2023 and the associated order on rehearing and clarification, 2023-A, referred to collectively as Order No. 2023), July 2023. (hereinafter “Order No. 2023”)

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The authors thank the following reviewers for their thoughtful insights on drafts of this report: Kevin O'Rourke and Elise Caplan of the American Council on Renewable Energy (ACORE); Melissa Alfano of the Solar Energy Industries Association (SEIA); Gabe Tabak of the American Clean Power Association (ACP); Steve Gaw and Maya Nevels of the Advanced Power Alliance (APA); and David Sapper of Clean Grid Alliance. The analysis and recommendations presented here were also informed by extensive interviews with market participants across multiple regions.

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ONE INTRODUCTION

Open access remains the foundation of competitive wholesale electricity markets, a principle rooted in the Energy Policy Act of 1992 and codified in FERC Orders No. 888 and 2003. These policies require utilities to file transmission tariffs that provide comparable, non-discriminatory service, enabling third parties to access the grid and fostering technology-neutral competition. By leveling the playing field, open access encourages innovation, supports investment in diverse resources, and helps deliver lower costs and improved reliability for consumers.

The United States is undergoing a major energy transition that is putting record pressure on the grid’s “front door”—the interconnection process. Queued capacity has grown from under 500 gigawatts (GW)¹¹ in 2010 to more than 2,300 GW of generation and storage by the end of 2024, well above the roughly 1,200 GW installed on the U.S. grid.¹² Fewer than one in five queued projects reach commercial operation, and average interconnection timelines have lengthened from about two years to more than five.¹³ This problem has been intensified by a simultaneous surge in electricity demand, driven by data centers, industrial reshoring, and electrification, while aging thermal units are retiring.¹⁴ The convergence of rising demand and retiring capacity, while new generation is stuck in interconnection queues, has created a critical challenge for resource adequacy.

Delays in connecting new generation projects are multifaceted. Limited transmission capacity, rising network upgrade costs, and protracted study timelines slow down the process. Even after navigating the interconnection study process, more than 408 GW of projects that have signed generation interconnection agreements (GIAs) face additional hurdles, such as permitting delays, equipment shortages, and supply-chain disruptions.¹⁵ Investor confidence has been further shaken by shifting federal and regional policies, such as high interest rates, tariffs, changing tax credit eligibility and timelines, and evolving capacity accreditation rules. These compounding issues have led to fewer power purchase agreements and deferred commercial

11 U.S. Department of Energy, Transmission Interconnection Roadmap: Transforming Bulk Transmission Interconnection by 2035, April 2024.

12 LBNL, Queued Up: 2025 Edition.

13 Id.

14 Grid Strategies LLC, Power Demand Forecasts Revised Up for Third Year Running, Led by Data Centers, November 2025.

15 LBNL, Queued Up: 2025 Edition.

operation dates.¹⁶ When new cost-effective capacity is delayed, reserve margins shrink, prices for capacity and energy rise, and customers pay more than necessary for electricity.

In an attempt to address these challenges, grid operators have turned to emergency rationing mechanisms that prioritize a limited number of projects outside the standard interconnection queue sequence. These mechanisms, ranging from one-time fast tracks to permanent zonal caps, are controversial. They deviate from open-access principles, often favor thermal resources over renewables, and risk worsening congestion and attrition in the broader queue.

This report describes and critically reviews interconnection queue rationing policies. It begins with an overview of Order No. 2023 and the scale of the interconnection challenge, describes the causes of grid congestion, and outlines short-term reforms and longer-term solutions to improve standard interconnection processes. It then evaluates the emergency rationing mechanisms adopted in PJM, MISO, and SPP, and examines the permanent zonal rationing framework adopted by CAISO. The report analyzes the effectiveness, fairness, and unintended consequences of these initiatives and contrasts regional approaches. It concludes with recommendations on how to design any unavoidable queue prioritization in a manner that preserves speed, fairness, and open-access principles while ensuring reliability.

16 American Clean Power Association (ACP), Report: Federal Chaos Sparks Warning Signs for Clean Energy Investment, According to Q2 Data, September 2025.



TWO BACKGROUND

For decades, the electricity sector's interconnection policy operated under a simple premise that was suited to the circumstances at the time. In the early 2000s, FERC established a framework based on a "first-come, first-served" queuing principle.¹⁷ In an era of abundant transmission capacity, this approach seemed both administratively straightforward and formally fair. It worked well enough for a queue filled with fewer, mostly gas units that were less location-constrained and had more predictable network interactions. The system's design relied on participant-funding rules, shifting site-specific network upgrade costs onto individual interconnection customers. This inadvertently created an incentive for interconnection customers to file multiple requests, turning the queue into a speculative market and discovery process in which developers needed to enter the queue to determine their assigned interconnection costs and "shopped" for the lowest-cost connection point, fueling churn and cost uncertainty.

Over time, the reality of the grid has changed from one of abundant transmission capacity to meet the needs of a few large generators to one of scarce transmission and ballooning generation additions. The modern resource mix, featuring geographically concentrated wind and solar, hybrid and storage projects, and soaring demand from data centers, has exposed

¹⁷ Order No. 2003.

the deep, systemic flaws of the legacy interconnection policy. A mechanism built for an era of abundance has become hopelessly gridlocked by an era of scarcity. The “first-come, first-served” approach has proven unacceptably slow at scale and blind to project merit or reliability. Under serial processing, a single suspended project can stall many others, creating a cascading failure that threatens grid reliability. The old system is not just inefficient; it is an active impediment to the very resource development it is meant to facilitate.

Recognizing that chronic delays and high-cost uncertainty pose a grave threat to long-term reliability, regulators and regional grid operators have pursued multiple interconnection reforms in recent years. After a two-year process of considering many reforms, FERC issued Order No. 2023¹⁸ in July 2023, a significant overhaul of federal interconnection policy. However, because the rule applies nationwide across a highly diverse industry, it ultimately introduced only modest changes—many of which had already been adopted regionally.

Order No. 2023 requires all FERC-jurisdictional transmission providers to adopt cluster studies, replacing serial processing with a “first-ready, first-served” approach. Transmission providers are required to group requests received during common request windows into a single cluster study and identify shared network upgrades, allocating upgrade costs using a proportional-impact method. This parallel processing, already employed by multiple transmission providers, has proven to accelerate studies and allow for a more comprehensive assessment of shared network upgrade costs.

To deter speculative requests, the rule increases study deposits and mandates that interconnection customers demonstrate 90% site control at the time of request and 100% site control before the facilities study. Commercial readiness deposits at each study phase and withdrawal penalties, triggered when a withdrawal materially increases costs or delays for lower-priority projects, further discourage queue placeholders. These filters, while placing heavier burdens on less-capitalized entrants, are technology-neutral and satisfy open-access norms by ensuring that scarce engineering and grid capacity are reserved for projects most likely to be built. In effect, these reforms weed out speculation. Critically, Order No. 2023 eliminates the prior “reasonable efforts” standard and imposes a 150-day deadline for cluster studies and an equal 150-day deadline for restudies with enforceable penalties if transmission providers miss these deadlines. These changes impose a new level of accountability and discipline, supporting the efficient and timely allocation of grid capacity.

FERC also requires transmission providers to maintain public “heatmaps” showing available transmission capacity and to standardize affected-system studies across neighboring grids, with a 150-day timeline and proportional-impact cost allocation. The heatmap requirement is intended to improve developers’ ability to find appropriate points of interconnection, leading to more viable projects in the queue. Developers also have proprietary tools based on transmission provider models to evaluate points of interconnection. Order No. 2023 modernizes interconnection rules to accommodate co-located resources and hybrid projects. It allows multiple resources to share a single interconnection request, clarifies that energy storage facilities may charge and discharge under a single service agreement, and requires transmission

18 Order No. 2023.

providers to evaluate most grid-enhancing technologies (GETs) and advanced conductors as alternatives to traditional upgrades.

Beyond these FERC-required reforms, most RTOs/ISOs adopted a cluster approach prior to Order No. 2023 and implemented additional reforms that suit their region, as explained in more detail below. For example, MISO increased readiness requirements beyond those required by Order No. 2023 and adopted a queue cap, which limits total capacity admitted per cycle in each study region.¹⁹ CAISO adopted a zonal, deliverability-based approach to processing and studying interconnection requests. PJM implemented a three-phase system impact study process in place of the cluster study, cluster restudy, and individual facilities study structure adopted in Order No. 2023.²⁰

Early evidence suggests these reforms have begun to streamline queue processing and accelerate study completions. Measures like stricter readiness requirements have led to a record number of project withdrawals and signed GIAs over the last two years, and additional gains are expected as Order No. 2023-required reforms take effect.²¹ Although Order No. 2023 lays the foundation for a more disciplined and efficient interconnection process nationwide, many interconnection customers continue to face multi-year waits and high network upgrade costs, and some regions cannot begin new clusters until earlier cycles are cleared, creating further delays.

Order No. 2023 fell short of requiring reforms that would address more fundamental causes of interconnection delays, such as proactive transmission planning, automation, other innovations in study speed, alternative service option refinements, and time-limited application of queue caps. Such reforms are already under development in most regions. They show great promise thus far and are fully consistent with open-access principles. Giving these reforms enough time to work is essential before turning to any emergency queue rationing constructs.

19 FERC, Order Accepting in Part and Rejecting in Part Tariff Revisions, 186 FERC 61, ¶ 054 (2024); FERC, Order Accepting Tariff Revisions, 190 FERC ¶ 61, 057 (2025).

20 FERC, Order on Compliance, 192 FERC 61, 077 (2025).

21 LBNL, Queued Up: 2025 Edition, April 2025.

THREE INTERCONNECTION QUEUES: COMMON CHALLENGES

From both a regulatory and an economic perspective, today's interconnection bottleneck is driven by multiple interrelated constraints. On one level, processing interconnection requests is a complex administrative service. Transmission providers themselves face administrative scarcity; there are not enough experienced engineers to study every request simultaneously, and each study or restudy consumes constrained staff resources. Even clustered studies are constrained by engineering staffing levels, tools, and the time required to conduct feasibility, system impact, and facilities studies. The surge of interconnection requests, often numbering in the thousands of projects per cluster, has overwhelmed processing capability.²²

Uncertainty about network upgrade costs further exacerbates the problem. Projects can remain in the queue for years, only to encounter materially higher-than-expected network upgrade estimates late in the process. In many regions, the interconnection queue has effectively become one of the few practical ways for developers to obtain project-specific information about transmission costs and timelines. Faced with this uncertainty, some interconnection customers enter and maintain queue positions as contingent options. This behavior contributes to higher attrition but is an understandable response to how current rules allocate risk. Even when studies are completed, many projects face physical transmission scarcity. Deliverability on the grid is inherently limited by the thermal and stability constraints of existing lines. Generator interconnection has essentially turned into a competition for limited deliverability on existing wires. Much of the high-voltage transmission system was built decades ago, and expansion has lagged far behind generation development. Yet planning and funding new transmission lines has been difficult under existing regulations and cost allocation rules. In fact, interconnection queues have become de facto transmission queues, with projects waiting not just for studies or local upgrades but effectively waiting for a transmission owner to fund and build the necessary backbone network wires to accommodate them.²³ Because network planning has been largely reactive, new lines materialize only after the queue reveals the bottleneck, creating a chicken-and-egg loop: the transmission system needs expansion to accommodate new generation in the

²² FERC, *Explainer on the Interconnection Final Rule*, March 2024.

²³ Grid Strategies LLC, *Delaying Transmission Increases Costs and Reduces Benefits for Consumers*, November 2025.

interconnection queue, but the interconnection queue needs stability to justify that transmission expansion.

Large-scale generation facilities are often located far from population centers. In many zones, the network can accommodate only small, location-specific increments of additional injections that still meet contingency criteria. Projects beyond that threshold trigger long lead-time, high-cost upgrades that take years to complete. In practice, developers compete for a limited opportunity to inject deliverable megawatts before major upgrades are necessary. Order No. 2023 largely preserved the traditional participant funding framework — “identify all upgrades for firm service and assign costs to the interconnection customer.”²⁴ While potentially prudent for near-term reliability, this structure leaves projects in congested zones carrying the heaviest costs and longest waits, shifting the backlog from the study desk to a post-study, waiting-for-construction limbo. This means that, in the near term, only a few projects can connect, regardless of how many enter the queue.²⁵ In the face of growing demand, these delays can adversely impact overall resource adequacy.

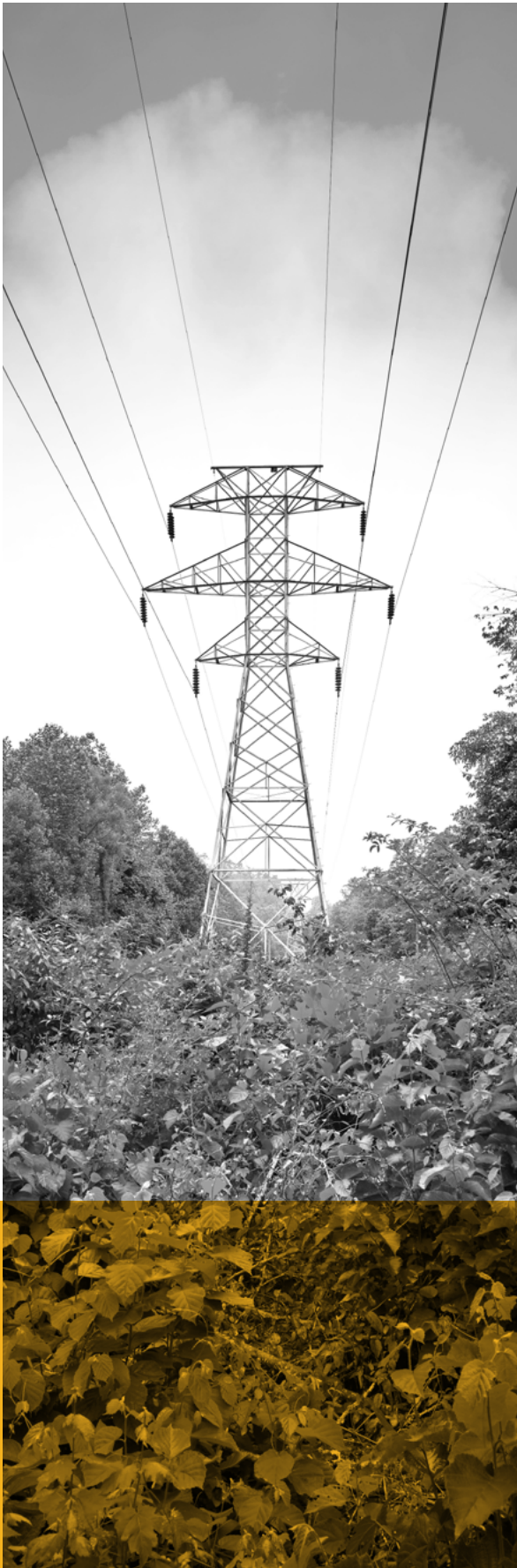
Additionally, the ad-hoc nature of relying primarily on individual interconnection requests to identify transmission expansion needs and then constructing that transmission based upon generators’ willingness to pay is unlikely to result in a cost-effective or efficient transmission system. This approach further compounds inefficiencies and ultimately increases costs to ratepayers who also pay for piecemeal transmission expansion via network upgrade costs flowing through energy prices. In economic terms, generation interconnection is a scarce good or service.²⁶ One of the primary challenges is the inefficiency in how current interconnection processes allocate scarce transmission capacity. Crucially, this allocation does not occur through a transparent market price that reflects true system needs or customer value. Instead, access is governed by administrative procedures such as readiness screens, deposits, and milestones.

This framing underscores that interconnection queue reform cannot rest solely on adding staff or accelerating studies. While staffing and speed matter, they do not alone create deliverability; likewise, better economic signals cannot substitute for physical capability. In the near term, the emphasis should be on an improved neutral, transparent interconnection process that preserves open access, including: (1) standardizing and automating studies to produce reproducible results; (2) publishing clear hosting-capacity and upgrade-lead-time information so developers can self-screen viable sites; and (3) synchronizing interconnection milestones with proactive transmission planning and timely construction. With this approach, regions can improve throughput and decision quality today while addressing the underlying scarcity through longer-term transmission expansion.

²⁴ Order No. 2023.

²⁵ Grid Strategies LLC, *Disconnected: The Need for a New Generator Interconnection Policy*, January 2021.

²⁶ Michael G. Pollitt, Daniel Duma, Andrei Covatariu, *Trading Connections: Literature Review and Conceptual Design*, September 2024.



FOUR MEASURES TO ACCELERATE THE INTERCONNECTION PROCESS

Addressing the challenges described above requires a two-tier policy approach: short-term reforms that accelerate throughput and improve decision quality in interconnection processes, and longer-term reforms that integrate interconnection with proactive, benefit-based transmission planning. Together, these reforms: (1) expand physical and analytical capacity; (2) unlock latent capability on existing transmission assets; and (3) standardize and automate processes so that all viable interconnection projects can be studied and energized without excluding any class of project.

4.1 Long-Term Reforms

Proactive Transmission Planning: While not the primary focus of this report, it is important to note that interconnection policy cannot be isolated from regional transmission planning and resource adequacy. The most robust measure to address transmission capacity scarcity is to regionally plan and expand that capacity ahead of the need arising and to right-size assets due for

upgrade and/or rebuild. Long-term, forward-looking regional transmission planning should identify multi-value transmission projects that create deliverability headroom and reduce per-project costs relative to piecemeal, interconnection project-triggered network upgrades and local utility upgrades.

In 2024, FERC adopted the most significant overhaul of regional transmission planning in decades when it issued Order No. 1920²⁷ (and the associated orders on rehearing and clarification, 1920-A and 1920-B, referred to collectively as Order No. 1920). To comply, transmission providers must now: plan on a 20-year, forward-looking basis, using a set of scenarios of the future that account for a specific list of factors driving transmission needs; consider a standardized set of benefits of regional transmission projects to meet long-term transmission needs; and reassess scenarios at least every five years. The benefits that must be used in the selection of transmission facilities include reliability replacements and reduced loss-of-load probability, production cost savings, reduced energy losses, reduced outage-induced congestion, extreme-weather mitigation, and capacity cost savings. The rule also directs transmission planners to “right-size” transmission system rebuilds, to add capacity while assets are already out of service, and to examine advanced transmission technologies such as high-performance conductors. These changes provide one key component of moving the system away from reactive, project-by-project network upgrades planned and paid for through generator interconnection toward portfolios of transmission projects that create deliverability headroom in advance of where the market continually shows interest. If robustly implemented, Order No. 1920 should lead to the type of long-term investments needed in backbone regional transmission infrastructure to allow for more expedited generator interconnection, without the need for band-aid fixes to interconnection queues that attempt to overcome the challenge of idiosyncratically charging whichever generator happens to require an upgrade for major grid improvements.

Transmission planning is particularly consequential for generator interconnection if it translates into earlier, more predictable transmission capacity at specific points of interconnection. Here, two implementation choices are critical. First, transmission planners must fold “queue-revealed” needs—upgrades that appear in study after study but never get built—into their long-term scenarios so those reinforcements are identified in the transmission planning process and a cost-effective and efficient solution is constructed once, not adjudicated anew for every individual generation project. Chronic transmission constraints need to be addressed proactively. Second, cost allocation for transmission system costs must reflect shared benefits, consistent with SPP’s proposed Consolidated Planning Process (CPP) and Entry Fee construct discussed below.²⁸

Order No. 1920 benefit-based framework gives transmission planners and states the tools to socialize the costs of backbone elements that repeatedly show up in interconnection studies, replacing late-stage sticker shock for the unlucky first-movers in the interconnection queue with ex ante, broadly supported cost sharing that is consistent with cost causation and beneficiary-pays principles.

27 FERC, Building for the Future Through Electric Regional Transmission Planning and Cost Allocation (Order No. 1920), May 2024. (hereinafter “Order No. 1920”)

28 Grid Strategies and the Brattle Group, Unlocking America’s Energy: How to Efficiently Connect New Generation to the Grid, August 2024.

4.2 Short-Term Reforms

While these long-term reforms are being pursued, several near-term actions are available to improve interconnection performance, which FERC and other policymakers can encourage.

Increase the Use of Advanced Transmission Technologies (ATTs) to Address Interconnection

Needs: While new transmission is needed to meet growing demand reliably and affordably, physical transmission capacity can be created faster than planning, permitting, and constructing a new line by treating existing wires as controllable assets. ATTs including GETs like topology optimization, advanced power flow controllers, and dynamic line ratings (DLRs), as well as high-performance conductors (HPCs), can unlock latent transfer capability on existing transmission facilities. Order No. 2023 requires transmission providers to consider specified ATTs during cluster studies and to document why an alternative was or was not selected. While FERC ultimately declined to list DLRs as an ATT that transmission providers must consider, FERC was clear that nothing prevents transmission providers from evaluating DLRs.²⁹ The policy signal is clear: transmission providers must evaluate lower-cost, faster-to-deploy options alongside traditional new builds and explain those choices publicly.

Adopt Less Restrictive Treatment of Energy Resource Interconnection Service (ERIS): ERIS was standardized in Order No. 2003 as a non-deliverable, energy-only interconnection service.³⁰ In contrast, Network Resource Interconnection Service (NRIS) is studied so that a resource can be used as or designated as a Network Resource for capacity purposes. ERIS studies identify only the reliability upgrades (if any) needed to allow injection on an “as-available” basis. Neither interconnection service, by itself, confers transmission delivery or capacity accreditation. In practice, some regions’ tariffs and study practices have treated ERIS in ways that resemble “NRIS-light,” imposing deliverability-style assumptions, protracted timelines, and costs on energy-only requests, an approach that stakeholders have challenged in FERC proceedings.³¹

To align ERIS with its intended purpose, transmission providers can codify study assumptions, curtailment priority, and operating logic (e.g., provisional energization with explicit real-time curtailment rules) so ERIS remains a lower-cost path for projects that do not seek capacity accreditation. Restoring ERIS as a strictly non-deliverable, energy-only product, while still performing necessary reliability studies, would enable earlier, lower-cost energization.³² Where feasible, provisional interconnection service (consistent with FERC Order No. 845³³) managed through operational curtailment can bring units online sooner and better utilize existing capacity. PJM stakeholders endorsed expanding provisional interconnection service in September 2025 to permit energy-only operation based on interim studies while upgrades are underway; successful implementation will hinge on transparent curtailment logic and clear fallback procedures under system stress.³⁴

29 The Brattle Group and Grid Strategies, Incorporating GETs and HPCs into Transmission Planning Under FERC Order 1920, April 2025.

30 Order No. 2003.

31 FERC, *EDF Renewable Energy, Inc. v. Midcontinent Independent System Operator, Inc.; Southwest Power Pool, Inc.; and PJM Interconnection, L.L.C.*—Order on Complaint and Technical Conference (168 FERC ¶ 61,173), September 2019.

32 Rocky Mountain Institute, et al., Joint Post-Workshop Comments, Docket No. AD24-9-000, November 2024.

33 FERC, *Reform of Generator Interconnection Procedures and Agreements* (Order No. 845), 163 FERC ¶ 61,043, April 2018. (hereinafter “Order No. 845”)

34 PJM, *Expansion of Provisional Service* (Planning Committee; Jason Shoemaker, Director, Interconnection Analysis), September 2025.

Enable a Fast-track Process for New Generators to Use Grid Capacity Reserved for Existing Generators: Surplus Interconnection Service (SIS) remains a critical, rapid deployment pathway that utilizes underused interconnection service at an existing point of interconnection (POI). SIS allows new supply resources to use the grid infrastructure already serving an existing generator so long as the combined injections behind the POI do not exceed the existing interconnection service amount. Studies are typically limited and, while direct-assigned interconnection facilities may be needed, SIS generally proceeds without triggering new network upgrades. Order No. 845 requires transmission providers to offer a SIS process, though implementation has been uneven across regions. In February 2025, FERC approved PJM’s reforms expanding SIS eligibility (including storage and earlier access), bringing PJM more in line with MISO and SPP practices. Emerging analyses put the technical potential from SIS-based additions in the 800–1,000 GW range nationally.³⁵ To capture that potential while avoiding “quasi-NRIS” creep and cost over-allocation, transmission providers should standardize SIS study scopes, clarify queue positioning, and publish transparent rules for incremental deliverability.

In parallel, generator-replacement frameworks can leverage existing interconnection rights at retiring facilities. MISO³⁶ and SPP³⁷ have FERC-approved generator-replacement processes that allow retiring units to efficiently transfer interconnection rights to replacement generation, minimizing stranded capacity and reducing duplicative studies. PJM is modernizing the transfer of Capacity Interconnection Rights (CIRs) to create a clearer, time-bound path for replacement resources.³⁸ Done well, these frameworks can accelerate backfill where infrastructure already exists, while deterring hoarding through milestone enforcement and retirement.

Automate Study Processes: Interconnection studies have long been criticized for being resource-intensive, slow, and highly dependent on manual engineering labor, which has not scaled alongside surging queue volumes. Automation and digitalization, using advanced analytics and AI-enabled tooling, are increasingly promoted by RTOs/ISOs to accelerate throughput without commensurate staff expansion. MISO’s use of the System for Unified Grid Analysis & Reporting (SUGAR) platform is the most advanced example in production today, applying advanced optimization and circuit-solver automation to speed study work.³⁹ MISO’s 2025 benchmarking found that SUGAR produced initial power-flow outputs much faster while yielding upgrade-cost estimates similar to traditional methods (e.g., \$13.25B vs. \$13.36B in a comparable prior cycle).⁴⁰ The platform is commercial/proprietary, so results are not independently reproducible without access to the software and underlying study cases, reinforcing why consistency in study inputs and results will continue to matter as much as speed.

Without transparency, faster studies alone won’t yield more buildable projects. The credibility of early-phase outputs hinges on standardized base cases, published contingency/monitoring sets, and reproducible model runs. Regions should publish inputs, solver versions, and

35 Miles Farmer and Abe Silverman, *Unlocking the Power of Surplus Interconnection: Barriers, Opportunities, and Strategic Solutions*, February 2025.

36 FERC, *Order Accepting Tariff Revisions*, 191 FERC ¶ 61,154, May 2025.

37 FERC, *Order Accepting Tariff Revisions*, 171 FERC ¶ 61,270, June 2020.

38 PJM’s CIR filing is currently pending before FERC in Docket No. ER26-403-000.

39 MISO, *SUGAR Implementation — Interconnection Process Working Group*, March 2025.

40 MISO, *MISO’s Benchmarking of Pearl Street SUGAR*, April 2025.

contingency libraries alongside automated outputs and demonstrate reproducibility before scaling, a theme FERC has elevated through its automation letters⁴¹ and interconnection-innovation workshop.⁴² Similarly, regions should be careful about simultaneously implementing multiple software solutions to increase study speed as it may work against transparency and common understanding of the models and outputs. Independent or third-party oversight can further standardize criteria, oversee model changes, and provide transparent rationales that reduce disputes and re-studies; DOE's i2X roadmap⁴³ likewise calls for improved data access, transparency, benchmarking, and auditing to enable automation.

No single reform will address interconnection challenges. A comprehensive strategy requires both near-term fixes and structural investments: disciplined queue management, proactive transmission planning, equitable cost allocation, widespread adoption of GETs and HPCs, streamlined siting, and the judicious use of market-based allocation tools. The most promising path is to combine near-term fixes with longer-term investments. While Order No. 1920 reforms require significant time to achieve their benefits, short-term reforms primarily improve queue discipline, transparency, and flexibility. When interconnection is integrated with long-term planning, when costs are predictable and shared fairly, and when automation delivers reliable results, the interconnection pipeline can improve dramatically without relying indefinitely on blunt instruments like ad-hoc queue rationing.

41 FERC, Commissioner Rosner's Letters to ISO/RTOs Regarding Interconnection Automation, March 2025.

42 FERC, Innovations and Efficiencies in Generator Interconnection Workshop, AD24-9-000, September 2024.

43 U.S. Department of Energy (DOE), Interconnection Innovation e-Xchange (i2X), Transmission Interconnection Roadmap, April 2024.

FIVE MANAGING SCARCITY

While recent reforms are making interconnection queues more manageable for transmission providers, further improvements in queue management are needed. In the face of FERC-approved “one-time” approaches to ration scarce interconnection processing capacity and federal legislation approved by the House of Representatives⁴⁴ that would require similar measures in other regions or extend them beyond a one-time approach, it is timely to consider which forms of rationing are fair, non-discriminatory, and therefore worthy of extension, and which are not. This analysis is crucial for ensuring the grid’s reliability while upholding the principle of open access.

As discussed in the previous sections, Order No. 2023 reforms discourage speculative requests and ensure a more efficient study process, but they do not, by themselves, address the fundamental lack of deliverable transmission capacity, which remains a significant binding constraint in many areas. This reality is pushing grid operators and regulators to explore interconnection rationing methods, moving beyond reactive queue management toward proactive intake control and system-value prioritization. Such measures determine which interconnection customer goes first when not everyone can be served at once (i.e., when to ration).

This section looks at how different rationing approaches allocate scarce study bandwidth and deliverability, and how they stack up on speed, efficiency, fairness, reliability, and market neutrality considerations. Any allocation rule creates winners and losers, so the policy challenge is to choose rules that maximize system benefit and customer value without undermining open access. The intent here is not to present rationing as a necessary intervention or declare one rationing approach superior to another but to highlight the strategic choices and trade-offs involved in rationing frameworks.

Open Seasons: The first response to the persistent problem of oversubscription and study backlogs has been to reform how interconnection customers enter the queue in the first place. A structured intake process can address initial cluster sizes that exceed what a region can feasibly study or process. Subscription windows, or open seasons, have emerged as a powerful

44 See Balderson bill, <https://balderson.house.gov/news/documentsingle.aspx?DocumentID=2887>.

tool for this purpose. This approach, with precedents in natural gas pipeline allocation, allows a transmission provider to announce available capacity in a specific zone and invite all parties to subscribe during a defined window with a defined cost allocation. If oversubscribed, rights can be allocated via a lottery, timestamp within the window, or sealed-bid auction, often with the rights becoming tradable.

Well-designed open seasons can provide a fair, synchronized opportunity to convert diffuse interest into executable programs, particularly when combined with long-range transmission plans. They can turn an unmanageable queue into a transparent, time-bound subscription window that funds upgrades for those who remain. Designated timing windows are now standard practice for entering the queue in almost all regions, and they are fundamental to the cluster study approach. Rather than a continuous rolling queue, grid operators could instead open periodic intake windows for defined transmission upgrades. This batching is a form of rationing insofar as projects outside the window must wait for the next, and if too many apply, further triage must occur within the batch.

The Bonneville Power Administration's (BPA) Network Open Season illustrates how a properly designed open season can clear speculative backlogs and finance needed transmission upgrades.⁴⁵ BPA conducted Network Open Season from 2008 to 2010 and effectively illustrated how financial requirements can clear speculative backlogs.⁴⁶ By requiring generators to post security and sign precedent agreements, BPA successfully filtered the queue, with 263 requests totaling 11,722 MW receiving service commitments over the three open seasons.⁴⁷ Of note, while this effort addressed the immediate queue congestion, BPA's experience demonstrates that the open season model is not a complete solution for grid expansion. Significant delays and project cancellations occurred in subsequent years due to complex and lengthy permitting processes, evolving market conditions, and public opposition. Furthermore, BPA has faced recurring issues with oversubscription, necessitating repeated reforms to its planning processes, most recently in 2024 and 2025.

Queue Caps: Another rationing method for controlling intake and managing workload is the use of queue caps. Instead of picking winners, this approach acts as an administrative throttle. In January 2025, FERC approved MISO's proposed queue cap, which limits total capacity admitted per cycle in each study region (i.e., subregion of MISO) to 50% of non-coincident peak load.⁴⁸ For MISO's 2025 Definitive Planning Phase, the combined overall cap was 77.8 GW. By the time the application window closed, 77.8 GW across 263 projects had entered, filling the overall cap as well as four of the five regional caps.⁴⁹ While proponents argue that caps, coupled with readiness requirements, could improve modeling fidelity and yield more actionable results, critics contend that they merely allocate scarcity rather than solve it and risk constraining competition. Because they do not create additional grid headroom, caps are best deployed as a

45 Grid Strategies LLC, Resolving Interconnection Queue Logjams: Lessons for CAISO from the US and Abroad, Grid Strategies Analysis for CAISO, October 2021.

46 BPA, Statement of Stephen J. Wright, Administrator, before the U.S. Senate Committee on Energy and Natural Resources, hearing on "Challenges and Regional Solutions for Developing Transmission for Renewable Electricity Sources," June 2008.

47 BPA, Federal Transmission Expansion in the West (DOE Tribal Leader Forum: Transmission and Clean Energy Development in the West; Denver, Colorado; Bill Drummond, Deputy Administrator), February 2012.

48 FERC, Order Accepting Tariff Revisions, 190 FERC ¶ 61,057, January 2025.

49 MISO, Queue Cap Tracker and ERAS Process Overview, October 2025.

temporary measure, paired with transparent screening and explicit build programs, rather than as a standing constraint on future generation.

Entry Fee: Another approach, beyond simply managing intake, is to adopt an “entry fee” for potential new generators. The entry-fee approach is a transformative model designed to address inefficiencies in the generator interconnection process by providing cost certainty and streamlining access to planned transmission capacity.⁵⁰ This approach, which is emerging in regions like SPP and CAISO,⁵¹ prioritizes ready-to-develop projects based on their willingness to pay and meet readiness criteria. It shifts the focus from reactive, piecemeal upgrades to proactive, long-term planning, ensuring the transmission grid is prepared to accommodate future generation needs efficiently. Transmission providers conduct scenario-based planning to identify future grid requirements, considering factors such as anticipated generation growth, resource locations, and evolving system demands. Through this process, they design and implement upgrades that create headroom in transparent, pre-planned interconnection zones, ensuring the grid can accommodate new generation resources without requiring extensive last-minute modifications.

Interconnection customers seeking access to this planned capacity pay a fixed, pre-determined entry fee, calculated based on the forecasted costs of regional and sub-regional upgrades identified during the proactive planning process. This fee provides clear, upfront cost information, eliminating the uncertainty and variability associated with current interconnection processes, where costs often fluctuate due to restudies, project withdrawals, and unforeseen network upgrade requirements. The entry-fee approach simplifies the interconnection process by allowing customers to compete for access to planned capacity based on their readiness and willingness to pay the entry fee. Once the fee is paid, interconnection customers are fast-tracked through the interconnection study process, avoiding the lengthy and complex cluster studies that are typically required. While the entry-fee model offers significant advantages, because it goes beyond rationing to address the fundamental scarcity problem for transmission, its implementation requires careful planning and coordination. Transmission providers must accurately forecast costs and capacity needs, design equitable cost allocation mechanisms, and ensure that the entry fee aligns with the beneficiary-pays principle. The transmission planning process is a future cast assessment of needs for resources and load, and to find solutions that cost-effectively address them. Mechanisms must also be in place to address potential cost overruns or revenue shortfalls, ensuring that the model remains financially sustainable.

Customer Purchase Commitment: Another pivotal turn in the rationing approaches involves formalizing priority around projects with demonstrated customer purchase commitment. This approach recognizes that projects selected through open, all-source competitive procurements are more likely to deploy. In California, CAISO’s IPE incorporates demonstrated commercial interest into its interconnection process, allowing it to prioritize the most viable and needed projects.⁵² As part of a weighted scoring system, a project’s potential is evaluated based on customer commitments, such as expressions of interest from Load-Serving Entities (LSEs)

50 Grid Strategies and the Brattle Group, *Unlocking America’s Energy: How to Efficiently Connect New Generation to the Grid*, August 2024.

51 FERC, *Order on Tariff Revisions*, 188 FERC ¶ 61,225, September 2024.

52 Energy Bar Association (EBA), *EBA Brief: Fall 2025*, Vol. 6, Issue 1, Fall 2025.

or affidavits from non-LSE commercial customers. In this model, projects that receive higher scores due to this customer commitment and other scoring criteria advance through the IPE's redesigned queue process, in which project feasibility is determined by CAISO. This construct rations limited transmission capacity by prioritizing resources that are expected to have a higher likelihood of succeeding and are directly aligned with state resource planning and reliability goals. However, this method requires careful implementation to maintain fairness and uphold open access principles. Additionally, safeguards should be in place to ensure that merchant projects or innovative technologies, which may not initially secure contracts, are not unfairly excluded from the interconnection process.

Load-based Rationing: The concept of allocating scarce transmission headroom to proposed projects that deliver the highest value to the customer and system is gaining traction as a market-driven approach to interconnection queue reform.^{53,54} Under this framework, interconnection rights are increasingly awarded through competitive processes that link resource allocation to the needs of end-use customers and their LSEs. Projects compete based on transparent, predefined criteria and scoring mechanisms, with priority often given to those that demonstrate the greatest customer and system value. Allocating interconnection rights through market mechanisms, such as auctions or network open seasons, that are based on the customers' willingness to pay for scarce capacity, remain a subject of ongoing discussion but limited implementation. This transparent process, guided by clear criteria, aims to minimize the risk of self-dealing by utilities and promote open access.

By prioritizing projects that offer the most value, this approach ensures that limited interconnection capacity is used efficiently. It fosters robust competition among interconnection customers, which can drive down costs and improve project quality, while also reducing the incentive for speculative filings that can cause interconnection backlogs. Moreover, by integrating interconnection decisions with resource planning, this method ensures that new generation aligns with the grid's long-term needs, ultimately improving reliability. Several regions are implementing or exploring variations of this approach. Colorado, for example, has established a competitive resource acquisition process where winning bids can be awarded interconnection rights through a dedicated pathway, based on alignment with state resource plans and value to customers. Similarly, CAISO uses a scoring mechanism to allocate priority interconnection rights in areas with limited transmission. Under this system, LSEs can allocate "commercial interest points" to projects that demonstrate customer commitments, with consideration for overall project viability and system needs.

However, this promising approach is not without its tradeoffs and challenges. A reliance on market-based mechanisms could potentially favor larger entities, raising concerns, about market concentration and the disproportionate influence and control exerted by utility affiliates, creating an unfair advantage. For these reasons, new systems must be carefully designed with strong guardrails to protect open access principles and ensure a level playing field for all participants, from large-scale utilities to smaller, independent developers. The complexity

53 Energy Policy Research Group, Managing the Electricity Distribution Connection Queue in Great Britain: Lessons from Auction Theory and a Potential Position Trading System, June 2025.

54 WindEurope, Grid Access Challenges for Wind Farms in Europe, June 2024.

of assessing grid reliability and establishing fair cost allocation among different stakeholders remains a persistent challenge that is only intensified by the need for these new processes.

The preceding pages have compared a spectrum of rationing approaches, including subscription windows, queue caps, entry-fee models, customer commitment, and load-contract priority. No single strategy is a panacea to address the challenges of interconnecting significant new generation in the face of scarce engineering and transmission capacity; each presents trade-offs that must be weighed in light of regional circumstances and open-access principles. In economic terms, “beneficial” rationing uses objective, technology-neutral criteria to select projects that maximize reliability and consumer benefit, and “harmful” rationing relies on subjective discretion or opaque criteria that favor incumbents or particular technologies. Open seasons with binding commitments, readiness-based clustering, and competitive solicitations fall in the first category when designed transparently, whereas ad-hoc emergency fast tracks for favored technologies fall in the latter. Nonetheless, it is more productive to view various rationing approaches as components of a broader strategy, each contributing to the overall goal of improving standard interconnection processes. Viewed in this light, mechanisms like entry-fee models or queue caps are building blocks within a larger framework. Importantly, these rationing approaches should complement—not displace—the ongoing structural queue reforms.

Some regions have changed long-standing market rules to prioritize certain types of generators over others in the interconnection process. Unfortunately, this appears to be a temporary fix at best and, at worst, could result in lasting damage to business confidence in the integrity of market rules and discourage future private investment. To see how these mechanisms play out on the ground, the next section analyzes how four regional grid operators, PJM, MISO, SPP, and CAISO, have developed and implemented various rationing strategies within their unique regulatory and market environments.

SIX REGIONAL QUEUE RATIONING APPROACHES

This section provides an in-depth analysis of four recently implemented interconnection queue management reforms: PJM’s RRI, MISO’s ERAS, SPP’s ERAS, and CAISO’s IPE. It examines the current state of interconnection queues in the four regions and evaluates early evidence on effectiveness, fairness, and trade-offs of the adopted reforms.

6.1 PJM

For decades, PJM managed interconnection requests through a serial “first-come, first-served” queue and “participant funding” paradigm in which network upgrade costs were assigned to interconnection customers. This policy provided for network upgrades that were not needed “but for” the interconnection customers and were therefore assigned to those customers. Although workable in the early years, this framework became untenable as applications surged, driven by state policies and shifting market dynamics. Beginning in 2018, PJM experienced an unprecedented escalation in interconnection requests, with volumes climbing 25% in 2018, 50% in 2019, and ultimately more than doubling by 2020. By 2021, the number of requests had nearly tripled, overwhelming PJM’s administrative capacity and triggering widespread delays; 99% of PJM’s facilities studies (the last study phase preceding a GIA) were completed late. By late 2022, PJM’s queue had grown to more than 2,000 projects totaling over 200 GW of proposed capacity. Renewable energy projects accounted for over 95% of PJM’s queue and average study timelines extended to nearly four years.⁵⁵ The bottleneck constrained market growth and posed growing risks to PJM’s long-term reliability planning.

Recognizing the scale of the problem, PJM and stakeholders developed a comprehensive queue reform to replace the serial process with a “first-ready, first-served” cluster study process, which FERC approved in November 2022.⁵⁶ The new process replaced individual project evaluations with collective studies conducted in synchronized three-phase cluster cycles. This structure introduced key reforms, including grouping projects for simultaneous analysis, establishing

55 PJM, Tariff Revisions for Interconnection Process Reform, filed June 14, 2022.

56 FERC, Order Accepting Tariff Revisions Subject to Condition, 181 FERC ¶ 61,162, November 2022.

structured Decision Points tied to incremental financial readiness deposits, and requiring demonstrable project maturity at earlier stages. These measures were designed to filter out non-viable applications, reduce cascading delays from late-stage withdrawals, and provide developers with more predictable study timelines.

To manage the substantial backlog, PJM adopted a phased approach, comprising an Expedited Process for projects requiring minimal system upgrades, Transition Cycle 1 (TC1) for projects submitted between April 2018 and September 2020, and Transition Cycle 2 (TC2) for those submitted between October 2020 and September 2021. New interconnection requests submitted after the transition period will enter the fully restructured Cycle Process, expected to begin in spring 2026. Moreover, PJM instituted a two-year new-request moratorium from 2021 to 2023 to clear the backlog and launched the transition to the reformed process in July 2023. Since resuming processing, PJM has processed nearly 140 GW of interconnection projects, including 26 GW through a Fast Track process for backlogged requests with upgrades costing less than \$5 million. Through these efforts, PJM reduced its interconnection queue to approximately 63 GW, which PJM expects to process by 2026.⁵⁷

The critical junction remains where network upgrade costs are revealed, causing the steepest project exodus. For instance, the biggest drop historically occurs immediately after the System Impact Study is completed, with projects that agree to absorb the costs and move to the Facilities Study stage having a high probability of signing an interconnection agreement. Energy storage projects, in particular, have shown high withdrawal rates in TC1, as tightening economics and upgrade costs rendered many economically unfeasible. Since PJM began its transition process in 2022, PJM has executed roughly 46 GW of interconnection agreements, but only about 20% of the projects are in service; the majority remain in procurement or construction stages, and some have withdrawn notwithstanding their executed agreements.⁵⁸

PJM's RRI: Despite PJM's interconnection reforms, network upgrade costs and long lead times continue to hinder many projects. The new process still requires several years from application to agreement. With load forecasts rising sharply, especially from data centers in the PJM region, PJM's own planning analysis suggested a 10 GW to 20 GW capacity shortfall by the 2030/31 delivery year. Faced with this projected shortfall, PJM proposed RRI in December 2024 as a one-time, fast-track program to expedite the interconnection of up to 50 projects capable of providing significant near-term capacity by adding them to TC2, alongside projects that had been waiting in the queue since the 2020-21 period. FERC accepted PJM's RRI proposal in February 2025, concluding that the program was narrowly tailored to address urgent reliability risks.⁵⁹ Under RRI, projects applied during a one-time application window, and PJM studied them as part of TC2, including them within the cluster's cost allocation framework. In so doing, original projects in TC2 are subject to additional upgrades introduced by the RRI project additions. While RRI projects do not receive a separate queue position, they are expected to be processed nearly 18 months faster than if they had been instead added to Cycle 1 of PJM's

⁵⁷ PJM Interconnection, Generation Interconnection fact sheet, June 2025, <https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/interconnection-reform-progress-fact-sheet.pdf>.

⁵⁸ Id.

⁵⁹ RRI Order.

reformed Cycle Process.⁶⁰

Eligible projects must provide at least 10 MW of unforced capacity (UCAP) and commit to participating in PJM’s capacity market for 10 consecutive delivery years. Selection is based on a 100-point scoring rubric. The process places 65 points on a project’s contribution to resource adequacy, its UCAP, effective load-carrying capability (ELCC), and locational value. The remaining 35 points are based on commercial operation date viability, including planned in-service date, project support, uprates, and headroom. FERC agreed with PJM that combining UCAP and ELCC captures both capacity magnitude and availability and is a just and reasonable way to prioritize resources. Applicants must post a readiness deposit of \$4,000 per MW, which is forfeited if the project withdraws.

During the stakeholder process and before FERC, opponents argued that RRI would undermine the structural reforms already approved in 2022 to address interconnection delays and improve queue processing.⁶¹ They contended that these reforms, including the Transition Cycles and Surplus Interconnection Service, should be given sufficient time to work before introducing new measures like RRI. They emphasized that these existing reforms, combined with other viable solutions, have the potential to address PJM’s reliability concerns without the negative impacts of “queue jumping,” increased costs, and market distortion that could be caused by RRI. They urged FERC to allow these structural reforms to demonstrate their effectiveness rather than quickly implementing PJM’s proposal.

Critics further contended that the RRI’s design undermines the competitive market signals that are intended to incentivize efficient new entry. They reasoned that weighing UCAP and ELCC would favor thermal resources over renewable energy resources and structurally disadvantage wind, solar, and standalone battery projects.⁶² Stakeholders further objected to the 10-year capacity market participation requirement, which they see as incompatible with the financing model widely used by many independent power producers (IPPs). By prioritizing certain resource types, particularly large thermal projects at the expense of renewable energy projects, RRI would distort the capacity market and its ability to deliver least-cost, reliable energy solutions.

The protests emphasized that TC2 projects have been in the queue for years, adhering to the rules and requirements set forth in PJM’s Tariff. These projects have made significant investments in securing site control, providing readiness deposits, and meeting PJM requirements based on the understanding that the TC2 cluster would be limited to projects that entered the queue between October 1, 2020, and September 30, 2021. By retroactively allowing RRI projects to enter TC2, PJM effectively changed the rules midstream. Adding RRI projects to TC2 would disrupt these settled expectations and impose new, unforeseen costs. Because the RRI and TC2 projects are studied together in the same cluster, the addition of new, large RRI projects could increase the overall cost of necessary network upgrades for existing TC2 projects. The RRI projects would compete for the same limited system headroom, potentially triggering larger and more expensive network upgrades that would be shared among all projects in the cluster, a risk

60 PJM, Tariff Revisions for Reliability Resource Initiative, Docket Nos. ER25-1674-000 and ER25-712-000, December 2024.

61 Clean Energy Associations, Protest, Docket No. ER25-712-000, January 8, 2025.

62 Sierra Club and Appalachian Voices, Protest, Docket No. ER25-712-000, January 2025.

that could threaten the viability of those projects with tight financial margins.

Notably, PJM did not propose a mechanism to hold TC2 projects harmless from the additional costs caused by the inclusion of RRI projects. This concern is reinforced by the high project withdrawal rate in TC1, where many projects were canceled due to higher-than-anticipated network upgrade costs. RRI could lead to a similar or worse outcome in TC2. Some stakeholders were skeptical that PJM could handle the additional work without delaying the study process, further prolonging the wait times for existing TC2 projects. Given that RRI lacks essential safeguards to prevent expedited requests from causing cost shifts, delays, or other negative impacts on existing interconnection customers, they concluded RRI is incompatible with open access principles, which are designed to ensure fair and non-discriminatory access to the transmission system for all generators.

This unpredictability could make it difficult to secure financing and maintain commercial arrangements, potentially leading to more project withdrawals and further exacerbating the grid's resource adequacy problems. FERC acknowledged these concerns but found PJM's program justified by the near-term reliability gap and noted that RRI's one-time nature, deposit requirements, and integration into the cluster study should mitigate potential harms to other projects. Commissioner Chang, in her dissent, criticized the prioritization of large projects over speed as "poorly designed" and warned it could compromise the entire process.

PJM opened a single RRI application window in February 2025 and received 94 applications. In March 2025, PJM selected 51 projects totaling 9.31 GW of new construction and 2.49 GW of upgrades. The portfolio is dominated by natural gas combined-cycle plants, supplemented by 2.28 GW of battery storage, 1.39 GW of nuclear (new builds and uprates), smaller combustion turbine uprates, and a single coal uprate. Notably, none of the 51 selected projects is new wind or solar, reinforcing concerns that RRI sidelines renewable generation projects.⁶³

In October 2025, PJM released the Phase 1 System Impact Study for TC2 including about 50 RRI projects.⁶⁴ PJM aims to execute final interconnection agreements with these projects by late 2026 and expects them to come online by 2030 and 2031. However, the study reveals substantial challenges—high interconnection costs and lengthy transmission upgrade construction timelines—that threaten the ability of these projects to meet their target commercial operation dates. Because firm commercial operation date commitments were not required as part of RRI eligibility, there is no guarantee that expedited projects will deliver capacity when needed. If even a few of the expedited natural gas plants fail to reach commercial operation, PJM risks controversy and potential disruption to TC2 for limited reliability gain.

In particular, the RRI portfolio faces an estimated \$3 billion in upgrade costs, with less than 500 MW of the approximately 11 GW of Installed Capacity (ICAP) avoiding cost allocation. Nine projects, totaling about 6.6 GW ICAP, have interconnection cost allocations of around \$90 million or more each, with some projects facing costs as high as \$1.3 billion. These financial burdens raise concerns about the feasibility of certain projects. In addition, project withdrawals

63 PJM, Generation Interconnection fact sheet, June 2025.

64 PJM, Transition Cycle 2, See at https://www.pjm.com/pjmfiles/pub/planning/project-queues/Cluster-Reports/TC2/TC2_PH1_Executive_Summary.htm#exec-sum-cost-summary.

from the interconnection queue could further increase costs for remaining projects if upgrades are still deemed necessary.⁶⁵

Looking ahead, PJM plans to rely on its improved cluster process and better regional transmission planning to manage new generation, rather than more queue rationing mechanisms. PJM anticipates reducing interconnection study timelines to less than two years, with efforts underway to further accelerate the process. While the RRI project selection was based on objective criteria, the scoring metrics favored a final portfolio dominated by natural gas plants. The financial burden, including a 10-year commitment to PJM's capacity market, also created headwinds for certain project types with different financing structures. How these trade-offs are ultimately assessed will depend on whether those fast-tracked capacities come online in time to help put downward pressure on capacity prices and strengthen resource adequacy. Any delays will erode the program's value, and substantial upgrades could make expedited projects infeasible. In any case, RRI will not fully solve PJM's reliability issues. PJM's own analysis shows significant new capacity will be needed each year beyond 2030. RRI may have only reshuffled select projects to the front without resolving the structural challenges. If PJM seeks further queue-jumping methods to bring specific resources online more quickly, it may continue to undermine the integrity of the standard interconnection queue.

6.2 MISO

MISO's generator interconnection queue contains more than 1,100 active projects representing roughly 215 GW of capacity.⁶⁶ The pipeline is concentrated in solar and hybrid storage projects in the South and Upper Midwest. MISO's core process is the three-phase clustered Definitive Planning Phase (DPP) studies. Phase 1 (DPP1) provides preliminary feasibility; Phase 2 assesses system impacts and network upgrades; and Phase 3 finalizes upgrade requirements and leads to an executed interconnection agreement. To advance through each phase, interconnection customers must post increasing security deposits and demonstrate readiness. Despite these measures, attrition remains substantial.⁶⁷ Historically, only about 46% of projects entering DPP1 ultimately executed an interconnection agreement, and of those executed since 2020, a modest share is in service, while many remain in procurement or construction. Attrition spikes after upgrade costs are revealed: about 25% withdraw after Phase 2 and another 27% after Phase 3, producing churn of up to 70% in some cycles.⁶⁸

Queue processing times significantly lag behind MISO's tariff requirements. While the MISO tariff outlines a total processing time of 373 days, actual processing times have reached over 1,500 days. Interconnection agreements executed in 2024 originated largely from the 2019 DPP cycle. Over 20 GW of projects exited MISO's queue before starting the study process, primarily due to delays in initiating cluster studies. In parallel, MISO is investing in automation, through the SUGAR tool, to improve modeling and reduce cycle times to about one year by 2028. To suppress speculative filings, MISO paused its 2024 intake and introduced a queue cap that

⁶⁵ Id.

⁶⁶ MISO, Long Term Resource Adequacy & Interconnection Queue Update, System Planning Committee of the Board of Directors, September 16, 2025.

⁶⁷ MISO, Open Access Transmission, Energy and Operating Reserve Markets Tariff, Attachment X—Generator Interconnection Procedures (GIP), August 2025.

⁶⁸ Wood Mackenzie, Measuring the Progress of US Grid Interconnection: 2025 Market Update, August 2025.

limits annual interconnection requests to 50% of each planning region's non-coincident peak load, which is 77.8 GW for the 2025 cycle.⁶⁹ The overall cap and four of the five regional caps were hit for the 2025 cycle with overflow requests placed in the 2026 cycle.⁷⁰ These measures, combined with higher deposits and site control requirements, are intended to right-size intake and gradually align processing times with tariff expectations.

MISO's ERAS: Despite these reforms, MISO asserted that it faces near-term resource adequacy challenges. Industrial expansion, data center demand, and electrification are driving rapid load growth in the region, while retirements of aging coal and natural gas units reduce reserve margins. In response to concerns from state regulators that MISO's standard interconnection process could not deliver new capacity in time to meet expected shortfalls, MISO proposed ERAS in March 2025.⁷¹ FERC initially rejected the filing, but a revised proposal was approved in July 2025.⁷²

MISO's ERAS is strictly bounded in time and volume, including a hard cap of 68 projects, a firm sunset no later than August 31, 2027, objective eligibility and selection criteria, and explicit integration of ERAS outcomes back into the standard planning baseline. Application windows open quarterly, with no more than 10 projects admitted per window⁷³ until the 68-project cap is reached. Projects are scored based on interconnection capacity, alignment with verified resource adequacy needs, location in resource-deficient zones, and commercial readiness. Eligible projects must seek NRIS, demonstrate at least 75% deliverability, show at least 80% site control, provide a non-refundable deposit of \$100,000 plus a \$24,000 per MW milestone payment, and agree to fund 100% of identified network upgrade costs even if the project later withdraws from the program. A mandatory commercial operation date of June 1, 2030, is intended to ensure that the program effectively addresses late-decade reliability needs. Applicants to MISO's ERAS must submit verification from the relevant state regulator or other resource adequacy authority (called a RERRA) certifying a local capacity shortfall and confirming that the proposed project addresses that need. A transmission-owning municipality or cooperative provides similar verification.

Interconnection customers must withdraw any overlapping DPP position upon acceptance into ERAS. To mitigate cost shifts, MISO commits to roll ERAS-driven network upgrades into subsequent DPP base cases so later clusters study against models that reflect those changes. Upgrade cost allocation follows pro forma principles: ERAS projects pay their way, while any broader cost sharing for multi-value facilities is handled through established processes. Studies are targeted for completion in roughly three months, followed by expedited interconnection agreements. Projects are limited in size relative to the certified resource adequacy or reliability need (no more than 150% of the need).

69 MISO, Revisions to the Open Access Transmission, Energy and Operating Reserve Tariff—Queue Cap Proposal and Exemptions to the Queue Cap Proposal, Docket No. ER25-507-000, November 2024.

70 MISO, Queue Cap Tracker and ERAS Process Overview, October 2025.

71 MISO, "Revisions to the Open Access Transmission, Energy and Operating Reserve Tariff Expedited Resource Addition Study Filing," Docket No. ER25-1674-000 (March 17, 2025) and Docket No. ER25-2454-000 (June 6, 2025).

72 MISO's ERAS Order.

73 On September 26, 2025, MISO submitted a filing to FERC proposing to increase the number of ERAS projects studied per quarterly cycle from 10 to 15. The stated purpose is to accelerate the timeline for processing ERAS projects, reducing the number of study cycles required and enabling faster issuance of GIAs. MISO requested an effective date of November 26, 2025, to implement the changes ahead of the next ERAS quarterly study cycle, scheduled to begin on December 1, 2025.

MISO's ERAS integrates both state commission and municipal/cooperative utility authorization directly into the interconnection process. Significantly, MISO acknowledges that retail-choice states, such as Illinois and Michigan, need tailored procedures to participate. The program reserves some slots for IPPs and retail-choice providers but otherwise allows any resource type to apply. Within each quarterly window, MISO first reviews applications for completeness with a short cure period. If more than 10 valid applications are received, MISO ranks projects using a published rubric. The primary weighting is on accredited capacity and location relative to zones with identified shortfalls, while secondary factors include the credibility of the proposed commercial operation date and maturity of permits and procurement. Oversubscribed windows are resolved by rankings rather than filing time.

MISO's ERAS has drawn strong criticism, particularly regarding the absence of clearly defined, technology-neutral criteria for project evaluation. During the stakeholder process and before FERC, critics argued that without transparent and standardized criteria, similarly situated resources may not be treated equitably, potentially violating open-access principles. IPPs argued that requiring a RERRA certification, high security postings, and aggressive commercial operation date favors vertically integrated utilities and thermal projects.⁷⁴ Unlike the CAISO approach to load-based rationing identified in the earlier discussion, ERAS has no requirement for a RERRA to use a competitive process. IPPs also argued that ERAS would undermine open-access principles by creating a special queue for a few privileged projects and noted that MISO already had provisional interconnection tools that could accelerate some resources without a new construct. Critics further argued that MISO should allow recent structural reforms, such as automation tools like SUGAR, to take effect and address interconnection queue inefficiencies before introducing ERAS. They believe these reforms have the potential to significantly reduce delays and streamline the process, and rushing to implement ERAS risks undermining these improvements, creating additional complexity, and harming projects already in the queue. Additional concerns include the limit on nameplate capacity of a project to 150% of the identified capacity need, which implies a 66.6% ELCC threshold, potentially disadvantaging intermittent renewable resources.⁷⁵

According to opponents, ERAS projects could consume scarce transmission headroom and trigger restudies in the regular queue to the extent that new combined uses of different models identify pertinent constraints in those restudies, raising costs or delays for other interconnection customers.⁷⁶ Notably, the ERAS study methodology excludes higher-queued projects without interconnection agreements, which may underestimate reliability impacts and cost shifts to other customers. Some also raised concern that state nominations may be politicized, and regulators might prioritize projects aligned with local economic goals even when other technologies could meet the need more economically or quickly. MISO, for its part, countered that ERAS formalizes what might otherwise occur through ad hoc emergency filings and would provide a transparent, state-driven mechanism for triaging urgent needs while broader queue and transmission reforms mature.

74 Independent Power Producers, Protest, Docket No. ER25-1674-000, June 2025.

75 Clean Energy Associations, Protest, Docket No. ER25-2454-000, June 2025.

76 Public Interest Organizations, Protest, Attachment A (Testimony of Houtan Moaveni), Docket No. ER25-1674-000, April 2025.

In August 2025, the first MISO ERAS application window attracted 49 projects representing about 27 GW of nameplate capacity.⁷⁷ Seventy-four percent of the applications were for natural gas-fired units, 15% for solar, 4% for wind, 4% for storage, and 3% for nuclear. After withdrawals, 47 applications remained, from which MISO selected ten projects for Cycle 1 studies: five natural gas plants, three solar projects, one wind facility, and one battery storage project, totaling 5.3 GW of capacity, with natural gas plants accounting for roughly 3.8 GW.⁷⁸ The early portfolio illustrates how ERAS's emphasis on deliverability favors thermal resources, though the inclusion of four renewable energy projects shows that non-thermal resources are not excluded by design. Of six large natural gas projects submitted in Louisiana and Texas, totaling nearly 7 GW, only a 1,640 MW Louisiana facility advanced into Cycle 1, underscoring how certified-need scoring and geographic transmission constraints narrowed participation. The ten Cycle 1 projects target in-service dates between January 2027 and August 2028, consistent with the late-decade reliability horizon.⁷⁹ The remaining 37 eligible applications may be considered in future quarterly windows, subject to program limits.

In October 2025, MISO posted the first-round ERAS study models and results. As discussed above, each ERAS project is modeled individually rather than as part of a cluster, and only resources with signed GIAs are included. The models also reflect major system changes that were not present in earlier DPP studies, including Long Range Transmission Planning (LRTP) Tranche 2.1 transmission projects, Expedited Project Review (EPR) upgrades associated with large customers, and significantly higher load assumptions. In this configuration, none of the Cycle 1 ERAS projects triggered incremental network upgrade costs, in sharp contrast to recent DPP clusters that have produced upgrade estimates in the billions. This analysis underscores how heavily ERAS outcomes depend on which upgrades and loads are included in the base case.

The long-term effectiveness of ERAS remains uncertain. Its critics continue to express concern that ERAS could consume scarce transmission headroom, trigger restudies, and delay standard queue projects, even with MISO's attempts to integrate ERAS upgrades into subsequent studies. Its effectiveness, therefore, will depend on consistent application of rules across quarterly windows, balanced technology selection, timely completion of studies and agreements, and careful integration of upgrades into the standard queue. More broadly, MISO views ERAS as a temporary bridge while automation of the standard queue matures. The SUGAR platform is expected to reduce cycle times to about one year by 2028, but credibility and reproducibility of results will be as important as speed.

6.3 SPP

SPP serves 14 states in the central United States and has been a pioneer in using cluster studies since adopting the Definitive Interconnection System Impact Study (DISIS) process in 2009. Under DISIS, SPP groups projects into clusters with milestone-based decision points: 50% site

⁷⁷ MISO, News Release:

<https://www.misoenergy.org/meet-miso/media-center/2025---news-releases/expedited-resource-addition-study-attracts-large-diverse-applicant-pool/>

⁷⁸ MISO, ERAS Cycle 1: <https://cdn.misoenergy.org/ERAS%20Cycle%201717096.pdf?v=20250904134938>.

⁷⁹ MISO, Long Term Resource Adequacy & Interconnection Queue Update, System Planning Committee of the Board of Directors, September 16, 2025.

control and roughly 9% of estimated upgrade costs after Phase 1, and 100% site control with approximately 20% security after Phase 2.⁸⁰

In 2022, SPP launched an aggressive backlog-clearing plan. In 2024, SPP sought and received a FERC waiver to defer the start of the 2024 DISIS cluster study and to delay the opening of the 2025 DISIS cluster window, citing limited staff resources and the need to complete restudies of earlier clusters with more realistic assumptions. By September 2025, the RTO had completed 24 cluster studies, evaluated more than 1,600 projects, and analyzed roughly 340 GW of generation — about six times its peak load, and signed 190 new interconnection agreements.⁸¹ More than 30 GW of new generation had executed interconnection agreements, and SPP expects another 20 GW to sign within the next year. Despite the progress, over 110 GW remain active in SPP’s interconnection queue, and load forecasts indicate rising demand from data centers, industrial expansion, and electrification in the region.

SPP’s backlog reflects not only the volume of interconnection requests but also years of relatively conservative transmission planning and heavy congestion in high-resource zones. In particular, western Kansas, the Oklahoma Panhandle, and neighboring zones remain heavily congested, and available transmission headroom has often been so limited that most new projects have triggered large, costly upgrades that few interconnection customers could accept. Historically, fewer than 15% of projects entering a DISIS cycle ultimately reach commercial operation, largely because many projects withdraw when costly, long-lead transmission upgrades are revealed.⁸² Even projects that sign interconnection agreements often later suspend or cancel due to financing, permitting, or excessive upgrade obligations.⁸³

Recognizing that individual project upgrades cannot sustainably address the growing system needs, SPP is pursuing both near-term and long-term reforms. CPP represents SPP’s long-term structural solution to interconnection congestion. Rather than relying on cycle upgrades triggered by clustered projects, CPP merges generator interconnection, long-term transmission planning, and reliability forecasting into a single proactive 20-year framework. Each CPP cycle spans three years and consists of one forward-looking 20-year study (CPP-20) followed by two 10-year studies (CPP-10). Within this structure, SPP will evaluate network needs in a unified portfolio, optimizing upgrades to maximize regional benefits and reducing redundant studies. A key feature of CPP is the introduction of an entry-fee financing construct, which establishes a uniform, per-MW payment from interconnection customers to help fund regionally beneficial upgrades upfront. This investment-based model will enable SPP to coordinate resource interconnection with anticipated load growth, policy targets, and economic development, avoiding the fragmented and reactive processes that have historically delayed grid expansion.

The technical foundation of CPP follows an ERIS versus NRIS service-selection framework. Under this approach, generation developers choose between ERIS with operational flexibility or NRIS for full deliverability rights. These service selections inform the sizing, prioritization, and funding of necessary network upgrades and will ultimately drive the scope of SPP’s optimized

80 Generator Interconnection Department, Generator Interconnection Manual (DISIS Manual), Version 4.2, September 2025.

81 SPP News Release: <https://www.spp.org/news-list/southwest-power-pool-reaches-milestone-in-acceleration-of-generation-interconnection-requests/>

82 LBNL, Queued Up: 2025 Edition.

83 Wood Mackenzie, Measuring the Progress of US Grid Interconnection: 2025 Market Update, August 2025.

portfolio. CPP thus establishes a planning paradigm in which transmission is built ahead of demand and generation is integrated based on modeled system need rather than discrete cycle and project requirements. The full rollout will take time, leaving SPP with an immediate reliability challenge in the latter half of the decade.

SPP's ERAS: To address its concerns with near-term capacity risks while CPP is developed and operational, SPP proposed ERAS, a one-time fast-track process approved by FERC on July 21, 2025.⁸⁴ SPP's ERAS process allows only LREs, such as utilities, cooperatives, or other entities responsible for resource adequacy, to nominate projects for a special queue granted preferred status. Each LRE is required to commit an ERAS project's accredited capacity to its resource adequacy obligation for at least five delivery years. Nomination rights are constrained by each LRE's accredited capacity shortfall, determined by the LRE's projection of resources needed to meet the planning reserve margin by 2030.

SPP proposed an estimated study timeline of 270 days, and the program will conclude no later than December 31, 2028, though it may terminate earlier if the project limit is reached and all agreements are executed. Moreover, ERAS participants must post financial security equal to \$8,000 per MW of the requested maximum injection capability of the proposed generating facility as a requirement for entering the ERAS process. These funds are forfeitable upon withdrawal to the extent that the withdrawal increases network upgrade costs for other ERAS interconnection requests. This requirement is intended to deter speculative participation and protect other customers from cost exposure risk.

Stakeholder reactions to SPP's ERAS mirror debates with PJM's RRI and MISO's ERAS.⁸⁵ Utilities, LREs, and several state commissions strongly supported the proposal as a pragmatic, one-time bridge to avoid capacity shortfalls during the 2027–2028 period. In contrast, IPPs⁸⁶ criticized the program as “queue-jumping” that may favor LRE-sponsored plants and consume scarce transmission headroom at the expense of other interconnection customers and projects. Because ERAS projects would be studied in a separate, one-time cluster, largely in parallel with but omitting most DISIS-modeled generation, they could obtain earlier queue positions and reserve scarce headroom without being subjected to the full stability, deliverability, and upgrade analyses that apply in DISIS. Opponents warned that this asymmetry would allow ERAS projects to consume transmission capacity that DISIS customers reasonably expected to rely on, while preventing either track from fully accounting for cumulative system impacts and deferring many ERAS-driven reliability and congestion impacts to future ITP cycles where costs are largely socialized to regional load. With no reconciliation or true-up mechanism to assign those later upgrades back to triggering ERAS projects, critics viewed the proposal as double-counting headroom, shifting risk and cost onto other interconnection customers and ratepayers, and undermining basic open-access and cost-causation principles.⁸⁷

Critics further raised concerns about the ERAS framework's implicit 80% ELCC requirement, which stems from its rule that nameplate capacity additions can only exceed the projected

⁸⁴ SPP's ERAS Order

⁸⁵ Id.

⁸⁶ Independent Power Producers, Protest, Docket No. ER25-2296-000, June 2025.

⁸⁷ Public Interest Organizations, Attachment A (Testimony of Houtan Moaveni), Docket No. ER25-2296-000, June 2025.

shortfall by 25%.⁸⁸ They reasoned this places renewable resources at a structural disadvantage, and argued that SPP should prioritize the completion and implementation of structural reforms like CPP over the adoption of ERAS. This approach would allow SPP to address its resource adequacy challenges in a manner that aligns with principles of fairness, transparency, and long-term planning. They also raised concerns that ERAS could divert resources and staff time away from these critical reforms, introduce risks like cost-shifting, preferential treatment for certain projects, and reliability issues, ultimately exacerbating existing challenges and delaying sustainable progress.

The absence of clear, objective criteria for project selection and the lack of oversight from SPP or state regulators further exacerbate concerns about fairness and accountability. SPP, for its part, emphasized that any project, including independently developed wind, solar, or hybrid resources, may participate if nominated by an LRE, and it expects several non-utility nominations where independent projects align with documented capacity needs. However, critics asserted that each LRE can potentially choose to engage in discriminatory practices against particular resource types as it sees fit, with no oversight. SPP committed to quarterly public progress reports via a dashboard disclosing each accepted project's nominating LRE, zone, need, upgrade costs, security postings, target commercial operation date, and any forfeitures.

The ERAS submission window opened September 2, 2025, and closed October 2, 2025. The ERAS cluster is comprised of 36 projects totaling about 13.3 GW of new capacity. The portfolio is dominated by roughly 9.6 GW of thermal resources, followed by 1.7 GW of hybrid resources, 833 MW of battery storage, 639 MW of solar, and 500 MW of wind.⁸⁹ The ERAS cluster study is currently underway, and SPP expects to issue GIAs in May 2026. Under SPP's current schedule, ERAS projects will be studied ahead of the 2024 DISIS cluster, effectively giving them earlier claim on limited transmission headroom and potentially lower incremental upgrade costs than later-queued projects. Ultimately, the success of SPP's ERAS will be measured not only by how many projects reach commercial operation but also by whether it avoids collateral damage to the broader queue and whether LRE nominations reflect unbiased capacity needs rather than preferential resource selection.

6.4 CAISO

In 2023, CAISO's interconnection queue exceeded several times California's projected need for the 2030 energy portfolio. The scale of the problem became acute in Cluster 15, when CAISO received a record 541 interconnection requests, totaling approximately 347 GW, roughly seven times California's peak load.⁹⁰ Facing a backlog of this magnitude, CAISO received FERC approval in August 2023 for IPE Track 1, which addressed immediate needs by prioritizing the completion of the Cluster 14 study and temporarily pausing Cluster 15. The pause allowed CAISO to develop broader and more permanent reforms under IPE Track 2, which featured a permanent restructuring to align the interconnection process with transmission headroom,

88 Clean Energy Associations, Protest, Docket No. ER25-2296-000, June 2025.

89 SPP Interconnection Queue Dashboard, accessed November 2025.

90 CAISO, Tariff Amendment to Implement Track 2 of Interconnection Process Enhancements 2023 Initiative, August 2024.

procurement readiness, and state policy priorities.⁹¹

The foundation of CAISO's IPE is a zonal, deliverability-based cap on new interconnection study volume. Under IPE, CAISO divides the transmission system into planning zones and admits only up to 150% of the deliverable capacity reasonably available within each zone based on existing and approved transmission upgrades. Projects proposing to interconnect in zones where transmission is fully subscribed must either wait until additional capacity is planned and approved through the transmission planning process or pursue a merchant pathway by funding required network upgrades at their own expense. Within these zonal caps, CAISO applies a scoring system to determine which projects advance. Scores weight three factors: commercial interest, measured through point allocations from LSEs and affidavits from non-LSE off-takers; project viability, including site control, permitting progress, developer experience, and equipment procurement plans; and alignment with system needs as defined in the California Public Utility Commission (CPUC) and California Energy Commission (CEC) resource portfolios and local capacity requirements.⁹² Where scoring cannot break ties among similarly ranked projects, CAISO uses a sealed-bid auction as a last-resort tiebreaker, with payments refundable at commercial operation to deter speculative queue entries while ensuring only committed developers bid for priority.⁹³

Because transmission deliverability is central to capacity accreditation and resource adequacy in California, IPE also integrates CAISO's annual Transmission Plan Deliverability (TPD) allocation process into queue management. Each year, CAISO allocates limited TPD to eligible projects; those that fail to secure deliverability after three consecutive annual allocation rounds must withdraw under a three-strike rule. Projects that proceed without deliverability may interconnect on an energy-only basis, accepting curtailment risk and forgoing capacity revenue in exchange for earlier interconnection; roughly one-third of Cluster 15 projects elected this energy-only path, primarily solar and hybrid solar-battery systems. CAISO also allows developers to self-fund additional transmission upgrades to secure resource adequacy-eligible deliverability, but uptake remains minimal given high costs and limited reimbursement pathways. To reduce speculative filings and improve siting discipline, CAISO paired these reforms with new transparency measures. Publicly available hosting capacity tables, constraint maps, and heatmap visualizations now show where deliverability remains, and early scoping meetings introduced for Cluster 15 allowed developers to review interconnection constraints before committing significant deposits, helping redirect proposals to more viable locations.⁹⁴

The effects of IPE became clear in Cluster 15, the first test of the new framework. After resubmissions in the 2025 window, this was reduced to 255 projects and 118 GW of capacity, representing a 53% reduction in requests and a 66% reduction in capacity. Following scoring and ranking, 177 projects with 96 GW of capacity proceeded to validation, further reducing requests by 31% and capacity by 19%. Ultimately, 145 projects with 68 GW of capacity proceeded to studies, reflecting an overall reduction of 73% in requests and 80% in capacity. The projects moving forward are heavily weighted toward storage, reflecting both CPUC

91 CAISO's IPE Order.

92 CAISO, Memorandum of Understanding Between ISO, CPUC, and CEC, December 2022.

93 Id.

94 Id.

procurement signals and scoring advantages for commercially ready hybrid systems, alongside a significant tranche of utility-scale solar and a deliberately preserved slice of wind capacity supported by LSE portfolio-diversity targets.⁹⁵

Despite these sharper filters, interconnection timelines remain long. Initial study results indicate that no new interconnection agreements from Cluster 15 will be executed until 2027, implying spans of roughly four years from request to agreement even for the winnowed projects.⁹⁶ CAISO's effective success rate, projects entering the queue that advance to signed interconnection agreements, remains among the lowest nationally at approximately 20%, driven primarily by limited transmission headroom, complex permitting processes, and the persistent presence of speculative filings.⁹⁷ This underscores that while IPE has made significant strides in prioritizing viable projects, transmission expansion, not queue reform alone, remains the binding constraint on California's resource integration.

Recognizing these structural limits, CAISO launched its IPE 5.0 initiative in August 2025 to further refine its reformed process based on lessons learned from Cluster 15 and stakeholder feedback.⁹⁸ Among the top priorities under review is whether operational energy-only projects should be allowed to compete for deliverability allocations in future cycles, an approach strongly supported by key stakeholders to maximize utilization of existing built capacity without undermining the competitive scoring framework. Another focus is resolving persistent challenges associated with long lead-time deliverability network upgrades, where otherwise viable projects are assigned network buildouts stretching eight to ten years, locking up capacity and jeopardizing procurement timelines. CAISO has committed to coordinating more tightly with CAISO's Transmission Planning Process to align upgrade schedules with interconnection needs and avoid stranded project scenarios.

Stakeholders have also raised equity concerns regarding the commercial interest scoring system, which some argued advantages incumbents with long-standing LSE relationships and procurement pipelines.⁹⁹ Initial results from the Cluster 15 intake process indicated the reforms were effective in reducing project volume, with non-utility projects showing competitive participation in the scoring. While non-utility entities participated, CAISO is evaluating potential auditing and transparency mechanisms to ensure the LSE allocation process remains objective and accessible to independent developers. Additionally, CAISO is considering changes to better sequence interconnection agreement execution with TPD allocations so that projects are not required to execute interconnection agreements before knowing whether they can secure deliverability, addressing a significant source of developer risk.

CAISO's reforms are not without controversy. Projects in resource-rich but transmission-poor areas, such as high-quality wind or geothermal zones, face development delays until new transmission lines can be planned and approved. Smaller IPPs and merchant developers often struggle to compete in the scoring framework, which rewards power purchase agreements,

95 CAISO, Summary of Cluster 15 Intake Scoring Results, June 2025.

96 CAISO, Updated Resource Interconnection Standards Study Timeline for Cluster 15, August 2025.

97 Wood Mackenzie, Measuring the Progress of US Grid Interconnection: 2025 Market Update, August 2025.

98 CAISO, Interconnection Process Enhancements 5.0 Straw Proposal, August 2025.

99 ACP-California et al., Comments on Scoping Document: Initiative—Interconnection Process Enhancements 5.0, July 2025.

site control, and demonstrated experience that established players secure more easily. The sealed-bid auction mechanism introduces a willingness-to-pay element, though used sparingly and refundable in commercial operation. Because CAISO's zonal caps are based on currently approved transmission capacity, critics warn that the reforms risk dampening forward-looking market signals that would otherwise help justify earlier transmission investment in emerging resource areas. CAISO aims to mitigate these effects by maintaining close alignment between its interconnection process, CPUC procurement planning, and its transmission planning process, ensuring that suppressed interconnection interest feeds directly into long-range infrastructure development.

On balance, CAISO's IPE represents one of the most comprehensive queue reforms among system operators to date. By combining zonal deliverability caps, scoring-based prioritization, and transparent governance of deliverability allocations, CAISO has replaced an overloaded, speculative queue with a structured pipeline designed to integrate the resources most likely to be financed, built, and aligned with California's needs. Yet, Cluster 15 demonstrates that administrative reforms alone cannot overcome physical infrastructure limits: timelines remain long, the share of projects advancing remains low, and significant low-cost energy potential remains stranded behind constrained transmission corridors. The upcoming refinements under IPE 5.0, particularly around energy-only conversion, long lead-time upgrades, and equitable scoring oversight, will determine whether CAISO can transform this framework into a sustainable, scalable model for integrating the volumes of clean energy required to meet California's 2030 and 2045 goals.

6.5 Comparative Analysis of Regional Queue Rationing Approaches

When comparing interconnection reforms, it is important to consider each RTO/ISO's specific approach, market structure, and unique pressures shaped by geography, regulatory frameworks, state policies, and shifting demands on the grid. However, their queue rationing initiatives share a common motivation: the need to maintain reliability in the face of surging interconnection requests, rapid load growth, and resource retirements. Despite this shared context, these grid operators have adopted markedly different queue rationing philosophies, shaped by their unique regional circumstances.

While PJM, MISO, and SPP pursued temporary, reliability-driven triage measures to address immediate capacity shortages, CAISO fundamentally restructured its interconnection queue to permanently align with long-term policy goals. This core divergence in philosophy is the most significant point of comparison. RRI and ERAS programs are narrowly scoped, one-time or time-limited interventions intended as pressure valves in congested queues. Conversely, CAISO's IPE is a comprehensive, long-term fix that fundamentally re-engineered the process for every project going forward.

The selection mechanisms employed by the RTOs/ISOs highlight their different priorities. PJM used a scoring rubric that prioritized commercial readiness, deliverability, and the timely provision of UCAP. This approach effectively identified commercially viable projects capable of near-term delivery, but it was criticized for potentially favoring thermal resources and

discouraging resources whose financing structures may not have aligned with the criteria, particularly the 10-year capacity market commitment. MISO's ERAS, by contrast, relies on a first-come, first-served approach within each quarterly window, but only for projects certified by a state or local regulatory authority as necessary for resource adequacy. This cedes a degree of control to these regulators, whose assessments of need can also influence the type of resource prioritized. SPP's ERAS further delegates project selection, giving LREs the power to nominate a limited number of projects. This could, critics argue, favor incumbents and projects aligned with existing resource portfolios rather than least-cost solutions. In contrast, CAISO's IPE uses scoring criteria tied directly to policy objectives, like alignment with CPUC procurement portfolios and deliverability in specific zonal regions. By limiting study admission based on available transmission headroom, CAISO enforces a market discipline tied to long-term planning, rather than reacting to near-term shortages with a fast-track process.

Beyond selection, the comparative impact on open access principles and market fairness reveals significant trade-offs. The RRI and ERAS programs explicitly depart from strict queue order, allowing later-filed, "first-ready" projects to jump ahead of earlier ones. FERC's approval of these proposals, particularly PJM's RRI, established a precedent that this trade-off is acceptable when programs are narrowly tailored and based on objective criteria. However, this raises legitimate concerns among stakeholders that such "queue-jumping" undermines the integrity of the standard process, increases costs or delays for projects remaining in the regular queue, and could erode confidence among developers. The high financial requirements in MISO's and SPP's ERAS programs, including 100% network upgrade security, as well as non-refundable application fees and significant study/security deposits (and, in MISO, 100% NRIS and three-year commercial operation date timeline), also shift risk to developers and may favor larger, well-capitalized players. CAISO's IPE, on the other hand, avoids a separate priority queue but permanently embeds prioritization criteria into its core framework. By focusing on deliverability and policy alignment, it redirects market signals to better reflect system needs, though it also creates its own set of winners and losers based on those criteria.

Finally, a comparative look at speed and outcomes shows how each RTO/ISO's approach addresses its specific challenges. While RRI and the ERAS programs aim to accelerate a limited subset of projects, potentially bringing them online faster than the standard queue, they do not resolve the underlying systemic bottlenecks. CAISO's IPE, having been implemented earlier, has proven effective at reducing speculative requests and streamlining the process for viable projects by moving them through a more stringent initial screening.

SEVEN

OPTIMAL APPROACHES TO INTERCONNECTION QUEUE RATIONING

While a convergence of rapid load growth, record interconnection requests, and generator retirements has created near-term pressure, the reliance on one-off measures undermines the very structural reforms needed for a lasting and systemic fix. Recent ad hoc rationing efforts, such as PJM's RRI, MISO's ERAS, and SPP's ERAS, have exposed vulnerabilities stemming from discretion, opacity, and legal risk. These programs were developed quickly, with arguably inconsistent application and varying levels of transparency.

Queue rationing mechanisms like these should not become the default operating model or a substitute for comprehensive reforms. As a guiding principle, grid operators should exhaust all other alternatives that make the standard interconnection queue more effective before invoking new emergency rationings. To reconcile the growing need for speed with the foundational requirement of fairness, this report proposes a durable, two-path architecture for queue rationing. This approach, which draws on lessons from across the industry, would establish clear, codified pathways for projects while ensuring priority treatment remains a narrowly applied tool of last resort.

PATH 1 | The Enhanced Readiness Fast Lane

Unlike the ad hoc rationing efforts that have undermined systemic reforms, Path 1 is a strategic, codified tool of last resort. This fast lane provides a transparent, narrowly applied pathway for projects to address a verified, near-term reliability need. Rather than being a disruptive measure, it is a carefully calibrated valve, with activation based on objective, pre-published triggers, such as specified planning reserve margin (PRM) or loss of load expectation (LOLE) thresholds over a defined three-to-five-year horizon. Activation should also be preceded by a certification from a state regulator or LSE that a clear deficiency is expected within that horizon and that no existing queued project can feasibly meet the need, with the RTO/ISO independently verifying those findings against the PRM/LOLE thresholds.

Upon activation, the operator should publicly certify the magnitude of the deficiency. Eligibility for this expedited path should be strictly tied to the publicly identified grid need and restricted

to highly mature, ready-to-build projects. Applicants must provide secure site control, demonstrate major permits, and confirm a credible in-service date. Applicants must further commit to a deliverability floor (for example, at least 80% of accredited capacity). To deter speculative entry, applicants must post substantial, non-refundable deposits and adhere to a strict schedule of milestone payments. These financial safeguards should ensure only serious and capable developers participate, protecting the rest of the queue from the costs of stranded or withdrawn projects. Each invocation of the fast lane should feature a tariff-set application window of 30–45 days and an MW cap aligned with the verified deficiency.

If the application window is oversubscribed, a technology-neutral scoring rubric should rank projects based on readiness, accredited capacity, and timeline credibility. Tie-breakers, such as a lottery or sealed-bid additional security, should be used only when scores are statistically indistinguishable, with anonymized outcomes published for transparency. Independent scoring audits and public posting of results should be required for each invocation to prevent any perception of favoritism. Selected fast-lane projects should be fully integrated into existing cluster base cases; projects already in the queue must withdraw their original position to prevent double-counting, with any costs incurred by that withdrawal charged to the project. Where applicable, selected projects should commit to defined resource-adequacy or must-offer obligations. This fast lane should be automatically deactivated when the certified deficiency window closes, or sufficient accredited MW are on track to meet the need. To avoid creating a permanent parallel queue, the tariff should cap the number of projects or total capacity per invocation and set a defined program duration (e.g., two to three years).

PATH 2 | Proactive Integration with Transmission Planning

Path 2 is the embodiment of giving structural queue reforms time to work, but with enhanced guardrails. The baseline interconnection queue should be permanently restructured to be capacity-aware and proactively integrated with long-term transmission planning. This shifts the queue from a reactive process that simply accepts its limits to an active driver of grid expansion. Project intake should be capped by the grid's available and planned transmission headroom, with these caps announced transparently during each cluster cycle. If project demand exceeds these capacity caps, an objective, policy-aligned scoring system should determine which projects proceed. This system should prioritize projects based on commercial readiness, financial commitment, site control, and alignment with regional policy goals. Projects that are part of an approved resource plan or hold executed power purchase agreements should receive higher priority because they are more likely to reach completion and match system needs. Projects that score below the cutoff should not be rejected but should instead be deferred to a subsequent cluster or offered alternative arrangements, such as energy-only interconnection, thereby managing timelines rather than denying access.

Critically, interconnection studies should be performed against a forward-looking grid topology, anticipating planned upgrades and expanding headroom. Interconnection outcomes should feed upgrades into regional plans and future base cases; conversely, planning outcomes should pre-announce headroom and should adjust intake caps as that headroom materializes, creating a durable feedback loop. To provide developers with upfront cost certainty, a pooled, ex-ante

zonal fee should be implemented. The contribution level should be published ahead of the window, should fund a portfolio of pre-identified upgrades, and should be credited through tariffed mechanisms, fostering proactive investment.

Harmonizing the Two Paths for a Reliable Grid

The effectiveness of this framework lies in the strategic harmonization of its two paths. Data from each fast-lane invocation, including project locations, MW served, and upgrade needs, should feed directly into the next planning cycle and inform baseline intake caps. Conversely, planning outcomes should pre-announce the creation of new headroom, shaping baseline queue entry. Independent audits, public posting of all results, and sustained regulatory oversight should apply to both paths to ensure fairness and transparency. Over time, this predictability should reduce the need for emergency interventions like RRI and ERAS as capacity-aware entry and proactive investment keep the pipeline flowing. The fast lane should be explicitly designed as a temporary mechanism, phased out as proactive planning and transmission expansion create sufficient headroom. By adopting this two-path architecture, policymakers and grid operators can establish a rational and predictable interconnection process that manages scarcity with transparency and fairness, ultimately building a more resilient, reliable, and adaptable grid for decades to come.

CONCLUSION

The changing energy landscape necessitates accelerated yet fair and non-discriminatory interconnection processes, anchored in open-access principles. Interconnection queues have ballooned, transmission capacity remains constrained, and study timelines have lengthened, even as demand increases—threatening both reliability and affordability. These challenges are not merely procedural; they reflect deep structural imbalances in how the grid is planned, built, and accessed.

In response to these drivers and Order No. 2023, grid operators have begun to move away from the legacy “first-come, first-served” interconnection model, adopting a range of rationing mechanisms. Regional initiatives such as PJM’s RRI, MISO’s and SPP’s ERAS demonstrate that fast-tracking projects is possible. However, these programs also reveal the trade-offs inherent in queue rationing, particularly the risks of undermining open-access principles, favoring well-capitalized incumbents, and increasing uncertainty and additional costs for projects left in the standard queue. This highlights a crucial lesson that ad-hoc fixes can never be a substitute for fixing the regular queue itself. Such mechanisms should be used sparingly and only when structural reforms cannot meet urgent reliability needs. Notably, these grid operators have recently implemented significant structural reforms to their interconnection processes, and, if implemented successfully and given sufficient time to mature, may be enough to address near-term resource-adequacy needs while longer-lead transmission solutions scale.

This report proposes a balanced, two-tiered framework to reconcile the need for speed with the imperative of fairness, by prescribing exactly how to fix the standard interconnection process and manage scarcity strategically. These proposals consist of:

- ▶ An enhanced readiness fast lane for projects that address verified, near-term reliability needs, governed by transparent criteria and activated only under specific grid stress conditions; and
- ▶ A proactive, capacity-aware baseline queue integrated with long-term transmission planning, ensuring that project intake aligns with available and planned grid headroom.

Together, these paths offer a rational and predictable interconnection process that manages scarcity without compromising competition or transparency. Over time, as transmission expansion accelerates and process discipline improves, the need for emergency rationing

should diminish. The fast lane should remain a narrowly tailored, temporary tool, while the baseline queue evolves into a robust, forward-looking mechanism for integrating new resources. Ultimately, the success of interconnection reform should be measured not by the number of studies completed, but by the timely energization of shovel-ready projects that meet real system needs. By adopting best-in-class practices and harmonizing interconnection with transmission planning, grid operators and policymakers can unlock the bottlenecks that constrain progress and build a grid capable of supporting the nation's energy future.



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Grid Strategies LLC is a power sector consulting firm helping clients understand the opportunities and barriers to integrating clean energy into the electric grid. Drawing on extensive experience in state regulation, transmission planning, and wholesale markets, Grid Strategies analyzes and helps advance grid integration solutions.

Based in the Washington DC area, the firm is actively engaged with the Federal Energy Regulatory Commission, Department of Energy, state Public Utility Commissions, Regional Transmission Organizations, the North American Electric Reliability Corporation, Congressional committees, the administration, and various stakeholders.

